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PSEG
Services Corporation

April 15, 2024

In the Matter of the Petition of
Public Service Electric and Gas Company
for Approval of an Increase in Electric and Gas
Rates and for Changes in the Tariffs for
Electric and Gas Service, B.P.U.N.J. No. 17
Electric and B.P.U.N.J. No. 17 Gas,
and for Changes in Depreciation Rates,
Pursuant to *N.J.S.A.* 48:2-18,
N.J.S.A. 48:2-21 and *N.J.S.A.* 48:2-21.1, and
for Other Appropriate Relief

BPU Docket Nos. ER23120924 and GR23120925
OAL Docket No. PUC 00926-24

VIA BPU E-FILING SYSTEM & ELECTRONIC MAIL
Honorable Irene Jones
Office of Administrative Law
33 Washington Street, 7th Floor
Newark, NJ 07102
Irene.Jones@oal.nj.gov

Dear Judge Jones:

Enclosed for filing are the following documents that comprise Public Service Electric and Gas Company's ("PSE&G" or "Company") update to reflect nine months of actual data and three months of forecast data in its base rate case filing in the above proceeding ("9+3 Update"):[1]

Exhibit P-1 R-1	Schedule 1:	Proposed Tariff for Electric Service, Public Service Electric and Gas Company, B.P.U. N.J. No. 17 Electric
	Schedule 2:	Comparison of Present and Proposed Electric Rates, using redlined Schedule 1 and Guide to Tariff Changes
	Schedule 3:	Proposed Tariff for Gas Service, Public Service Electric and Gas Company, B.P.U. N.J. No. 17 Gas

[1] The Company's initial filing was based on a test year ending May 31, 2024, as adjusted for certain known and measurable post-test year adjustments and reflected five months of actual and seven months of forecast data for the test year.

	Schedule 4: Comparison of Present and Proposed Gas Rates, using redlined Schedule 3 and Guide to Tariff Changes Schedule 6: Tables included in public notice, as updated to reflect 9+3 Update
Exhibit P-2 R-1	Direct Testimony of Michael McFadden, Director, Sales and Revenue Forecasting, and supporting schedules
Exhibit P-3 R-1	Direct Panel Testimony of Michael Schmid, Vice President, Asset Management and Planning and Ricardo G. Fonseca, Senior Director, Utility Finance, and schedules 2(a), 2(b), 3, 4(b), 4(c), 4(d), 5(a), and 5(b)
Exhibit P-4 R-1	Direct Testimony of Clifford Pardo, Vice President – Tax PSEG Services Corporation, and supporting schedules
Exhibit P-8 R-1	Direct Testimony of Michael Adams, Concentric Energy Advisors, and supporting schedules
Exhibit P-9E R-1, Exhibit P-9G R-1	Direct Testimony of Stephen Swetz, Senior Director – Rate and Regulation, PSE&G, and supporting schedules
Exhibit P-10 R-1	Ahmad Faruqui, Principal Emeritus, The Brattle Group, and supporting schedules
Exhibit P-11 R-1	Direct Testimony of Karen Reif, Vice President Renewables & Energy Solutions, and supporting schedule
Exhibit P-12 R-1	Direct Testimony of David Johnson, Vice President Customer Care and Chief Customer Officer, and supporting schedule

These documents completely supersede and replace the comparable documents included with PSE&G's initial filing, dated December 29, 2023.

The 9+3 update reflects proposed increases of approximately $485M in annual electric revenues and approximately $339M in annual gas revenues, which in total represents a net decrease of approximately $2M from the initial filing.

Among other revisions, the 9+3 Update includes the following:

- In the testimony of Mr. McFadden:
  - A new deferral request related to new New Jersey Department of Community Affairs ("DCA") regulations regarding the utilization of off-duty law enforcement officers for traffic safety control.
  - A change in the calculation of Materials and Supplies inventory costs to account for supply shortages and inflation on material costs, particularly transformers.

    - A new pro forma to annualize the costs associated with 2024 BPU and Rate Counsel assessments that are now known and measurable compared to the amount included in the test year.
- In the testimony of Mr. Pardo:
    - Clarification of corporate alternative minimum tax ("CAMT") impacts that will be included in the Tax Adjustment Credit ("TAC") filing rather than being recovered in this case.

- In the panel testimony of Mr. Schmid and Mr. Fonseca:
    - Addition of information on one storm that occurred after the Company's initial filing.
    - An explanation of the requirements and expected operational impacts of the new DCA regulations regarding traffic safety control related to the deferral mechanism set forth in Mr. McFadden's updated testimony.

Please contact the undersigned if you require further information concerning this filing.

Very truly yours,

Katherine E. Smith

Katherine E. Smith

cc: Attached service list

Public Service Electric and Gas Company
2023 PSEG Rate Case
BPU Docket Nos. ER23120924 and GR23120925
OAL Docket No. PUC 00926-24

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TARIFF

FOR

ELECTRIC SERVICE

Applicable in

Territory served as shown on

Sheet Nos. 4 through 7 of this Tariff

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

GENERAL OFFICES

80 PARK PLAZA

NEWARK, NEW JERSEY 07102

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 2**

TABLE OF CONTENTS

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 3**

TABLE OF CONTENTS
(Continued)

Rate Schedules and Payment Schedule as listed below:

Other Services:

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 4**

TERRITORY SERVED

BERGEN COUNTY

Bergenfield, Borough of
Bogota, Borough of
Carlstadt, Borough of
Cliffside Park, Borough of
Dumont, Borough of
East Rutherford, Borough of
Edgewater, Borough of
Elmwood Park, Borough of
Emerson, Borough of
Englewood, City of
Englewood Cliffs, Borough of
Fair Lawn, Borough of
Fairview, Borough of
Fort Lee, Borough of
Garfield, City of
Glen Rock, Borough of
Hackensack, City of
Hasbrouck Heights, Borough of
Haworth, Borough of
Hillsdale, Borough of
Ho-Ho-Kus, Borough of
Leonia, Borough of
Little Ferry, Borough of
Lodi, Borough of
Lyndhurst, Township of
Maywood, Borough of
Midland Park, Borough of
Moonachie, Borough of
New Milford, Borough of
North Arlington, Borough of
Oakland, Borough of
Old Tappan, Borough of
Oradell, Borough of
Palisades Park, Borough of
Paramus, Borough of
Ridgefield, Borough of
Ridgefield Park, Village of
Ridgewood, Village of
River Edge, Borough of
River Vale, Township of
Rochelle Park, Township of
Rutherford, Borough of
Saddle Brook, Township of
Saddle River, Borough of
South Hackensack, Township of
Teaneck, Township of
Tenafly, Borough of
Teterboro, Borough of
Waldwick, Borough of
Wallington, Borough of
Washington, Township of
Westwood, Borough of
Woodcliff Lake, Borough of
Wood-Ridge, Borough of
Wyckoff, Township of

BURLINGTON COUNTY

Beverly, City of
Bordentown, City of
Bordentown, Township of
Burlington, City of
Burlington, Township of
Chesterfield, Township of
Cinnaminson, Township of
Delanco, Township of
Delran, Township of
Eastampton, Township of
Edgewater Park, Township of
Evesham, Township of
Fieldsboro, Borough of
Florence, Township of
Hainesport, Township of
Lumberton, Township of
Mansfield, Township of
Maple Shade, Township of
Medford, Township of
Medford Lakes, Borough of
Moorestown, Township of
Mount Holly, Township of
Mount Laurel, Township of
Palmyra, Borough of
Pemberton, Township of

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 5**

TERRITORY SERVED
(Continued)

BURLINGTON COUNTY (continued)

Riverside, Township of
Riverton, Borough of
Southampton, Township of
Springfield, Township of
Westamptown, Township of
Willingboro, Township of

CAMDEN COUNTY

Audubon, Borough of
Audubon Park, Borough of
Barrington, Borough of
Bellmawr, Borough of
Brooklawn Borough of
Camden, City of
Cherry Hill, Township of
Collingswood, Borough of
Gloucester, City of
Gloucester, Township of
Haddon, Township of
Haddonfield, Borough of
Haddon Heights, Borough of
Hi-Nella , Borough of
Lawnside, Borough of
Magnolia, Borough of
Merchantville, Borough of
Mount Ephraim, Borough of
Oaklyn, Borough of
Pennsauken, Township of
Runnemede, Borough of
Somerdale, Borough
Tavistock, Borough of
Voorhees, Township of
Wood-Lynne, Borough of

ESSEX COUNTY

Belleville, Town of
Bloomfield, Township of
Caldwell, Borough of
Cedar Grove, Township of
East Orange, City of
Essex Fells, Borough of
Fairfield, Township of
Glen Ridge, Borough of
Irvington, Township of
Livingston, Township of
Maplewood, Township of
Montclair, Township of
Newark, City of
North Caldwell, Borough of
Nutley, Township of
Orange, City of
Roseland, Borough of
South Orange Village, Township of
Verona, Township of
West Caldwell, Township of
West Orange, Township of

GLOUCESTER COUNTY

Deptford, Township of
National Park, Borough of
Washington, Township of
West Deptford, Township of
Westville, Borough of
Woodbury, City of
Woodbury Heights, Borough of

HUDSON COUNTY

Bayonne, City of
East Newark, Borough of
Guttenberg, Town of
Harrison, Town of
Hoboken, City of
Jersey City, City of
Kearny, Town of
North Bergen, Township of
Secaucus, Town of

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 6**

TERRITORY SERVED
(Continued)

HUDSON COUNTY (continued)

Union City, City of
Weehawken, Township of
West New York, Town of

MERCER COUNTY

Ewing, Township of
Hamilton, Township of
Hopewell, Borough of
Hopewell, Township of
Lawrence, Township of
Pennington, Borough of
Princeton, Borough of
Princeton, Township of
Robbinsville, Township of
Trenton, City of
West Windsor, Township of

MIDDLESEX COUNTY

Carteret, Borough of
Cranbury, Township of
Dunellen, Borough of
East Brunswick, Township of
Edison, Township of
Highland Park, Borough of
Metuchen, Borough of
Middlesex, Borough of
New Brunswick, City of
North Brunswick, Township of
Perth Amboy, City of
Piscataway, Township of
Plainsboro, Township of
South Brunswick, Township of
South Plainfield, Borough of
Woodbridge, Township of

MONMOUTH COUNTY

Allentown, Borough of
Upper Freehold, Township of

MORRIS COUNTY

Lincoln Park, Borough of

PASSAIC COUNTY

Clifton, City of
Haledon, Borough of
Hawthorne, Borough of
Little Falls, Township of
North Haledon, Borough of
Passaic, City of
Paterson, City of
Prospect Park, Borough of
Totowa, Borough of
Wayne, Township of
Woodland Park, Borough of

SOMERSET COUNTY

Bound Brook, Borough of
Branchburg, Township of
Bridgewater, Township of
Franklin, Township of
Green Brook, Township of
Hillsborough, Township of
Manville, Borough of
Millstone, Borough of
Montgomery, Township of
North Plainfield, Borough of
Raritan, Borough of
Rocky Hill, Borough of
Somerville, Borough of
South Bound Brook, Borough of
Warren, Township of
Watchung, Borough of

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 7**

TERRITORY SERVED
(Continued)

UNION COUNTY

Clark, Township of
Cranford, Township of
Elizabeth, City of
Fanwood, Borough of
Garwood, Borough of
Hillside, Township of
Kenilworth, Borough of
Linden, City of
Mountainside, Borough of
Plainfield, City of
Rahway, City of
Roselle, Borough of
Roselle Park, Borough of
Scotch Plains, Township of
Union, Township of
Westfield, Town of
Winfield, Township of

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 8**

STANDARD TERMS AND CONDITIONS – INDEX

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 9**

STANDARD TERMS AND CONDITIONS – INDEX
(Continued)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 10**

STANDARD TERMS & CONDITIONS

1. GENERAL

These Standard Terms and Conditions, filed as a part of the Electric Tariff of Public Service Electric and Gas Company, hereinafter referred to as "Public Service," set forth the terms and conditions under which electric service will be supplied and govern all classes of service to the extent applicable, and are made a part of all agreements for the supply of electric service unless specifically modified in a particular rate schedule.

No representative of Public Service has authority to modify any provision contained in this Tariff or to bind Public Service by any promise or representation contrary thereto.

Public Service will construct, own, and maintain distribution equipment located on land, streets, highways, rights of way acquired by Public Service, and on private property, used or usable as part of the distribution system of Public Service. Payment of monthly charges, or a deposit, or a contribution shall not give the customer, Applicant or depositor any interest in the facilities, the ownership being vested exclusively in Public Service.

Publications set forth by title in sections of these Standard Terms and Conditions are incorporated in this Tariff by reference.

This tariff is subject to the lawful orders of the Board of Public Utilities of the State of New Jersey. Complaints may be directed to: Board of Public Utilities, Division of Customer Assistance, 44 South Clinton Avenue, P.O. Box 350, Trenton, New Jersey, 08625-0350, 1-800-624-0241; www.nj.gov/bpu.

2. OBTAINING SERVICE

2.1. Application: An application for service may be made at any of the Customer Service Centers of Public Service in person, or by telephone, by the Company's website at www.pseg.com, or electronic mail, where available. Forms for application for service, when required, together with terms and conditions and rate schedules, will be furnished upon request. All customers shall be given a copy of the Customer Bill of Rights, effective at the time of service initiation. Customer shall state, at the time of making application for service, the conditions under which service will be required and customer may be required to sign an agreement or other form then in use by Public Service covering special circumstances for the supply of electric service. Data requested from customers may include proof of identification as well as copies of leases, deeds and corporate charters, in accordance with N.J.A.C. 14:3-3.2(e) and (f). Such information shall be considered confidential.

Public Service may reject applications for service where such service is not available or where such service might affect the supply of electricity to other customers, or for failure of customer to agree to comply with any of these Standard Terms and Conditions.

See also Section 13, Service Limitations and Section 14, Third Party Supplier Service Provisions of these Standards Terms and Conditions.

2.2. Initial Selection of Rate Schedule: Public Service will assist in the selection of the available rate schedule, which is most favorable from the standpoint of the customer. Any advice given by Public Service will necessarily be based on customer's written statements detailing the customer's proposed operating conditions.

Customer may, upon written notice to Public Service within three months after service is begun, elect to change and to receive service under any other available rate schedule. Public Service will furnish service to and bill the customer under the rate schedule so selected from the date of last scheduled meter reading, but no further change will be allowed during the next twelve months.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

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2.2.1. Change of Rate Schedule: Subsequent to initial selection of a rate schedule, customer shall notify Public Service in writing of any change in the customer's use of service which might affect the selection of a rate schedule or provision within a rate schedule. Any change in schedule or provision shall be applicable, if permitted, to the next regular billing subsequent to such notification.

2.3. Deposit and Guarantee: Public Service may require a reasonable deposit as a condition of supplying service, in accordance with the provisions as set forth in Board of Public Utility regulations.

A deposit may be required from a customer equal to the average monthly charge for a twelve-month period and one month's average bill. A customer taking service for a period of less than thirty days may be required to deposit an amount equal to the estimated bill for such temporary period.

Upon closing any account, the balance of any deposit remaining after the closing bill for service has been settled, shall be returned promptly to the customer with any interest due. The customer has the option of having the deposit refund applied to the account in the form of a credit or of having the deposit refunded by separate check in a period not to exceed one full billing cycle. Deposits shall cease to bear interest upon discontinuance of service.

Public Service shall review a residential customer's account at least once every year and a non-residential customer's account at least once every 2 years. If such review indicates that the customer has established credit satisfactory to Public Service, then the outstanding deposit shall be refunded to the customer. The customer has the option of having the deposit refund applied to the account in the form of a credit or of having the deposit refunded by separate check in a period not to exceed one billing cycle.

In accordance with N.J.A.C. 14:3-3.5(d), simple interest at a rate equal to the average yields on new six-month Treasury Bills for the twelve month period ending each September 30 shall be paid by Public Service on all deposits held by it, after notification by the BPU of the new effective rate. Said rate shall be determined by the Board of Public Utilities, and shall become effective on January 1 of the following year.

Interest payments shall be made at least once during each 12-month period in which a deposit is held and Public Service shall offer the customer the option of credits on bills toward utility service rendered or to be rendered or a separate check, in accordance with N.J.A.C. 14:3-3.5(h).

A deposit is not a payment or part payment of any bill for service, except that on discontinuance of service, Public Service may apply said deposit against unpaid bills for service, and only the remaining balance of the deposit will be refunded. Public Service shall promptly read the meters and ascertain that the obligations of the customer have been fully performed before being required to return any deposit. To have service resumed, a deposit may be required, but the deposit shall not be required prior to restoration of service. Public Service shall bill the customer for the deposit and allow at least 15 days after the billing for payment of deposit, or make other reasonable arrangements.

STANDARD TERMS AND CONDITIONS
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2.4. **Permits:** Public Service, where necessary, will make application for any street opening permits for installing its service connections and shall not be required to furnish service until after such permits are granted. The Applicant may be required to pay the municipal charge, if any, for permission to open the street. The Applicant shall obtain and present to Public Service, for recording or for registration, all instruments providing for easements or rights of way, and all permits (except street opening permits), consents, and certificates necessary for the introduction of service.

2.5. **Selection of Lighting Options:** Public Service will assist in the selection of lighting options by making recommendations for the most appropriate option based on the customer's defined illumination needs. However, responsibility for the final selection shall, at all times, rest with the customer. Any advice given by Public Service will be based on the customer's statements and by giving such advice, Public Service assumes no responsibility, nor shall it incur liability.

3. CHARGES FOR SERVICE

3.1. **General:** Charges for electrical usage are set forth in the rate schedules included elsewhere in this Tariff. In addition to the charges for electrical usage, Public Service may require additional monthly charges, up-front contributions or deposits (including the gross-up for income tax effects) from an Applicant for providing Temporary Services, for certain Standard or Atypical Conditions, or for an Extension.

3.2. **Definitions:** The following are defined terms as used in this Tariff:

a) Applicant is the individual or entity, who may or may not be the ultimate customer, requesting new, additional, temporary, or upgraded electric service from Public Service.
b) Applicant For An Extension is an Applicant where Public Service has determined that an Extension is necessary to provide service.
c) N.J.A.C. is the New Jersey Administrative Code.
d) Distribution Revenue as used in this Section 3 means the total revenue, plus related New Jersey Sales and Use Tax (SUT), charged a customer by Public Service, minus the sum of Basic Generation Service charges including SUT, and, unless included with Basic Generation Service charges, Transmission Charges, including SUT, derived from FERC approved transmission charges; all assessed in accordance with this Tariff for Electric Service.
e) Temporary Service is where service is provided through an installation for a limited period and such installation is not permanent in nature.

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f) An Extension means the construction or installation of plant and/or facilities by Public Service used to convey service from existing or new plant and/or facilities to one or more new customers, and also means the plant and/or facilities themselves. An Extension includes all Public Service plant and/or facilities used for electric transmission (non-FERC jurisdictional) and/or distribution, whether located overhead or underground, on a public street or right of way, or on private property or private right of way, and includes the conductors, poles or supports, cable, conduit, rights of way, land, site restoration, handholes, manholes, vaults, line transformers, protection devices, metering equipment and other means of conveying service from existing plant and/or facilities to each unit or structure to be served. An Extension does not include equipment solely used for administrative purposes, such as office equipment used for administering a billing system.

An Extension begins at the existing Public Service infrastructure and ends at the point of connection with the customer's facilities, but also includes the meter. Details of the requirements for Service Connections and Service Entrance Installations are provided in Sections 5 and 6 of these Standard Terms and Conditions and in the New Jersey Uniform Construction Code. The new plant and/or facilities installed constituting an Extension must be nominally physically and electrically continuous from the beginning to the end of the Extension, but also includes the meter.

Plant and/or facilities installed to supply the increased load of existing non-residential customers are also considered an Extension where either: 1) Public Service facilities of the required voltage or number of phases did not previously exist, or 2) existing Public Service facilities are upgraded or replaced due to an Applicant's new or additional electrical load being greater than 50% of the total design capacity of the pre-existing facilities.

g) Cost means, with respect to the cost of construction of an Extension, actual and/or site-specific unitized expenses incurred by Public Service for materials and labor, including both internal and external labor, employed in the actual design, purchase, construction, and/or installation of the Extension, including overhead directly attributable to the work, as well as overrides or loading factors such as those for mapping and design. This term does not include expenses for clerical, dispatching, supervision, or general office functions. Costs shall be determined by the company and shall include all costs inclusive of upgrades to existing infrastructure as well as tax gross ups, inclusive of the applicable bonus depreciation credits. Costs related to plant and/or facilities installed to serve increased load from an existing customer are determined on a similar basis.

3.3. **Removal of Public Service Facilities:** There is normally no charge for the permanent removal of above ground Public Service facilities or the abandonment in place of underground Public Service facilities where an easement for such facilities does not exist. Where an easement exists, and when approved by Public Service, and unless preempted by statute, the requesting party shall be responsible for all costs related to the removal or abandonment of requested facilities and if necessary, the installation of all new facilities necessary to provide the same level of service to all other customers.

3.4. **Temporary Service:** Where Public Service provides Temporary Service, the customer will be required to pay to Public Service the cost of the installation and removal of facilities required to furnish service. The minimum period of temporary service for billing purposes shall be one month.

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After two years of service, a Temporary Service installation shall be eligible for refunds. Excluding the first two annual service periods, refunds equal to 10% of the Distribution Revenue received by Public Service during each annual service period shall be made at the end of such period. In no case shall the total amount refunded be in excess of the installation and removal cost paid by the customer, nor shall refunds be made for more than eight consecutive annual service periods.

Temporary service will be furnished only under Rate Schedules GLP, LPL, and HTS except that it will not be supplied for cogeneration or standby purposes under any rate schedule at locations where electric service is regularly supplied from another source, nor will it be supplied under Rate Schedules BPL, BPL-POF and PSAL.

3.5. **Provision of Service:** Electric service shall be supplied in accordance with these Standard Terms and Conditions and the applicable rate schedule and shall be based upon Applicant's anticipated load and upon plant facilities that are sufficient for safe, proper, and adequate service based upon Public Service's design standards and reliability criteria. Both the Applicant's anticipated load and sufficient plant facilities will be as determined by Public Service.

3.5.1. **Standard Conditions**: Overhead construction will be utilized for all distribution lines except in certain areas designated by Public Service as underground zones where underground construction will be utilized. An area is designated as an underground zone by Public Service based upon load density, area size, building occupation and the need for multiple and/or express circuits.

3.5.2. **Atypical Conditions:** When underground distribution lines or service connections in overhead zones are required due to conditions beyond the control of Public Service, or are requested by the Applicant and approved by Public Service, or are required due to local ordinance, the added cost of such underground construction over the estimated costs of equivalent overhead construction, such total grossed up for income tax effects, shall be paid by the Applicant as a non-refundable contribution.

Public Service may require agreements for a longer term than specified in the rate schedule, may require contributions toward the investment, and may establish such Minimum Charges, Facilities Charges, distribution capacity reservation charges or other charges as may be equitable under the circumstances involved where: (1) large or special investment is either necessary for the supply of service or is requested by the Applicant; (2) oversized transformers, feeders, or other special facilities are installed to serve an Applicant using equipment in such manner that the use of electric service is intermittent, momentary or subject to violent fluctuations; (3) capacity required to serve Applicant's equipment is out of proportion to the use of electric service for occasional or low load factor purposes, or is for short durations; or (4) service characteristics requested by Applicant differ from those normally supplied for a given size and type of load as specified in the current "Information and Requirements for Electric Service".

Unless there is a material change in the provision of service, once charges are established for a premises pursuant to this Section 3.5.2, they shall be used for all subsequent customers at that premises requesting such similar service, regardless of any lapse in the provision of such similar service characteristics to that premises.

Facility Charges will be assessed on a monthly basis equal to 1.45% (1.55% including SUT) times the total installed cost of the excess facilities.

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3.6. **Extensions – General Provisions:** Where it is necessary for Public Service to construct an Extension to serve the requirements of an Applicant, Public Service may require a deposit or contribution from the Applicant to cover all or part of the cost of the Extension, which is required to be paid to Public Service prior to any work being performed. Where a large portion of the cost of construction is related to the installation of underground facilities, the costs may be increased if severe conditions, such as excessive rock or other unknown conditions, are found during excavation.

3.7. **Charges for Extensions:** Applicants requesting service may be charged a deposit for service. Such deposit will be determined by Public Service by comparing the estimated Distribution Revenue to the applicable costs of the Extension. The detailed calculations of such deposits, if any, are contained in the remainder of Section 3.7 of these Standard Terms and Conditions.

3.7.1. **Individual Residential Customer**: Where application for service is made by an Applicant for individual residential use, and the service requested is not for a limited period of less than ten (10) years, the following shall apply:

a) Excess cost is defined as the total cost of the Extension less any contribution required for Atypical Conditions less ten times the estimated average annual Distribution Revenue, such result grossed up for income tax effects. The excess cost shall not be less than zero in any case.

   Any excess cost shall be deposited and remain with Public Service without interest. Public Service will waive the deposit requirement where the excess cost is $15,000.00 or less.

b) In each annual period from the date of connection, if the actual Distribution Revenue from the customer exceeds the greater of either: (1) the estimated annual Distribution Revenue used as the basis for the initial deposit, or (2) the highest actual Distribution Revenue from any prior year, there shall be returned to the Applicant an additional amount, equal to ten times such excess multiplied by the tax gross up factor used when the deposit was taken.

c) As additional customers not originally anticipated are supplied from this Extension and Public Service still holds at least some part of the deposit from the original Applicant, a reduction may be made to such remaining deposit. The cost of the Extension or cost for Increased Load for any such additional customer will be first compared to the estimated additional Distribution Revenue as detailed in the appropriate paragraph of this Section 3. Once any deposit requirement has been satisfied, any remaining Distribution Revenue credit will be applied toward the original customer's remaining deposit in an amount equal to ten times such excess Distribution Revenue multiplied by the tax gross up factor used when the deposit was taken.

d) In no event shall more than the original deposit be returned to the Applicant nor shall any part of the deposit remaining after ten years from the date of the original deposit be returned.

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3.7.2. Multi-unit Developments: Where application for service is made for electric service to a multi-unit residential or multi-unit non-residential development, the following shall apply:

a) The Regulations on Residential Underground Extensions, New Jersey Administrative Code 14:5-4.1 *et seq.* shall apply regarding the installation of Public Service facilities within the boundaries of such applicable developments. Such charges, referred to hereafter as B.U.D. Charges, are included elsewhere in this Tariff and shall be treated as a non-refundable contribution.

b) Excess cost for an Applicant is defined as the total cost of the Extension less any contribution required for Atypical Conditions and, if applicable, B.U.D. Charges, such result grossed up for income tax effects.

Any excess cost shall be deposited and remain with Public Service without interest. Public Service will waive the deposit requirement where the excess cost is $3,000.00 or less, or where the ten times the estimated annual Distribution Revenue is greater than the excess costs and the excess cost is less than $20,000.00.

c) As each unit is connected, as determined by the setting and activation of the Public Service electric meter, there shall be returned to the Applicant an amount equal to ten times the estimated annual Distribution Revenue from that unit multiplied by the tax gross up factor used when the deposit was taken.

d) In each annual period from the date of deposit, if for all customers receiving service for the entire prior one year period the actual annual Distribution Revenue exceeds the greater of either: (1) the estimated annual Distribution Revenue, or (2) the highest actual Distribution Revenue from any prior year, there shall be returned to the Applicant an additional amount equal to ten times such excess multiplied by the tax gross up factor used when the deposit was taken.

e) As additional customers not originally anticipated are supplied from this Extension and Public Service still holds at least some part of the deposit from the original Applicant, a reduction may be made to such remaining deposit. The cost of the Extension or cost for Increased Load for any such additional customer will be first compared to the estimated additional Distribution Revenue as detailed in the appropriate paragraph of this Section 3. Once any deposit requirement has been satisfied, any remaining Distribution Revenue credit will be applied toward the original customer's remaining deposit in an amount equal to ten times such excess Distribution Revenue multiplied by the tax gross up factor used when the deposit was taken.

f) In no event shall more than the original deposit be returned to the Applicant nor shall any part of the deposit remaining after ten years from the date of the original deposit be returned.

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3.7.3. Individual Commercial and Industrial Customers: Where application for service is made for individual non-residential use, and the service requested is not for a limited period of less than ten (10) years, the following shall apply:

a) Excess cost for an Applicant is defined as the total cost of the Extension less any contribution required for Atypical Conditions, less ten times the estimated average annual distribution revenue, such result grossed up for income tax effects. The excess cost shall not be less than zero in any case.

Any excess cost shall be deposited and remain with Public Service without interest. Public Service will waive the deposit requirement where the excess cost is $3,000.00 or less, or where ten times the estimated annual Distribution Revenue is greater than the excess costs and the excess cost is less than $20,000.00.

b) As the Public Service electric meter is set, there shall be returned to the Applicant an amount equal to ten (10) times the estimated average annual Distribution revenue multiplied by the tax gross up factor used when the deposit was taken.

c) In each annual period from the date of deposit, if the actual Distribution Revenue from the customer exceeds the greater of: (1) the estimated annual Distribution Revenue used as the basis for the initial deposit computation, or (2) the highest actual Distribution Revenue from any prior year; there shall be returned to the Applicant an additional amount, equal to ten times such excess multiplied by the tax gross up factor used when the deposit was taken.

d) As additional customers not originally anticipated are supplied from this Extension and Public Service still holds at least some part of the deposit from the original Applicant, a reduction may be made to such remaining deposit. The cost of the Extension or cost for Increased Load for any such additional customer will be first compared to the estimated additional Distribution Revenue as detailed in the appropriate paragraph of this Section 3. Once any deposit requirement has been satisfied, any remaining Distribution Revenue credit will be applied toward the original customer’s remaining deposit in an amount equal to ten times such excess Distribution Revenue multiplied by the tax gross up factor used when the deposit was taken.

e) In no event shall more than the original deposit be returned to the Applicant nor shall any part of the original deposit remaining after ten years from the date of the original deposit be returned.

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3.8. Charges for Increased Load: When it is necessary for Public Service to construct, upgrade, or install facilities necessary to service the additional requirements of existing customers and these facilities do not meet the definition of an Extension as defined in Section 3.2. (f) of these Standard Terms and Conditions, the following shall apply:

a) Public Service may require a deposit from the customer to cover all or part of the investment necessary to supply service. Any such deposit will be calculated by comparing the estimated annual increase in Distribution Revenue as determined by Public Service to the total cost of the applicable work to determine if excess costs exist.

b) Excess cost is defined as the total cost of the applicable work less any contribution required for Atypical Conditions less the ten times the estimated average annual increase in Distribution Revenue, such result grossed up for income tax effects. The excess cost shall not be less than zero in any case.

c) Any excess cost shall be deposited and remain with Public Service without interest. Public Service will waive the deposit requirement where the excess cost is $3,000.00 or less.

d) In each annual period from the date of connection of such additional load, if the actual increase in Distribution Revenue from the customer exceeds the greater of either: (1) the estimated annual increase in Distribution Revenue used as the basis for the initial deposit computation, or (2) the highest increase in actual Distribution Revenue from any prior year, there shall be returned to the Applicant an additional amount, equal to ten times such excess multiplied by the tax gross up factor used when the deposit was taken.

e) In no event shall more than the original deposit be returned to the Applicant nor shall any part of the deposit remaining after ten years from the date of the original deposit be returned.

4. CHARACTERISTICS OF SERVICE

4.1. General: The standard service supply of Public Service is alternating current with a nominal frequency of 60 hertz (cycles per second). All types of service listed below are not available at all locations, and service from the primary distribution, subtransmission, transmission or high voltage system may be specified under special conditions, such as location, size, or type of load. The customer shall ascertain and comply with the service characteristics requirements of Public Service which are covered in detail in “Information and Requirements for Electric Service,” issued by Public Service and available on request.

Public Service must always be consulted to determine the type of service to be supplied to a particular installation. The type of service may govern the characteristics of equipment to be connected.

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4.2. **Types of Service:** Subject to the restrictions in Section 4.1, the types of service available, with their nominal voltages are:

Type of Service		Volts
Secondary Distribution Service	Single-phase, two-wire	120
	Single-phase, three wire	120/240
	Single-phase, three-wire	120/208
	Three-phase, three-wire	240
	Three-phase, four wire	120/240
	Three-phase, four wire	120/208
	Three-phase, four-wire	277/480
Primary Distribution Service	Three-phase, four wire	2,400/4,160
	Three-phase, four-wire	13,200
Subtransmission Service:	Three-phase, three-wire	26,400
	Three-phase, three-wire	69,000
High Voltage Service:	Three-phase, three-wire	138,000
	Three-phase, three-wire	230,000
Transmission Service	Three-phase, three-wire	69,000

4.3. **Losses:** Nominal electric losses and unaccounted for percentages:

Type of Service	Losses
Secondary Distribution Service:	5.8327%
Primary Distribution Service:	3.3153%
Subtransmission Service:	2.0472%
Transmission High Voltage Service:	0.8605%

5. SERVICE CONNECTIONS

5.1. **General:** The customer shall consult Public Service before starting work, to determine the type of service facilities involved, the exact location of the point of connection between customer's service entrance and Public Service's facilities and the construction to be installed by each.

Electric service will be supplied to each building or premises through a single service connection unless otherwise agreed in accordance with the detailed requirements of "Information and Requirements for Electric Service," Section 3.

Whenever conductors are required under or within a building to provide a continuous service run to the customer's entrance equipment, they shall be installed by Public Service at the expense of the customer.

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Where a customer is provided Subtransmission, Transmission or High Voltage Service, the customer's high side bus shall be considered part of the Public Service distribution system for operational purposes with no remuneration to the customer by Public Service.

5.2. **Overhead Service:** For overhead service in overhead zones, Public Service will furnish, install, and maintain the overhead service facilities to the point of connection to the customer's facilities. A deposit or non-refundable contribution may be required as provided in Section 3 of these Standard Terms and Conditions.

5.3. **Underground Service in Underground Zone:** For underground service in underground zones, Public Service will furnish, install, and maintain the underground service facilities to the point of connection to customer's facilities. A deposit or non-refundable contribution may be required as provided in Section 3 of these Standard Terms and Conditions.

5.4. **Underground Service in Overhead Zone:**

5.4.1. **Secondary Distribution Service**: Where underground service in an overhead zone is to be supplied, and secondary voltage supply from overhead facilities is inadequate for the size of customer's load, the customer shall furnish and install at its expense and in accordance with the specifications of Public Service the primary conduits and any necessary manholes, which will be maintained by Public Service. The customer shall also be required to furnish, install, and maintain all secondary conduits and conductors and provide space on its property for necessary transformation.

Where underground service in an overhead zone is to be supplied, and secondary voltage supply from overhead facilities is adequate for the size of customer's load, such service will be supplied under the following conditions:

At Request of Customer: The customer shall furnish and install the service facilities at its expense and in accordance with the specifications of Public Service. Public Service will connect the service conductors and maintain the service facilities without charge to the customer.

Operating Reasons Beyond the Control of Public Service: The customer shall furnish and install at its expense and in accordance with the specifications of Public Service the service conduit which will be maintained by Public Service. Public Service will furnish, install, and maintain the service conductors to the point of connection to customer's facilities.

5.4.2. **Primary Distribution Service:** Where underground service in an overhead zone is to be supplied, and primary voltage supply is required because of the size of the customer's load, such service will be supplied under the following condition:

At Request of Customer or for Operating Reasons Beyond the Control of Public Service: The customer shall furnish and install at its expense and in accordance with the specifications of Public Service the service conduit and any necessary manholes which will be maintained by Public Service. Public Service will furnish, install, and maintain the service conductors to the point of connection to customer's facilities.

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5.4.3. **Subtransmission Service:** Where underground service in an overhead zone is to be supplied, and subtransmission voltage supply is required because of the size of customer's load, such service will be supplied under the following condition:

At Request of Customer or for Operating Reasons Beyond the Control of Public Service: The customer shall furnish and install at its expense and in accordance with the specifications of Public Service, the service conduit and any necessary manholes which will be maintained by Public Service. Public Service will furnish, install, and maintain the service conductors to the point of connection to customer's facilities.

5.5. **Change in Location of Existing Service Line:** Any change requested by the customer in the location of the existing service line, if approved by Public Service, will be made at the expense of the customer. A request to install facilities for the same building within 12 months of the removal of similar facilities may be considered a relocation of the existing facilities if the load served is similar or lower and the building served is essentially the same.

6. SERVICE ENTRANCE INSTALLATIONS

6.1. **General:** The customer is required to furnish, install, and maintain the service entrance wiring and equipment on the customer's premises with the exception of transformers and network protectors for secondary service, and meters and metering equipment as enumerated in detail in the following paragraphs. All materials and equipment used shall be of a type approved by Public Service and must be installed according to the requirements of governmental authorities, Public Service, and the current edition of the National Electrical Code. The location of the service entrance installation must be designated by Public Service.

6.2. **Seals:** Public Service will seal or lock all meters and enclosures containing meters and associated metering equipment, service entrance interrupting devices acceptable to Public Service, or unmetered wiring. No person except a duly authorized employee of Public Service is permitted to break or remove a Public Service seal or lock.

6.3. **Secondary Distribution Service:** For new installations to be metered at voltages not exceeding 600 volts, meter-mounting equipment and, where required, current transformers, potential transformers, time switches, and associated unmetered wiring will be furnished without charge to the contractor, or may be furnished by the contractor at its expense if approved by Public Service. The contractor will install and wire this equipment as part of its contract with the customer. Public Service will furnish and install the meter.

For large secondary installations, the customer may be required to furnish a vault or space for a transformer mat, pad, manhole, or vault.

The customer shall ascertain and comply with the general requirements of Public Service for secondary installations, which are covered in detail in "Information and Requirements for Electric Service," issued by Public Service and available on request.

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6.4. Primary Distribution, Subtransmission, Transmission or High Voltage Service: For new installations to be metered at voltages exceeding 600 volts, meter-mounting equipment, current transformers, potential transformers, test switches, time switches, and associated unmetered wiring will be furnished without charge to the contractor, or may be furnished by the contractor at its expense if approved by Public Service. The contractor will install and wire this equipment as part of its contract with the customer. Public Service will furnish and install the meter.

Where service is received at primary distribution, subtransmission, transmission or high voltage entrance voltages, customer must furnish, install and maintain a service entrance interrupting device acceptable to Public Service and, where necessary, transformers and appurtenances.

The customer shall ascertain and comply with the general requirements of Public Service for primary distribution, subtransmission, transmission or high voltage service installations, which are covered in detail in "Information and Requirements for Electric Service," issued by Public Service and available on request.

Where subtransmission, transmission or high voltage service is supplied, it is necessary that the switching operations be controlled by Public Service; therefore, customer shall agree to abide by the operating instructions issued to customer by Public Service.

7. METERS AND OTHER EQUIPMENT

7.1. General: The installation of meters and connections shall be in accordance with N.J.A.C. 14:3-4.2.

Public Service will select the type and make of metering and its other equipment, and may, from time to time, change or alter such equipment; its sole obligation is to supply metering that will furnish accurate and adequate records for billing purposes.

Electric service normally will be supplied to each building or premises at a single metering point, by one watthour meter equipped, where necessary, with demand and recording devices. Additional meters will be installed (1) where, in the judgment of Public Service, the operating characteristics of its system require the installation of more than one meter, or (2) at the customer's request provided that the service measured by each meter shall be billed separately at an applicable rate schedule.

No person except a duly authorized employee or agent of Public Service is permitted to alter or change a meter or its connection.

When requested by a customer, equipment to provide data pulses and/or advanced interval meter access may be installed, if feasible, at the expense of the customer. The payment shall not give the customer any interest in the equipment thus installed, the ownership being vested exclusively in Public Service.

A customer may choose to opt-out of remote meter reading and request a conventional meter and will be charged additional fees as detailed in Section 9.4.1.

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7.2. **Other Devices:** No branch circuits or devices are permitted on the supply side of the meter, except those for Police Recall or Fire Alarm System Service as provided in this Tariff.

Public Service will not permit the connection of the customer's ammeters, voltmeters, pilot lamps, or any other energy-using devices to the instrument transformers used in conjunction with its meter.

7.3. **Protection of Meters and Other Equipment:** Customer shall provide for the safekeeping of the meter and other equipment of Public Service, and shall not tamper with or remove such meter or other equipment, nor permit access thereto except by duly authorized employees or agents of Public Service. In case of loss or damage to the property of Public Service from the act or negligence of the customer or its agents or servants, or of failure to return equipment supplied by Public Service, customer shall pay to Public Service the amount of such loss or damage to the property. All equipment furnished at the expense of Public Service shall remain its property and may be replaced whenever deemed necessary and may be removed by it at any reasonable time after the discontinuance of service. In the case of defective service, the customer shall not interfere or tamper with the apparatus belonging to Public Service but shall immediately notify Public Service to have the defects remedied.

7.4. **Tampering:** In the event it is established that Public Service meters or other equipment on the customer's premises have been tampered with, and, such tampering results in incorrect measurement of the service supplied, the charges for such electric service under the applicable rate schedule including Basic Generation Service default service, exclusive of any reduction in charges for third party supplied electric services, based upon the Public Service estimate from available data and not registered by Public Service meters shall be paid by the beneficiary of such service. In the case of a residential customer, such unpaid service shall be limited to not more than one year prior to the date of correcting the tampered account and for no more than the unpaid service under the applicable rate schedule, exclusive of any reduction in charges for third party supplied electric services, alleged to be used by such customer. The beneficiary shall be the customer or other party who benefits from such tampering. The actual cost of investigation, inspection, and determination of such tampering, and other costs, such as but not limited to, the installation of protective equipment, legal fees, and other costs related to the administrative, civil or criminal proceedings, shall be billed to the responsible party. The responsible party shall be the party who either tampered with or caused the tampering with a meter or other equipment or knowingly received the benefit of tampering by or caused by another. In the event a residential customer unknowingly received the benefit of meter or equipment tampering, Public Service shall only seek from the benefiting customer the cost of the service provided under the applicable rate schedule including Basic Generation Service default service, exclusive of any reduction in charges for third party supplied electric services, but not the cost of investigation.

These provisions are subject to the customer's right to pursue a bill dispute proceeding pursuant to N.J.A.C. 14:3-7.6.

Tampering with Public Service facilities may be punishable by fine and/or imprisonment under the New Jersey Code of Criminal Justice.

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8. CUSTOMER'S INSTALLATION

8.1. **General:** Public Service makes no new electric installations on the customer's premises other than the installation of its services, meters and other equipment as set forth in these Standard Terms and Conditions except to continue a service run, a portion of which is installed under or within a building at the customer's expense. Public Service will assume no responsibility for the condition of customer's electric installation or for accidents, fires, or failures which may occur as the result of the condition of such electric installation. No material change in the size, total electrical capacity, or method of operation of customer's equipment shall be made without previous written notice to Public Service.

Failure of the Customer to give prior notice of changes in conditions as described above shall render the Customer responsible and liable for any personal injury and any property damage caused by the changed conditions, including damage to the Company's property and injury to its employees.

8.2. **Wiring:** Wiring installed on the customer's premises must conform to all requirements of governmental authorities and to the regulations set forth in the current edition of the National Electrical Code.

8.3. **Inspection and Acceptance:** The customer's service entrance installation must be inspected and approved by Public Service before service will be supplied. Public Service may refuse to connect with any customer's installation or make additions or alterations to the service connection when it is not in accordance with the National Electrical Code and with these Standard Terms and Conditions, and where a certificate approving the customer's electrical installation has not been issued by a county or a municipality or by any other organization authorized to perform such functions and services as may be designated and approved by the Board of Public Utilities. Information regarding the above inspection service is detailed in "Information and Requirements for Electric Service," issued by Public Service and available on request.

8.4. **Customer On-Site Generation:**

8.4.1. **General:** Electric service from a customer's on-site generation facility, or from sources other than that delivered by Public Service's system shall not be used for the operation of customer's electrical equipment without previous written notice to Public Service. The requirements in this Section 8.4.1 do not apply when the on-site generation facility is used exclusively as an emergency source of power during Public Service electric delivery service interruptions.

8.4.2. **Parallel Operation:** Customer may operate on-site generation facility in parallel with the service delivered by Public Service only with previous written notice to Public Service and written Public Service approval**,** and must conform with all applicable interconnection standards.

Public Service may re-energize the Public Service delivery service following an interruption without prior notice to the customer.

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8.5. Maintenance of Customer's Installation: Customer's entire electrical installation shall be maintained in the condition required by the electrical inspection agency having jurisdiction and by Public Service, and all repairs shall be made by the customer at their expense. Preventative and corrective maintenance on customer owned equipment is the responsibility of the customer. Further, customer electrical equipment under the operational control of Public Service shall be subject to Public Service's inspection and where necessary Public Service will advise the customer to make necessary repairs at customer expense. In the event PSE&G provides assistance in repairs or maintenance activities, customers will be responsible for those costs. If the customer fails to make the necessary repairs in a timely manner, then Public Service will have the repairs made and bill the customer.

8.6. Electrical Equipment and Appliances: Motors, welders, and other electrical equipment and appliances shall be so wired, connected, and operated as to produce no disturbing effects on the Public Service electrical system which will affect the adequacy or quality of service to other customers.

Where the use of electric service is to be intermittent, occasional or momentary, or subject to violent fluctuations, or for low load factor purposes or for short durations equipment shall not be connected without previous written notice to Public Service.

8.7. Power Factor: The average power factor under operating conditions of customer's load at the point where the electric service is metered shall not be less than 85%. Public Service may inspect customer's installed equipment and may place instruments for test purposes at its own expense on the premises of the customer.

Where neon, fluorescent, or other types of lighting or sign equipment having similar low power factor characteristics are installed or moved to a new location, the customer shall furnish, install, and maintain at its own expense corrective apparatus which will increase the power factor of the individual units or the entire lighting installation to not less than 90%.

8.8. Liability for Customer's Installation: Public Service will not be liable for damages or for injuries sustained by customers or others or by the equipment of customers or others by reason of the condition or character of customer's facilities or the equipment of others on customer's premises. Public Service will not be liable for the use, care or handling of the electric service delivered to the customer after same passes beyond the point at which the service facilities of Public Service connect to the customer's facilities.

8.9. Replacement of Customer Owned Equipment Due to System Upgrades: If customer owned communication equipment, such as relays, requires replacement in order to be compatible with PSE&G's system due to upgrade work being performed by PSE&G, the Company will provide the replacement at no cost to the Customer. Any equipment replaced by PSE&G under this section shall be owned by PSE&G. In all other circumstances including customer requirements or obsolescence, the equipment will be replaced at their expense and in accordance with other sections of this tariff.

9. METER READING AND BILLING

9.1. Measurement of Electric Service: Public Service will select the type and make of metering equipment and may, from time to time, change or alter such equipment; its sole obligation is to supply meters that will accurately and adequately furnish records for billing purposes.

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Where more than one meter is furnished and installed for Public Service operating reasons, as set forth in Section 7.1 of these Standard Terms and Conditions, the kilowatt-hour use measured by the meters will be combined for billing purposes at an applicable rate schedule selected by the customer.

When demand is measured, the customer's monthly maximum demand shall be the sum of the maximum kilowatt demands, determined in accordance with the provisions of the selected rate schedule, as recorded by the individual meters.

Where more than one meter is furnished and installed at the request of the customer, kilowatt-hour use and kilowatt demand measured by each meter will be billed separately at an applicable rate schedule selected by the customer.

Bills will be based upon registration of Public Service meters, except as otherwise provided for in this tariff.

The customer's Generation Obligation, in kilowatts, is determined by Public Service no less frequently than once a year. The Generation Obligation for existing customers or for new customers utilizing an existing building or premises is based upon the customer's share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM) as adjusted by PJM assigned capacity related factors. The Generation Obligation for customers taking service in a new facility, as determined by Public Service, is based upon the load requirements, as estimated by Public Service, of the customer's building or premises. More specifically the customer's Generation Obligation is established based upon the following: 1) an estimate of the customer's peak demand, based upon the load shape of a representative sample of customers served under the same rate schedule, in conjunction with the actual or estimated, as applicable, summer energy use of that customer, or on the customer's actual or estimated, as applicable, summer peak demand, depending upon the type of metering equipment installed by Public Service, and 2) the aforementioned PJM assigned capacity related factors which are established no less frequently than once a year.

The customer's Transmission Obligation, in kilowatts, is determined in a similar manner to the Generation Obligation described above.

9.2. Metering on Customer's Premises:

9.2.1. General: The service and supply of electrical energy by Public Service for the use of owners, landlords, tenants or occupants of newly constructed or renovated residential units will be furnished to them as customers of Public Service through Public Service individual meters.

The service and supply of electrical energy by Public Service to owners, landlords, tenants or occupants of industrial or commercial buildings or residential premises as noted below in Section 9.2.2 and not limited by the above paragraph may be further distributed to other users within such structures and such use and resultant charges, including reasonable administrative costs apportioned to such users. However, such charges shall not exceed the amount that Public Service would charge if the tenant were served and billed directly by Public Service on the most appropriate rate schedule. In no event will a customer buying electric service from Public Service be permitted to resell it for a profit.

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9.2.2. Sub-Metering: The practice where a customer of Public Service or a customer of record, through the use of direct metering devices, installed, maintained and operated at such customer's expense, monitors, evaluates or measures their own consumption of electrical energy or the consumption of a tenant for accounting or conservations purposes.

Sub-metering will be permitted in new or existing buildings or premises where the basic characteristic of use is industrial or commercial. Sub-metering will not be permitted in new or existing buildings or premises where the basic characteristic of use is residential, except where such buildings or premises are publicly financed or government owned; or are condominiums or cooperative housing; or are eleemosynary in nature. In the case of dwelling units, all electric consuming devices must be metered through a single sub-meter.

Sub-metering for the aforementioned purposes and applications shall not adversely affect the ability of Public Service to render service to any customer within the affected building or premises or any other customer. The ownership of all sub-metering devices is that of the customer, along with all incidents in connection with said ownership, including accuracy of the equipment, meter reading and billing, liability arising from the presence of the equipment and the maintenance and repair of the equipment. Any additional costs which may result from and are attributable to the installation of sub-metering devices shall be borne by the customer.

The customer shall be responsible for the accuracy of sub-metering equipment. In the event of a dispute involving such accuracy, the Public Service meter will be presumed correct, subject to test results.

9.3. Testing of Meters: At such times as Public Service may deem proper, or as the Board of Public Utilities may require, Public Service will test its meters in accordance with the standards and bases prescribed by the Board of Public Utilities.

Public Service shall, without charge, make a test of the accuracy of a meter(s) upon request of the customer, provided such customer does not make a request for test more frequently than once in 12 months. A report giving results of such tests shall be made to the customer, and a complete record of such tests shall be kept on file at the office of Public Service in conformance with the New Jersey Administrative Code.

9.4. Metering Options: The following optional metering services are available to customers and are subject to the charges as indicated in the following subsections:

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9.4.1. **Remote Meter Reading (AMI):** In addition to the terms specified in Section 9, Meter Reading and Billing, of these Standard Terms and Conditions, Public Service currently provides remote capable AMI meters as the standard equipment. For residential customers only, a non-communicating meter can be installed at the customer's expense.

In the event the customer chooses not to have an interval meter/advanced meter installed on their premises, the following fees shall apply.

Type of Service	Set-Up Charge	Charge Including SUT	Monthly Charge	Monthly Charge Including SUT
Meter Change (residential only)	$45.00	$47.98		
Monthly meter reading fee			$12.00	$12.79

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9.4.2. Customer Access to Meter Data:

a) **Data Pulses:** Public Service will install and maintain the necessary equipment to supply data pulses for the customer's use at the customer's request, in accordance with the applicable charges listed below. Customers requesting these services are subject to a minimum term of one year.

Type of Service	Set-Up Charges	Set-Up Charges Including SUT	Monthly Charge
Single Phase	$ 364.52	$ 388.67	$ 1.00
Three Phase	364.52	388.67	2.00
Three Phase – time and data pulses	410.00	437.16	3.00

b) **Access to Historical Interval Usage Data:** Where Public Service has an interval meter installed, Public Service will provide Internet access to customer historical interval usage data on a next-day basis through the customer account portal, including Green Button download.

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9.5. **Billing Adjustments:** Whenever a meter is found to be registering fast by 2% or more, an adjustment of charges shall be made. When a meter is found to be registering slow by more than 2%, an adjustment of charges may be made in the case of meter tampering, non-register meters, or in circumstances in which a customer, other than RS, RHS or RLM, should reasonably have known that the bill did not accurately reflect the usage. Billing adjustments will be made in accordance with N.J.A.C. 14:3-4.6.

9.6. **Meter Reading and Billing Period:** All charges are stated on a monthly basis. The term "month" for billing purposes shall mean the period between any two consecutive regularly scheduled meter readings. Meter reading schedules provide for reading meters, in accordance with their geographic location, as nearly as may be practicable every thirty days. Schedules are prepared in advance by Public Service and are available for inspection.

9.7. **Proration of Monthly Charges:** For all billings for service, including initial bills, final bills, and bills for periods other than twenty-five to thirty-six days inclusive, except for temporary service accounts, the monthly charges will be prorated based on the number of days in the billing month. For temporary service accounts, the minimum period for billing purposes shall be one month.

9.8. **Averaged Bills:** Where Public Service is unable to read the meter, Public Service may estimate the amount of electric service supplied and submit an averaged bill, so marked, for customer's acceptance. Adjustments for averaged bills shall be made in accordance with N.J.A.C. 14:3-7.2. Adjustment of such customer's averaged use to actual use will be made after an actual meter reading is obtained.

Public Service reserves the right to discontinue electric service when a meter reading is not obtained for eight (8) consecutive billing periods (monthly accounts), and after written notice is sent to a customer on the fifth and seventh months explaining that a meter reading must be obtained. Public Service will take all reasonable means to obtain a meter reading during normal working hours, evening hours, or Saturdays before discontinuing service. After all reasonable means to obtain a meter reading have been exhausted, Public Service may discontinue service provided at least eight months have passed since the last meter reading was obtained, the Board of Public Utilities has been so notified and the customer has been properly notified by prior mailing.

9.9. **Budget Plan (Equal Payment Plan):** Customers billed under Rate Schedules RS or RHS or GLP (where GLP electric service is used for residential purposes in buildings of four or fewer units) shall have the option of paying for their Public Service charges in equal, estimated monthly installments. Budget plans for residential accounts shall be made in accordance with N.J.A.C. 14:3-7.5. The total Public Service charges for a twelve-month period will be averaged over twelve months and may be paid in twelve equal monthly installments. A review between the actual cost of service and the monthly budget amount will be made at least once in the budget plan year. A final bill for a budget plan year shall be issued at the end of the budget plan year and shall contain that month's monthly budget amount plus any adjustments will be made if actual charges are more or less than the budget amount billed.

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9.10. **Billing of Charges in Tariff:** Unless otherwise ordered by the Board of Public Utilities, the charges and the classification of service set forth in this Tariff or in amendments hereof shall apply to the first month's billing of service in the regular course on and after the effective date set forth in such Tariff covering the use of electric service subsequent to the scheduled meter reading date for the immediately preceding month.

9.11. **Payment of Bills:** At least 15 days time for payment shall be allowed after sending a bill. Bills are payable at any Customer Service Center of Public Service, or by mail, or to any collector or collection agency duly authorized by Public Service. Whenever a residential customer advises Public Service that the customer wishes to discuss a deferred payment agreement because the customer is presently unable to pay a total outstanding bill and/or deposit, Public Service will make a good-faith effort to allow a customer the opportunity to enter into a fair and reasonable deferred payment agreement, which takes into consideration the customer's financial situation. A residential electric or gas customer is not required to pay, as a down payment, more than 25% of the total outstanding bill due at the time of the agreement. Such agreements which extend more than 2 months must be in writing and shall provide that a customer who is presently unable to pay an outstanding debt for Public Service services may make reasonable periodic payments until the debt is liquidated, while continuing payment of current bills. While a deferred payment agreement for each separate service need not be entered into more than once a year, Public Service may offer more than one such agreement in a year. If the customer defaults on any of the terms of the agreement, Public Service may discontinue service after providing the customer with a notice of discontinuance. If a customer's service has been terminated for non-payment of bills, and has met all requirements for restoration of service, Public Service may require a deposit, but not prior to service restoration. Instead, Public Service will bill payment of the deposit, or make other reasonable arrangements. The amount of the deposit required for restoration of service will be determined in accordance with N.J.A.C. 14:3-3.4.

In the case of a residential customer who receives more than one utility service from Public Service and has entered into a separate agreement for each separate service, default on one such agreement shall constitute grounds for discontinuance of only that service.

9.12. **Late Payment Charge:** A late payment charge at the rate of 1.416% per monthly billing period shall be applied to the accounts of customers taking service under all rate schedules contained herein except for Rate Schedules RS, RHS, RLM, WH, WHS, BPL and BPL-POF. Service to a body politic will not be subject to a late payment charge. The charge will be applied to all amounts billed including accounts payable and unpaid finance charges applied to previous bills, and will not be applied sooner than 25 days after a bill is rendered, in accordance with N.J.A.C. 14:3-7.1(e). The amount of the finance charge to be added to the unpaid balance shall be calculated by multiplying the unpaid balance by the late payment charge rate. When payment is received by the Company from a customer who has an unpaid balance which includes charges for late payment, the payment shall be applied first to such charges and then to the remainder of the unpaid balance.

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9.13. Returned Check Charge: A $15.00 charge shall be applied to the accounts of customers who have checks to Public Service returned unhonored by the bank.

9.14. Field Collection Charge: A charge may be applied to the accounts of customers when it becomes necessary for Public Service to make a collection visit to the customer or premises. A charge of $30.00 may be applied to commercial and industrial accounts which include Rate Schedules GLP, LPL, PSAL, HS and HTS.

10. ACCESS TO CUSTOMER'S PREMISES

Public Service shall have the right of reasonable and safe access to customer's premises, and to all property furnished by Public Service, at all reasonable times for the purpose of inspection of customer's premises incident to the rendering of service, reading meters or inspecting, testing, or repairing its facilities used in connection with supplying the service, or for the removal of its property. The customer shall obtain, or cause to be obtained, all permits needed by Public Service for access to its facilities. Access to facilities of Public Service shall not be given except to authorized employees of Public Service or duly authorized government officials.

10.1. Drivable Surfaces: When a vehicle is needed to drive on customer's property to access Public Service facilities, the customer shall ensure that the path has a drivable surface that will prevent the vehicle from becoming disabled.

11. DISCONTINUANCE OF SERVICE

11.1. By Public Service: Public Service, upon notice, when it can be reasonably given, may suspend or curtail or discontinue service for the following reasons: (1) for the purpose of making permanent or temporary repairs, changes or improvements in any part of its system; (2) for compliance in good faith with any governmental order or directive notwithstanding such order or directive subsequently may be held to be invalid; (3) for any of the following acts or omissions on the part of the customer: (a) nonpayment of a valid bill due for service furnished at a present or previous location, however, nonpayment for business service shall not be a reason for discontinuance of residential service except in cases of diversion of service pursuant to N.J.A.C. 14:3-7.8; (b) tampering with any facility of Public Service; (c) fraudulent representation in relation to the use of service; (d) customer moving from the premises, unless the customer requests that service be continued; (e) providing service to others without approval of Public Service except as permitted under Section 9.3 Metering on Customer's Premises of these Standard Terms and Conditions; (f) failure to make or increase an advance payment or deposit as provided for in these Standard Terms and Conditions; (g) refusal to contract for service where such contract is required; (h) connecting and operating equipment in such manner as to produce disturbing effects on the service of Public Service or other customers; (i) failure of the customer to comply with any of these Standard Terms and Conditions; (j) where the condition of the customer's installation presents a hazard to life or property; or (k) failure of customer to repair any faulty facility of the customer; (4) for refusal of reasonable and safe access to customer's premises for necessary purposes in connection with rendering of service, including meter installation, reading or testing, or the maintenance or removal of the property of Public Service.

Public Service shall apply the regulations set forth in N.J.A.C. 14:3.3A.2(a), and only discontinue service for nonpayment of bills if one or both of the following criteria are met: 1) the customer's arrearage is more than $200.00; and 2) the customer's account is more than 3 months in arrears.

Public Service may not discontinue service for nonpayment of bills unless it gives the customer at least 10 days written notice of its intentions to discontinue service, 15 days if a

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landlord-tenant relationship is known to exist. The notice of discontinuance shall not be served until the expiration of the 15-day period indicated in Section 9.11 Payment of Bills of these Standard Terms and Conditions. No additional notice will be required when, in a response to a notice of discontinuance, payment by check is subsequently dishonored. However, in case of fraud, illegal use, or when it is clearly indicated that the customer is preparing to leave, immediate payment of accounts may be required.

Public Service may not discontinue service because of nonpayment of bills in cases where a charge is in dispute, provided that the undisputed charges are paid and a request is made to the Board for investigation of the disputed charge. In such cases, Public Service shall notify the customer that unless steps are taken to invoke formal or informal Board action within 5 days, service will be discontinued for nonpayment.

Public Service may not discontinue residential service involuntarily except between the hours of 8:00 A.M. and 4:00 P.M., Monday through Thursday, unless there is a safety related emergency. There shall be no involuntary termination of service on Friday, Saturday, and Sunday or on the day before a holiday or a holiday, absent such emergency.

Subject to the conditions set forth below, discontinuance of residential service for nonpayment is prohibited if a medical emergency exists within the premises which would be aggravated by discontinuance of service. Discontinuance shall be prohibited for a period of 90 days initially when a customer submits a licensed medical professional's statement in writing to Public Service as to the existence of the emergency, its nature and probable duration, and that termination of service will aggravate the medical emergency. Public Service may also require the customer to give reasonable proof of inability to pay. However, at the end of such period of emergency, the customer shall still remain liable for payment of service(s) rendered, subject to the provisions of N.J.A.C. 14:3-7.6.

1. The Board may extend the 90-day period for good cause upon the receipt of a written request from the customer. The written request shall be in accordance with the preceding terms. Pending the Board's consideration and decision regarding the request for extension, service shall not be discontinued.

2. Public Service may in its discretion, delay discontinuance of residential service for non-payment prior to submission of the licensed medical professional's statement required by this subsection when a medical emergency is known to exist.

If Public Service disconnects service to an unknown account and is notified that a medical emergency exists in the residential premises, Public Service shall: (1) restore service immediately; (2) allow 14 days to apply for service; and (3) allow 7 additional days following the service activation date or 21 days following the date it is notified of a medical emergency, whichever date is later, to submit a medical certification to Public Service written by a licensed medical professional in accordance with the preceding terms.

If a residential customer offers payment of the full amount or a reasonable portion of the amount due at the time of discontinuance, a Public Service representative shall accept payment without discontinuance of service. Whenever such payment is made, the representative shall provide the customer with a receipt showing the date, account number, customer's name and address and amount received.

Public Service shall make every reasonable effort to determine when a landlord-tenant relationship exists at residential premises being served. If such a relationship is known to exist, and if the tenants are not the customers of record but are end-users, service will not be discontinued unless Public Service has given a 15-day written notice to the owner of the premises or to the customer of record to whom the last preceding bill was rendered. Public Service will use its best efforts to provide discontinuance notices to all tenants, including providing tenants with a 15-day written notice, which will be hand-delivered, mailed or posted in a conspicuous area of the premises and in the common areas of multiple family premises.

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In addition, if posting is the method of notification used, Public Service will use its best efforts to place a copy of the notice on each tenant's car windshield or under the door of each tenant's dwelling. In the case of tenants of single and two-family dwellings, each tenant will be provided with a 15-day individual notice.

When a landlord-tenant relationship is known to exist, at the landlord's request, Public Service will provide the landlord with notice and/or have the service placed in the landlord's name if the tenant's service is being discontinued.

If Public Service disconnects service to a master metered premises in which the landlord is the actual customer of record and Public Service has been notified that a medical emergency exists by a tenant, Public Service shall restore service for a period of 7 days to allow the customer of record to resolve the nonpayment issue and to provide the tenant with time to make alternative arrangements.

Public Service shall not discontinue service during the period from November 15 through March 15, in accordance with N.J.A.C. 14:3-3A.5(a), unless otherwise ordered by the Board of Public Utilities, to those residential customers who demonstrate at the time of the intended termination that they are: (1) recipients of benefits under the Lifeline Credit Program; (2) recipients of benefits under the Federal Home Energy Assistance Program (HEAP), or certified as eligible therefor under standards set by the New Jersey Department of Human Services; (3) recipients of Temporary Assistance to Needy Families (TANF); (4) recipients of Federal Supplemental Security Income (SSI); (5) recipients of Pharmaceutical Assistance to the Aged and Disabled (PAAD); (6) recipients of General Assistance (GA) benefits; (7) recipients of the Universal Service Fund (USF); or (8) persons unable to pay their utility bills because of circumstances beyond their control.

Public Service shall not discontinue service to any residential customer, for reasons of nonpayment, failure to pay a cash security deposit or guarantee, or failure to comply with the terms of a deferred payment plan, whenever the high temperature is forecast to be 32 degrees Fahrenheit or below during the next 24 hours, in accordance with N.J.A.C. 14:3-3A.2(e)1.

Public Service shall not discontinue service to any residential customer eligible for the Winter Termination Program, for reasons of nonpayment, failure to pay a cash security deposit or guarantee, or failure to comply with a deferred payment agreement, whenever the high temperature is forecast to be 90 degrees Fahrenheit or more at any time during the following 48 hours, in accordance with N.J.A.C. 14:3-3A.2(e)3.

11.2. At Customer's Request: A customer wishing to discontinue service must give notice as provided in the applicable rate schedule. Within 48 hours of said notice, Public Service will discontinue service or obtain a meter reading for the purpose of calculating a final bill. Where such notice is not received by Public Service, customer shall be liable for service until final reading of the meter is taken. Notice to discontinue service will not relieve a customer from any minimum or guaranteed payment under any contract or rate schedule.

12. RECONNECTION CHARGE

A reconnection charge of $45.00 will be made for restoration of service when service has been suspended or discontinued for nonpayment of any bill due.

13. SERVICE LIMITATIONS

13.1. Continuity of Service: Public Service will use reasonable diligence to provide a regular and uninterrupted supply of service; but, should the supply be suspended, curtailed, or discontinued by Public Service for any of the reasons set forth in Section 11 of these Standard Terms and Conditions, or should the supply of service be interrupted, curtailed, deficient, defective, or fail, by reason of any act of God, accident, strike, legal process, governmental interference, or by reason of compliance in good faith with any governmental order or directive, notwithstanding such order or directive subsequently may be held to be invalid, Public Service shall not be liable for any loss or damage, direct or consequential, resulting from any such suspension, discontinuance, interruption, curtailment, deficiency, defect, or failure.

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13.2. Emergencies: Public Service may curtail or interrupt service or reduce voltage to any customer or customers in the event of an emergency threatening the integrity of its system or the systems to which it is directly or indirectly connected if, in its sole judgment, such action will prevent or alleviate the emergency condition.

In the event of an actual or threatened restriction of electric supplies available to its system or the systems to which it is directly or indirectly connected, Public Service may, after due notice to the Board, curtail or interrupt service or reduce voltage to any customer or customers if such action will prevent or alleviate the emergency condition.

13.3. Unusual Conditions: Public Service may place limitations on the amount and character of electric service it will supply and may refuse service to new customers or to existing customers for additional load if the necessary electric supply is unavailable or if Public Service is or will be unable to deliver, the necessary energy, or to obtain the necessary equipment and facilities to supply such service.

14. THIRD PARTY SUPPLIER SERVICE PROVISIONS

14.1. Third Party Supplier Electric Supply: Customers served on any of the applicable rate schedules of this Tariff for Electric Service and who desire to purchase their electric supply of capacity, transmission, and energy, hereinafter referenced as electric supply, from a Third Party Supplier (TPS) must provide appropriate authorization as required by the TPS. Customers who are not enrolled with a TPS will continue to receive Basic Generation Service electric supply.

A TPS is a retail energy and capacity provider that has been licensed by the Board and has executed a Third Party Supplier Agreement with Public Service so as to be eligible to furnish electric supply with delivery to the retail customer by Public Service. The customer may act as a third party supplier for its account if the customer meets all of the requirements of this Tariff.

14.1.1. Enrollment: Customers may request an enrollment package from Public Service which in addition to providing general information regarding electric supply, describes the process necessary for a customer to obtain a TPS for electric supply. This enrollment package will be provided to the customer at no charge and may be obtained by calling or writing Public Service or visiting a Customer Service Center.

14.2. Initiation of Service: In order to be eligible to receive electric supply from a TPS, the customer must contract with a TPS to obtain electric supply for delivery to the customer by Public Service. Delivery of electric supply to retail customers will be provided in accordance with the terms of the Third Party Supplier Agreement. The customer's designated TPS is required to notify Public Service of its selection as the customer's provider of electric supply. Initiation of service will become effective on the customer's next scheduled meter reading date that is at least thirteen (13) days following the receipt by Public Service from the TPS of the customer's selection.

Once Public Service has received the TPS notification for the initial, or subsequent, enrollment with a TPS, which process is as set forth in this subsection and in Section 14.1, Public Service will confirm the customer's selection of its designated TPS by sending a letter of confirmation to the customer. This letter of confirmation shall be provided within one day and shall include notification of the customer's right to rescind their contract with their designated TPS in accordance with Board established procedures. This right to rescind must be exercised within seven (7) days of mailing of the letter of confirmation. In the event of a dispute, assignment of a customer will not

STANDARD TERMS AND CONDITIONS
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occur unless and until the dispute is resolved. Once assignment has occurred, the TPS will be required to provide all of the electric supply consumed on the Public Service customer's account (single point of delivery).

14.2.1. Customer Change of Third Party Supplier: If a customer subsequently elects to change its TPS, the customer must provide appropriate authorization as required by their TPS and as set forth in Section 14.1 and Section 14.2. Service from this alternate TPS will become effective on the customer's next scheduled meter reading date that is at least thirteen (13) days following the receipt by Public Service from the TPS of the customer's selection. Upon enrollment with a TPS, the customer may not change its TPS more frequently then once every billing month cycle.

14.2.2. Customer Return to Public Service Rate Schedule Electric Supply:

a) If the customer subsequently returns to Public Service as supplier of electric supply, the return to Public Service will become effective on the customer's next scheduled meter reading date that is at least thirteen (13) days following the receipt of customer notification by Public Service. Public Service shall confirm the customer's selection of Public Service as its provider of electric supply by sending a letter of confirmation to the customer and the customer shall have the right to rescind in accordance with Section 14.2, Initiation of Service, of these Standard Terms and Conditions.

b) If a customer's TPS no longer satisfies the requirements imposed on it by the Third Party Supplier Agreement, such customer shall immediately return to, and receive electric supply from Public Service under customer's applicable rate schedule unless and until customer selects another TPS in accordance with Section 14.2.1. The customer shall be advised by Public Service in writing of this change in supplier.

14.2.3. Third Party Supplier's Termination of Customer's Electric Supply: A TPS will not be permitted to physically connect or disconnect energy service to a customer.

14.3. Customer Billing Process: Public Service will provide one combined bill to the TPS's retail customer(s) containing both Public Service charges and TPS electric supply charges, providing the TPS executes and satisfies the terms of the Third Party Supplier Customer Account Services Master Service Agreement, and the retail customer(s) maintain a satisfactory bill payment history. Customer(s) may elect to receive a separate bill directly from its TPS for TPS services. If a customer requests and is permitted to receive a combined bill, but the customer's account subsequently becomes 120 days in arrears at any point in the future, such customer will thereafter be required to receive a separate bill directly from its TPS (including any subsequent TPS) for TPS services and will not be permitted to receive a combined bill from Public Service until such time the customer's arrearage is reduced to 60 days or less. Only Public Service owned, installed, and read meters will be used to determine customer usage for the purpose of calculating Public Service charges.

14.3.1. Payment of Bills: Payment of bills, including TPS's charges for electric supply if billed by Public Service, shall be made to Public Service and shall be in accordance with Section 9, Meter Reading and Billing, of these Standard Terms and Conditions. Any customer overpayment will be held in the customer's Public Service account to be applied against future customer bills or will be refunded to the customer at the customer's request.

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14.3.2. Late Payment Charges: A late payment charge in accordance with Section 9.12, Late Payment Charge, of these Standard Terms and Conditions is to be applicable to Public Service customer charges and TPS's charges for electric supply if billed by Public Service. Customer shut-offs in cases where there is non-payment to Public Service for its customer charges and TPS's charges for electric supply if billed by Public Service, are only performed in accordance with Section 11, Discontinuance of Service, of these Standard Terms and Conditions.

Billing Disputes: In the event of a billing dispute between the customer and the TPS, Public Service's sole duty is to verify its customer charges and billing determinants. Customer continues to remain responsible for the timely payment of all Public Service charges, and all undisputed TPS charges for electric supply if such charges are billed by Public Service, in accordance with Section 9, Meter Reading and Billing, and Section 14.3.1, Payment of Bills, of these Standard Terms and Conditions. All questions regarding TPS's charges or other terms of the customer's agreement with a TPS are to be resolved between the customer and its TPS. Public Service will not be responsible for the enforcement, intervention, mediation, or arbitration of agreements entered into between TPS customers and their TPS. Billing disputes that may arise regarding Public Service's charges shall be subject to Section 11, Discontinuance of Service, of these Standard Terms and Conditions.

14.4. Continuity of Service: In addition to the terms specified in Section 11, Discontinuance of Service, and Section 13, Service Limitations, of these Standard Terms and Conditions, Public Service shall have the right (i) to require a TPS's electric supply sources to be disconnected from Public Service's electrical system; (ii) to otherwise curtail, interrupt, or reduce a TPS's electric supply; or (iii) to disconnect a TPS's customer(s) whenever Public Service determines, or whenever Public Service is directed by PJM, that such a disconnection, curtailment, interruption or reduction is necessary to facilitate construction, installation, maintenance, repair, replacement or inspection of any of Public Service's or PJM members' facilities; to maintain the safety and reliability of Public Service's electrical system and any generation facilities attached thereto; or due to Emergencies, minimum generation ("light load") conditions, forced outages, potential overload of Public Service's or PJM's transmission and/or distribution circuits or events of Force Majeure including, but not limited to, those events specified in Section 13.1, Continuity of Service, of these Standard Terms and Conditions.

14.5. Interval Metering: In addition to the terms specified in Section 9, Meter Reading and Billing, of these Standard Terms and Conditions, customers being served by a TPS that have interval meters will be billed using the data obtained from those meters. If the interval meter is not operational, customer's hourly usage and demand, where applicable, will be determined by employing load profiling based upon the customer's rate schedule or historical customer usage and demand data, at the discretion of Public Service.

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15. NET METERING INSTALLATIONS

15.1. **General:** For the purpose of this Section of the Tariff for Electric Service a customer-generator is a customer that generates electricity using Class I renewable resources as defined in N.J.A.C. 14:8-1.2 on the customer's side of the meter. Net Metering provides for the billing or crediting, as applicable, of energy usage by measuring the difference between the amount of electricity delivered by Public Service to a Qualified Customer Generator, as defined in Section 15.2, in a given billing period and the electricity delivered by Qualified Customer Generator into the Public Service distribution system. Public Service will select and supply the type of meter(s) that will enable the measurement of the electricity for the billing or crediting of energy delivered as indicated above.

Customers qualified for Net Metering shall be responsible for all interconnection costs as defined in N.J.A.C. 14:8-4.1 *et seq*., which shall be in addition to any line or service extension charge required to meet service requirements. For customers eligible for Net Metering the term usage as applied in Section 3, Charges for Service, shall mean net usage as determined by Net Metering.

15.2. **Limitations and Qualifications for Net Metering:** To qualify for Net Metering, a customer-generator must generate Class I renewable energy as defined in N.J.A.C. 14:8-1.2. Further, to qualify for Net Metering, the capacity of the customer's generating system cannot exceed the amount of electricity supplied by the electric power supplier or basic generation service provider to the customer's residence or facility, as applicable, over an annualized period. Customer-generators that qualify for Net Metering shall be referred to as "Qualified Customer-Generators."

Additionally, customers participating in Community Solar cannot participate in Net Metering unless each project is metered separately.

15.3. **Installation Standards:** A Qualified Customer-Generator shall ascertain and comply with the requirements of Public Service which are covered in detail in the "Information and Requirements for Electric Service", available on www.pseg.com or by request as designated in Section 6.3, Secondary Distribution Service, of these Standard Terms and Conditions. In addition, the Qualified Customer-Generator shall be responsible for meeting all applicable safety and power quality standards as set forth below.

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Qualified Customer-Generator's generating system shall comply with all applicable safety and power quality standards specified by the National Electrical Code, Institute of Electrical and Electronics Engineers, accredited testing institutions, such as Underwriters Laboratories. The customer's installation should be made in accordance with the State of New Jersey Uniform Construction Code requirements for electrical installations, UL 1741 and the IEEE Standard 1547. Net Metering systems served by network distribution systems, shall comply to standards established by Public Service and approved by the New Jersey Board of Public Utilities ("Board") in addition to the aforementioned applicable safety and power quality standards and all other requirements in N.J.A.C. 14:8-4.1 *et seq*.

15.4. **Initiation of Service:** Prior to interconnecting with the Public Service distribution system the Qualified Customer-Generator is required to provide Public Service with an Interconnection Application provided by the Office of Clean Energy and pay all appropriate charges as detailed in the Interconnection Application Process. Additionally, Public Service may, at its option, inspect the interconnection prior to the initiation of Net Metering service for Qualified Customer-Generators.

Initiation of service will become effective on the Qualified Customer-Generator's first regularly scheduled meter reading date that is at least twenty (20) days after the customer elects this provision, by executing an Interconnection Application, but in no case prior to the installation of the necessary meter(s), and shall terminate at a regularly scheduled meter reading date that is at least twenty (20) days following the receipt of customer notification by Public Service. The Qualified Customer-Generator shall provide Public Service on a regular basis with access to the customer's telephone service when required for the purposes of acquiring metering data.

15.5. **Net Billing:** Where the amount of electricity delivered by the Qualified Customer-Generator plus any kilowatt-hour credits held over from the previous billing periods exceeds the electricity supplied by the Qualified Customer-Generator's electric supplier or basic generation service provider, as applicable, the Qualified Customer-Generator shall be credited for the excess kilowatt-hours to the next billing period. At the end of the annualized period the Qualified Customer-Generator will be compensated for any remaining credits by the Qualified Customer-Generator's electric supplier or basic generation service provider, as applicable, at their avoided cost of wholesale power.

A Qualified Customer-Generator shall have a one-time opportunity to select a monthly billing period as the start of the Qualified Customer-Generator's annualized period. This selection will become effective on the first regularly scheduled meter reading date that is at least twenty (20) days after the Qualified Customer-Generator notifies Public Service of the selection of their alternate monthly billing period. If a Qualified Customer-Generator initiating service after March 2, 2009 does not submit an annualized period selection they shall be assigned a default annualized period until such time as they notify Public Service of the selection of their alternate annualized period.

In the event that a Qualified Customer-Generator changes suppliers, the electric power supplier or basic service provider with whom service is terminated shall treat the end of the service period as if it were the end of the annualized period. Changes in supplier are to be in accordance with Section 14.2.1, Customer Change of Third Party Supplier, or Section 14.2.2, Customer Returns to Public Service Rate Schedule Electric Supply, of these Standard Terms and Conditions, as applicable.

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(Continued)

15.6. **Billing Adjustments:** In addition to Section 9.5, Billing Adjustments, of these Standard Terms and Conditions whenever a meter measuring energy delivered from a Qualified Customer-Generator to Public Service's distribution system is found to be registering slow by 2% or more an adjustment of the energy delivered shall be made and an adjustment may be made if the meter is found to be registering fast by more than 2%. The Qualified Customer-Generator's electric supplier or basic generation service provider, as applicable, will determine the applicability of this latter adjustment.

15.7. **Budget Plan (Equal Payment Plan):** The payment option described in Section 9.9, Budget Plan, is not available for customers taking service under this Section 15, Net Metering.

15.8. **Program Availability:** In accordance with N.J.S.A. 48:3-87(e)(1), Public Service may be authorized by the Board to cease offering net metering to customers that are not already net metered whenever the total rated generating capacity owned and operated by net metering customer-generators Statewide equals 5.8 percent of the total annual kilowatt-hours sold in this State by each electric power supplier and each basic generation service provider during the prior one-year period.

16. NEW JERSEY AUTHORIZED TAXES

The following taxes are authorized by the State of New Jersey and are applied in accordance with P.L. 1997, c. 162 (the "Energy Tax Reform Statute"), as amended by P. L. 2006, c. 44, as amended by P.L. 2016, c. 57, and are included in the appropriate charges contained within this Tariff for Electric Service.

16.1. **New Jersey Sales and Use Tax:**
In accordance with P.L. 1997, c. 162, as amended by P. L. 2006, c. 44, as amended by P.L. 2016, c. 57, provision for the New Jersey Sales and Use Tax (SUT) has been included in all applicable charges by multiplying the charges that would apply before application of the SUT by the factor 1.06625.

16.1.1. The Energy Tax Reform Statute exempts the following customers from the SUT provision, and when billed to such customers, the charges otherwise applicable shall be reduced by the provision for the SUT included therein:

a) Franchised providers of utility services (gas, electricity, water, wastewater and telecommunications services provided by local exchange carriers) within the State of New Jersey.

b) Special contract customers for which a customer-specific tax classification was approved by a written Order of the New Jersey Board of Public Utilities prior to January 1, 1998.

c) Agencies or instrumentalities of the federal government.

d) International organizations of which the United States of America is a member.

e) Additional customers as authorized by the State of New Jersey Department of Treasury in accordance with the provisions of P.L. 1997, c. 162, as amended by P. L. 2006, c. 44, as amended by P.L. 2016, c. 57.

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16.1.2. The Business Retention and Relocation Assistance Act (P.L. 2004, c. 65) and subsequent amendment (P.L. 2005, c.374) exempts the following customers from the SUT provision, and when billed to such customers, the charges otherwise applicable shall be reduced by the provision for the SUT included therein:

a) A qualified business that employs at least 250 people within an enterprise zone, at least 50% of whom are directly employed in a manufacturing process, for the exclusive use or consumption of such business within an enterprise zone, and

b) A group of two or more persons:

(b-1) Each of which is a qualified business that are all located within a single redevelopment area adopted pursuant to the "Local Redevelopment and Housing Law," P.L.1992, c.79 (C.40A:12A-1 *et seq.*);
(b-2) That collectively employ at least 250 people within an enterprise zone, at least 50% of whom are directly employed in a manufacturing process;
(b-3) Are each engaged in a vertically integrated business, evidenced by the manufacture and distribution of a product or family of products that, when taken together, are primarily used, packaged and sold as a single product; and
(b-4) Collectively use the energy and utility service for the exclusive use or consumption of each of the persons that comprise a group within an enterprise zone.

c) A business facility located within a county that is designated for the 50% tax exemption under section 1 of P.L. 1993, c.373 (C.54:32B-8.45) provided that the business certifies that it employs at least 50 people at that facility, at least 50% of whom are directly employed in a manufacturing process, and provided that the energy and utility services are consumed exclusively at that facility.

A business that meets the requirements in (a), (b) or (c) above shall not be provided the exemption described in this section until it has complied with such requirements for obtaining the exemption as may be provided pursuant to P.L.1983, c.303 (C.52:27H-60 *et seq.*) and P.L.1966, c.30 (C.54:32B-1 *et seq.*) and Public Service has received a sales tax exemption letter issued by the New Jersey Department of Treasury, Division of Taxation.

16.2. **New Jersey Corporation Business Tax:**
In accordance with P.L. 1997, c. 162, provision for the New Jersey Corporation Business Tax (CBT) has been included in the Service Charge, Distribution Charge, and the Demand Charge.

16.2.1. The Energy Tax Reform Statute exempts the following customers from the CBT provision, and when billed to such customers, the charges otherwise applicable shall be reduced by the provision for the CBT (and related SUT) included therein.

a) Franchised providers of utility services (gas, electricity, water, wastewater and telecommunications services provided by local exchange carriers) within the State of New Jersey.

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b) Special contract customers for which a customer-specific tax classification was approved by a written Order of the New Jersey Board of Public Utilities prior to January 1, 1998.

c) Additional customers as authorized by the State of New Jersey Department of Treasury in accordance with the provisions of P.L. 1997, c. 162.

17. TERMINATION, CHANGE OR MODIFICATION OF PROVISIONS OF TARIFF

This tariff is subject to the lawful orders of the Board of Public Utilities of the State of New Jersey.

Public Service may at any time and in any manner permitted by law, and the applicable rules and regulations of the Board of Public Utilities of the State of New Jersey, terminate, or change or modify by revision, amendment, supplement, or otherwise, this Tariff or any part thereof, or any revision or amendment hereof or supplement hereto.

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY

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REGULATION FOR RESIDENTIAL UNDERGROUND EXTENSIONS

The following are the charges applicable for certain residential underground extensions, in compliance with the Regulations on Residential Underground Extensions as per N.J.A.C. 14:3-8 et seq., and referenced in the Sections 3.7.2. – Multi-unit Developments of the Standard Terms and Conditions of this tariff.

The Applicant will be charged for standard electric service as calculated in Section A – Base Charges and/or Section B – Additional Charges. The charges in Sections A and B will be adjusted for tax gross-up effects consistent with all applicable federal and state tax laws, including, but not limited to, the “Protecting Americans from Tax Hikes Act of 2015” (“the PATH Act”). For non-typical situations, including service to multiple family buildings and other situations as detailed below, such charges shall be equal to estimated cost of the underground construction less the total estimated costs of the otherwise applicable overhead construction, such result shall include the gross-up for income tax effects. Such cost estimates shall be based on the unit costs as detailed in Exhibits I to III and shall be based on the necessary construction to supply the same loads and locations utilizing Public Service’s standard design and construction standards. Requests for additional facilities shall be considered as Atypical Conditions and other charges may apply in accordance with Section 3.5.2 of these Standard Terms and Conditions.

Charges for street and area lighting provided by Public Service under Rate Schedules PSAL or BPL are as indicated in Section C – Street and Area Lighting Charges.

A. Base Charges:

		Charge Per Building Lot	Charge Per Foot For Total Front Footage
1.	Single-family	$ 529.43	$ 1.43
2.	Duplex-family buildings, mobile homes, multiple occupancy buildings, three-phase, high capacity extensions, lots requiring primary extensions thereon, excess transformer capacity above 8.5 kVA, etc.	Charge to be based on differential cost according to unit costs specified in Exhibit I to III.	

B. Additional Charges:

	Item	Unit	Charge
1.	Primary termination...	Each	$ 310.57
2.	Primary junction enclosure	Each	$ 1,639.80
3.	Excess service length over 50 feet.....................	Per foot trench 100 & 150 amp	$ 5.47
4.	Excess service length over 50 feet.....................	Per foot trench 100 & 150 amp	$ 5.47
	....	Over 150 amp	$ 6.37
5.	Excess service length over 50 feet.....................	Per foot trench 100 & 150 amp	$ 5.47
6.	Multi-phase constructions..................................	Per foot per phase	$ (3.90)
7.	Pavement cutting and restoration, rock removal, blasting, difficult digging and special backfill	At actual low bid cost with option of Applicant to contract for as limited by N.J.A.C. 14:5-2.4 et seq.	

REGULATION FOR RESIDENTIAL UNDERGROUND EXTENSIONS
(Continued)

C. Street and Area Lighting Charges:

The Applicant shall pay the normal charges for all luminaires as indicated in the applicable street and area lighting rate schedule.

The monthly charge and up-front contribution for all lighting poles not installed on public streets shall be at the full charges indicated in the applicable street and area lighting rate schedule.

1. Street lighting poles where spacing is equal to or greater than 200 feet.

   For street and area lighting poles installed on public streets, PSE&G will provide, as the standard lighting pole, a laminated wood pole (PSE&G part number W04-0197) at no up-front contribution or monthly charge. Requests for use of another type or size lighting pole shall be considered as a request for a Specialty Lighting Pole. In these cases, an up-front contribution credit equal to the installed cost of the standard lighting pole shall be provided by Public Service, with monthly charges calculated as per the applicable street and area lighting rate schedule.

2. Additional street lighting poles where spacing is less than 200 feet.

   The Applicant shall pay the full normal charges for lighting poles as indicated in the applicable street and area lighting rate schedule where the spacing of such lighting poles is less than 200 feet.

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REGULATION FOR RESIDENTIAL UNDERGROUND EXTENSIONS
(Continued)
EXHIBIT I - UNIT COSTS OF UNDERGROUND CONSTRUCTION - SINGLE PHASE

	Item	Unit	Total Charge*
1.	Trenching		
	Sole Trenching	Per foot	$ 2.22
	Joint Trenching**	Per foot	$ 1.28
2.	Primary cable (1/0 AWG Al.)	Per foot	$ 3.93
3.	Secondary wire		
	2/0 AWG Cu	Per foot	$ 3.59
	350 kcmil Cu	Per foot	$ 10.75
4.	Services		
	50 feet complete - 100 & 150 amp	Each	$ 552.58
	100 & 150 amp (#2 AWG Cu.)	Per foot	$ 11.05
	50 feet complete - over 150 amp	Each	$ 675.06
	Service - over 150 amp (2/0 AWG Cu.)	Per foot	$ 13.50
5.	Primary termination - branch	Each	$ 1,563.94
6.	Primary junction enclosure - branch	Each	$ 2,294.67
7.	Secondary enclosure	Each	$ 692.09
8.	Street light cable (#8 AWG Cu.)	Per foot	$ 4.32
9.	Transformers - including fiberglass pad		
	25 kVA - single-phase	Each	$ 1,376.93
	50 kVA - single-phase	Each	$ 5,290.64
	75 kVA - single-phase	Each	$ 5,645.29
	100 kVA - single-phase	Each	$ 6,285.68
	167 kVA - single-phase	Each	$ 3,632.41
10.	Street light poles (standard pole only)		
	30 foot laminated pole	Each	$ 1,100.00

*Charges do not include costs for clerical, dispatching, supervision, or general office functions as, except for third-party damage or other actions by third-parties, those costs are considered legitimate costs of doing business and incurred as part of the Company's normal operations in meeting its regulatory duty to furnish service.

** Joint trench calculation: 0.5 (0.85 x $2.22) + 0.15 x $2.22 =$1.28

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REGULATION FOR RESIDENTIAL UNDERGROUND EXTENSIONS
(Continued)
EXHIBIT II - UNIT COSTS OF UNDERGROUND CONSTRUCTION - THREE-PHASE

	Item	Unit	Total Charge*
1.	Primary cable		
	750 kcmil Cu.	Per foot	$ 25.24
	500 kcmil Cu.	Per foot	$ 17.92
	4/0 AWG Al.	Per foot	$ 12.62
	1/0 AWG Al.	Per foot	$ 7.06
2.	Secondary 4-wire (350 kcmil Cu.)	Per foot	$ 11.34
3.	Primary Terminations		
	Main line (750 kcmil)	Set of 3	$ 3,387.34
	Three phase branch (500 kcmil)	Set of 3	$ 785.25
	Two phase branch (4/0 AWG)	Set of 2	$ 425.38
4.	5 inch conduit	Per foot	$ 5.87
	6 inch conduit	Per foot	$ 2.26
5.	Transformers - including fiberglass pad		
	150 kVA - three-phase	Each	$ 11,158.06
	225 kVA - three-phase	Each	$ 10,085.50
	300 kVA - three-phase	Each	$ 20,902.25
	500 kVA - three-phase	Each	$ 23,728.71
	750 kVa - three-phase	Each	$ 22,574.76
	1000 kVa - three-phase	Each	$ 34,287.53
	1500 kVa - three-phase	Each	$ 38,672.75

*Charges do not include costs for clerical, dispatching, supervision, or general office functions as, except for third-party damage or other actions by third-parties, those costs are considered legitimate costs of doing business and incurred as part of the Company's normal operations in meeting its regulatory duty to furnish service.

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REGULATION FOR RESIDENTIAL UNDERGROUND EXTENSIONS
(Continued)
EXHIBIT III - UNIT COSTS OF OVERHEAD CONSTRUCTION
SINGLE-PHASE AND THREE-PHASE

	Item	Unit	Total Charge*
1.	Pole line - including 7-35 foot and 2-40 foot poles,		
	anchors and guys per 1000 feet	Per foot	$ 6.48**
2.	Primary wire		
	1/0 AWG AAAC covered, one phase	Per foot	$ 7.25
	379.5 kcmil Al. covered, three phase	Per foot	$ 11.11
	1/0 AWG AAAC base, one phase	Per foot	$ 7.30
	379.5 kcmil Al. bare, three phase	Per foot	$ 10.85
3.	Primary wire neutral (1/0 AWG AAAC)	Per foot	$ 2.76
4.	Secondary cable		
	3 wire (2/0 AWG Al.)	Per foot	$ 5.16
	4 wire (2/0 AWG Al.)	Per foot	$ 8.45
5.	Services - single-phase		
	50 feet complete - 100 & 150 amp	Each	$ 259.25
	100 & 150 amp (#2 AWG Al.)	Per foot	$ 5.19
	50 feet complete - over 150 amp	Each	$ 379.01
	Over 150 amp (2/0 AWG Al.)	Per foot	$ 7.58
	Services - three-phase		
	up to 200 amp (2/0 AWG Al.)	Per foot	$ 7.76
	over 200 amp (397.5 kcmil Al.)	Per foot	$ 12.27
6.	Transformers		
	25 kVA - single-phase	Each	$ 1,353.88
	50 kVA - single-phase	Each	$ 3,946.82
	100 kVA - single-phase	Each	$ 5,247.55
	3 - 25 kVA - three-phase	Per set	$ 4,061.65
	3 - 50 kVA - three-phase	Per set	$ 11,840.85
	3 - 100 kVA - three-phase	Per set	$ 15,742.65

*Charges do not include costs for clerical, dispatching, supervision, or general office functions as, except for third-party damage or other actions by third-parties, those costs are considered legitimate costs of doing business and incurred as part of the Company's normal operations in meeting its regulatory duty to furnish service.

**Joint pole line cost to be used = $3.23

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RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 57**

SOCIETAL BENEFITS CHARGE

Cost Recovery
(per kilowatt-hour)

Component:

Social Programs	$ 0.001728
Energy Efficiency and Renewable Energy Programs	0.003287
Manufactured Gas Plant Remediation	0.000471
Sub-total per kilowatt-hour	$ 0.005486

Charge including losses, USF and Lifeline:

	Loss Factor	Sub-total Including Losses	USF	Lifeline	Total Charge
Secondary Service	5.8327%	$ 0.005826	$ 0.001243	$ 0.000698	$ 0.007767
LPL Primary	3.3153%	0.005674	0.001243	0.000698	0.007615
HTS Subtransmission	2.0472%	0.005601	0.001243	0.000698	0.007542
HTS High Voltage & HTS Transmission	0.8605%	0.005534	0.001243	0.000698	0.007475

Charges including New Jersey Sales and Use Tax (SUT)

Secondary Service	$ 0.008282
LPL Primary	0.008119
HTS Subtransmission	0.008042
HTS High Voltage & HTS Transmission	0.007970

SOCIETAL BENEFITS CHARGE

This mechanism is designed to insure recovery of costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Actual costs incurred by the Company for each of these cost components will be subject to deferred accounting. Interest at the two-year constant maturity treasury rate plus 60 basis points will be accrued monthly on any under- or over-recovered balances for all components other than Manufactured Gas Plant Remediation. Interest at the seven-year constant maturity treasury rate plus 60 basis points will be accrued monthly on any under- or over-recovered balances for the Manufactured Gas Plant Remediation. The interest rates for all components other than USF and Lifeline shall change each August 1. The interest rates for the USF and Lifeline components shall be reset each month. In appropriate circumstances, the Board of Public Utilities may approve a discount from the Societal Benefits Charge.

(Charges are for illustrative purposes only and are based on the Tenth Revised Sheet No. 57 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 58**

SOCIETAL BENEFITS CHARGE
(Continued)

SOCIAL PROGRAMS

This component shall recover costs associated with existing social programs. This includes but is not limited to uncollectible customers' accounts.

ENERGY EFFICIENCY AND RENEWABLES (EE&R) PROGRAMS

This factor is a recovery mechanism which will operate in accordance with the Demand Side Management (DSM) conservation incentive regulations and successor regulations. The factor has been used to recover past Core and Performance Program Costs and Performance Program Payments, payments for Large-Scale Conservation Investments, and all recoverable costs associated with the Board's Comprehensive Resource Analysis Orders, including but not limited to the low income Comfort Partners Program.

The New Jersey Clean Energy Program energy efficiency and renewable energy programs (formerly CRA Programs) are approved by the Board pursuant to N.J.S.A. 48:3-60(a)(3). They include energy efficiency programs, customer-sited renewable energy programs, grid supply renewable energy programs and any other programs the BPU may approve. These programs may be administered and or implemented by Public Service, the BPU, or a third party appointed by the BPU. New Jersey Clean Energy Program Costs consist of, but are not limited to, rebates, grants, payments to third parties for program implementation, direct marketing costs, energy efficiency and renewable energy hardware, administration, measurement and evaluation of energy efficiency and renewable energy programs, customer communication and education, market research, costs associated with developing, implementing and obtaining regulatory approval, costs of research and development activities associated with energy efficiency and renewable energy programs, applicable Lost Revenues, and New Jersey Clean Energy Program advertising costs.

MANUFACTURED GAS PLANT REMEDIATION

This factor shall recovery costs associated with addressing and resolving claims by and or requirements of governmental entities and private parties related to activities necessary to perform investigations and the remediation of environmental media.

UNIVERSAL SERVICE FUND

These factors shall recover costs associated with new or expanded social programs.

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 60**

NON-UTILITY GENERATION CHARGE

Cost Recovery (per kilowatt-hour)

	St Lawrence NYPA Credit RS, RHS and RLM	Non-Utility Generation above market costs	Total
Total Cost per kilowatt-hour		$0.000023	
Amount per kilowatt-hour of cost recovery after application of losses:			
RS, RHS & RLM (Loss Factor =5.8327%)	($ 0.000000)	$0.000024	$0.000024
Other Secondary (Loss Factor =5.8327%)		0.000024	0.000024
LPL Primary (Loss Factor =3.3153%)		0.000024	0.000024
HTS Subtransmission (Loss Factor =2.0472%)		0.000023	0.000023
HTS High Voltage & HTS Transmission (Loss Factor =0.8605%)		0.000023	0.000023
Charges including New Jersey Sales and Use Tax (SUT)			
RS, RHS & RLM	($ 0.000000)	$0.000026	$0.000026
Other Secondary Service		0.000026	0.000026
LPL Primary		0.000026	0.000026
HTS Subtransmission		0.000025	0.000025
HTS High Voltage & HTS Transmission		0.000025	0.000025

NON-UTILITY GENERATION CHARGE

This mechanism is designed to insure recovery of costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. This charge shall recover: 1) above market costs associated with non-regulated generation costs which are related to long-term contractual power purchase arrangements approved by the Board and/or established under requirements of the Public Utility Regulatory Policies Act of 1978 and 2) other generation costs as may be approved by the Board. Actual costs incurred by the Company will be subject to deferred accounting. The St. Lawrence New York Power Authority (NYPA) Annual Benefit Allocation credit reflects the annual Economic Benefit allocation for New Jersey’s investor owned utilities to supply residential customers’ load.

Interest at the two-year constant maturity treasury rate plus 60 basis points will be accrued monthly on any under- or over-recovered Non-utility Generation above market cost balances. This interest rate shall change each August 1.

(Charges are for illustrative purposes only and are based on the Sixth Revised Sheet No. 60 filed with the BPU on November 1, 2023)

Date of Issue: Effective:

Issued by SCOTT S. JENNINGS, SVP – Finance, Planning & Strategy – PSE&G
80 Park Plaza, Newark, New Jersey 07102
Filed pursuant to Order of Board of Public Utilities dated
in Docket No.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 61**

ZERO EMISSION CERTIFICATE RECOVERY CHARGE

Charge (per kilowatt-hour)

ZERO EMISSION CERTIFICATE RECOVERY CHARGE:

Charge	$ 0.004000
Return of Excess Collections	$ 0.000000
Total Charge	$ 0.004000
Charge including New Jersey Sales and Use Tax (SUT)	$ 0.004265

ZERO EMISSION CERTIFICATE RECOVERY CHARGE

This charge provides for the recovery of costs associated with the Zero Emission Certificate Program directed by the Board of Public Utilities ("BPU" or "Board") as detailed below.
Pursuant to the BPU's Zero Emission Certificate Charge Order dated November 19, 2018 in Docket No. EO18091004, the Board approved the implementation of a non-bypassable, irrevocable ZEC Charge of $0.004000 per kWh for all customers. The ZEC Charge reflects the emission avoidance benefits of the continued operation of selected nuclear plants as determined in L. 2018, c. 16 ("ZEC Law"). The ZEC Charge has been set at the rate specified in the ZEC Law and may be adjusted periodically by the Board, in accordance with the methodology provided for in the ZEC Law.

In accordance with the ZEC Law, the proceeds of the ZEC Charge will be placed in a separate, interest-bearing account and will be used solely to purchase ZECs and to reimburse the Board for its reasonable, verifiable costs incurred to implement the ZEC program. Refunds will be provided to the customers served under each of the Company's rate schedules in proportion to the ZEC Charge revenues contributed by the rate schedule.

The ZEC Charge will become effective upon the issuance of the April 2019 Board Order in Docket No. EO18080899.

(Charges are for illustrative purposes only and are based on the Fourth Revised Sheet No. 61 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 62**
Original Sheet No. 63

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 64**

SOLAR PILOT RECOVERY CHARGE

Charge
(per kilowatt-hour)

SOLAR PILOT RECOVERY CHARGE:

Charge.. $ 0.000063

Charge including New Jersey Sales and Use Tax (SUT).. $ 0.000067

SOLAR PILOT RECOVERY CHARGE

This charge is designed to recover the revenue requirements associated with the Public Service Solar Pilot Program per the Board Order in Docket Nos. ER18010029, GR18010030, AX18010001 and ER18030231 EO07040278 less the net proceeds from the sale of associated Solar Renewable Energy Certificates (SRECs) or cash received in lieu of SRECs. The net recovery by the Company is subject to deferred accounting. Interest at the two-year constant maturity treasury rate plus 60 basis points will be accrued monthly on any under- or over-recovered balances. This interest rate shall change each August 1.

(Charges are for illustrative purposes only and are based on the Fifth Revised Sheet No. 64 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 65**

GREEN PROGRAMS RECOVERY CHARGE

Component:	Charge (per kilowatthour)
Carbon Abatement Program	($0.000010)
Energy Efficiency Economic Stimulus Program	0.000004
Solar Generation Investment Program	0.000297
Solar Loan II Program	0.000109
Energy Efficiency Economic Extension Program	0.000034
Solar Generation Investment Extension Program	(0.000222)
Solar Loan III Program	0.000015
Energy Efficiency Economic Extension Program II	0.000108
Solar Generation Investment Extension II Program	(0.000105)
Energy Efficiency 2017 Program	0.000268
Transition Renewable Energy Certificate Program	0.002480
Clean Energy Future - Energy Efficiency Program	0.001257
Successor Solar Incentive Program	0.000601
Community Solar Energy Program	0.000084
Sub-total per kilowatthour	$0.004920
Charge including New Jersey Sales and Use Tax (SUT)	$0.005246

GREEN PROGRAMS RECOVERY CHARGE

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs. The charge will be reset nominally on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under- or over- recovered balances. The interest rates shall be reset each month.

(Charges are for illustrative purposes only and are based on the Eighth Revised Sheet No. 61 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 66**

CONSERVATION INCENTIVE PROGRAM

CHARGE APPLICABLE TO RATE SCHEDULES RS, RHS, RLM, GLP, LPL-S

	Conservation Incentive Program	Conservation Incentive Program including SUT	
RS & RHS	$0.000271	$0.000289	Per kilowatt-hour
RLM	$0.000965	$0.001029	Per kilowatt-hour
GLP	$1.2193	$1.3001	Per kilowatt of monthly peak demand
LPL-S	$1.0290	$1.0972	Per kilowatt of monthly peak demand

Conservation Incentive Program

This charge shall be applicable to the rate schedules listed above. The Conservation Incentive Program shall be based on the differences between actual and allowed revenue per customer during the preceding annual period. The Conservation Incentive Program mechanism shall be determined as follows:

I. DEFINITION OF TERMS AS USED HEREIN

1. Actual Number of Customers
– the Actual Number of Customers (“ANC”) shall be determined on a monthly basis for each of the Customer Class Groups to which the Conservation Incentive Program (“CIP”) Clause applies. The ANC shall equal the aggregate actual monthly Service Charge revenue for each class of customers subject to the CIP as recorded on the Company’s books, divided by the service charge rate applicable to such class of customers in each Customer Class Group.

2. Actual Revenue Per Customer
– the Actual Revenue per Customer (“ARC”) shall be determined in dollars per customer on a monthly basis for each of the Customer Class Groups to which the CIP applies. The ARC shall equal the aggregate actual booked variable margin revenue per applicable rate schedule for the month as recorded on the Company’s books divided by the Actual Number of Customers for the corresponding month. Actual revenues shall include Distribution Kilowatt-hour and Distribution Kilowatt charges as well as any Infrastructure Investment Program revenues, and shall not include the Service Charge and any non-base rate charges such as the Societal Benefits, Non-Utility Generation Charge, Zero Emission Certificate Recovery Charge, Solar Pilot Recovery Charges, Green Programs Recovery Charges, or the Tax Adjustment Credit.

3. Adjustment Period
– shall be the year beginning immediately following the conclusion of the Annual Period.

4. Annual Period
– shall be the twelve consecutive months from June 1 of one calendar year through May 31 of the following calendar year.

5. Average 13 Month Common Equity Balance
– shall be the average of the beginning and ending common equity balances based on the latest publically available financials available before the end of the Annual Period. The Company shall provide the most recently available actual months plus forecasted data at the time of each Initial Filing. The forecasted data will be updated with actuals once the financial statements for the months have been disclosed.

(Charges are for illustrative purposes only and are based on the Third Revised Sheet No. 66 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 66A**

CONSERVATION INCENTIVE PROGRAM
(Continued)

6. Baseline Revenue per Customer
– the Baseline Revenue per Customer ("BRC") shall be stated in dollars per customer on a monthly basis for each of the Customer Class Groups to which the CIP applies. The BRC shall be calculated as the current variable margin revenue per rate schedule, including any revenue from Infrastructure Investment Program rate adjustments, divided by the number of customers from the most recent approve base rate case for the rate schedule. Baseline revenues shall include Distribution Kilowatt-hour and Distribution Kilowatt charges, and shall not include the Service Charge and any non-base rate charges such as the Societal Benefits, Non-Utility Generation Charge, Zero Emission Certificate Recovery Charge, Solar Pilot Recovery Charges, Green Programs Recovery Charges, or the Tax Adjustment Credit.

7. Customer Class Group
– for purposes of determining and applying the CIP, customers shall be aggregated into four separate recovery class groups. The Customer Class Groups shall be as follows:

Group I:	RS & RHS
Group IA:	RLM
Group II:	GLP
Group III:	LPL-S

8. Forecast Annual Usage
– the Forecast Annual Usage ("FAU") shall be the projected total annual throughput for all customers within the applicable Customer Class Group. The FAU shall be estimated based on normal weather.

9. Degree Days (DD)
– the difference between 65^{o}F and the mean daily temperature. The mean daily temperature is the simple average of the 24 hourly temperature observations for a day. Heating Degree Days (HDD) are used to measure winter weather.

10. Temperature Humidity Index (THI)
– a measure of the degree of discomfort experienced by an individual in warm weather that includes temperature and humidity which is included by incorporating the dew point in the measure. The daily THI is the sum of the 24 hourly THI observations for a day. THI is used to measure summer weather.

11. Actual Calendar Month HDD and THI
– the accumulation of the actual HDD and THI for each day of a calendar month.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 66B**

CONSERVATION INCENTIVE PROGRAM
(Continued)

12. Normal Calendar Month HDD and THI
– the level of calendar month HDD and THI to which the weather portion of this CIP applies.

The normal calendar month HDD and THI will be based on the twenty-year average of the National Oceanic and Atmospheric Administration (NOAA) First Order Weather Observation Station hourly observations at the Newark airport and will be updated annually. The base level of normal HDD and THI for the defined winter and summer period months for the 2022-2023 Periods are set forth in the table below:

Month	Normal Heating Degree Days	Normal Temperature Humidity Index
January 2023	989	
February 2023	838	
March 2023	684	
April 2023	354	187
May 2023	128	931
June 2022		3,043
July 2022		5,624
August 2022		4,861
September 2022		2,237
October 2022	228	414
November 2022	523	
December 2022	816	

13. Winter Period
– shall be the eight consecutive calendar months from October of one calendar year through May of the following calendar year.

14. Summer Period
– shall be the seven consecutive calendar months from April of one calendar year through October of the calendar year.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 66C**

CONSERVATION INCENTIVE PROGRAM
(Continued)

15. Consumption Factors
– the use per HDD and THI component by month used in forecasting sales for the applicable rate schedules. These factors will be updated annually. Consumption Factors for the 2022-2023 Winter Period for HDD and 2022 Summer Period for THI are set forth below and presented as kWh per degree day:

	Consumption Factors (kWh per HDD and THI)					
	RS		RHS		RLM	
Month	HDD	THI	HDD	THI	HDD	THI
January 2023	469,298	150,909	11,303	409	6,341	1,577
February 2023	469,294	150,908	11,258	407	6,286	1,563
March 2023	469,288	150,906	11,276	408	6,207	1,543
April 2023	469,533	150,984	11,219	406	6,200	1,541
May 2023	469,777	151,063	11,163	404	6,193	1,540
June 2022	463,870	149,164	11,707	423	6,341	1,577
July 2022	461,601	148,434	11,568	418	6,287	1,563
August 2022	460,471	148,070	11,545	418	6,588	1,638
September 2022	461,466	148,390	11,469	415	6,061	1,507
October 2022	460,832	148,186	11,445	414	6,172	1,534
November 2022	461,133	148,283	11,350	410	6,412	1,594
December 2022	462,271	148,649	11,347	410	6,289	1,563

II. BASELINE REVENUE PER CUSTOMER

– the BRC for each Customer Class Group by month are as follows:

Month	RS & RHS	RLM	GLP	LPL-S
Jun	$32.30	$90.17	$130.32	$2,691.79
Jul	39.76	102.12	150.23	3,943.65
Aug	36.78	95.84	145.41	3,981.31
Sep	22.10	43.79	90.80	2,236.34
Oct	13.79	17.31	54.66	1,623.92
Nov	14.98	15.85	48.76	1,008.96
Dec	18.58	20.42	48.68	863.90
Jan	20.61	22.23	52.13	926.21
Feb	17.06	19.36	49.77	928.65
Mar	16.39	18.57	49.83	930.16
Apr	13.98	14.68	49.36	886.19
May	15.43	18.93	87.85	1,721.67
Total Annual	**$261.75**	**$479.26**	**$957.80**	**$21,742.74**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 66D**

CONSERVATION INCENTIVE PROGRAM
(Continued)

III. DETERMINATION OF THE CONSERVATION INCENTIVE PROGRAM

1. At the end of the Annual Period, a calculation shall be made that determines for each Customer Class Group the deficiency or excess to be surcharged or credited to customers pursuant to the CIP mechanism. The deficiency or excess shall be calculated each month by multiplying the result obtained from subtracting the Baseline Revenue per Customer from the Actual Revenue per Customer by the Actual Number of Customers.

2. The weather related change in customer usage shall be calculated as the difference between actual HDD and THI and the above HDD and THI multiplied by the consumption factors, and multiplying the result by the margin revenue factors as defined in Section I.10. of this rate schedule to determine the weather-related deficiency or excess. The weather-related amount will be subtracted from the total deficiency or excess to determine the non-weather related deficiency or excess.

3. Recovery of margin deficiency associated with non-weather related changes in customer usage will be subject to a BGS savings test and a Variable Margin Revenue recovery limitation (“recovery tests”). Recovery of non-weather related margin deficiency will be limited to the smaller of (1) the level of BGS savings achieved when such savings are less than 75 percent of the non-weather related margin deficiency, i.e. BGS savings test, and (2) 6.5 percent of variable margins for the CIP Annual Period, i.e., Variable Margin Revenue recovery limitation. Any amount that exceeds the above limitations may be deferred for future recovery and is subject to either or both of the recovery tests in a future year consistent with the amount by which either or both of the non-weather related margin deficiency exceeded the recovery tests. For the purposes of this calculation, the value of the weather related portion shall be calculated as set forth in Section III.2. of this rate schedule.

4. In addition, if the calculated ROE exceeds the allowed ROE from the utility's last base rate case by 50 basis points or more, recovery of lost revenues through the CIP shall not be allowed for the applicable filing period. For purposes of this section, the Company's rate of return on common equity shall be calculated by dividing the Company's net income for the applicable period as defined in the Average 13 Month Common Equity Balance by the Company's average common equity balance for the same period, all as reflected in the Company's monthly reports to the Board of Public Utilities. The Company's net income shall be calculated by subtracting from total operating income, any clause related Net Income, such as the Green Program’s Recovery Charge and interest expenses. The Company's Average 13 Month Common Equity Balance shall be the ratio of Electric Distribution Net Plant (including the Electric Distribution allocation of Common Plant) to total PSE&G Net Plant for the Average 13 Month Common Equity Balance period multiplied by the Company's total common equity for the same period.

5. The amount to be surcharged or credited shall equal the eligible aggregate deficiency or excess for all months during the Annual Period determined in accordance with the provisions herein, divided by the Forecast Annual Usage for the Customer Class Group.

IV. TRACKING THE OPERATION OF THE CONSERVATION INCENTIVE PROGRAM

The revenues billed, or credits applied, net of taxes and assessments, through the application of the Conservation Incentive Program Rate shall be accumulated for each month of the Adjustment Period and applied against the CIP excess or deficiency from the Annual Period and any cumulative balances remaining from prior periods.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 67**

DISTRIBUTION ADJUSTMENT CHARGE

	Charge (per kilowatthour)
Component:	
Storm Recovery Charge	$0.XXXXXX
COVID-19 Cost Recovery	0.XXXXXX
Distribution Adjustment Charge	$0.XXXXXX
Charge including New Jersey Sales and Use Tax (SUT)	$0.XXXXXX

DISTRIBUTION ADJUSTMENT CHARGE

This non-bypassable charge is designed to recover Board-approved costs. The charge will be reset nominally on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under- or over- recovered balances. The interest rates shall be reset each month.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 68**

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 69**

TAX ADJUSTMENT CREDIT

Rate Schedule	Charge per kilowatt-hour	Charge per kilowatt-hour Including SUT
RS	($0.005250)	($0.005598)
RHS	($0.006603)	($0.007040)
RLM	($0.004760)	($0.005075)
WH	($0.000000)	($0.000000)
WHS	($0.000000)	($0.000000)
HS	($0.003743)	($0.003991)
GLP	($0.001622)	($0.001729)
LPL – Secondary	($0.000929)	($0.000991)
LPL – Primary	($0.000600)	($0.000640)
HTS – Subtransmission	($0.000563)	($0.000600)
HTS – High Voltage & HTS – Transmission	($0.000224)	($0.000239)
BPL	($0.000000)	($0.000000)
BPL-POF	($0.001418)	($0.001512)
PSAL	($0.000000)	($0.000000)

Tax Adjustment Credit

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month.

(Charges are for illustrative purposes only and are based on the Sixth Revised Sheet No. 69 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 70**

INFRASTRUCTURE IMPROVEMENT PROGRAM CHARGES

Rate Schedule		Base Distribution Charges Including SUT	Energy Strong II Charges	Energy Strong II Charges Including SUT	Total Charges Including SUT
RS					
Service Charge	per Month	$4.95	$0.00	$0.00	$4.95
Distribution 0-600, June-September	per kWhr	0.040752	0.007484	0.007980	0.048732
Distribution 0-600, October-May	per kWhr	0.035553	0.000000	0.000000	0.035553
Distribution over 600, June-September	per kWhr	0.044826	0.007484	0.007980	0.052806
Distribution over 600, October-May	per kWhr	0.035553	0.000000	0.000000	0.035553
RHS					
Service Charge	per Month	4.95	0.00	0.00	4.95
Distribution 0-600, June-September	per kWhr	0.051834	0.004222	0.004501	0.056335
Distribution 0-600, October-May	per kWhr	0.034956	0.001935	0.002063	0.037019
Distribution over 600, June-September	per kWhr	0.057058	0.004222	0.004502	0.061560
Distribution over 600, October-May	per kWhr	0.016190	0.001935	0.002063	0.018253
Common Use	per kWhr	0.057058	0.004222	0.004502	0.061560
RLM					
Service Charge	per Month	13.94	0.00	0.00	13.94
Distribution, June-September, On-Peak	per kWhr	0.075220	0.006391	0.006814	0.082034
Distribution, June-September, Off-Peak	per kWhr	0.015703	0.001335	0.001423	0.017126
Distribution, October-May, On-Peak	per kWhr	0.015703	0.001335	0.001423	0.017126
Distribution, October-May, Off-Peak	per kWhr	0.015703	0.001335	0.001423	0.017126
WH					
Distribution	per kWhr	0.050538	0.002084	0.002222	0.052760
WHS					
Service Charge	per Month	0.63	0.04	0.04	0.67
Distribution	per kWhr	0.001722	0.000310	0.000331	0.002053

(Charges are for illustrative purposes only and are based on the Fourth Revised Sheet No. 70 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 71**

INFRASTRUCTURE IMPROVEMENT PROGRAM CHARGES
(Continued)

Rate Schedule		Base Distribution Charges Including SUT	Energy Strong II Charges	Energy Strong II Charges Including SUT	Total Charges Including SUT
HS					
Service Charge	per Month	$3.74	$0.24	$0.26	$4.00
Distribution, June-September	per kWhr	0.102660	0.001730	0.001844	0.104504
Distribution, October-May	per kWhr	0.030703	0.000631	0.000672	0.031375
GLP					
Service Charge	per Month	4.77	0.31	0.33	5.10
Service Charge-Unmetered	per Month	2.21	0.13	0.14	2.35
Service Charge-Night Use	per Month	370.81	0.00	0.00	370.81
Annual Demand	per kW	3.9378	0.0729	0.0777	4.0155
Summer Demand, June-September	per kW	9.8746	0.1830	0.1952	10.0698
Distribution, June-September	per kWhr	0.003219	0.000060	0.000064	0.003283
Distribution, October-May	per kWhr	0.008217	0.000152	0.000162	0.008379
Distribution-Night Use, June-September	per kWhr	0.008217	0.000152	0.000162	0.008379
Distribution-Night Use, October-May	per kWhr	0.008217	0.000152	0.000162	0.008379
LPL-Secondary					
Service Charge	per Month	370.81	0.00	0.00	370.81
Annual Demand	per kW	3.7617	0.0944	0.1007	3.8624
Summer Demand, June-September	per kW	8.9495	0.2245	0.2393	9.1888
Distribution	per kWhr	0.000000	0.000000	0.000000	0.000000
LPL-Primary					
Service Charge	per Month	370.81	0.00	0.00	370.81
Service Charge-Primary Alternate	per Month	21.54	1.38	1.47	23.01
Annual Demand	per kW	1.7531	0.0443	0.0473	1.8004
Summer Demand, June-September	per kW	9.7321	0.2457	0.2620	9.9941
Distribution	per kWhr	0.000000	0.000000	0.000000	0.000000

(Charges are for illustrative purposes only and are based on the Fourth Revised Sheet No. 71 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 72**

INFRASTRUCTURE IMPROVEMENT PROGRAM CHARGES
(Continued)

Rate Schedule		Base Distribution Charges Including SUT	Energy Strong II Charges	Energy Strong II Charges Including SUT	Total Charges Including SUT
HTS-Subtransmission					
Service Charge	per Month	$2,038.02	$0.00	$0.00	$2,038.02
Annual Demand	per kW	1.1432	0.0720	0.0768	1.2200
Summer Demand, June-September	per kW	4.1326	0.2603	0.2775	4.4101
Distribution	per kWhr	0.000000	0.000000	0.000000	0.000000
HTS-High Voltage					
Service Charge	per Month	1,834.22	0.00	0.00	1,834.22
Annual Demand	per kW	0.6574	0.0156	0.0167	0.6741
Distribution	per kWhr	0.000000	0.000000	0.000000	0.000000
BPL					
Distribution	per kWhr	0.007181	0.000159	0.000170	0.007351
BPL-POF					
Distribution	per kWhr	0.007174	0.000203	0.000216	0.007390
PSAL					
Distribution	per kWhr	0.007660	0.000171	0.000182	0.007842

INFRASTRUCTURE IMPROVEMENT PROGRAM CHARGE

These charges are designed to recover the revenue requirements associated with the Company's Infrastructure Improvement Programs (IIPs) in accordance with the New Jersey Board of Public Utilities' rules on IIPs, N.J.A.C. 14:3-2A.

For detail concerning individual rate class base distribution charges, see individual rate class tariff sheets.

(Charges are for illustrative purposes only and are based on the Fourth Revised Sheet No. 72 filed with the BPU on November 1, 2023)

Date of Issue: Effective:
Issued by SCOTT S. JENNINGS, SVP – Finance, Planning & Strategy – PSE&G
80 Park Plaza, Newark, New Jersey 07102
Filed pursuant to Order of Board of Public Utilities dated
in Docket No.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 73**

COMMERCIAL AND INDUSTRIAL ENERGY PRICING (CIEP) STANDBY FEE

APPLICABLE TO:

All kilowatt-hour usage under Rate Schedules LPL-Secondary (500 kilowatts or greater), LPL-Primary, HTS-Subtransmission, HTS-Transmission, HTS-High Voltage and all kilowatt-hour usage for customers under Rate Schedules HS, GLP and LPL-Secondary (less than 500 kilowatts) who have elected hourly energy pricing service from either BGS-CIEP or a Third Party Supplier.

	Charge (per kilowatt-hour)
Commercial and Industrial Energy Pricing (CIEP) Standby Fee	$ 0.000150
Charge including New Jersey Sales and Use Tax (SUT)	$ 0.000160

The above charges shall recover costs associated with the administration, maintenance and availability of the Basic Generation Service default electric supply service for applicable rate schedules. These charges shall be combined with the Distribution Kilowatt-hour Charges for billing.

Kilowatt threshold noted above is based upon the customer's Peak Load Share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM). See Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions of this Tariff.

(Charges are for illustrative purposes only and are based on the Original Sheet No. 73 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 74**

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 75**

**BASIC GENERATION SERVICE – RESIDENTIAL SMALL COMMERCIAL PRICING (BGS-RSCP)
ELECTRIC SUPPLY CHARGES**

APPLICABLE TO:

Default electric supply service for Rate Schedules RS, RHS, RLM, WH, WHS, HS, BPL, BPL-POF, PSAL, GLP and LPL-Secondary (less than 500 kilowatts).

BGS ENERGY & CAPACITY CHARGES:

Applicable to Rate Schedules RS, RHS, RLM, WH, WHS, HS, BPL, BPL-POF and PSAL

Charges per kilowatt-hour:

	For usage in each of the months of October through May		For usage in each of the months of June through September	
Rate Schedule	Energy & Capacity Charges	Charges Including SUT	Energy & Capacity Charges	Charges Including SUT
RS – first 600 kWh	$ 0.075527	$ 0.080531	$ 0.072237	$ 0.077023
RS – in excess of 600 kWh	0.075527	0.080531	0.081381	0.086772
RHS – first 600 kWh	0.076746	0.081830	0.068808	0.073367
RHS – in excess of 600 kWh	0.076746	0.081830	0.081036	0.086405
RLM On-Peak	0.089221	0.095132	0.094156	0.100394
RLM Off-Peak	0.064475	0.068746	0.059459	0.063398
WH	0.068204	0.072723	0.066577	0.070988
WHS	0.066441	0.070843	0.066429	0.070830
HS	0.078509	0.083710	0.075325	0.080315
BPL	0.066509	0.070915	0.061239	0.065296
BPL-POF	0.066509	0.070915	0.061239	0.065296
PSAL	0.066509	0.070915	0.061239	0.065296

The above Basic Generation Service Energy Charges reflect costs for Energy, Generation Capacity, and Ancillary Services (including PJM Interconnection, L.L.C. (PJM) Administrative Charges).

Kilowatt threshold noted above is based upon the customer's Peak Load Share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM). See Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions of this Tariff.

(Charges are for illustrative purposes only and are based on the Fourteenth Revised Sheet No. 75 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 76**

BASIC GENERATION SERVICE – RESIDENTIAL SMALL COMMERCIAL PRICING (BGS-RSCP) ELECTRIC SUPPLY CHARGES (Continued)

BGS TRANSMISSION CHARGES:

Applicable to Rate Schedules RS, RHS, RLM, WH, WHS, HS, BPL, BPL-POF and PSAL

Charges per kilowatt-hour:

Rate Schedule	Transmission Charges (For usage in all months)	Charges Including SUT (For usage in all months)
RS	$0.057428	$0.061233
RHS	0.037541	0.040028
RLM On-Peak	0.124829	0.133099
RLM Off-Peak	0.000000	0.000000
WH	0.000000	0.000000
WHS	0.000000	0.000000
HS	0.047976	0.051154
BPL	0.000000	0.000000
BPL-POF	0.000000	0.000000
PSAL	0.000000	0.000000

The above charges shall recover all costs related to the overall summer peak transmission load assigned to the Public Service Transmission Zone by the PJM Interconnection, L.L.C. (PJM) as adjusted by PJM assigned transmission capacity related factors and allocated to the above Rate Schedules. These charges will be changed from time to time on the effective date of such change to the PJM rate for charges for Network Integration Transmission Service, including the PJM Seams Elimination Cost Assignment Charges, the PJM Reliability Must Run Charge and PJM Transmission Enhancement Charges as approved by Federal Energy Regulatory Commission (FERC).

BGS ENERGY CHARGES:

Applicable to Rate Schedules GLP and LPL-Sec.

Charges per kilowatt-hour:

	For usage in each of the months of October through May		For usage in each of the months of June through September	
Rate Schedule	Charges	Charges Including SUT	Charges	Charges Including SUT
GLP	$0.067068	$0.071511	$0.067343	$0.071804
GLP Night Use	0.063526	0.067735	0.059237	0.063161
LPL-Sec. under 500 kW				
On-Peak	0.070936	0.075636	0.075223	0.080207
Off-Peak	0.063526	0.067735	0.059237	0.063161

The above Basic Generation Service Energy Charges reflect costs for Energy and Ancillary Services (including PJM Administrative Charges).

Kilowatt thresholds noted above are based upon the customer's Peak Load Share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM). See Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions of this Tariff.

(Charges are for illustrative purposes only and are based on the Fifteenth Revised Sheet No. 76 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 77**
Original Sheet No. 78

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 79**

BASIC GENERATION SERVICE – RESIDENTIAL SMALL COMMERCIAL PRICING (BGS-RSCP)
ELECTRIC SUPPLY CHARGES
(Continued)

BGS CAPACITY CHARGES:

Applicable to Rate Schedules GLP and LPL-Sec.
Charges per kilowatt of Generation Obligation:

Charge applicable in the months of June through September .... $ 1.6327
Charge including New Jersey Sales and Use Tax (SUT) .... $ 1.7409

Charge applicable in the months of October through May .... $ 1.6327
Charge including New Jersey Sales and Use Tax (SUT) .... $ 1.7409

The above charges shall recover each customer's share of the overall summer peak load assigned to the Public Service Transmission Zone by the PJM Interconnection, L.L.C. (PJM) as adjusted by PJM assigned capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions.

BGS TRANSMISSION CHARGES

Applicable to Rate Schedules GLP and LPL-Sec.
Charges per kilowatt of Transmission Obligation:

Currently effective Annual Transmission Rate for
Network Integration Transmission Service for the Public
Service Transmission Zone as derived from the
FERC Electric Tariff of the PJM Interconnection, LLC .... $ 142,957.59 per MW per year
EL05-121 .... $ 77.54 per MW per month
FERC 680 & 715 Reallocation .... $ 0.00 per MW per month
PJM Seams Elimination Cost Assignment Charges .... $ 0.00 per MW per month
PJM Reliability Must Run Charge .... $ 0.00 per MW per month
PJM Transmission Enhancements
Trans-Allegheny Interstate Line Company .... $ 52.61 per MW per month
Virginia Electric and Power Company .... $ 63.65 per MW per month
Potomac-Appalachian Transmission Highline L.L.C .... $ 0.49 per MW per month
PPL Electric Utilities Corporation .... $ 181.69 per MW per month
American Electric Power Service Corporation .... $ 17.58 per MW per month
Atlantic City Electric Company .... $ 8.46 per MW per month
Delmarva Power and Light Company .... $ 1.28 per MW per month
Potomac Electric Power Company .... $ 2.70 per MW per month
Baltimore Gas and Electric Company .... $ 3.89 per MW per month
Jersey Central Power and Light .... $ 60.23 per MW per month
Mid Atlantic Interstate Transmission .... $ 18.06 per MW per month
PECO Energy Company .... $ 23.93 per MW per month
Silver Run Electric, Inc .... $ 44.16 per MW per month
Northern Indiana Public Service Company .... $ 0.73 per MW per month
Commonwealth Edison Company .... $ 0.13 per MW per month
South First Energy Operating Company .... $ 0.66 per MW per month
Duquesne Light Company .... $ 0.33 per MW per month
Above rates converted to a charge per kW of Transmission
Obligation, applicable in all months .... $ 12.4713
Charge including New Jersey Sales and Use Tax (SUT) .... $ 13.2975

The above charges shall recover each customer's share of the overall summer peak transmission load assigned to the Public Service Transmission Zone by the PJM Interconnection, L.L.C. (PJM) as adjusted by PJM assigned transmission capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions. These charges will be changed from time to time on the effective date of such change to the PJM rate for charges for Network Integration Transmission Service, including the PJM Seams Elimination Cost Assignment Charges, the PJM Reliability Must Run Charge and PJM Transmission Enhancement Charges as approved by Federal Energy Regulatory Commission (FERC).

(Charges are for illustrative purposes only and are based on the Twenty-Third Revised Sheet No. 79 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 80**

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 81**

BASIC GENERATION SERVICE – RESIDENTIAL SMALL COMMERCIAL PRICING (BGS-RSCP)
ELECTRIC SUPPLY CHARGES
(Continued)

BGS RECONCILIATION CHARGES:

Charges per kilowatthour:

Basic Generation Service Reconciliation Charge .... $(0.006791)

Charge including New Jersey Sales and Use Tax (SUT).. $(0.007241)

The above charges shall recover the difference between the monthly amount paid to Basic Generation Service (BGS) suppliers and the total revenue from customers for BGS for the preceding months for the applicable BGS supply. These charges include all applicable taxes and are updated quarterly. These charges shall be combined with the BGS Energy Charges for billing.

(Charges are for illustrative purposes only and are based on the Fortieth Revised Sheet No. 81 filed with the BPU on August 15, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 82**

BASIC GENERATION SERVICE – COMMERCIAL AND INDUSTRIAL ENERGY PRICING (CIEP) ELECTRIC SUPPLY CHARGES

APPLICABLE TO:

Default electric supply service for Rate Schedules LPL-Secondary (500 kilowatts or greater), LPL-Primary, HTS-Subtransmission, HTS-Transmission, HTS-High Voltage and to customers served under Rate Schedules HS, GLP and LPL-Secondary (less than 500 kilowatts) who have elected BGS-CIEP as their default supply service.

BGS ENERGY CHARGES:

Charges per kilowatt-hour:

BGS Energy Charges are hourly and include PJM Locational Marginal Prices, and PJM Ancillary Services. The total BGS Energy Charges are based on the sum of the following:

- The real time PJM Load Weighted Average Residual Metered Load Aggregate Locational Marginal Prices for the Public Service Transmission Zone, adjusted for losses (tariff losses, as defined in Standard Terms and Conditions Section 4.3, adjusted to remove the mean hourly PJM marginal losses of 0.79690%), and adjusted for SUT, plus
- Ancillary Services (including PJM Administrative Charges) at the rate of $0.006000 per kilowatt-hour, adjusted for losses (tariff losses, as defined in Standard Terms and Conditions Section 4.3, adjusted to remove the mean hourly PJM marginal losses of 0.79690%), and adjusted for SUT, plus

BGS CAPACITY CHARGES:

Charges per kilowatt of Generation Obligation:

Charge applicable in the months of June through September $10.0663
Charge including New Jersey Sales and Use Tax (SUT) $10.7332

Charges applicable in the months of October through May $10.0663
Charges including New Jersey Sales and Use Tax (SUT)... $10.7332

The above charges shall recover each customer's share of the overall summer peak load assigned to the Public Service Transmission Zone by the PJM Interconnection, L.L.C. (PJM) as adjusted by PJM assigned capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions.

(Charges are for illustrative purposes only and are based on the Sixth Revised Sheet No. 82 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 83**

BASIC GENERATION SERVICE – COMMERCIAL AND INDUSTRIAL ENERGY PRICING (CIEP) ELECTRIC SUPPLY CHARGES (Continued)

BGS TRANSMISSION CHARGES

Charges per kilowatt of Transmission Obligation:

Currently effective Annual Transmission Rate for Network Integration Transmission Service for the Public Service Transmission Zone as derived from the FERC Electric Tariff of the PJM Interconnection, LLC	$ 142,957.59 per MW per year
EL05-121	$ 77.54 per MW per month
FERC 680 & 715 Reallocation	$ 0.00 per MW per month
PJM Seams Elimination Cost Assignment Charges	$ 0.00 per MW per month
PJM Reliability Must Run Charge	$ 0.00 per MW per month
PJM Transmission Enhancements	
Trans-Allegheny Interstate Line Company	$ 52.61 per MW per month
Virginia Electric and Power Company	$ 63.65 per MW per month
Potomac-Appalachian Transmission Highline L.L.C.	$ 0.49 per MW per month
PPL Electric Utilities Corporation	$ 181.69 per MW per month
American Electric Power Service Corporation	$ 17.58 per MW per month
Atlantic City Electric Company	$ 8.46 per MW per month
Delmarva Power and Light Company	$ 1.28 per MW per month
Potomac Electric Power Company	$ 2.70 per MW per month
Baltimore Gas and Electric Company	$ 3.89 per MW per month
Jersey Central Power and Light	$ 60.23 per MW per month
Mid Atlantic Interstate Transmission	$ 18.06 per MW per month
PECO Energy Company	$ 23.93 per MW per month
Silver Run Electric, Inc	$ 44.16 per MW per month
Northern Indiana Public Service Company	$ 0.73 per MW per month
Commonwealth Edison Company	$ 0.13 per MW per month
South First Energy Operating Company	$ 0.66 per MW per month
Duquesne Light Company	$ 0.33 per MW per month

Above rates converted to a charge per kW of Transmission Obligation, applicable in all months	$ 12.4713
Charge including New Jersey Sales and Use Tax (SUT)	$ 13.2975

The above charges shall recover each customer's share of the overall summer peak transmission load assigned to the Public Service Transmission Zone by the PJM Interconnection, L.L.C. (PJM) as adjusted by PJM assigned transmission capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions. These charges will be changed from time to time on the effective date of such charge to the PJM rate for charges for Network Integration Transmission Service, including the PJM Seams Elimination Cost Assignment Charges, the PJM Reliability Must Run Charge and PJM Transmission Enhancement Charges as approved by Federal Energy Regulatory Commission (FERC).

Kilowatt threshold noted above is based upon the customer's Peak Load Share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM). See Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions of this Tariff.

(Charges are for illustrative purposes only and are based on the Eighteenth Revised Sheet No. 83 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 84**

**BASIC GENERATION SERVICE – COMMERCIAL AND INDUSTRIAL ENERGY PRICING (CIEP)
ELECTRIC SUPPLY CHARGES
(Continued)**

BGS RECONCILIATION CHARGES:

Charges per kilowatthour:

Basic Generation Service Reconciliation Charge $0.003332

Charge including New Jersey Sales and Use Tax (SUT) $0.003553

The above charges shall recover the difference between the monthly amount paid to Basic Generation Service (BGS) suppliers and the total revenue from customers for BGS for the preceding months for the applicable BGS supply. These charges include all applicable taxes and are updated quarterly. These charges shall be combined with the BGS Energy Charges for billing.

(Charges are for illustrative purposes only and are based on the Fortieth Revised Sheet No. 84 filed with the BPU on August 15, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 85**
Original Sheet No. 86

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 87**

THIRD PARTY SUPPLIER

APPLICABLE TO:

A third party supplier is an entity that has executed a Third Party Supplier Agreement (Agreement) with Public Service so as to be eligible to furnish electric supply with delivery to the retail customer by Public Service. This Agreement sets forth the specific terms and conditions with which Third Party Suppliers must comply to use Public Service's distribution system to supply energy to retail customers in Public Service's service territory. This Agreement is standardized in form and will apply in an equal and uniform manner to all Third Party Suppliers requesting to provide competitive energy supply to retail customers in Public Service's service territory. The Agreement is hereby incorporated by reference herein, and similarly incorporates this Tariff for Electric Service in its terms.

All modifications to the Agreement must be approved by the Board, consistent with the process set forth below, prior to implementation. Any such modifications, other than Third Party Supplier fee changes, shall be undertaken in accordance with the following procedures. Specifically, Public Service may amend the Agreement by providing simultaneous written notice of such change, by regular mail, or electronic means, to the Board of Public Utilities (Board), Division of Ratepayer Advocate (RPA), Jersey Central Power and Light, Atlantic City Electric Company, Rockland Electric and to Third Party Suppliers licensed as Electric Power Suppliers in New Jersey, a list of which will be provided by the Board. Within seventeen (17) days of such notice, the RPA or any New Jersey licensed Electric Power Supplier wishing to contest the amendment of the Agreement must submit in writing to the Board its reason for contesting the change, and must simultaneously provide a copy of such document to Public Service. Within forty-five (45) days of such notice, the Board may either (i) approve the amendment; (ii) determine through a suspension order that the proposed amendment needs further study, and thus place the request on hold pending future action by the Board; or (iii) take no action, in which case Public Service may implement the amendment at the conclusion of the forty-five (45) day period; provided, however, that the Board is not thereby precluded from taking action on the amendment in the future.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC

Original Sheet No. 88
Original Sheet No. 89
Original Sheet No. 90
Original Sheet No. 91
Original Sheet No. 92

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 93**

RATE SCHEDULE RS
RESIDENTIAL SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Delivery service for residential purposes. Customers may either purchase electric supply from a Third Party Supplier (TPS) or from Public Service's Basic Generation Service default service as detailed in this rate schedule.

DELIVERY CHARGES:

Service Charge:

$4.64 in each month [$4.95 including New Jersey Sales and Use Tax (SUT)].

Distribution Charges per Kilowatt-hour:

First 600 hours used in each of the months of:

October through May		June through September	
Charge	Charge Including SUT	Charge	Charge Including SUT
$ 0.033344	$ 0.035553	$ 0.045704	$ 0.048732

In excess of 600 hours used in each of the months of:

October through May		June through September	
Charge	Charge Including SUT	Charge	Charge Including SUT
$ 0.033344	$ 0.035553	$ 0.049525	$ 0.052806

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 70 for details of these charges.

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Non-utility Generation Charge:

This charge shall recover above market costs associated with non-utility generation costs and other generation related costs as may be approved by the Board. Refer to the Non-utility Generation Charge sheet of this Tariff for the current charge.

Solar Pilot Recovery Charge:

This charge is designed to recover the revenue requirements associated with the Public Service Solar Pilot Program per the Board Order in Docket Nos. ER18010029, GR18010030, AX18010001 and ER18030231 EO07040278 less the net proceeds from the sale of associated Solar Renewable Energy Certificates (SRECs) or cash received in lieu of SRECs. Refer to the Solar Pilot Recovery Charge sheet of this tariff for the current charge.

(Charges are for illustrative purposes only and are based on the Seventh Revised Sheet No. 93 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 93 for Future**

RATE SCHEDULE RS
RESIDENTIAL SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Delivery service for residential purposes. Customers may either purchase electric supply from a Third Party Supplier (TPS) or from Public Service's Basic Generation Service default service as detailed in this rate schedule.

DELIVERY CHARGES:

Service Charge:
$4.64 in each month [$4.95 including New Jersey Sales and Use Tax (SUT)].

Distribution Charges per Kilowatt-hour for RS non-Time of Use (TOU) customers:

First 600 hours used in each of the months of:

October through May		June through September	
Charge	Charge Including SUT	Charge	Charge Including SUT
$ 0.033344	$ 0.035553	$ 0.045704	$ 0.048732

In excess of 600 hours used in each of the months of:

October through May		June through September	
Charge	Charge Including SUT	Charge	Charge Including SUT
$ 0.033344	$ 0.035553	$ 0.049525	$ 0.052806

Distribution Charges per Kilowatt-hour for RS TOU customers (see Special Provision (a-8) for details)

For customers selecting two-period option (TOU-2P):

		June through September		October through May	
		Charges	Charges Including SUT	Charges	Charges Including SUT
On-Peak	4 pm - 9 pm (weekdays)*	$ X.XXXXXX	$ X.XXXXXX	$ X.XXXXXX	$ X.XXXXXX
Off-Peak	10 pm - 11 am	$ X.XXXXXX	$ X.XXXXXX	$ X.XXXXXX	$ X.XXXXXX

For customers selecting three-period option (TOU-3P):

		June through September		October through May	
		Charges	Charges Including SUT	Charges	Charges Including SUT
On-Peak	4 pm - 9 pm (weekdays)*	$ X.XXXXXX	$ X.XXXXXX	$ X.XXXXXX	$ X.XXXXXX
Mid-Peak	All other times	$ X.XXXXXX	$ X.XXXXXX	$ X.XXXXXX	$ X.XXXXXX
Off-Peak	Midnight - 6 am	$ X.XXXXXX	$ X.XXXXXX	$ X.XXXXXX	$ X.XXXXXX

* Weekdays exclude PJM holidays.

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 70 for details of these charges.

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Non-utility Generation Charge:

This charge shall recover above market costs associated with non-utility generation costs and other generation related costs as may be approved by the Board. Refer to the Non-utility Generation Charge sheet of this Tariff for the current charge.

Solar Pilot Recovery Charge:

This charge is designed to recover the revenue requirements associated with the Public Service Solar Pilot Program per the Board Order in Docket Nos. ER18010029, GR18010030, AX18010001 and ER18030231 EO07040278 less the net proceeds from the sale of associated Solar Renewable Energy Certificates (SRECs) or cash received in lieu of SRECs. Refer to the Solar Pilot Recovery Charge sheet of this tariff for the current charge.

(Charges are for illustrative purposes only and are based on the Seventh Revised Sheet No. 93 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 94**

RATE SCHEDULE RS
RESIDENTIAL SERVICE
(Continued)

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

Tax Adjustment Credit:

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current credit.

Zero Emission Certificate Recovery Charge:

This charge provides for the recovery of costs associated with the Zero Emission Certificate Program directed by the Board of Public Utilities ("BPU" or "Board"). Refer to the Zero Emission Certificate Recovery Charge sheet of this Tariff for the current charge.

Conservation Incentive Program Charge:

This mechanism provides for recovery of lost revenues associated with various energy efficiency programs. Refer to the Conservation Incentive Program sheet of this Tariff for the current charge.

Distribution Adjustment Charge:

This charge is designed to recover Board-approved costs. Refer to the Distribution Adjustment Charge sheet of this Tariff for the current charge.

The Distribution Charges, Societal Benefits Charge, Non-utility Generation Charge, the Solar Pilot Recovery Charge, the Green Programs Recovery Charge, the Tax Adjustment Credit, the Zero Emission Certificate Recovery Charge, the Conservation Incentive Program Charge, and the Distribution Adjustment Charge shall be combined for billing.

ELECTRIC SUPPLY CHARGES:

A customer may choose to receive electric supply from either:

a) A TPS as described in Section 14 of this Tariff, or
b) Public Service through its Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP) default service.

Third Party Supply:

A customer that receives electric supply from a TPS will be charged for electric supply according to any agreement between the customer and the TPS. The customer will not be charged for electric supply by Public Service.

Basic Generation Service:

Customers that do not receive electric supply from a TPS will be supplied under the Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP) default service.

The BGS Energy Charges and the BGS Reconciliation Charge, as applicable, will be applied to all kilowatt-hours billed each month. Refer to the Basic Generation Service sheets of this Tariff for the current charges applicable to Rate Schedule RS.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 95**

RATE SCHEDULE RS
RESIDENTIAL SERVICE
(Continued)

MINIMUM CHARGE:

The minimum charge shall be equal to the monthly Service Charge.

GENERATION CAPACITY AND TRANSMISSION OBLIGATIONS:

Generation Obligation:

The customer's Generation Obligation, in kilowatts, is determined by Public Service no less frequently than once a year. The Generation Obligation for existing customers or for new customers utilizing an existing building or premise is based upon the customer's share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM) as adjusted by PJM assigned capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions. The Generation Obligation for customers taking service in a new building or premise, as determined by Public Service, is based upon the load requirements, as estimated by Public Service, of the customer's building or premise. The Generation Obligation represents the generator capacity that PJM requires an electric supplier to have available to provide electric supply to a customer.

Transmission Obligation:

The customer's Transmission Obligation, in kilowatts, is determined in a similar manner to the Generation Obligation described above. The Transmission Obligation represents the level of transmission network service that must be procured by the customer's electric supplier from PJM to provide service to the customer.

Costs associated with the Generation and Transmission Obligations are included in the charges for Basic Generation Service and may affect the price offered by a Third Party Supplier.

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill.

TERM:

Customer may discontinue delivery service upon notice.

SPECIAL PROVISIONS:

(a) **Limitations on Service:** This rate schedule is available where all service is measured by one meter, except for service provided under Rate Schedules WH or WHS:

(a-1) In individual residences and appurtenant outbuildings;

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 96**

RATE SCHEDULE RS
RESIDENTIAL SERVICE
(Continued)

(a-2) In residential premises where customer's use of electric service for purposes other than residential is incidental to its residential use;

(a-3) On residential farms;

(a-4) For rooming or boarding houses where the number of rented rooms does not exceed twice the number of bedrooms occupied by the customer;

(a-5) To a customer in a two- or three-family building who has the service for incidental common-use equipment registered on its meter;

(a-6) In individual flats or apartments in multiple-family buildings;

(a-7) In multiple-family buildings of two or more individual flats or apartments where electric service is furnished to the tenants or occupants of the flats or apartments by the owner without a specific charge for such service, provided that the number of kilowatt-hours in each block of the Distribution Charge are multiplied by the number of individual flats or apartments, whether occupied or not.

(b) **Resale:** Service under this rate schedule is not available for resale.

(c) **TPS Supply:** Customers who desire to purchase their electric supply from a TPS may request an enrollment package from Public Service that describes the process necessary for the customer to obtain a TPS for electric supply. This package will be provided to the customer at no charge by Public Service.

(c-1) The customer must contract with a TPS to arrange for deliveries to Public Service of the electric supply. A customer is limited to one TPS for electric supply for each account for which the customer receives delivery service.

(c-2) The customer's TPS is required to notify Public Service of the customer's selection prior to 13 days before the customer's scheduled Public Service meter reading date for deliveries to commence on such scheduled meter reading date, and such selection shall remain in effect for the entire billing month. Customer can change TPSs effective only on the date of the customer's scheduled Public Service meter reading date.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 96 for Future**

RATE SCHEDULE RS
RESIDENTIAL SERVICE
(Continued)

(a-2) In residential premises where customer's use of electric service for purposes other than residential is incidental to its residential use;

(a-3) On residential farms;

(a-4) For rooming or boarding houses where the number of rented rooms does not exceed twice the number of bedrooms occupied by the customer;

(a-5) To a customer in a two- or three-family building who has the service for incidental common-use equipment registered on its meter;

(a-6) In individual flats or apartments in multiple-family buildings;

(a-7) In multiple-family buildings of two or more individual flats or apartments where electric service is furnished to the tenants or occupants of the flats or apartments by the owner without a specific charge for such service, provided that the number of kilowatt-hours in each block of the Distribution Charge are multiplied by the number of individual flats or apartments, whether occupied or not;

(a-8) In multiple-family buildings of two or more individual flats or apartments where a dedicated parking space is available and where a customer is served on a separate meter for electric vehicle charging use. This provision is only available to customers receiving this service under special provision (d);

(a-9) In detached garage on a residential parcel for the purposes of charging electric vehicles. This provision is only available to customers receiving this service under special provision (d);

(a-10) **Multi-Family Residential Electric Vehicle Charging:** Available to new and existing all Company-qualified Level 2 Electric Vehicle Charging Stations located at Multifamily Dwellings ("Multifamily Level 2 Electric Vehicle Charging Station") at a separately metered premise from the metering at the multifamily complex.

(b) **Resale:** Service under this rate schedule is not available for resale.

(c) **TPS Supply:** Customers who desire to purchase their electric supply from a TPS may request an enrollment package from Public Service that describes the process necessary for the customer to obtain a TPS for electric supply. This package will be provided to the customer at no charge by Public Service.

(c-1) The customer must contract with a TPS to arrange for deliveries to Public Service of the electric supply. A customer is limited to one TPS for electric supply for each account for which the customer receives delivery service.

(c-2) The customer's TPS is required to notify Public Service of the customer's selection prior to 13 days before the customer's scheduled Public Service meter reading date for deliveries to commence on such scheduled meter reading date, and such selection shall remain in effect for the entire billing month. Customer can change TPSs effective only on the date of the customer's scheduled Public Service meter reading date.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 97**

RATE SCHEDULE RS
RESIDENTIAL SERVICE
(Continued)

(d) **Electric Vehicle Distribution Only:** Based upon the following eligibility criteria, residential customers may elect to receive on-peak and off-peak distribution energy charges from the Residential Load Management (RLM) rate schedule exclusively for their electric vehicle usage. This option, upon Company approval into the program, will be issued as a credit on the customer bill on at least a quarterly basis, after the entire usage has been billed at the RS rate. All other provisions of this tariff will remain in effect.

(d-1) A customer taking service under this special provision must install or utilize PSE&G approved smart charging hardware and network technology. The customer must also agree to share the Electric Vehicle Charging Data with PSE&G in a manner specified by PSE&G. Data must be available to the Company and necessary billing system changes must be in place in order for these incentives to begin.

(d-2) The electric vehicle credit will be calculated by the Company's program administrator at least quarterly using the electric vehicle usage at the Rate Schedule RLM distribution rates less the electric vehicle usage billed at Rate Schedule RS distribution rates for the corresponding billing period. If the credit calculation results in charges that would be in excess of the bill calculated using the RS distribution rates, no adjustment for the corresponding period will be applied.

(d-3) For ratemaking purposes, the electric vehicle RLM Distribution Only Provision credits associated with this special provision will be reflected as a reduction to the Rate Schedule RS distribution revenue. The credit will be applied at least quarterly to the customer bill and will indicate the corresponding period(s) for which the credit applies.

(d-4) This special provision will remain in effect until the conclusion of the Company's Next Base Rate Case.

(e) **Electric Vehicle Basic Generation Supply (BGS) Customers Only**: Based upon the following eligibility criteria, residential customers who receive their electric supply via BGS may elect to receive on-peak and off-peak supply charges based on BGS rates applicable to Rate Schedule Residential Load Management (RLM) exclusively for their electric vehicle charging usage. This option, upon Company approval into the program, will be issued as a credit on the customer bill on at least a quarterly basis, after the entire usage has been billed at the BGS rates applicable to Rate Schedule RS. All other provisions of this tariff will remain in effect.

(e-1) A customer taking service under this special provision must install or utilize PSE&G approved smart charging hardware and network technology. The customer must also agree to share the Electric Vehicle Charging Data with PSE&G in a manner specified by PSE&G. Data must be available to the Company and necessary billing system changes must be in place in order for these incentives to begin.

(e-2) The electric vehicle credit will be calculated by the Company's program administrator at least quarterly using the electric vehicle usage at the BGS rates applicable to Rate Schedule RLM less the electric vehicle usage billed at the BGS rates applicable to Rate Schedule RS for the corresponding billing period. If the credit calculation results in charges that would be in excess of the bill calculated using the BGS rates applicable to Rate Schedule RS, no adjustment for the corresponding period will be applied.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 97 for Future**

RATE SCHEDULE RS
RESIDENTIAL SERVICE
(Continued)

(d) **Residential Time of Use**: RS customers may elect to take the RS TOU rate.

(d-1) Such customers will be required to stay on the RS TOU rate for a minimum of twelve (12) months.

(d-2) At the end of the initial 12-month period, the Company will provide the customer with reporting showing their 12-month bill on the new RS TOU rate and what their 12-month bill would have been on the non-TOU RS rate schedule. The customer will be offered a one-time refund of the difference if the 12 month bill on the RS TOU rate was higher compared to the RS rate schedule. This provision is available only to customers who enroll in RS TOU rates during the first twenty-four (24) months following the effective date of this tariff provision..

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 98**

RATE SCHEDULE RS
RESIDENTIAL SERVICE
(Continued)

(e-3) This special provision will remain in effect until the conclusion of the Company's Next Base Rate Case.

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 16 of the Standard Terms and Conditions for additional details and/or exceptions.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 98 for Future**

RATE SCHEDULE RS
RESIDENTIAL SERVICE
(Continued)

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 16 of the Standard Terms and Conditions for additional details and/or exceptions.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 99**

RATE SCHEDULE RHS
RESIDENTIAL HEATING SERVICE

APPLICABLE TO USE OF SERVICE FOR:

This rate schedule is closed and is in the process of elimination. Delivery service under this rate schedule is limited to residential purposes where electricity is the sole source of space heating for customers at their current premise that are presently served under this rate schedule. Customers may either purchase electric supply from a Third Party Supplier (TPS) or from Public Service's Basic Generation Service default service as detailed in this rate schedule.

DELIVERY CHARGES:

Service Charge:

$4.64 in each month [$4.95 including New Jersey Sales and Use Tax (SUT)].

Distribution Charges per Kilowatt-hour:

First 600 hours used in each of the months of:

October through May		June through September	
Charge	Charge Including SUT	Charge	Charge Including SUT
$ 0.034719	$ 0.037019	$ 0.052835	$ 0.056335

In excess of 600 hours used in each of the months of:

October through May		June through September	
Charge	Charge Including SUT	Charge	Charge Including SUT
$ 0.017119	$ 0.018253	$ 0.057735	$ 0.061560

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 70 for details of these charges.

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Non-utility Generation Charge:

This charge shall recover above market costs associated with non-utility generation costs and other generation related costs as may be approved by the Board. Refer to the Non-utility Generation Charge sheet of this Tariff for the current charge.

Solar Pilot Recovery Charge:

This charge is designed to recover the revenue requirements associated with the Public Service Solar Pilot Program per the Board Order in Docket No. EO07040278 less the net proceeds from the sale of associated Solar Renewable Energy Certificates (SRECs) or cash received in lieu of SRECs. Refer to the Solar Pilot Recovery Charge sheet of this tariff for the current charge.

(Charges are for illustrative purposes only and are based on the Seventh Revised Sheet No. 99 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 100**

RATE SCHEDULE RHS
RESIDENTIAL HEATING SERVICE
(Continued)

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

Tax Adjustment Credit:

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current credit.

Zero Emission Certificate Recovery Charge:

This charge provides for the recovery of costs associated with the Zero Emission Certificate Program directed by the Board of Public Utilities ("BPU" or "Board"). Refer to the Zero Emission Certificate Recovery Charge sheet of this Tariff for the current charge.

Conservation Incentive Program Charge:

This mechanism provides for recovery of lost revenues associated with various energy efficiency programs. Refer to the Conservation Incentive Program sheet of this Tariff for the current charge.

Distribution Adjustment Charge:

This charge is designed to recover Board-approved costs. Refer to the Distribution Adjustment Charge sheet of this Tariff for the current charge.

The Distribution Charges, Societal Benefits Charge, Non-utility Generation Charge, the Solar Pilot Recovery Charge, the Green Programs Recovery Charge, the Tax Adjustment Credit, the Zero Emission Certificate Recovery Charge, the Conservation Incentive Program Charge, and the Distribution Adjustment Charge shall be combined for billing.

ELECTRIC SUPPLY CHARGES:

A customer may choose to receive electric supply from either:

a) A TPS as described in Section 14 of this Tariff, or
b) Public Service through its Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP) default service.

Third Party Supply:

A customer that receives electric supply from a TPS will be charged for electric supply according to any agreement between the customer and the TPS. The customer will not be charged for electric supply by Public Service.

Basic Generation Service:

Customers that do not receive electric supply from a TPS will be supplied under the Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP) default service.

The BGS Energy Charges and the BGS Reconciliation Charge, as applicable, will be applied to all kilowatt-hours billed each month. Refer to the Basic Generation Service sheets of this Tariff for the current charges applicable to Rate Schedule RHS.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 101**

RATE SCHEDULE RHS
RESIDENTIAL HEATING SERVICE
(Continued)

MINIMUM CHARGE:

The minimum charge shall be equal to the monthly Service Charge.

GENERATION CAPACITY AND TRANSMISSION OBLIGATIONS:

Generation Obligation:

The customer's Generation Obligation, in kilowatts, is determined by Public Service no less frequently than once a year. The Generation Obligation for existing customers or for new customers utilizing an existing building or premise is based upon the customer's share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM) as adjusted by PJM assigned capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions. The Generation Obligation for customers taking service in a new building or premise, as determined by Public Service, is based upon the load requirements, as estimated by Public Service, of the customer's building or premise. The Generation Obligation represents the generator capacity that PJM requires an electric supplier to have available to provide electric supply to a customer.

Transmission Obligation:

The customer's Transmission Obligation, in kilowatts, is determined in a similar manner to the Generation Obligation described above. The Transmission Obligation represents the level of transmission network service that must be procured by the customer's electric supplier from PJM to provide service to the customer.

Costs associated with the Generation and Transmission Obligations are included in the charges for Basic Generation Service and may affect the price offered by a Third Party Supplier.

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill.

TERM:

Customer may discontinue delivery service upon notice.

SPECIAL PROVISIONS:

(a) **General Limitations on Service:** This rate schedule is available where space heating equipment is permanently installed and is operated at not less than 208 volts and where all service is measured by one meter, except for service provided under Rate Schedules WH and WHS:

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 102**

RATE SCHEDULE RHS

RESIDENTIAL HEATING SERVICE

(Continued)

(a-1) In individual residences and appurtenant outbuildings;

(a-2) In individual apartments in a multiple-family building;

(a-3) In all-electric multiple-family building where electricity is furnished to the tenants as an incident to tenancy and is included in the rent, provided that the number of kilowatt-hours in each block of the Kilowatt-hour Charge are multiplied by the number of individual flats or apartments, whether occupied or not;

(a-4) Common-use equipment in an all electric multiple-family building in which each tenant is served individually under this rate schedule. The Distribution Charge for the kilowatt-hours used in each month shall be $0.057735 per kilowatt-hour ($0.061560 including SUT).

(b) **Limitations on Water Heating Service:** When electricity is used for water heating under this rate schedule, such service shall be to an automatic type water heater approved by Public Service; furthermore, if the water heater is equipped with more than one heating element, the thermostats controlling the heating elements shall be interlocked so that only one of such elements can operate at a time.

If water is centrally heated under (a-4), equipment shall be of an automatic type approved by Public Service, and billing under this rate schedule is not required.

(c) **Resale:** Service under this rate schedule is not available for resale.

(d) **TPS Supply:** Customers who desire to purchase their electric supply from a TPS may request an enrollment package from Public Service that describes the process necessary for the customer to obtain a TPS for electric supply. This package will be provided to the customer at no charge by Public Service.

(d-1) The customer must contract with a TPS to arrange for deliveries to Public Service of the electric supply. A customer is limited to one TPS for electric supply for each account for which the customer receives delivery service.

(d-2) The customer's TPS is required to notify Public Service of the customer's selection prior to 13 days before the customer's scheduled Public Service meter reading date for deliveries to commence on such scheduled meter reading date, and such selection shall remain in effect for the entire billing month. Customer can change TPSs effective only on the date of the customer's scheduled Public Service meter reading date.

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 16 of the Standard Terms and Conditions for additional details and/or exceptions.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff.

(Charges are for illustrative purposes only and are based on the Fifth Revised Sheet No. 102 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 103**
Original Sheet No. 104

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 105**

RATE SCHEDULE RLM
RESIDENTIAL LOAD MANAGEMENT SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Delivery service for residential purposes. Customers may either purchase electric supply from a Third Party Supplier (TPS) or from Public Service's Basic Generation Service default service as detailed in this rate schedule.

DELIVERY CHARGES:

Service Charge:

$13.07 in each month [$13.94 including New Jersey Sales and Use Tax (SUT)].

Distribution Charges per Kilowatt-hour:

	In each of the months of October through May		In each of the months of June through September	
	Charges	Charges Including SUT	Charges	Charges Including SUT
On-Peak	$ 0.016062	$ 0.017126	$ 0.076937	$ 0.082034
Off-Peak	$ 0.016062	$ 0.017126	$ 0.016062	$ 0.017126

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 70 for details of these charges.

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Non-utility Generation Charge:

This charge shall recover above market costs associated with non-utility generation costs and other generation related costs as may be approved by the Board. Refer to the Non-utility Generation Charge sheet of this Tariff for the current charge.

Solar Pilot Recovery Charge:

This charge is designed to recover the revenue requirements associated with the Public Service Solar Pilot Program per the Board Order in Docket No. EO07040278 less the net proceeds from the sale of associated Solar Renewable Energy Certificates (SRECs) or cash received in lieu of SRECs. Refer to the Solar Pilot Recovery Charge sheet of this tariff for the current charge.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

(Charges are for illustrative purposes only and are based on the Seventh Revised Sheet No. 105 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 105 for Future**

RATE SCHEDULE RLM
RESIDENTIAL LOAD MANAGEMENT SERVICE

APPLICABLE TO USE OF SERVICE FOR:

This rate schedule is closed and is in the process of elimination. Delivery service for residential purposes. Customers may either purchase electric supply from a Third Party Supplier (TPS) or from Public Service's Basic Generation Service default service as detailed in this rate schedule.

DELIVERY CHARGES:

Service Charge:

$13.07 in each month [$13.94 including New Jersey Sales and Use Tax (SUT)].

Distribution Charges per Kilowatt-hour:

	In each of the months of October through May		In each of the months of June through September	
	Charges	Charges Including SUT	Charges	Charges Including SUT
On-Peak	$ 0.016062	$ 0.017126	$ 0.076937	$ 0.082034
Off-Peak	$ 0.016062	$ 0.017126	$ 0.016062	$ 0.017126

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 70 for details of these charges.

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Non-utility Generation Charge:

This charge shall recover above market costs associated with non-utility generation costs and other generation related costs as may be approved by the Board. Refer to the Non-utility Generation Charge sheet of this Tariff for the current charge.

Solar Pilot Recovery Charge:

This charge is designed to recover the revenue requirements associated with the Public Service Solar Pilot Program per the Board Order in Docket No. EO07040278 less the net proceeds from the sale of associated Solar Renewable Energy Certificates (SRECs) or cash received in lieu of SRECs. Refer to the Solar Pilot Recovery Charge sheet of this tariff for the current charge.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

(Charges are for illustrative purposes only and are based on the Seventh Revised Sheet No. 105 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 106**

RATE SCHEDULE RLM

RESIDENTIAL LOAD MANAGEMENT SERVICE

(Continued)

Tax Adjustment Credit:

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current credit.

Zero Emission Certificate Recovery Charge:

This charge provides for the recovery of costs associated with the Zero Emission Certificate Program directed by the Board of Public Utilities ("BPU" or "Board"). Refer to the Zero Emission Certificate Recovery Charge sheet of this Tariff for the current charge.

Conservation Incentive Program Charge:

This mechanism provides for recovery of lost revenues associated with various energy efficiency programs. Refer to the Conservation Incentive Program sheet of this Tariff for the current charge.

Distribution Adjustment Charge:

This charge is designed to recover Board-approved costs. Refer to the Distribution Adjustment Charge sheet of this Tariff for the current charge.

The Distribution Charges, Societal Benefits Charge, Non-utility Generation Charge, the Solar Pilot Recovery Charge, the Green Programs Recovery Charge, the Tax Adjustment Credit, the Zero Emission Certificate Recovery Charge, the Conservation Incentive Program Charge, and the Distribution Adjustment Charge shall be combined for billing.

ELECTRIC SUPPLY CHARGES:

A customer may choose to receive electric supply from either:

a) A TPS as described in Section 14 of this Tariff, or
b) Public Service through its Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP) default service.

Third Party Supply:

A customer that receives electric supply from a TPS will be charged for electric supply according to any agreement between the customer and the TPS. The customer will not be charged for electric supply by Public Service.

Basic Generation Service:

Customers that do not receive electric supply from a TPS will be supplied under the Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP) default service.

The BGS Energy Charges and the BGS Reconciliation Charge, as applicable, will be applied to all kilowatt-hours billed each month. Refer to the Basic Generation Service sheets of this Tariff for the current charges applicable to Rate Schedule RLM.

MINIMUM CHARGE:

The minimum charge shall be equal to the monthly Service Charge.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 107**

RATE SCHEDULE RLM

RESIDENTIAL LOAD MANAGEMENT SERVICE

(Continued)

GENERATION CAPACITY AND TRANSMISSION OBLIGATIONS:

Generation Obligation:

The customer's Generation Obligation, in kilowatts, is determined by Public Service no less frequently than once a year. The Generation Obligation for existing customers or for new customers utilizing an existing building or premise is based upon the customer's share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM) as adjusted by PJM assigned capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions. The Generation Obligation for customers taking service in a new building or premise, as determined by Public Service, is based upon the load requirements, as estimated by Public Service, of the customer's building or premise. The Generation Obligation represents the generator capacity that PJM requires an electric supplier to have available to provide electric supply to a customer.

Transmission Obligation:

The customer's Transmission Obligation, in kilowatts, is determined in a similar manner to the Generation Obligation described above. The Transmission Obligation represents the level of transmission network service that must be procured by the customer's electric supplier from PJM to provide service to the customer.

Costs associated with the Generation and Transmission Obligations are included in the charges for Basic Generation Service and may affect the price offered by a Third Party Supplier.

TIME PERIODS:

The On-Peak time period shall be considered as the hours from 7 A.M. to 9 P.M. (EST) Monday through Friday. All other hours shall be considered the Off-Peak time period.

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill.

TERM:

The term for delivery service is one year and thereafter until terminated by five days notice.

SPECIAL PROVISIONS:

(a) **Limitations on Service:** This rate schedule is available where all service is measured by one meter, except for service provided under Rate Schedules WH or WHS:

(a-1) In individual residences and appurtenant outbuildings;

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 108**

RATE SCHEDULE RLM

RESIDENTIAL LOAD MANAGEMENT SERVICE

(Continued)

(a-2) In residential premises where customer's use of electric service for purposes other than residential is incidental to its residential use;

(a-3) On residential farms;

(a-4) For rooming or boarding houses where the number of rented rooms does not exceed twice the number of bedrooms occupied by the customer;

(a-5) To a customer in a two- or three-family building who has the service for incidental common-use equipment registered on its meter;

(a-6) In individual flats or apartments in multiple-family buildings;

(a-7) In multiple-family buildings of two or more individual flats or apartments where electric service is furnished to the tenants or occupants of the flats or apartments by the owner without a specific charge for such service;

(b) **Resale:** Service under this rate schedule is not available for resale.

(c) **TPS Supply:** Customers who desire to purchase their electric supply from a TPS may request an enrollment package from Public Service that describes the process necessary for the customer to obtain a TPS for electric supply. This package will be provided to the customer at no charge by Public Service.

(c-1) The customer must contract with a TPS to arrange for deliveries to Public Service of the electric supply. A customer is limited to one TPS for electric supply for each account for which the customer receives delivery service.

(c-2) The customer's TPS is required to notify Public Service of the customer's selection prior to 13 days before the customer's scheduled Public Service meter reading date for deliveries to commence on such scheduled meter reading date, and such selection shall remain in effect for the entire billing month. Customer can change TPSs effective only on the date of the customer's scheduled Public Service meter reading date.

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 16 of the Standard Terms and Conditions for additional details and/or exceptions.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 108 for Future**

RATE SCHEDULE RLM

RESIDENTIAL LOAD MANAGEMENT SERVICE

(Continued)

(a-2) In residential premises where customer's use of electric service for purposes other than residential is incidental to its residential use;

(a-3) On residential farms;

(a-4) For rooming or boarding houses where the number of rented rooms does not exceed twice the number of bedrooms occupied by the customer;

(a-5) To a customer in a two- or three-family building who has the service for incidental common-use equipment registered on its meter;

(a-6) In individual flats or apartments in multiple-family buildings;

(a-7) In multiple-family buildings of two or more individual flats or apartments where electric service is furnished to the tenants or occupants of the flats or apartments by the owner without a specific charge for such service;

(a-8) In multiple-family buildings of two or more individual flats or apartments where a dedicated parking space is available and where a customer is served on a separate meter for electric vehicle charging use;

(a-9) In detached garage on a residential parcel for the purposes of charging electric vehicles.

(a-10) **Multi-Family Residential Electric Vehicle Charging:** Available to new and existing all Company-qualified Level 2 Electric Vehicle Charging Stations located at Multifamily Dwellings ("Multifamily Level 2 Electric Vehicle Charging Station") at a separately metered premise from the metering at the multifamily complex.

(b) **Resale:** Service under this rate schedule is not available for resale.

(c) **TPS Supply:** Customers who desire to purchase their electric supply from a TPS may request an enrollment package from Public Service that describes the process necessary for the customer to obtain a TPS for electric supply. This package will be provided to the customer at no charge by Public Service.

(c-1) The customer must contract with a TPS to arrange for deliveries to Public Service of the electric supply. A customer is limited to one TPS for electric supply for each account for which the customer receives delivery service.

(c-2) The customer's TPS is required to notify Public Service of the customer's selection prior to 13 days before the customer's scheduled Public Service meter reading date for deliveries to commence on such scheduled meter reading date, and such selection shall remain in effect for the entire billing month. Customer can change TPSs effective only on the date of the customer's scheduled Public Service meter reading date.

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 16 of the Standard Terms and Conditions for additional details and/or exceptions.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 109**
Original Sheet No. 110

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 111**

RATE SCHEDULE WH
WATER HEATING SERVICE

APPLICABLE TO USE OF SERVICE FOR:

This rate schedule is closed and is in the process of elimination. Delivery service under this rate schedule is limited to premises with controlled water heating installations that are presently served under this rate schedule. Customers may either purchase electric supply from a Third Party Supplier (TPS) or from Public Service's Basic Generation Service default service as detailed in this rate schedule.

DELIVERY CHARGES:

Distribution Charges per Kilowatt-hour:

For all use during the controlled heating period	
Charge	Charge Including SUT
$ 0.049482	$ 0.052760

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 70 for details of these charges.

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Non-utility Generation Charge:

This charge shall recover above market costs associated with non-utility generation costs and other generation related costs as may be approved by the Board. Refer to the Non-utility Generation Charge sheet of this Tariff for the current charge.

Solar Pilot Recovery Charge:

This charge is designed to recover the revenue requirements associated with the Public Service Solar Pilot Program per the Board Order in Docket No. EO07040278 less the net proceeds from the sale of associated Solar Renewable Energy Certificates (SRECs) or cash received in lieu of SRECs. Refer to the Solar Pilot Recovery Charge sheet of this tariff for the current charge.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

(Charges are for illustrative purposes only and are based on the Fifth Revised Sheet No. 111 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 112**

RATE SCHEDULE WH

WATER HEATING SERVICE

(Continued)

Tax Adjustment Credit:

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current credit.

Zero Emission Certificate Recovery Charge:

This charge provides for the recovery of costs associated with the Zero Emission Certificate Program directed by the Board of Public Utilities ("BPU" or "Board"). Refer to the Zero Emission Certificate Recovery Charge sheet of this Tariff for the current charge.

Distribution Adjustment Charge:

This charge is designed to recover Board-approved costs. Refer to the Distribution Adjustment Charge sheet of this Tariff for the current charge.

The Distribution Charges, Societal Benefits Charge, Non-utility Generation Charge, the Solar Pilot Recovery Charge, the Green Programs Recovery Charge, the Tax Adjustment Credit, the Zero Emission Certificate Recovery Charge, and the Distribution Adjustment Charge shall be combined for billing.

ELECTRIC SUPPLY CHARGES:

A customer may choose to receive electric supply from either:

a) A TPS as described in Section 14 of this Tariff, or
b) Public Service through its Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP) default service.

Third Party Supply:

A customer that receives electric supply from a TPS will be charged for electric supply according to any agreement between the customer and the TPS. The customer will not be charged for electric supply by Public Service.

Basic Generation Service:

Customers that do not receive electric supply from a TPS will be supplied under the Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP) default service.

The BGS Energy Charges and the BGS Reconciliation Charge, as applicable, will be applied to all kilowatt-hours billed each month. Refer to the Basic Generation Service sheets of this Tariff for the current charges applicable to Rate Schedule WH.

GENERATION CAPACITY AND TRANSMISSION OBLIGATIONS:

Generation Obligation:

The customer's Generation Obligation, in kilowatts, is determined by Public Service no less frequently than once a year. The Generation Obligation for existing customers or for new customers utilizing an existing building or premise is based upon the customer's share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM) as adjusted by PJM assigned capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions. The Generation Obligation for customers taking service in a new building or premise, as determined by Public Service, is based upon the load requirements, as estimated by Public Service, of the customer's building or premise. The Generation Obligation represents the generator capacity that PJM requires an electric supplier to have available to provide electric supply to a customer.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 113**

RATE SCHEDULE WH
WATER HEATING SERVICE
(Continued)

Transmission Obligation:

The customer's Transmission Obligation, in kilowatts, is determined in a similar manner to the Generation Obligation described above. The Transmission Obligation represents the level of transmission network service that must be procured by the customer's electric supplier from PJM to provide service to the customer.

Costs associated with the Generation and Transmission Obligations are included in the charges for Basic Generation Service and may affect the price offered by a Third Party Supplier.

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill.

TERM:

Customer may discontinue delivery service upon notice.

SPECIAL PROVISIONS:

(a) **Limitations on Service:** Electric service will be furnished under this rate schedule during the controlled heating period under the following conditions:

(a-1) Line capacity at location is sufficient to supply water heating service;

(a-2) Customer shall be using service for some purpose other than water heating and water heating service shall be furnished through the same service connection which supplies such other service;

(a-3) Electricity used for water heating during periods other than the controlled heating periods shall be registered on the meter measuring customer's other use and shall be billed under the rate schedule applicable to such other service;

(a-4) Service for controlled water heating will be controlled by a time switch and registered on a separate meter furnished and installed by Public Service for that purpose;

(a-5) Service is to an automatic storage-type water heater approved by Public Service; if the water heater is equipped with more than one heating element, the thermostats controlling the heating elements shall be interlocked so that only one of such elements can operate at a time;

(a-6) Customer shall install, at its own expense, a separate circuit of approved standard wiring for such water heater including proper connections for the installation of the meter and time switch;

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 114**

RATE SCHEDULE WH
WATER HEATING SERVICE
(Continued)

(a-7) Public Service shall furnish, install, and maintain a suitable time switch on the separate circuit for limiting to the controlled heating periods, hereinafter specified, the use of electric service at this rate schedule. The time switch shall remain the property of Public Service and shall be set and controlled exclusively by Public Service;

(a-8) The controlled heating period shall be normally from 11:00 P.M. of one day to 9:30 A.M. of the following day. Public Service may change such period depending upon load conditions on its system.

(b) **Resale:** Service under this rate schedule is not available for resale.

(c) **TPS Supply:** Customers who desire to purchase their electric supply from a TPS may request an enrollment package from Public Service that describes the process necessary for the customer to obtain a TPS for electric supply. This package will be provided to the customer at no charge by Public Service.

(c-1) The customer must contract with a TPS to arrange for deliveries to Public Service of the electric supply. A customer is limited to one TPS for electric supply for each account for which the customer receives delivery service.

(c-2) The customer's TPS is required to notify Public Service of the customer's selection prior to 13 days before the customer's scheduled Public Service meter reading date for deliveries to commence on such scheduled meter reading date, and such selection shall remain in effect for the entire billing month. Customer can change TPSs effective only on the date of the customer's scheduled Public Service meter reading date.

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 16 of the Standard Terms and Conditions for additional details and/or exceptions.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 115**
Original Sheet No. 116

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 117**

RATE SCHEDULE WHS
WATER HEATING STORAGE SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Delivery service for controlled water heating storage or for the electric heating elements of a water heating system connected to an active solar collection system. Customers may either purchase electric supply from a Third Party Supplier (TPS) or from Public Service's Basic Generation Service default service as detailed in this rate schedule.

DELIVERY CHARGES:

Service Charge:

$0.63 in each month [$0.67 including New Jersey Sales and Use Tax (SUT)].

Distribution Charges per Kilowatt-hour:

For all use during the controlled storage heating period	
Charge	Charge Including SUT
$ 0.001925	$ 0.002053

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 70 for details of these charges.

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Non-utility Generation Charge:

This charge shall recover above market costs associated with non-utility generation costs and other generation related costs as may be approved by the Board. Refer to the Non-utility Generation Charge sheet of this Tariff for the current charge.

Solar Pilot Recovery Charge:

This charge is designed to recover the revenue requirements associated with the Public Service Solar Pilot Program per the Board Order in Docket No. EO07040278 less the net proceeds from the sale of associated Solar Renewable Energy Certificates (SRECs) or cash received in lieu of SRECs. Refer to the Solar Pilot Recovery Charge sheet of this tariff for the current charge.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

(Charges are for illustrative purposes only and are based on the Fifth Revised Sheet No. 117 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 118**

RATE SCHEDULE WHS

WATER HEATING STORAGE SERVICE

(Continued)

Tax Adjustment Credit:

This mechanism is designed to return the Safe Harbor Adjusted Repair Expense (SHARE) deductions to customers net of any offsets for deferred storm and regulatory costs, IRS adjustments and adjust for any major tax changes, such as tax reform. Interest at the two-year treasury rate plus 60 basis points. Refer to the Tax Adjustment Credit sheet of this Tariff for the current credit.

Zero Emission Certificate Recovery Charge:

This charge provides for the recovery of costs associated with the Zero Emission Certificate Program directed by the Board of Public Utilities ("BPU" or "Board"). Refer to the Zero Emission Certificate Recovery Charge sheet of this Tariff for the current charge.

Distribution Adjustment Charge:

This charge is designed to recover Board-approved costs. Refer to the Distribution Adjustment Charge sheet of this Tariff for the current charge.

The Distribution Charges, Societal Benefits Charge, Non-utility Generation Charge, the Solar Pilot Recovery Charge, the Green Programs Recovery Charge, the Tax Adjustment Credit, the Zero Emission Certificate Recovery Charge, and the Distribution Adjustment Charge shall be combined for billing.

ELECTRIC SUPPLY CHARGES:

A customer may choose to receive electric supply from either:

a) A TPS as described in Section 14 of this Tariff, or
b) Public Service through its Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP) default service.

Third Party Supply:

A customer that receives electric supply from a TPS will be charged for electric supply according to any agreement between the customer and the TPS. The customer will not be charged for electric supply by Public Service.

Basic Generation Service:

Customers that do not receive electric supply from a TPS will be supplied under the Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP) default service.

The BGS Energy Charges and the BGS Reconciliation Charge, as applicable, will be applied to all kilowatt-hours billed each month. Refer to the Basic Generation Service sheets of this Tariff for the current charges applicable to Rate Schedule WHS.

GENERATION CAPACITY AND TRANSMISSION OBLIGATIONS:

Generation Obligation:

The customer's Generation Obligation, in kilowatts, is determined by Public Service no less frequently than once a year. The Generation Obligation for existing customers or for new customers utilizing an existing building or premise is based upon the customer's share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM) as adjusted by PJM assigned capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions. The Generation Obligation for customers taking service in a new building or premise, as determined by Public Service, is based upon the load requirements, as estimated by Public Service, of the customer's building or premise. The Generation Obligation represents the generator capacity that PJM requires an electric supplier to have available to provide electric supply to a customer.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 119**

RATE SCHEDULE WHS
WATER HEATING STORAGE SERVICE
(Continued)

Transmission Obligation:

The customer's Transmission Obligation, in kilowatts, is determined in a similar manner to the Generation Obligation described above. The Transmission Obligation represents the level of transmission network service that must be procured by the customer's electric supplier from PJM to provide service to the customer.

Costs associated with the Generation and Transmission Obligations are included in the charges for Basic Generation Service and may affect the price offered by a Third Party Supplier.

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill.

TERM:

Customer may discontinue delivery service upon notice.

SPECIAL PROVISIONS:

(a) **Limitations on Service:** Electric service will be furnished under this rate schedule during the controlled storage heating period under the following conditions:

(a-1) Line capacity at location is sufficient to supply water heating service;

(a-2) Customer shall be using service for some purpose other than water heating and water heating service shall be furnished through the same service connection which supplies such other service;

(a-3) Water heating equipment shall be operated at not less than 208 volts;

(a-4) Service for all water heating use will be controlled by a time switch or other control device and registered on a separate meter furnished and installed by Public Service for that purpose;

(a-5) Service is to an automatic storage-type water heater approved by Public Service; if the water heater is equipped with more than one heating element, the thermostats controlling the heating elements shall be interlocked so that only one of such elements can operate at a time;

(a-6) Customer shall install, at its own expense, a separate circuit of approved standard wiring for such water heater including proper connections for the installation of the meter and time switch or other control device;

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 120**

RATE SCHEDULE WHS
WATER HEATING STORAGE SERVICE
(Continued)

(a-7) Where the water heater load does not preclude the use of a Public Service time switch or other control device, Public Service shall furnish, install, regulate and maintain a suitable time switch or other control device to limit the hours of energy available to the water heater. Where the water heater load does preclude the use of a Public Service time switch or other control device, the customer must furnish, install, and maintain a suitable relay, contact or other device which; in response to a Public Service signal, will energize the water heating installation;

(a-8) The controlled storage heating period shall be from 9 P.M. (EST) of one day to 7 A.M. (EST) of the following day. Public Service may change such period depending upon load conditions on its system.

(b) **Resale:** Service under this rate schedule is not available for resale.

(c) **TPS Supply:** Customers who desire to purchase their electric supply from a TPS may request an enrollment package from Public Service that describes the process necessary for the customer to obtain a TPS for electric supply. This package will be provided to the customer at no charge by Public Service.

(c-1) The customer must contract with a TPS to arrange for deliveries to Public Service of the electric supply. A customer is limited to one TPS for electric supply for each account for which the customer receives delivery service.

(c-2) The customer’s TPS is required to notify Public Service of the customer’s selection prior to 13 days before the customer’s scheduled Public Service meter reading date for deliveries to commence on such scheduled meter reading date, and such selection shall remain in effect for the entire billing month. Customer can change TPSs effective only on the date of the customer’s scheduled Public Service meter reading date.

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 16 of the Standard Terms and Conditions for additional details and/or exceptions.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 121**
Original Sheet No. 122

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 123**

RATE SCHEDULE HS
BUILDING HEATING SERVICE

APPLICABLE TO USE OF SERVICE FOR:

This rate schedule is closed and is in the process of elimination. Delivery service under this rate schedule is limited to permanently installed comfort building heating equipment in premises that are presently served under this rate schedule. Customers may either purchase electric supply from a Third Party Supplier (TPS) or from Public Service's Basic Generation Service default service as detailed in this rate schedule.

DELIVERY CHARGES:

Service Charge:

$3.75 in each month [$4.00 including New Jersey Sales and Use Tax (SUT)].

Distribution Charges per Kilowatt-hour:

In each of the months of October through May		In each of the months of June through September	
Charges	Charges Including SUT	Charges	Charges Including SUT
$ 0.029426	$ 0.031375	$ 0.098011	$ 0.104504

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 71 for details of these charges.

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Non-utility Generation Charge:

This charge shall recover above market costs associated with non-utility generation costs and other generation related costs as may be approved by the Board. Refer to the Non-utility Generation Charge sheet of this Tariff for the current charge.

Commercial and Industrial Energy Pricing (CIEP) Standby Fee:

Applicable to all kilowatt-hour usage for customers who have selected the option of hourly energy pricing service from either Basic Generation Service-Commercial and Industrial Energy Pricing (BGS-CIEP) or a Third Party Supplier. This charge shall recover costs associated with the administration, maintenance and availability of BGS-CIEP default supply service. Refer to the CIEP Standby Fee sheet of this Tariff for the current charge.

(Charges are for illustrative purposes only and are based on the Fifth Revised Sheet No. 123 filed with the BPU on November 1, 2023)

Date of Issue: Effective:

Issued by SCOTT S. JENNINGS, SVP – Finance, Planning & Strategy – PSE&G
80 Park Plaza, Newark, New Jersey 07102
Filed pursuant to Order of Board of Public Utilities dated
in Docket No.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 124**

RATE SCHEDULE HS
BUILDING HEATING SERVICE
(Continued)

Solar Pilot Recovery Charge:

This charge is designed to recover the revenue requirements associated with the Public Service Solar Pilot Program per the Board Order in Docket No. EO07040278 less the net proceeds from the sale of associated Solar Renewable Energy Certificates (SRECs) or cash received in lieu of SRECs. Refer to the Solar Pilot Recovery Charge sheet of this tariff for the current charge.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

Tax Adjustment Credit:

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current credit.

Zero Emission Certificate Recovery Charge:

This charge provides for the recovery of costs associated with the Zero Emission Certificate Program directed by the Board of Public Utilities ("BPU" or "Board"). Refer to the Zero Emission Certificate Recovery Charge sheet of this Tariff for the current charge.

Distribution Adjustment Charge:

This charge is designed to recover Board-approved costs. Refer to the Distribution Adjustment Charge sheet of this Tariff for the current charge.

The Distribution Charges, Societal Benefits Charge, Non-utility Generation Charge, the Solar Pilot Recovery Charge, the Green Programs Recovery Charge, the Tax Adjustment Credit, the Zero Emission Certificate Recovery Charge, and the Distribution Adjustment Charge shall be combined for billing. The CIEP Standby Fee shall also be combined with these charges where applicable.

ELECTRIC SUPPLY CHARGES:

A customer may choose to receive electric supply from either:
a) A TPS as described in Section 14 of this Tariff, or
b) Public Service through its Basic Generation Service.

Third Party Supply:

A customer that receives electric supply from a TPS will be charged for electric supply according to any agreement between the customer and the TPS. The customer will not be charged for electric supply by Public Service.

Basic Generation Service:

Customers that do not receive electric supply from a TPS will be supplied by Public Service through its Basic Generation Service - Residential Small Commercial Pricing (BGS-RSCP) default service. Customers may elect BGS-CIEP as their default supply but must notify Public Service of their election of BGS-CIEP as their default supply no later than the second business day in January of each year. Such election shall be effective June 1st of that year and BGS-CIEP will remain as the customer's default supply until they notify Public Service of their election of BGS-RSCP as their default supply no later than the second business day in January and their election of BGS-RSCP shall be effective June 1st of that year.

The BGS Energy Charges and the BGS Reconciliation Charge, as applicable, will be applied to all kilowatt-hours billed each month. Refer to the Basic Generation Service sheets of this Tariff for the current charges applicable to Rate Schedule HS.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 125**

RATE SCHEDULE HS

BUILDING HEATING SERVICE

(Continued)

GENERATION CAPACITY AND TRANSMISSION OBLIGATIONS:

Generation Obligation:

The customer's Generation Obligation, in kilowatts, is determined by Public Service no less frequently than once a year. The Generation Obligation for existing customers or for new customers utilizing an existing building or premise is based upon the customer's share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM) as adjusted by PJM assigned capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions. The Generation Obligation for customers taking service in a new building or premise, as determined by Public Service, is based upon the load requirements, as estimated by Public Service, of the customer's building or premise. The Generation Obligation represents the generator capacity that PJM requires an electric supplier to have available to provide electric supply to a customer.

Transmission Obligation:

The customer's Transmission Obligation, in kilowatts, is determined in a similar manner to the Generation Obligation described above. The Transmission Obligation represents the level of transmission network service that must be procured by the customer's electric supplier from PJM to provide service to the customer.

Costs associated with the Generation and Transmission Obligations are included in the charges for Basic Generation Service and may affect the price offered by a Third Party Supplier.

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill and subject to a late payment charge at the rate of 1.416% per monthly billing period in accordance with Section 9.12 of the Standard Terms and Conditions. Service to a body politic will not be subject to a late payment charge.

TERM:

The term for delivery service is one year and thereafter until terminated by five days notice.

Customers who transfer from third party supply to Basic Generation Service may be subject to additional limitations regarding the term of Basic Generation Service as detailed in Section 14 of the Standard Terms and Conditions of this Tariff.

SPECIAL PROVISIONS:

(a) **Limitations on Service:** This rate schedule is available for permanently installed comfort building heating where:

(a-1) Building heating equipment is operated at not less than 208 volts and has a total capacity of not less than five kilowatts;

(a-2) The wiring system metered under this rate schedule utilizes panels, troughs, conduit and wiring completely independent of the general lighting service for the building.

RATE SCHEDULE HS
BUILDING HEATING SERVICE
(Continued)

(b) **Resale:** Service under this rate schedule is not available for resale.

(c) **TPS Supply:** Customers who desire to purchase their electric supply from a TPS may request an enrollment package from Public Service that describes the process necessary for the customer to obtain a TPS for electric supply. This package will be provided to the customer at no charge by Public Service.

(c-1) The customer must contract with a TPS to arrange for deliveries to Public Service of the electric supply. A customer is limited to one TPS for electric supply for each account for which the customer receives delivery service.

(c-2) The customer's TPS is required to notify Public Service of the customer's selection prior to 13 days before the customer's scheduled Public Service meter reading date for deliveries to commence on such scheduled meter reading date, and such selection shall remain in effect for the entire billing month. Customer can change TPSs effective only on the date of the customer's scheduled Public Service meter reading date.

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P. L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 16 of the Standard Terms and Conditions for additional details and/or exceptions.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 127**
Original Sheet No. 128

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 129**

RATE SCHEDULE GLP
GENERAL LIGHTING AND POWER SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Delivery service for general purposes at secondary distribution voltages. Customers may either purchase electric supply from a Third Party Supplier (TPS) or from Public Service's Basic Generation Service default service as detailed in this rate schedule.

DELIVERY CHARGES:

Service Charge:

$4.78 in each month [$5.10 including New Jersey Sales and Use Tax (SUT)].

Distribution Kilowatt Charges:

Annual Demand Charge applicable in all months:

Charge	Charge Including SUT	
$ 3.7660	$ 4.0155	per kilowatt of Monthly Peak Demand

Summer Demand Charge applicable in the months of June through September:

Charge	Charge Including SUT	
$ 9.4441	$ 10.0698	per kilowatt of Monthly Peak Demand

Distribution Kilowatt-hour Charges:

In each of the months of October through May		In each of the Months of June through September		
Charge	Charge Including SUT	Charge	Charge Including SUT	
$ 0.007858	$ 0.008379	$ 0.003079	$ 0.003283	per kilowatt-hour

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 71 for details of these charges.

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Non-utility Generation Charge:

This charge shall recover above market costs associated with non-utility generation costs and other generation related costs as may be approved by the Board. Refer to the Non-utility Generation Charge sheet of this Tariff for the current charge.

(Charges are for illustrative purposes only and are based on the Fifth Revised Sheet No. 129 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 130**

RATE SCHEDULE GLP
GENERAL LIGHTING AND POWER SERVICE
(Continued)

Commercial and Industrial Energy Pricing (CIEP) Standby Fee:

Applicable to all kilowatt-hour usage for customers who have selected the option of hourly energy pricing service from either Basic Generation Service-Commercial and Industrial Energy Pricing (BGS-CIEP) or a Third Party Supplier. This charge shall recover costs associated with the administration, maintenance and availability of BGS-CIEP default supply service. Refer to the CIEP Standby Fee sheet of this Tariff for the current charge.

Solar Pilot Recovery Charge:

This charge is designed to recover the revenue requirements associated with the Public Service Solar Pilot Program per the Board Order in Docket No. EO07040278 less the net proceeds from the sale of associated Solar Renewable Energy Certificates (SRECs) or cash received in lieu of SRECs. Refer to the Solar Pilot Recovery Charge sheet of this tariff for the current charge.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

Tax Adjustment Credit:

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current credit.

Zero Emission Certificate Recovery Charge:

This charge provides for the recovery of costs associated with the Zero Emission Certificate Program directed by the Board of Public Utilities ("BPU" or "Board"). Refer to the Zero Emission Certificate Recovery Charge sheet of this Tariff for the current charge.

Conservation Incentive Program Charge:

This mechanism provides for recovery of lost revenues associated with various energy efficiency programs. Refer to the Conservation Incentive Program sheet of this Tariff for the current charge.

Distribution Adjustment Charge:

This charge is designed to recover Board-approved costs. Refer to the Distribution Adjustment Charge sheet of this Tariff for the current charge.

The Distribution Kilowatt-hour Charge, the Non-utility Generation Charge, the Solar Pilot Recovery Charge, the Green Programs Recovery Charge, the Tax Adjustment Credit, the Zero Emission Certificate Recovery Charge, and the Distribution Adjustment Charge shall be combined for billing. The CIEP Standby Fee shall also be combined with these charges where applicable.

The Distribution Kilowatt Charge and the Conservation Incentive Program Charge shall be combined for billing.

ELECTRIC SUPPLY CHARGES:

A customer may choose to receive electric supply from either:
a) A TPS as described in Section 14 of this Tariff, or
b) Public Service through its Basic Generation Service.

RATE SCHEDULE GLP
GENERAL LIGHTING AND POWER SERVICE
(Continued)

Third Party Supply:

A customer that receives electric supply from a TPS will be charged for electric supply according to any agreement between the customer and the TPS. The customer will not be charged for electric supply by Public Service.

Basic Generation Service:

Customers that do not receive electric supply from a TPS will be supplied by Public Service through its Basic Generation Service - Residential Small Commercial Pricing (BGS-RSCP) default service. Customers may elect BGS-CIEP as their default supply but must notify Public Service of their election of BGS-CIEP as their default supply no later than the second business day in January of each year. Such election shall be effective June 1st of that year and BGS-CIEP will remain as the customer's default supply until they notify Public Service of their election of BGS-RSCP as their default supply no later than the second business day in January and their election of BGS-RSCP shall be effective June 1st of that year.

The BGS Energy Charges, BGS Capacity Charge, BGS Transmission Charge and BGS Reconciliation Charge are applicable. Refer to the Basic Generation Service sheets of this Tariff for the current charges applicable to Rate Schedule GLP.

MINIMUM CHARGE:

Where the use of electricity is for seldom used applications, an Annual Minimum charge may be applied. Such Annual Minimum charge shall equal the diversified connected load of the electric service, in kW, times the Annual Demand Charge times 6. Revenue to satisfy the Annual Minimum requirement shall be derived solely from Distribution Kilowatt Charges and Distribution Kilowatt-hour Charges.

BILLING DETERMINANTS:

Monthly Peak Demand:

The Monthly Peak Demand shall be determined either by the registration of a demand meter furnished by Public Service or by estimate.

Where a demand meter is installed, the customer's Monthly Peak Demand in any month shall be the greatest average number of kilowatts delivered by Public Service during any thirty-minute interval.

Where no demand meter is installed, the customer's Monthly Peak Demand shall be determined by estimate by dividing the kilowatt-hours by 100 for the applicable billing period.

New Customer: Where a new customer applying for service has an anticipated maximum Monthly Peak Demand of 10 kilowatts or more, that customer's Monthly Peak Demand shall be determined by measurement. If the anticipated maximum Monthly Peak Demand is less than 10 kilowatts, the demand may be determined by estimate or measurement.

Existing Customer: Where an existing customer's Monthly Peak Demand is determined, for billing, by measurement and is 10 kilowatts or greater in any of the preceding 12 months, the customer will continue to have their Monthly Peak Demand determined by measurement and is not eligible for determination by estimate.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 132**

RATE SCHEDULE GLP

GENERAL LIGHTING AND POWER SERVICE

(Continued)

Where an existing customer's Monthly Peak Demand is determined, for billing, by estimate and their monthly billed kilowatt-hours in any of the preceding 12 months exceeds 1,000 kilowatt-hours, or their Monthly Peak Demand exceeds 10 kilowatts by actual measurement, the customer will be converted to have their Monthly Peak Demand, for billing, determined by measurement. If customer's usage is always less than 1,000 kilowatt-hours per month, the customer may be billed under estimated or measured demand.

Self-Generation Customer: For customers with operational self-generation units: 1) with a combined maximum net kilowatt output rating equal to or greater than 50% of their Annual Peak Demand; or, 2) whose premise was served on the former special provision for Standby Service of this rate schedule on July 31, 2003; or 3) who have been granted all necessary air permits by August 1, 2004 for a new or expanded self-generation facility: The Monthly Peak Demand used in the determination of the Summer Demand Charges shall be equal to the greatest average number of kilowatts delivered by Public Service during any thirty-minute interval that occur during the single hour of monthly maximum peak demand of the Public Service distribution system for the applicable summer billing month. For self-generation customers served under this standby provision, the Annual Demand Charge will be applied to the customer's Annual Peak Demand in lieu of the Monthly Peak Demand.

Annual Peak Demand:

The customer's Annual Peak Demand in kilowatts shall be the highest Monthly Peak Demand occurring in any time period of the current month and the preceding 11 months.

Generation Obligation:

The customer's Generation Obligation, in kilowatts, is determined by Public Service no less frequently than once a year. The Generation Obligation for existing customers or for new customers utilizing an existing building or premise is based upon the customer's share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM) as adjusted by PJM assigned capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions. The Generation Obligation for customers taking service in a new building or premise, as determined by Public Service, is based upon the load requirements, as estimated by Public Service, of the customer's building or premise. The Generation Obligation represents the generator capacity that PJM requires an electric supplier to have available to provide electric supply to a customer.

Transmission Obligation:

The customer's Transmission Obligation, in kilowatts, is determined in a similar manner to the Generation Obligation described above. The Transmission Obligation represents the level of transmission network service that must be procured by the customer's electric supplier from PJM to provide service to the customer.

Generation and Transmission Obligations are used in the determination of the customer's charges for Basic Generation Service and may affect the price offered by a Third Party Supplier.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 133**

RATE SCHEDULE GLP

GENERAL LIGHTING AND POWER SERVICE

(Continued)

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill and subject to a late payment charge at the rate of 1.416% per monthly billing period in accordance with Section 9.12 of the Standard Terms and Conditions. Service to a body politic will not be subject to a late payment charge.

TERM:

The term for delivery service is one year and thereafter until terminated by five days notice.

Customers who transfer from third party supply to Basic Generation Service may be subject to additional limitations regarding the term of Basic Generation Service as detailed in Section 14 of the Standard Terms and Conditions of this Tariff.

SPECIAL PROVISIONS:

(a) **Limitations on Service:** Service under this rate schedule will not be supplied where:

(a-1) The customers' Monthly Peak Demand exceeds 150 kilowatts in any month;

(a-2) The customer is presently served under Rate Schedule LPL-secondary and their Monthly Peak Demand has exceeded 100 kilowatts in any of the prior 24 consecutive months;

(a-3) The electrical capacity installed by Public Service exceeds 400 kilowatts.

Customers receiving service on the Building Heating Special Provision in July 2003 are exempt from the above limitation (a-1) and (a-3), where in any of the months of October through May the Monthly Peak Demand may exceed 150 kilowatts.

(b) **Resale:** Service under this rate schedule is not available for resale.

(c) **Police Recall or Fire Alarm System Service:** Unmetered police recall or fire alarm system service will be furnished for signaling lamps, bells, or horns with an individual rating not greater than 100 watts or 1/8-horsepower, as rated by Public Service, at a charge of $0.180 ($0.192 including SUT) per month for each signaling lamp, bell, or horn connected, but the total charge shall in no case be less than $1.80 ($1.92 including SUT) per month. No other energy-using devices shall be connected to the police recall or fire alarm system. The customer shall provide, at its own expense, all necessary equipment and wiring, including the service connection. This Special Provision is only available with electric supply furnished by Public Service.

(d) **Religious Houses of Worship Service:** Where electric supply is provided by Public Service to a customer where the primary use of service is for public religious services and customer applies for and is eligible for such service, the customer's monthly bill will be subject to a credit of $0.0500 ($0.0533 including SUT) per kilowatt-hour but not to exceed $50.00 ($53.31 including SUT) in any billing period.

The customer will be required to sign an Application for Religious Houses of Worship Service certifying eligibility. Upon request by Public Service, the customer shall furnish satisfactory proof of eligibility for service under this Special Provision.

(Charges are for illustrative purposes only and are based on the Original Sheet No. 133 filed with the BPU on November 1, 2018)

RATE SCHEDULE GLP

GENERAL LIGHTING AND POWER SERVICE

(Continued)

(e) **Unmetered Service:** Unmetered service will be supplied, at the discretion of Public Service, where estimates of kilowatts and kilowatt-hours are based upon information supplied by the customer and agreed to by Public Service. Such estimates of demand and usage shall be constant on a monthly basis.

Unmetered service for automated license plate readers (ALPR) and/or closed-circuit television cameras (CCTV) or similar pole attachments used for body politic-affiliated safety activities may be supplied at the direction of Public Service. Unmetered service to ALPR and CCTV devices shall be based on estimates of kilowatts and kilowatt-hours based upon information supplied by the customer, including any available manufacturer specifications regarding power requirements of these devices. At the discretion of Public Service, the estimates for unmetered service to ALPR or CCTV or similar pole attachment devices may require the assumption that the devices are operate at 100 percent load factor based upon their maximum kilowatt rating.

Customer shall notify Public Service in writing at any time as to changes in conditions or operation of the equipment which may affect estimates of demand or use. Public Service reserves the right to meter any and all such installations where customer does not comply, and customer will no longer be eligible for service under this Special Provision. (See Section 7.1 of the Standard Terms and Conditions.) The customer may be required to furnish and install, at its own expense, a load-limiting device approved by Public Service, which shall be maintained by Public Service at customer's expense.

Customers taking service under this Special Provision shall be subject to a monthly Unmetered Service Charge of $2.20 ($2.35 including SUT) in lieu of the Service Charge hereinbefore set forth.

(f) **Area Development Service:** Where a new or existing customer takes service under this rate schedule at a single service connection located within the municipal boundaries of the cities of Newark, Jersey City, Paterson, Elizabeth, Camden, Trenton, East Orange, Hoboken, Union City, Plainfield, Gloucester City, Passaic City, Weehawken, Kearny, or Orange, service will be supplied under this provision subject to the following conditions:

(f-1) Each customer will be required to sign an Application for Area Development Service under this rate schedule. Public Service shall define a customer as new or existing for purposes of this application. In the case of existing customers, the base year period twelve Monthly Peak Demands in kilowatts shall be specified by Public Service and agreed to by the customer prior to institution of any credits.

(f-2) Customers shall be eligible for credits under this Special Provision only to the extent that they have signed an Application for Area Development Service and meet the minimum load conditions. For new customers, the minimum load must be no less than 25 kilowatts of the applicable Monthly Peak Demand. For existing customers, the average twelve-month minimum load must be no less than 50 kilowatts of applicable Monthly Peak Demand during the previous twelve months. In addition, during any three consecutive months subsequent to an acceptance of the application by Public Service, existing customer applicable Monthly Peak Demands must be at least 125%, or for customers under the minimum load an addition of at least 50 kilowatts, of applicable Monthly Peak Demands in comparable months of the previous 36 months to qualify for credits. Credits for new and existing customers shall commence in the first month subsequent to such qualification.

In no case shall any customer receive credits under this Special Provision who has previously applied for electric service at the same or new location in excess of 300 kilowatts which has been approved for service by Public Service 90 days from the effective date of this Special Provision for the original nine cities and 90 days from the effective date of the modified Special Provision for any additional cities.

(Charges are for illustrative purposes only and are based on the Fifth Revised Sheet No. 134 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 135**

RATE SCHEDULE GLP

GENERAL LIGHTING AND POWER SERVICE

(Continued)

(f-3) A credit of $2.69 ($2.87 including SUT) per kilowatt of Monthly Peak Demand shall apply to all kilowatts so measured for new customers. A new customer, for purposes of this Special Provision, shall be defined either as a customer taking service in a new or renovated building or premise, or a customer taking service in an existing building or premise whose activities or use of electric service is substantially different from that of the previous customer. Where no business has been conducted at a building or premise for at least three months, any customer shall be considered a new customer for purposes of this Special Provision.

(f-4) A credit of $2.69 ($2.87 including SUT) per kilowatt of Monthly Peak Demand shall apply only to those kilowatts so measured for existing customers which are in excess of comparable demands in the same month established in a base year period, which period shall be defined as the twelve calendar months immediately preceding the first month of qualification. An existing customer, for purposes of this Special Provision, shall be defined as a customer whose activities or use of electric service is substantially the same as that of the previous customer, except that such customer shall be eligible for this Special Provision to the extent that the previous customer was so eligible, and for the remainder of the previous customer's term.

(f-5) Where a customer signs an Application for Area Development Service and elects to be billed under this Special Provision, the term of service shall be seven years in lieu of the term stated in this rate schedule. For new customers, the term shall commence with the first month following qualification and, for existing customers, beginning with the first month following the three-month qualification period. In no case shall the term of service commence prior to the completion of the Application for Area Development Service by the customer and acceptance by Public Service.

Credits under (f-3) or (f-4) will be available to qualifying customers during the first five years of the term. Subsequently, such credits will be reduced by 50% during the final two years of the term.

(f-6) Public Service reserves the right to reject Applications for Area Development Service where the cost of facilities to supply new or existing customers is, in its judgment, excessive or might affect the supply of service to other customers.

(g) **Duplicate Service:** Where, at request of a customer, either: a) an additional source or sources of Public Service distribution supply is provided to serve all or part of their load when the principal Public Service distribution source or sources (termed the Normal Service) are unavailable, or b) where such additional sources are supplied as part of standard supply configuration provided by Public Service and such additional source is provided from a different substation or switching station than as determined by Public Service, such service is termed Duplicate Service. Duplicate Service will be furnished only if practical and safe from the standpoint of Public Service and will not be supplied where it would create an unusual hazard or interfere with the provision of service to other customers.

(Charges are for illustrative purposes only and are based on the Original Sheet No. 135 filed with the BPU on November 1, 2018)

RATE SCHEDULE GLP
GENERAL LIGHTING AND POWER SERVICE
(Continued)

(g-1) **Duplicate Service Capacity:** The maximum electrical requirement, in kilowatts, needed by the customer at any time on the Duplicate Service is defined as Duplicate Service Capacity. The value of the Duplicate Service Capacity will initially be determined by the customer and shall be used by Public Service as the design criteria in construction of the Duplicate Service. The Duplicate Service Capacity shall be reviewed periodically and shall be the greater of the then requested Duplicate Service Capacity, or the highest actual peak demand established in the prior 24 month period on the Duplicate Service or the Normal Service.

(g-2) **Duplicate Service Charges:** Duplicate service charges will be established for each Duplicate Service based on the sum of the following:

(g-2a) A monthly facilities charge as set forth in Section 3.5.2. of these Standard Terms and Conditions calculated as the Facilities Charge Rate times the total costs of any service or line work required to supply Duplicate Service, including extending or reinforcing Public Service distribution facilities and any distribution transformer or metering costs.

Once a facilities charge is established for a facility or premise and there is no material change in the Duplicate Service Capacity to be provided, the basis for the facilities charge shall remain the same as long as the Public Service facilities remain in service and shall be used for all subsequent customers at that facility requesting Duplicate Service, regardless of any lapse in the provision of Duplicate Service to that facility.

(g-2b) Charges for the kilowatts of Duplicate Service Capacity of:

Duplicate Service Capacity Charges		Applicable in all months
Charge	Charge Including SUT	
$ 2.22	$ 2.37	per kilowatt of Duplicate Service Capacity supplied from the same substation as the Normal Service
$ 3.20	$ 3.41	per kilowatt of Duplicate Service Capacity supplied from a different substation than the Normal Service

(g-3) **Metering and Billing:** Where separate metering is provided, all usage on the duplicate service will be combined for billing purposes with usage on the Normal Service meter.

(Charges are for illustrative purposes only and are based on the Original Sheet No. 136 filed with the BPU on November 1, 2018)

RATE SCHEDULE GLP
GENERAL LIGHTING AND POWER SERVICE
(Continued)

(g-4) **Changes in Duplicate Service Capacity**: Any material increase in the Duplicate Service Capacity that requires a change in the facilities related to extending Public Service facilities to the customer or the costs of reinforcing related Public Service facilities may require an increase in the monthly facilities charge. Any material decrease in the Duplicate Service Capacity shall not change the monthly facilities charge.

All initial requests or requests for an increase in Duplicate Service Capacity in excess of 5 megawatts shall require the customer to deposit with Public Service the first five year's facilities charges and applicable Duplicate Service Charges on a non-refundable basis prior to the start of any work by Public Service to supply such Duplicate Service. The monthly charges for Duplicate Service shall be applied against the deposited amount in lieu of being billed to the customer until such time as the customer's deposited amount is exhausted, at which time such charges shall be included in the customer's monthly bill. In no event shall any part of the deposit remaining after five years be returned or credited to the customer in any manner.

(h) **Night Use:** Where a customer has requested Public Service to install a time of day meter for billing under this Special Provision, the following shall apply:

(h-1) The Summer Demand Charge will be applicable only to the kilowatts of Day Period Monthly Peak Demand during the months of June through September.

(h-2) A Term of Service on this Special Provision of two years and thereafter until terminated by five days notice.

(h-3) The Day Period shall be considered as the hours of 8 A.M. to 8 P.M. Monday through Friday. All other hours shall be considered the Night Period.

(i) **Curtailable Electric Service:** Curtailable Electric Service will be furnished when and where available so as to preserve the reliability of the Public Service distribution system. Those customers that receive electric supply from a third party supplier may continue to receive service under this Special Provision. If a third party supplied customer chooses to no longer participate, or alternatively, a customer is disqualified for this Special Provision because of continued failure to meet agreed upon load reductions, the customer will be required to pay Public Service, in accordance with Standard Terms and Conditions, Section 9.4.2, Metering, for the installed interval metering device if the customer chooses to retain the installed interval meter and the meter is not otherwise required for service. Curtailable Electric Service will be furnished under the following conditions:

(Charges are for illustrative purposes only and are based on the Fifth Revised Sheet No. 137 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

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RATE SCHEDULE GLP

GENERAL LIGHTING AND POWER SERVICE

(Continued)

(i-1) A customer agrees to take service under this rate schedule at a single service connection and agrees to curtail its load during times of curtailment by the amount stated in the customer's Application/Agreement. A credit of $6.11 ($6.51 including SUT) per kilowatt of average actual curtailed demand for each curtailment period will be applied to the customer's bill in a succeeding month. The curtailed demands will be measured as the difference, for each hour, between a customer-specific hourly load curve developed by Public Service for customer's normal business operation and the actual recorded hourly load during the curtailment period. The curtailment period will commence a minimum of one hour from the time of notification and end at the time indicated in the restoration call but not later than 8:00 P.M. as indicated in (i-3) below. For each applicable calendar month, the customer's individual curtailment period results will be summed to determine the appropriate credit. There will be no penalty for failure to curtail load or meet the agreed upon load reduction when notified. Continued failure by a customer to meet agreed upon load reduction, however, will result in customer's disqualification for this Special Provision and Public Service may remove from the customer's premises the interval metering device installed solely for this Special Provision.

(i-1a) In the event that a customer-specific hourly load curve for customer's normal business operation cannot be developed by Public Service, the curtailed demands will be measured as the difference between the actual hourly load at the time of notification and the actual recorded hourly load for each hour during the curtailment period. Payment will be subject to a maximum equal to the estimated amount of load customer will curtail during curtailments in (i-2).

(i-2) A customer will be required to sign an Application/Agreement for Curtailable Electric Service under this rate schedule. The Application/Agreement will specify the estimated amount of load customer will curtail during curtailments. Curtailment payments will be subject to a maximum of 150% of the estimated amount of load customer will curtail during curtailments. The maximum shall apply subsequent to the customer's first curtailment after election to take service under this Special Provision. The minimum curtailable load is 100 kilowatts. The advanced notification period is a minimum of one hour.

(i-3) This Special Provision will be in effect for the four summer months June through September and apply on weekdays only, excluding holidays, and the potential daily curtailment period shall be the hours between 12:00 Noon and 8:00 P.M. Public Service agrees to limit curtailments, as described in this Special Provision, to a maximum of 120 total hours and a maximum of 15 curtailments during the calendar year.

(i-4) Public Service will contact the customer by telephone or otherwise of the need to curtail load under this Special Provision. The customer shall designate personnel who will accept notification of curtailment on summer weekdays from 9:00 A.M. to 8:00 P.M. Where necessary, Public Service will install and maintain suitable metering at its meter locations for verification of customer compliance with the curtailment and notification agreement.

(Charges are for illustrative purposes only and are based on the Original Sheet No. 138 filed with the BPU on November 1, 2018)

RATE SCHEDULE GLP
GENERAL LIGHTING AND POWER SERVICE
(Continued)

(i-5) When a customer signs an Application/Agreement for Curtailable Electric Service and elects to be billed under this Special Provision, the term of service will be for two years in lieu of the term stated in this rate schedule, with periodic review of curtailable demand not to exceed twelve months. Public Service reserves the right to determine whether successive terms may be negotiated and under what conditions curtailable demand may be changed.

(i-6) In the event of an emergency condition which occurs outside the period specified in (i-3) above and which threatens the integrity of the Public Service system or the systems to which Public Service is directly or indirectly connected, Public Service may contact customer of the need to curtail load. There will be no penalty for failure to curtail load or meet the agreed upon load reduction. Customers who are able to curtail load will have a credit applied to their bill.

(j) **TPS Supply:** Customers who desire to purchase their electric supply from a TPS may request an enrollment package from Public Service that describes the process necessary for the customer to obtain a TPS for electric supply. This package will be provided to the customer at no charge by Public Service.

(j-1) The customer must contract with a TPS to arrange for deliveries to Public Service of the electric supply. A customer is limited to one TPS for electric supply for each account for which the customer receives delivery service.

(j-2) The customer's TPS is required to notify Public Service of the customer's selection prior to 13 days before the customer's scheduled Public Service meter reading date for deliveries to commence on such scheduled meter reading date, and such selection shall remain in effect for the entire billing month. Customer can change TPSs effective only on the date of the customer's scheduled Public Service meter reading date.

RATE SCHEDULE GLP
GENERAL LIGHTING AND POWER SERVICE
(Continued)

(k) **Veterans' Organization Service:** Pursuant to N.J.S.A. 48:2-21.41, when electric service is delivered to a customer that is a Veterans' Organization, serving the needs of veterans of the armed forces, the customer may apply and be eligible for billing under this Special Provision.

(k-1) Each customer shall be eligible for billing under this Special Provision upon submitting an Application for Veterans' Organization Service under this rate schedule and by qualifying as a Veterans' Organization as defined by N.J.S.A. 48:2-21.41 as "an organization dedicated to serving the needs of veterans of the armed forces that: is chartered under federal law, qualifies as a tax exempt organization under paragraph (19) of subsection (c) of section 501 of the federal Internal Revenue Code of 1986, 26 U.S.C. s.501 (c)(19), or that is organized as a corporation under the 'New Jersey Nonprofit Corporation Act,' N.J.S.A. 15:1-1 et seq." Under N.J.S.A. 48:2-21.41, a qualified Veterans' Organization shall be charged the residential rate for service delivered to the property where the Veterans' Organization primarily operates, if the residential rate is lower than the commercial rate for service at that property.

The customer shall furnish satisfactory proof of eligibility of service under this Special Provision to the Company. Once proof of eligibility is determined by the Company, service under this Special Provision shall begin with the next billing cycle following receipt of the Application.

(k-2) The customer will continue to be billed on this rate schedule. At least once annually, the Company shall review eligible customers' delivery charges under this Special Provision for all relevant periods. If the comparable delivery charges under the Residential Service (RS) rate schedule are lower than the delivery charges under its current rate schedule, a credit in the amount of the difference will be applied to the customer's next bill.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 141**

RATE SCHEDULE GLP
GENERAL LIGHTING AND POWER SERVICE
(Continued)

(I) **Distribution Demand Charge Rebate:** A customer under this rate schedule whose sole usage is for Direct Current Fast Charging (DCFC) Electric Vehicle charging and ancillary energy consumption (communications, area lighting, etc.) and who meets all of the requirements of this special provision, will qualify for a Distribution Demand Charge Rebate. This rebate will remain in effect until the N.J.B.P.U approved $5 million program total has been reached or an electric vehicle specific tariff rate is established in a future rate proceeding.

(I-1) To qualify for the Demand Charge Rebate, a DCFC customer must agree to provide electric vehicle charging data to PSE&G in accordance with the approved program rules.

(I-2) Qualifying customers, upon Company approval into the program, will be issued an off bill rebate quarterly that will indicate the corresponding period(s) for which the credit applies, and that will apply to the portion of the approved demand charges set forth in (I-3) below. All rebates are contingent on timely availability of electric vehicle charging data for rebate calculation.

(I-3) As long as rebate funds are available, the following discounts will apply: For years one and two of the program, the monthly distribution demand charges will be rebated by 75% from the approved rates during the period being calculated. For years three and until new rates become effective following the Company's Next Base Rate Case, monthly distribution demand charges will be rebated by 50% from those in effect during the period being calculated.

(I-4) Both new and existing DCFC Charging Locations are eligible for this rebate.

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 16 of the Standard Terms and Conditions for additional details and/or exceptions.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 141 for Future**

RATE SCHEDULE GLP
GENERAL LIGHTING AND POWER SERVICE
(Continued)

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 16 of the Standard Terms and Conditions for additional details and/or exceptions.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 142**

RATE SCHEDULE LPL
LARGE POWER AND LIGHTING SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Delivery service for general purposes at secondary distribution voltages where the customer's measured peak demand exceeds 150 kilowatts in any month and also at primary distribution voltages. Customers may either purchase electric supply from a Third Party Supplier (TPS) or from Public Service's Basic Generation Service default service as detailed in this rate schedule.

DELIVERY CHARGES FOR SERVICE AT SECONDARY DISTRIBUTION VOLTAGES (excluding Direct Current Fast Charging [DCFC] customers):

Service Charge:

$347.77 in each month [$370.81 including New Jersey Sales and Use Tax (SUT)].

Distribution Kilowatt Charges:

Annual Demand Charge applicable in all months:

Charge	Charge Including SUT	
$ 3.6224	$ 3.8624	per kilowatt of highest Monthly Peak Demand in any time period

Summer Demand Charge applicable in the months of June through September:

Charge	Charge Including SUT	
$ 8.6179	$ 9.1888	per kilowatt of On-Peak Monthly Peak Demand

DELIVERY CHARGES FOR SERVICE AT SECONDARY DISTRIBUTION VOLTAGES FOR DCFC CUSTOMERS ONLY:

Service Charge:

$347.77 in each month [$370.81 including New Jersey Sales and Use Tax (SUT)].

Distribution Kilowatt-hour Charges:

All Use

Charge	Charge Including SUT	
$0.XXXXXX	$X.XXXXXX	per kilowatt-hour

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 71 for details of these charges.

(Charges are for illustrative purposes only and are based on the Fifth Revised Sheet No. 142 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 143**

RATE SCHEDULE LPL
LARGE POWER AND LIGHTING SERVICE
(Continued)

DELIVERY CHARGES FOR SERVICE AT PRIMARY DISTRIBUTION VOLTAGES:

Service Charge:

$347.77 in each month [$370.81 including New Jersey Sales and Use Tax (SUT)].

Distribution Kilowatt Charges:

Annual Demand Charge applicable in all months:

Charge	Charge Including SUT	
$ 1.6885	$ 1.8004	per kilowatt of highest Monthly Peak Demand in any time period

Summer Demand Charge applicable in the months of June through September:

Charge	Charge Including SUT	
$ 9.3731	$ 9.9941	per kilowatt of On-Peak Monthly Peak Demand

Distribution Kilowatt-hour Charges:

All Use

Charge	Charge Including SUT	
$0.000000	$0.000000	per kilowatt-hour

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 71 for details of these charges.

DELIVERY CHARGES FOR SERVICE AT SECONDARY AND PRIMARY DISTRIBUTION VOLTAGES:

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Non-utility Generation Charge:

This charge shall recover above market costs associated with non-utility generation costs and other generation related costs as may be approved by the Board. Refer to the Non-utility Generation Charge sheet of this Tariff for the current charge.

Commercial and Industrial Energy Pricing (CIEP) Standby Fee:

Applicable to all kilowatt-hour usage for customers who have selected the hourly energy pricing service from either Basic Generation Service - Commercial and Industrial Energy Pricing (BGS-CIEP) or a Third Party Supplier. This charge shall recover costs associated with the administration, maintenance and availability of BGS–CIEP default supply service. Refer to the CIEP Standby Fee sheet of this Tariff for the current charge.

(Charges are for illustrative purposes only and are based on the Seventh Revised Sheet No. 143 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 144**

RATE SCHEDULE LPL
LARGE POWER AND LIGHTING SERVICE
(Continued)

Solar Pilot Recovery Charge:

This charge is designed to recover the revenue requirements associated with the Public Service Solar Pilot Program per the Board Order in Docket No. EO07040278 less the net proceeds from the sale of associated Solar Renewable Energy Certificates (SRECs) or cash received in lieu of SRECs. Refer to the Solar Pilot Recovery Charge sheet of this tariff for the current charge.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

Tax Adjustment Credit:

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current credit.

Zero Emission Certificate Recovery Charge:

This charge provides for the recovery of costs associated with the Zero Emission Certificate Program directed by the Board of Public Utilities ("BPU" or "Board"). Refer to the Zero Emission Certificate Recovery Charge sheet of this Tariff for the current charge.

Conservation Incentive Program Charge:

This charge is applicable only to LPL customers for service at secondary distribution voltages. This mechanism provides for recovery of lost revenues associated with various energy efficiency programs. Refer to the Conservation Incentive Program sheet of this Tariff for the current charge.

Distribution Adjustment Charge:

This charge is designed to recover Board-approved costs. Refer to the Distribution Adjustment Charge sheet of this Tariff for the current charge.

The Distribution Kilowatt-hour Charge, the Non-utility Generation Charge, the Solar Pilot Recovery Charge, the Green Programs Recovery Charge, the Tax Adjustment Credit, the Zero Emission Certificate Recovery Charge, and the Distribution Adjustment Charge shall be combined for billing. The CIEP Standby Fee shall also be combined with these charges where applicable.

The Distribution Kilowatt Charge and the Conservation Incentive Program Charge shall be combined for billing.

ELECTRIC SUPPLY CHARGES:

A customer may choose to receive electric supply from either:
a) A TPS as described in Section 14 of this Tariff, or
b) Public Service through its Basic Generation Service.

Third Party Supply:

A customer that receives electric supply from a TPS will be charged for electric supply according to any agreement between the customer and the TPS. The customer will not be charged for electric supply by Public Service.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 145**

RATE SCHEDULE LPL

LARGE POWER AND LIGHTING SERVICE

(Continued)

Basic Generation Service:

A customer's Peak Load Share (PLS), with adjustments, is the basis for the customer's Generation Obligation. A customer's PLS in effect November 1 of a given year will determine the customer's default service type eligibility effective June 1 of the following year [Basic Generation Service - Residential Small Commercial Pricing (BGS-RSCP) or Basic Generation Service-Commercial and Industrial Pricing (BGS-CIEP)].

Customers that do not receive electric supply from a TPS will be supplied by Public Service through its BGS-RSCP default service for LPL-Secondary customers with a PLS less than 500 kilowatts or BGS-CIEP default service for LPL-Secondary customers with a PLS equal to or greater than 500 kilowatts and LPL-Primary. LPL-Secondary customers with a PLS less than 500 kilowatts may elect BGS-CIEP as their default supply but must notify Public Service of their election of BGS-CIEP as their default supply no later than the second business day in January of each year. Such election shall be effective June 1st of that year and BGS-CIEP will remain as the customer's default supply until they notify Public Service of their election of BGS-RSCP as their default supply no later than the second business day in January and their election of BGS-RSCP shall be effective June 1st of that year.

The BGS Energy Charges, BGS Capacity Charge, BGS Transmission Charge and BGS Reconciliation Charge are applicable. Refer to the Basic Generation Service sheets of this Tariff for the current charges applicable to Rate Schedule LPL for secondary or primary service.

MINIMUM CHARGE:

Where the use of electricity is for seldom used applications, an Annual Minimum charge may be applied. Such Annual Minimum charge shall equal the diversified connected load of the electric service, in kilowatts, times the Annual Demand Charge times 6. Revenue to satisfy the Annual Minimum requirement shall be derived solely from Distribution Kilowatt Charges and Distribution Kilowatt-hour Charges.

BILLING DETERMINANTS:

Monthly Peak Demand:

The Monthly Peak Demand for each time period shall be determined by the registration of a demand meter furnished by Public Service. The customer's Monthly Peak Demand in any month for each time period shall be the greatest average number of kilowatts delivered by Public Service during any thirty-minute interval for secondary distribution voltage customers and during any fifteen-minute interval for primary distribution voltage customers. Where the use of electric service is intermittent or subject to violent fluctuations, Public Service may base the customer's Monthly Peak Demand for each time period upon five-minute intervals in lieu of intervals hereinbefore set forth.

Where electric service is supplied for traction power to a rail rapid-transit system, for the purpose of determination of Monthly Peak Demands, the hours 8 A.M. to 10 A.M. and 4 P.M. to 7 P.M. shall be included in the Off-Peak time period, and Public Service shall base the customer's Monthly Peak Demand for each time period upon the greatest average number of kilowatts delivered by Public Service during any single coincident hour-ended sixty-minute interval during each time period, in lieu of fifteen minute intervals.

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RATE SCHEDULE LPL
LARGE POWER AND LIGHTING SERVICE
(Continued)

Self-Generation Customer:

For customers with operational self-generation units: 1) with a combined maximum net kilowatt output rating equal to or greater than 50% of their Annual Peak Demand; or, 2) whose premise was served on the former special provision for Standby Service of this rate schedule on July 31, 2003; or 3) who have been granted all necessary air permits by August 1, 2004 for a new or expanded self-generation facility: the On-Peak Monthly Peak Demand used in the determination of the Summer Demand Charges shall be equal to the greatest average number of kilowatts delivered by Public Service during any thirty-minute interval for secondary distribution voltage customers, and during any fifteen-minute interval for primary distribution voltage customers, that occur during the single hour of monthly maximum peak demand of the Public Service distribution system for the applicable summer billing month. For self-generation customers served under this standby provision, the Annual Demand Charge will be applied to the customer's Annual Peak Demand in lieu of the Monthly Peak Demand.

Annual Peak Demand:

The customer's Annual Peak Demand in kilowatts shall be the highest Monthly Peak Demand occurring in any time period of the current month and the preceding 11 months.

Generation Obligation:

The customer's Generation Obligation, in kilowatts, is determined by Public Service no less frequently than once a year. The Generation Obligation for existing customers or for new customers utilizing an existing building or premise is based upon the customer's share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM) as adjusted by PJM assigned capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions. The Generation Obligation for customers taking service in a new building or premise, as determined by Public Service, is based upon the load requirements, as estimated by Public Service, of the customer's building or premise. The Generation Obligation represents the generator capacity that PJM requires an electric supplier to have available to provide electric supply to a customer.

Transmission Obligation:

The customer's Transmission Obligation, in kilowatts, is determined in a similar manner to the Generation Obligation described above. The Transmission Obligation represents the level of transmission network service that must be procured by the customer's electric supplier from PJM to provide service to the customer.

Generation and Transmission Obligations are used in the determination of the customer's charges for Basic Generation Service and may affect the price offered by a Third Party Supplier.

TIME PERIODS:

The On-Peak time period shall be considered as the hours from 8 A.M. to 10 P.M. Monday through Friday. All other hours shall be considered the Off-Peak time period.

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RATE SCHEDULE LPL
LARGE POWER AND LIGHTING SERVICE
(Continued)

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill and subject to a late payment charge at the rate of 1.416% per monthly billing period in accordance with Section 9.12 of the Standard Terms and Conditions. Service to a body politic will not be subject to a late payment charge.

TERM:

The term for delivery service is one year and thereafter until terminated by five days notice.

Customers who transfer from third party supply to Basic Generation Service may be subject to additional limitations regarding the term of Basic Generation Service as detailed in Section 14 of the Standard Terms and Conditions of this Tariff.

SPECIAL PROVISIONS:

(a) **Primary Distribution Alternate Service Charge:** Customers taking service at primary distribution voltage, who were billed the under 100 kilowatt Service Charge in July 2003, and whose Monthly Peak Demand has not exceeded 100 kilowatts in any subsequent month shall be subject to a monthly Service Charge of $21.58 ($23.01 including SUT) in lieu of the otherwise applicable Service Charge.

(b) **Substation Service-Individual Customer:** Where special conditions such as location, size or type of load require that customer be supplied at a subtransmission voltage or at high-voltage as designated in Standard Terms and Conditions, Section 4.2., High Voltage Service, and customer and Public Service agree that Public Service will furnish, install, and maintain a substation solely to serve customer from the secondary side of the transformers at nominal voltages of 4,160 volts, 13,200 volts, or 26,400 volts, such service shall be considered as secondary distribution service. Customer may be required to sell or lease a site for the location of the substation. Public Service may require a guaranteed annual payment and a termination agreement.

This provision is closed and is in the process of elimination and is limited to premises presently served under this provision.

(c) **Resale:** Service under this rate schedule is not available for resale.

(d) **Area Development Service:** Where a new or existing customer takes service under this rate schedule at a single service connection located within the municipal boundaries of the cities of Newark, Jersey City, Paterson, Elizabeth, Camden, Trenton, East Orange, Hoboken, Union City, Plainfield, Gloucester City, Passaic City, Weehawken, Kearny, or Orange, service will be supplied under this provision subject to the following conditions:

(d-1) Each customer will be required to sign an Application for Area Development Service under this rate schedule. Public Service shall define a customer as new or existing for purposes of this application. In the case of existing customers, the base year period twelve Monthly Peak Demands in kilowatts shall be specified by Public Service and agreed to by the customer prior to institution of any credits.

(Charges are for illustrative purposes only and are based on the Fifth Revised Sheet No. 147 filed with the BPU on November 1, 2023)

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RATE SCHEDULE LPL

LARGE POWER AND LIGHTING SERVICE

(Continued)

(d-2) Customers shall be eligible for credits under this Special Provision only to the extent that they have signed an Application for Area Development Service and meet the minimum load conditions. For new customers, the minimum load must be no less than 25 kilowatts of the applicable Monthly Peak Demand. For existing customers, the average twelve-month minimum load must be no less than 50 kilowatts of applicable Monthly Peak Demand during the previous twelve months. In addition, during any three consecutive months subsequent to an acceptance of the application by Public Service, existing customer applicable Monthly Peak Demands must be at least 125%, or for customers under the minimum load an addition of at least 50 kilowatts, of applicable Monthly Peak Demands in comparable months of the previous 36 months to qualify for credits. Credits for new and existing customers shall commence in the first month subsequent to such qualification.

In no case shall any customer receive credits under this Special Provision who has previously applied for electric service at the same or new location in excess of 300 kilowatts which has been approved for service by Public Service 90 days from the effective date of this Special Provision for the original nine cities and 90 days from the effective date of the modified Special Provision for any additional cities.

(d-3) A credit of $2.69 ($2.87 including SUT) per kilowatt of Monthly Peak Demand shall apply to all kilowatts so measured for new customers. A new customer, for purposes of this Special Provision, shall be defined either as a customer taking service in a new or renovated building or premise, or a customer taking service in an existing building or premise whose activities or use of electric service is substantially different from that of the previous customer. Where no business has been conducted at a building or premise for at least three months, any customer shall be considered a new customer for purposes of this Special Provision.

(d-4) A credit of $2.69 ($2.87 including SUT) per kilowatt of Monthly Peak Demand shall apply only to those kilowatts so measured for existing customers which are in excess of comparable demands in the same month established in a base year period, which period shall be defined as the twelve calendar months immediately preceding the first month of qualification. An existing customer, for purposes of this Special Provision, shall be defined as a customer whose activities or use of electric service is substantially the same as that of the previous customer, except that such customer shall be eligible for this Special Provision to the extent that the previous customer was so eligible, and for the remainder of the previous customer's term.

(d-5) Where a customer signs an Application for Area Development Service and elects to be billed under this Special Provision, the term of service shall be seven years in lieu of the term stated in this rate schedule. For new customers, the term shall commence with the first month following qualification and, for existing customers, beginning with the first month following the three-month qualification period. In no case shall the term of service commence prior to the completion of the Application for Area Development Service by the customer and acceptance by Public Service.

(Charges are for illustrative purposes only and are based on the Original Sheet No. 148 filed with the BPU on November 1, 2018)

RATE SCHEDULE LPL

LARGE POWER AND LIGHTING SERVICE

(Continued)

Credits under (d-3) or (d-4) will be available to qualifying customers during the first five years of the term. Subsequently, such credits will be reduced by 50% during the final two years of the term.

(d-6) Public Service reserves the right to reject Applications for Area Development Service where the cost of facilities to supply new or existing customers is, in its judgment, excessive or might affect the supply of service to other customers.

(e) **Duplicate Service:** Where, at request of a customer, either: a) an additional source or sources of Public Service distribution supply is provided to serve all or part of their load when the principal Public Service distribution source or sources (termed the Normal Service) are unavailable, or b) where such additional sources are supplied as part of standard supply configuration provided by Public Service and such additional source is provided from a different substation or switching station than as determined by Public Service, such service is termed Duplicate Service. Duplicate Service will be furnished only if practical and safe from the standpoint of Public Service and will not be supplied where it would create an unusual hazard or interfere with the provision of service to other customers.

(e-1) **Duplicate Service Capacity:** The maximum electrical requirement, in kilowatts, needed by the customer at any time on the Duplicate Service is defined as Duplicate Service Capacity. The value of the Duplicate Service Capacity will initially be determined by the customer and shall be used by Public Service as the design criteria in construction of the Duplicate Service. The Duplicate Service Capacity shall be reviewed periodically and shall be the greater of the then requested Duplicate Service Capacity, or the highest actual peak demand established in the prior 24 month period on the Duplicate Service or the Normal Service.

(e-2) **Duplicate Service Charges**: Duplicate service charges will be established for each Duplicate Service based on the sum of the following:

(e-2a) A monthly facilities charge as set forth in Section 3.5.2 of these Standard Terms and Conditions calculated as the Facilities Charge Rate times the total costs of any service or line work required to supply Duplicate Service, including extending or reinforcing Public Service distribution facilities and any distribution transformer or metering costs.

Once a facilities charge is established for a facility or premise and there is no material change in the Duplicate Service Capacity to be provided, the basis for the facilities charge shall remain the same as long as the Public Service facilities remain in service and shall apply to all subsequent customers at that facility requesting Duplicate Service, regardless of any lapse in the provision of Duplicate Service to that facility.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

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RATE SCHEDULE LPL
LARGE POWER AND LIGHTING SERVICE
(Continued)

(e-2b) Charges for the kilowatts of Duplicate Service Capacity of:

Duplicate Service Capacity Charges Charge	Charge Including SUT	Applicable in all months
$ 2.22	$ 2.37	per kilowatt of Duplicate Service Capacity supplied from the same substation as the Normal Service
$ 3.20	$ 3.41	per kilowatt of Duplicate Service Capacity supplied from a different substation than the Normal Service

(e-3) **Metering and Billing:** Where separate metering is provided, all usage on the duplicate service will be combined for billing purposes with usage on the Normal Service meter.

(e-4) **Changes in Duplicate Service Capacity:** Any material increase in the Duplicate Service Capacity that requires a change in the facilities related to extending Public Service facilities to the customer or the costs of reinforcing related Public Service facilities may require an increase in the monthly facilities charge. Any material decrease in the Duplicate Service Capacity shall not change the monthly facilities charge.

All initial requests or requests for an increase in Duplicate Service Capacity in excess of 5 megawatts shall require the customer to deposit with Public Service the first five year's facilities charges and applicable Duplicate Service Charges on a non-refundable basis prior to the start of any work by Public Service to supply such Duplicate Service. The monthly charges for Duplicate Service shall be applied against the deposited amount in lieu of being billed to the customer until such time as the customer's deposited amount is exhausted, at which time such charges shall be included in the customer's monthly bill. In no event shall any part of the deposit remaining after five years be returned or credited to the customer in any manner.

(f) **Curtailable Electric Service:** Curtailable Electric Service will be furnished when and where available so as to preserve the reliability of the Public Service distribution system. Those customers that receive electric supply from a third party supplier may continue to receive service under this Special Provision. If a third party supplied customer chooses to no longer participate, or alternatively, a customer is disqualified for this Special Provision because of continued failure to meet agreed upon load reductions, the customer will be required to pay Public Service, in accordance with Standard Terms and Conditions, Section 9.4.2, Metering, for the installed interval metering device if the customer chooses to retain the installed interval meter and the meter is not otherwise required for service. Curtailable Electric Service will be furnished under the following conditions:

(Charges are for illustrative purposes only and are based on the Original Sheet No. 150 filed with the BPU on November 1, 2018)

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RATE SCHEDULE LPL

LARGE POWER AND LIGHTING SERVICE

(Continued)

(f-1) A customer agrees to take service under this rate schedule at a single service connection and agrees to curtail its load during times of curtailment by the amount stated in the customer's Application/Agreement. A credit of $6.11 ($6.51 including SUT) per kilowatt of average actual curtailed demand for each curtailment period will be applied to the customer's bill in a succeeding month. The curtailed demands will be measured as the difference, for each hour, between a customer-specific hourly load curve developed by Public Service for customer's normal business operation and the actual recorded hourly load during the curtailment period. The curtailment period will commence a minimum of one hour from the time of notification and end at the time indicated in the restoration call but not later than 8:00 P.M. as indicated in (f-3) below. For each applicable calendar month, the customer's individual curtailment period results will be summed to determine the appropriate credit. There will be no penalty for failure to curtail load or meet the agreed upon load reduction when notified. Continued failure by a customer to meet agreed upon load reduction, however, will result in customer's disqualification for this Special Provision and Public Service may remove from the customer's premises the interval metering device installed solely for this Special Provision.

(f-1a) In the event that a customer-specific hourly load curve for customer's normal business operation cannot be developed by Public Service, the curtailed demands will be measured as the difference between the actual hourly load at the time of notification and the actual recorded hourly load for each hour during the curtailment period. Payment will be subject to a maximum equal to the estimated amount of load customer will curtail during curtailments in (f-2).

(f-2) A customer will be required to sign an Application/Agreement for Curtailable Electric Service under this rate schedule. The Application/Agreement will specify the estimated amount of load customer will curtail during curtailments. Curtailment payments will be subject to a maximum of 150% of the estimated amount of load customer will curtail during curtailments. The maximum shall apply subsequent to the customer's first curtailment after election to take service under this Special Provision. The minimum curtailable load is 100 kilowatts. The advanced notification period is a minimum of one hour.

(f-3) This Special Provision will be in effect for the four summer months June through September and apply on weekdays only, excluding holidays, and the potential daily curtailment period shall be the hours between 12:00 Noon and 8:00 P.M. Public Service agrees to limit curtailments, as described in this Special Provision, to a maximum of 120 total hours and a maximum of 15 curtailments during the calendar year.

(f-4) Public Service will contact the customer by telephone or otherwise of the need to curtail load under this Special Provision. The customer shall designate personnel who will accept notification of curtailment on summer weekdays from 9:00 A.M. to 8:00 P.M. Where necessary, Public Service will install and maintain suitable metering at its meter locations for verification of customer compliance with the curtailment and notification agreement.

(Charges are for illustrative purposes only and are based on the Original Sheet No. 151 filed with the BPU on November 1, 2018)

RATE SCHEDULE LPL
LARGE POWER AND LIGHTING SERVICE
(Continued)

(f-5) When a customer signs an Application/Agreement for Curtailable Electric Service and elects to be billed under this Special Provision, the term of service will be for two years in lieu of the term stated in this rate schedule, with periodic review of curtailable demand not to exceed twelve months. Public Service reserves the right to determine whether successive terms may be negotiated and under what conditions curtailable demand may be changed.

(f-6) In the event of an emergency condition which occurs outside the period specified in (f-3) above and which threatens the integrity of the Public Service system or the systems to which Public Service is directly or indirectly connected, Public Service may contact customer of the need to curtail load. There will be no penalty for failure to curtail load or meet the agreed upon load reduction. Customers who are able to curtail load will have a credit applied to their bill.

(g) **TPS Supply:** Customers who desire to purchase their electric supply from a TPS may request an enrollment package from Public Service that describes the process necessary for the customer to obtain a TPS for electric supply. This package will be provided to the customer at no charge by Public Service.

(g-1) The customer must contract with a TPS to arrange for deliveries to Public Service of the electric supply. A customer is limited to one TPS for electric supply for each account for which the customer receives delivery service.

(g-2) The customer’s TPS is required to notify Public Service of the customer’s selection prior to 13 days before the customer’s scheduled Public Service meter reading date for deliveries to commence on such scheduled meter reading date, and such selection shall remain in effect for the entire billing month. Customer can change TPSs effective only on the date of the customer’s scheduled Public Service meter reading date.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 153**

RATE SCHEDULE LPL
LARGE POWER AND LIGHTING SERVICE
(Continued)

(h) **Veterans' Organization Service:** Pursuant to N.J.S.A. 48:2-21.41, when electric service is delivered to a customer that is a Veterans' Organization, serving the needs of veterans of the armed forces, the customer may apply and be eligible for billing under this Special Provision.

(h-1) Each customer shall be eligible for billing under this Special Provision upon submitting an Application for Veterans' Organization Service under this rate schedule and by qualifying as a Veterans' Organization as defined by N.J.S.A. 48:2-21.41 as "an organization dedicated to serving the needs of veterans of the armed forces that: is chartered under federal law, qualifies as a tax exempt organization under paragraph (19) of subsection (c) of section 501 of the federal Internal Revenue Code of 1986, 26 U.S.C. s.501 (c)(19), or that is organized as a corporation under the 'New Jersey Nonprofit Corporation Act,' N.J.S.A. 15:1-1 et seq." Under N.J.S.A. 48: 2-21.41, a qualified Veterans' Organization shall be charged the residential rate for service delivered to the property where the Veterans' Organization primarily operates, if the residential rate is lower than the commercial rate for service at that property.

The customer shall furnish satisfactory proof of eligibility of service under this Special Provision to the Company. Once proof of eligibility is determined by the Company, service under this Special Provision shall begin with the next billing cycle following receipt of the Application.

(h-2) The customer will continue to be billed on this rate schedule. At least once annually, the Company shall review eligible customers' delivery charges under this Special Provision for all relevant periods. If the comparable delivery charges under the Residential Service (RS) rate schedule are lower than the delivery charges under its current rate schedule, a credit in the amount of the difference will be applied to the customer's next bill.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 154**

RATE SCHEDULE LPL
LARGE POWER AND LIGHTING SERVICE
(Continued)

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 16 of the Standard Terms and Conditions for additional details and/or exceptions.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 155**

RATE SCHEDULE HTS
HIGH TENSION SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Delivery service for general purposes at subtransmission, transmission and high voltages. Customers may either purchase electric supply from a Third Party Supplier (TPS) or from Public Service's Basic Generation Service default service as detailed in this rate schedule.

DELIVERY CHARGES FOR SERVICE AT SUBTRANSMISSION VOLTAGES:

Service Charge:

$1,911.39 in each month [$2,038.02 including New Jersey Sales and Use Tax (SUT)].

Distribution Kilowatt Charges:

Annual Demand Charge applicable in all months:

Charge	Charge Including SUT	
$ 1.1442	$ 1.2200	per kilowatt of Annual Peak Demand

Summer Demand Charge applicable in the months of June through September:

Charge	Charge Including SUT	
$ 4.1361	$ 4.4101	per kilowatt of On-Peak Monthly Peak Demand

Distribution Kilowatt-hour Charges:

All Use

Charge	Charge Including SUT	
$0.000000	$0.000000	per kilowatt-hour

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 72 for details of these charges.

DELIVERY CHARGES FOR SERVICE AT TRANSMISSION VOLTAGES:

Customers historically served under rate schedule HTS-High Voltage currently receiving service at lower voltage levels on facilities under FERC jurisdiction as a result of system modifications mandated by the Company but have not changed their usage characteristics will continue to be billed as High Voltage customers by having their usage adjusted solely by a factor based upon the current Subtransmission and High Voltage Losses as detailed in the Standard Terms and Conditions, Section 4.3. The current adjustment factor for Subtransmission to High Voltage usage is 1.01212%.

(Charges are for illustrative purposes only and are based on the Fifth Revised Sheet No. 155 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 156**

RATE SCHEDULE HTS
HIGH TENSION SERVICE
(Continued)

DELIVERY CHARGES FOR SERVICE AT HIGH VOLTAGE:

Service Charge:

$1,720.25 in each month [$1,834.22 including New Jersey Sales and Use Tax (SUT)].

Distribution Kilowatt Charges:

Annual Demand Charge applicable in all months:

Charge	Charge Including SUT	
$ 0.6322	$ 0.6741	per kilowatt of Annual Peak Demand

Distribution Kilowatt-hour Charges:

All Use

Charge	Charge Including SUT	
$0.000000	$0.000000	per kilowatt-hour

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 72 for details of these charges.

DELIVERY CHARGES FOR SERVICE AT SUBTRANSMISSION, TRANSMISSION AND HIGH VOLTAGES:

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Non-utility Generation Charge:

This charge shall recover above market costs associated with non-utility generation costs and other generation related costs as may be approved by the Board. Refer to the Non-utility Generation Charge sheet of this Tariff for the current charge.

Commercial and Industrial Energy Pricing (CIEP) Standby Fee:

Applicable to all kilowatt-hour usage under this rate schedule. This charge shall recover costs associated with the administration, maintenance and availability of the Basic Generation Service default supply service. Refer to the CIEP Standby Fee sheet of this Tariff for the current charge.

Solar Pilot Recovery Charge:

This charge is designed to recover the revenue requirements associated with the Public Service Solar Pilot Program per the Board Order in Docket No. EO07040278 less the net proceeds from the sale of associated Solar Renewable Energy Certificates (SRECs) or cash received in lieu of SRECs. Refer to the Solar Pilot Recovery Charge sheet of this tariff for the current charge.

(Charges are for illustrative purposes only and are based on the Sixth Revised Sheet No. 156 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

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RATE SCHEDULE HTS
HIGH TENSION SERVICE
(Continued)

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

Tax Adjustment Credit:

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current credit.

Zero Emission Certificate Recovery Charge:

This charge provides for the recovery of costs associated with the Zero Emission Certificate Program directed by the Board of Public Utilities ("BPU" or "Board"). Refer to the Zero Emission Certificate Recovery Charge sheet of this Tariff for the current charge.

Distribution Adjustment Charge:

This charge is designed to recover Board-approved costs. Refer to the Distribution Adjustment Charge sheet of this Tariff for the current charge.

The Distribution Kilowatt-hour Charge, the Non-utility Generation Charge, the Solar Pilot Recovery Charge, the Green Programs Recovery Charge, the Tax Adjustment Credit, the Zero Emission Certificate Recovery Charge, the Distribution Adjustment Charge, and the CIEP Standby Fee shall be combined for billing.

ELECTRIC SUPPLY CHARGES:

A customer may choose to receive electric supply from either:

a) A TPS as described in Section 14 of this Tariff, or
b) Public Service through its Basic Generation Service – Commercial and Industrial Energy Pricing (BGS – CIEP) default service.

Third Party Supply:

A customer that receives electric supply from a TPS will be charged for electric supply according to any agreement between the customer and the TPS. The customer will not be charged for electric supply by Public Service.

Basic Generation Service:

Customers that do not receive electric supply from a TPS will be supplied under the Basic Generation Service - Commercial and Industrial Energy Pricing (BGS – CIEP) default service.

The BGS Energy Charges, BGS Capacity Charge, BGS Transmission Charge and BGS Reconciliation Charge are applicable. Refer to the Basic Generation Service sheets of this Tariff for the current charges applicable to Rate Schedule HTS for subtransmission, transmission or high voltage service.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 158**

RATE SCHEDULE HTS
HIGH TENSION SERVICE
(Continued)

MINIMUM CHARGE:

Where the use of electricity is for seldom used applications, an Annual Minimum charge may be applied. Such Annual Minimum charge shall equal the diversified connected load of the electric service, in kilowatts, times the Annual Demand Charge times 12. Revenue to satisfy the Annual Minimum requirement shall be derived solely from Distribution Kilowatt Charges and Distribution Kilowatt-hour Charges.

BILLING DETERMINANTS:

Monthly Peak Demand:

The Monthly Peak Demand for each time period shall be determined by the registration of a demand meter furnished by Public Service. The customer's Monthly Peak Demand in any month for each time period shall be the greatest average number of kilowatts delivered by Public Service during any fifteen-minute interval. Where the use of electric service is intermittent or subject to violent fluctuations, Public Service may base the customer's Monthly Peak Demand for each time period upon five-minute intervals in lieu of intervals hereinbefore set forth.

Where electric service is supplied for traction power to a rail rapid-transit system, for the purpose of determination of Monthly Peak Demands the hours 8 A.M. to 10 A.M. and 4 P.M. to 7 P.M. shall be included in the Off-Peak time period, and Public Service shall base the customer's Monthly Peak Demand for each time period upon the greatest average number of kilowatts delivered by Public Service during any single coincident hour-ended sixty-minute interval during each time period, in lieu of fifteen-minute intervals. Where traction power is supplied at high voltage (230,000 volts) and such power is being provided during a limited period to supplant power normally supplied by another utility, that limited period shall be excluded for the purpose of determining Monthly Peak Demand.

Self-Generation Customer:

For customers with operational self-generation units: 1) with a combined maximum net kilowatt output rating equal to or greater than 50% of their Annual Peak Demand; or, 2) whose premise was served on the former special provision for Standby Service of this rate schedule on July 31, 2003; or 3) who have been granted all necessary air permits by August 1, 2004 for a new or expanded self-generation facility: the On-Peak Monthly Peak Demand used in the determination of the Summer Demand Charges shall be equal to the greatest average number of kilowatts delivered by Public Service during any fifteen-minute interval that occur during the single hour of monthly maximum peak demand of the Public Service distribution system for the applicable summer billing month.

Annual Peak Demand:

The customer's Annual Peak Demand in kilowatts shall be the highest Monthly Peak Demand occurring in any time period of the current month and the preceding 11 months.

RATE SCHEDULE HTS
HIGH TENSION SERVICE
(Continued)

Generation Obligation:

The customer's Generation Obligation, in kilowatts, is determined by Public Service no less frequently than once a year. The Generation Obligation for existing customers or for new customers utilizing an existing building or premise is based upon the customer's share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM) as adjusted by PJM assigned capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions. The Generation Obligation for customers taking service in a new building or premise, as determined by Public Service, is based upon the load requirements, as estimated by Public Service, of the customer's building or premise. The Generation Obligation represents the generator capacity that PJM requires an electric supplier to have available to provide electric supply to a customer.

Transmission Obligation:

The customer's Transmission Obligation, in kilowatts, is determined in a similar manner to the Generation Obligation described above. The Transmission Obligation represents the level of transmission network service that must be procured by the customer's electric supplier from PJM to provide service to the customer.

Generation and Transmission Obligations are used in the determination of the customer's charges for Basic Generation Service and may affect the price offered by a Third Party Supplier.

TIME PERIODS:

The On-Peak time period shall be considered as the hours from 8 A.M. to 10 P.M. Monday through Friday. All other hours shall be considered the Off-Peak time period.

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill and subject to a late payment charge at the rate of 1.416% per monthly billing period in accordance with Section 9.12 of the Standard Terms and Conditions. Service to a body politic will not be subject to a late payment charge.

TERM:

The term for delivery service is one year and thereafter until terminated by five days notice.

Customers who transfer from third party supply to Basic Generation Service may be subject to additional limitations regarding the term of Basic Generation Service as detailed in Section 14 of the Standard Terms and Conditions of this Tariff.

SPECIAL PROVISIONS:

(a) **Limitations on Loads Served at 138,000 Volts or Higher:** Customer may be required to supply advance information as to conditions affecting its load as an aid to Public Service in load scheduling. Public Service shall not, without prior written acceptance, be obligated to deliver at a single service location an amount of power in excess of a maximum demand of 50,000 kilowatts at 85% power factor.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 160**

RATE SCHEDULE HTS
HIGH TENSION SERVICE
(Continued)

(b) **Termination of Service by Customer:** Where a customer, served at 138,000 volts or higher, terminates service prior to fifteen years from the initial date of service, customer shall be obligated to pay Public Service that part of the total actual cost of any of the 138,000 volt or higher facilities, land, easements, interests, or rights of way used in rendering such service, under the following schedules:

(b-1) Actual cost of facilities through the first year; thence such actual cost reduced by 5% quarterly during the next succeeding year; thence reduced by 1-1/4% quarterly during the next succeeding six years; thence reduced by 1-3/4% quarterly during the next succeeding six years; and then reduced by 2% quarterly during the remaining year.

(b-2) Actual cost of land, easements, interest, or rights of way through the first year; thence at 80% of actual cost during any of the next succeeding nine years; thence reduced by 4% quarterly during the remaining five years.

(b-3) In the event that Public Service determines to serve other load from or otherwise use the aforesaid facilities, lands, easements, interests, or rights of way, then their cost shall be allocated on an equitable basis for the determination of the termination payment reflecting the difference between the actual cost and the allocated cost.

(c) **Resale**: Service under this rate schedule is not available for resale.

(d) **Area Development Service**: Where a new or existing customer takes service under this rate schedule at a single service connection located within the municipal boundaries of the cities of Newark, Jersey City, Paterson, Elizabeth, Camden, Trenton, East Orange, Hoboken, Union City, Plainfield, Gloucester City, Passaic City, Weehawken, Kearny, or Orange, service will be supplied under this provision subject to the following conditions:

(d-1) Each customer will be required to sign an Application for Area Development Service under this rate schedule. Public Service shall define a customer as new or existing for purposes of this application. In the case of existing customers, the base year period twelve Monthly Peak Demands in kilowatts shall be specified by Public Service and agreed to by the customer prior to institution of any credits.

(d-2) Customers shall be eligible for credits under this Special Provision only to the extent that they have signed an Application for Area Development Service and meet the minimum load conditions. For new customers, the minimum load must be no less than 25 kilowatts of the applicable Monthly Peak Demand. For existing customers, the average twelve-month minimum load must be no less than 50 kilowatts of applicable Monthly Peak Demand during the previous twelve months. In addition, during any three consecutive months subsequent to an acceptance of the application by Public Service, existing customer applicable Monthly Peak Demands must be at least 110%, or for customers under the minimum load an addition of at least 50 kilowatts, of applicable Monthly Peak Demands in comparable months of the previous 36 months to qualify for credits. Credits for new and existing customers shall commence in the first month subsequent to such qualification.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 161**

RATE SCHEDULE HTS
HIGH TENSION SERVICE
(Continued)

In no case shall any customer receive credits under this Special Provision who has previously applied for electric service at the same or new location in excess of 300 kilowatts which has been approved for service by Public Service 90 days from the effective date of this Special Provision for the original nine cities and 90 days from the effective date of the modified Special Provision for any additional cities.

(d-3) A credit of $1.79 ($1.91 including SUT) per kilowatt of Monthly Peak Demand shall apply to all kilowatts so measured for new customers. A new customer, for purposes of this Special Provision, shall be defined either as a customer taking service in a new or renovated building or premise, or a customer taking service in an existing building or premise whose activities or use of electric service is substantially different from that of the previous customer. Where no business has been conducted at a building or premise for at least three months, any customer shall be considered a new customer for purposes of this Special Provision.

(d-4) A credit of $1.79 ($1.91 including SUT) per kilowatt of Monthly Peak Demand shall apply only to those kilowatts so measured for existing customers which are in excess of comparable demands in the same month established in a base year period, which period shall be defined as the twelve calendar months immediately preceding the first month of qualification. An existing customer, for purposes of this Special Provision, shall be defined as a customer whose activities or use of electric service is substantially the same as that of the previous customer, except that such customer shall be eligible for this Special Provision to the extent that the previous customer was so eligible, and for the remainder of the previous customer's term.

(d-5) Where a customer signs an Application for Area Development Service and elects to be billed under this Special Provision, the term of service shall be seven years in lieu of the term stated in this rate schedule. For new customers, the term shall commence with the first month following qualification and, for existing customers, beginning with the first month following the three-month qualification period. In no case shall the term of service commence prior to the completion of the Application for Area Development Service by the customer and acceptance by Public Service.

Credits under (d-3) or (d-4) will be available to qualifying customers during the first five years of the term. Subsequently, such credits will be reduced by 50% during the final two years of the term.

(d-6) Public Service reserves the right to reject Applications for Area Development Service where the cost of facilities to supply new or existing customers is, in its judgment, excessive or might affect the supply of service to other customers.

(Charges are for illustrative purposes only and are based on the Original Sheet No. 161 filed with the BPU on November 1, 2018)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 162**

RATE SCHEDULE HTS
HIGH TENSION SERVICE
(Continued)

(e) **Duplicate Service:** Where, at request of a subtransmission customer, either: a) an additional source or sources of Public Service distribution supply is provided to serve all or part of their load when the principal Public Service distribution source or sources (termed the Normal Service) are unavailable, or b) where such additional sources are supplied as part of standard supply configuration provided by Public Service and such additional source is provided from a different substation or switching station than as determined by Public Service, such service is termed Duplicate Service. Duplicate Service will be furnished only if practical and safe from the standpoint of Public Service and will not be supplied where it would create an unusual hazard or interfere with the provision of service to other customers.

(e-1) **Duplicate Service Capacity:** The maximum electrical requirement, in kilowatts, needed by the customer at any time on the Duplicate Service is defined as Duplicate Service Capacity. The value of the Duplicate Service Capacity will initially be determined by the customer and shall be used by Public Service as the design criteria in construction of the Duplicate Service. The Duplicate Service Capacity shall be reviewed periodically and shall be the greater of the then requested Duplicate Service Capacity, or the highest actual peak demand established in the prior 24 month period on the Duplicate Service or the Normal Service.

(e-2) **Duplicate Service Charges:** Duplicate service charges will be established for each Duplicate Service based on the sum of the following:

(e-2a) A monthly facilities charge as set forth in Section 3.5.2 of these Standard Terms and Conditions calculated as the Facilities Charge Rate times the total costs of any service or line work required to supply Duplicate Service, including extending or reinforcing Public Service distribution facilities and any distribution transformer or metering costs.

Once a facilities charge is established for a facility or premise and there is no material change in the Duplicate Service Capacity to be provided, the basis for the facilities charge shall remain the same as long as the Public Service facilities remain in service and shall apply to all subsequent customers at that facility requesting Duplicate Service, regardless of any lapse in the provision of Duplicate Service to that facility.

(e-2b) Charges for the kilowatts of Duplicate Service Capacity of:

Duplicate Service Capacity Charges		Applicable in all months
Charge	Charge Including SUT	
$ 1.83	$ 1.95	per kilowatt of Duplicate Service Capacity supplied from the same substation or switching station as the Normal Service
$ 2.20	$ 2.35	per kilowatt of Duplicate Service Capacity supplied from a different substation or switching station than the Normal Service

(Charges are for illustrative purposes only and are based on the Original Sheet No. 162 filed with the BPU on November 1, 2018)

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RATE SCHEDULE HTS
HIGH TENSION SERVICE
(Continued)

(e-3) **Metering and Billing:** Where separate metering is provided, all usage on the duplicate service will be combined for billing purposes with usage on the Normal Service meter.

(e-4) **Changes in Duplicate Service Capacity:** Any material increase in the Duplicate Service Capacity that requires a change in the facilities related to extending Public Service facilities to the customer or the costs of reinforcing related Public Service facilities may require an increase in the monthly facilities charge. Any material decrease in the Duplicate Service Capacity shall not change the monthly facilities charge.

All initial requests or requests for an increase in Duplicate Service Capacity in excess of 5 megawatts shall require the customer to deposit with Public Service the first five year's facilities charges and applicable Duplicate Service Charges on a non-refundable basis prior to the start of any work by Public Service to supply such Duplicate Service. The monthly charges for Duplicate Service shall be applied against the deposited amount in lieu of being billed to the customer until such time as the customer's deposited amount is exhausted, at which time such charges shall be included in the customer's monthly bill. In no event shall any part of the deposit remaining after five years be returned or credited to the customer in any manner.

(f) **Curtailable Electric Service:** Curtailable Electric Service will be furnished when and where available so as to preserve the reliability of the Public Service distribution system. Those customers that receive electric supply from a third party supplier may continue to receive service under this Special Provision. If a third party supplied customer chooses to no longer participate, or alternatively, a customer is disqualified for this Special Provision because of continued failure to meet agreed upon load reductions, the customer will be required to pay Public Service, in accordance with Standard Terms and Conditions, Section 9.4.2, Metering, for the installed interval metering device if the customer chooses to retain the installed interval meter and the meter is not otherwise required for service. Curtailable Electric Service will be furnished under the following conditions:

(f-1) A customer agrees to take service under this rate schedule at a single service connection and agrees to curtail its load during times of curtailment by the amount stated in the customer's Application/Agreement. A credit of $6.11 ($6.51 including SUT) per kilowatt of average actual curtailed demand for each curtailment period will be applied to the customer's bill in a succeeding month. The curtailed demands will be measured as the difference, for each hour, between a customer-specific hourly load curve developed by Public Service for customer's normal business operation and the actual recorded hourly load during the curtailment period. The curtailment period will commence a minimum of one hour from the time of notification and end at the time indicated in the restoration call but not later than 8:00 P.M. as indicated in (f-3) below. For each applicable calendar month, the customer's individual curtailment period results will be summed to determine the appropriate credit. There will be no penalty for failure to curtail load or meet the agreed upon load reduction when notified. Continued failure by a customer to meet agreed upon load reduction, however, will result in customer's disqualification for this Special Provision and Public Service may remove from the customer's premises the interval metering device installed solely for this Special Provision.

(Charges are for illustrative purposes only and are based on the Original Sheet No. 163 filed with the BPU on November 1, 2018)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

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RATE SCHEDULE HTS
HIGH TENSION SERVICE
(Continued)

(f-1a) In the event that a customer-specific hourly load curve for customer's normal business operation cannot be developed by Public Service, the curtailed demands will be measured as the difference between the actual hourly load at the time of notification and the actual recorded hourly load for each hour during the curtailment period. Payment will be subject to a maximum equal to the estimated amount of load customer will curtail during curtailments in (f-2).

(f-2) A customer will be required to sign an Application/Agreement for Curtailable Electric Service under this rate schedule. The Application/Agreement will specify the estimated amount of load customer will curtail during curtailments. Curtailment payments will be subject to a maximum of 150% of the estimated amount of load customer will curtail during curtailments. The maximum shall apply subsequent to the customer's first curtailment after election to take service under this Special Provision. The minimum curtailable load is 100 kilowatts. The advanced notification period is a minimum of one hour.

(f-3) This Special Provision will be in effect for the four summer months June through September and apply on weekdays only, excluding holidays, and the potential daily curtailment period shall be the hours between 12:00 Noon and 8:00 P.M. Public Service agrees to limit curtailments, as described in this Special Provision, to a maximum of 120 total hours and a maximum of 15 curtailments during the calendar year.

(f-4) Public Service will contact the customer by telephone or otherwise of the need to curtail load under this Special Provision. The customer shall designate personnel who will accept notification of curtailment on summer weekdays from 9:00 A.M. to 8:00 P.M. Where necessary, Public Service will install and maintain suitable metering at its meter locations for verification of customer compliance with the curtailment and notification agreement.

(f-5) When a customer signs an Application/Agreement for Curtailable Electric Service and elects to be billed under this Special Provision, the term of service will be for two years in lieu of the term stated in this rate schedule, with periodic review of curtailable demand not to exceed twelve months. Public Service reserves the right to determine whether successive terms may be negotiated and under what conditions curtailable demand may be changed.

(f-6) In the event of an emergency condition which occurs outside the period specified in (f-3) above and which threatens the integrity of the Public Service system or the systems to which Public Service is directly or indirectly connected, Public Service may contact customer of the need to curtail load. There will be no penalty for failure to curtail load or meet the agreed upon load reduction. Customers who are able to curtail load will have a credit applied to their bill.

(g) **TPS Supply:** Customers who desire to purchase their electric supply from a TPS may request an enrollment package from Public Service that describes the process necessary for the customer to obtain a TPS for electric supply. This package will be provided to the customer at no charge by Public Service.

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RATE SCHEDULE HTS

HIGH TENSION SERVICE

(Continued)

(g-1) The customer must contract with a TPS to arrange for deliveries to Public Service of the electric supply. A customer is limited to one TPS for electric supply for each account for which the customer receives delivery service.

(g-2) The customer's TPS is required to notify Public Service of the customer's selection prior to 13 days before the customer's scheduled Public Service meter reading date for deliveries to commence on such scheduled meter reading date, and such selection shall remain in effect for the entire billing month. Customer can change TPSs effective only on the date of the customer's scheduled Public Service meter reading date.

(h) **Special Provision per Docket No. EO16080788**: This provision of the HTS tariff applies to substation-related service provided to a rail-rapid transit traction power customer that currently subscribes to High Tension Service (HTS) traction power service delivered at 230 kV to an existing multi-substation facility that has been rebuilt by Public Service based upon the approval of the Board of Public Utilities where such approval permits Public Service to own and operate the multi-substation facility and recover the costs of the multi-substation through the traction power customer and distribution rates. In addition, the multi-substation shall provide unique operational characteristics where in disaster or storm events, in which the bulk electric system is inoperable, the multi-substation can operate in isolation to facilitate a microgrid type contingency scheme.

(h-1) The service provided herein shall be the provision of power to a multi- substation facility (meeting the eligibility requirement described herein) owned by Public Service that transforms and delivers power for a traction service HTS customer at voltage levels from 230 kV to 55kV, 27kV, and 12kV. Public Service and the customer will be required to enter into a protocols and operational responsibility agreement that addresses the maintenance and operational responsibilities for the substation. Unless the protocols and operational agreement specifically state otherwise, the terms and conditions of Public Service's tariff shall apply.

(h-2) A customer that is provided this service shall be subject to the requirements of this service tariff as applicable for service delivered at the 230 kV level. All service provided to the substation shall be metered at 230 kV and billed at the 230 kV service rate for traction power service as set forth in the HTS service tariff, except for power delivered to the substation under standard tariff provisions for 13kV which will be billed under the LPL-P tariff.

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P. L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 16 of the Standard Terms and Conditions for additional details and/or exceptions.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC

Original Sheet No. 166
Original Sheet No. 167
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RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 176**

PAYMENT SCHEDULE PEP
PURCHASED ELECTRIC POWER

APPLICABLE TO:

Electricity produced from a Qualifying Facility as defined in Section 210 of the Public Utility Regulatory Policies Act of 1978, with net capacity no greater than 20 MW and delivered by the Seller to Public Service lines.

RATE:

Service Charge:

$5.00 in each month for installations with a three time period watthour meter, or $30.00 in each month for installations with a recording demand meter.

Energy Payment:

The energy payment in any month for energy received by Public Service shall be based upon the avoided energy cost by time period or by hour, as applicable, in that month (defined as the load weighted average Residual Metered Load Aggregate Locational Marginal Price (LMP) for the Public Service Transmission Zone). Historical LMP data may be found on the Pennsylvania-Jersey-Maryland Independent System Operator (PJM) web site at www.pjm.com.

Capacity Payment:

Purchases from a Qualifying Facility that also qualifies as a PJM Installed Capacity Resource, may receive a capacity payment when the capacity exceeds 100 kilowatts and that capacity meets certain reliability criteria as established from time to time by PJM. Capacity payments or charges, if applicable, will be based on the revenue received by Public Service for selling such capacity in the final PJM capacity auction prior to delivery, adjusted for all penalties and other charges assessed to Public Service by PJM related to the non-performance or unavailability of such capacity.

TIME PERIODS:

The On-Peak time period shall be considered as the hours from 7 A.M. to 9 P.M. (EST) Monday through Friday. All other hours shall be considered the Off-Peak time period.

TERMS OF PAYMENT:

For any month payment to the Seller shall be the energy payment plus a capacity payment and/or capacity penalties, if applicable, less the Service Charge. Payment to the Seller shall be within approximately 90 days from the customer's meter reading date.

SPECIAL PROVISIONS:

(a) Seller shall pay all connection charges that are incurred by Public Service in excess of the costs for supplying the Qualifying Facility's maximum expected distribution delivery requirements including the costs of any required studies. Such charges may also include charges assessed by PJM.

(b) Seller's installation shall conform to Public Service specifications for interconnections as outlined in the applicable standards, and such installation is also subject to any applicable PJM requirements.

(Charges are for illustrative purposes only and are based on the Original Sheet No. 176 filed with the BPU on November 1, 2018)

PAYMENT SCHEDULE PEP
PURCHASED ELECTRIC POWER
(Continued)

(c) The Seller shall sign an application for Purchased Electric Power.

(d) All Sellers are required to execute an Operations Coordination and Interconnection Agreement with Public Service and comply with all then current PJM generator interconnection and operational standards. Additional information regarding current PJM generator interconnection standards and procedures may be found on the PJM web site at www.pjm.com.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 178**

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 179**

RATE SCHEDULE BPL
BODY POLITIC LIGHTING SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Luminaires, poles and appurtenances, maintenance and firm delivery service for dusk to dawn street lighting and area lighting to a body politic served from Company owned lighting facilities. Customers may either purchase electric supply from a Third Party Supplier (TPS) or from Public Service's Basic Generation Service default service as detailed in this rate schedule.

LUMINAIRE CHARGES (Monthly Charge Per Unit):

Standard Luminaires

High Pressure Sodium Luminaire Type	Lamp Wattage	Wattage Including Ballast	PSE&G Part Number	Charge	Charge Including SUT
Cobra-Head	50	58	05-0926	$ 7.49	$ 7.99
Cobra-Head Cut-Off	50	58	05-0990	8.02	8.55
Post-Top Town & Country	50	58	05-0946, 05-0947	7.35	7.84
Cobra-Head	70	83	05-0927	9.22	9.83
Franklin Park Type V	70	83	05-4054	20.08	21.41
Acorn Decorative	100	117	05-0969	21.13	22.53
Cobra-Head	100	117	05-0940	9.91	10.57
Cobra-Head Cut-Off Type III	100	117	05-0991	15.16	16.16
Deluxe Acorn	100	117	05-0967	19.43	20.72
Franklin Park Type IV	100	117	05-3328	21.87	23.32
Hagerstown Type V	100	130	05-3190	23.06	24.59
New Oxford Black Type III	100	117	05-3260	22.29	23.77
Post-Top Acorn	100	117	05-0963	17.91	19.10
Post-Top Town & Country	100	117	05-0948	11.07	11.80
Post-Top Town & Country	100	117	05-0949	11.67	12.44
Profiler Type III	100	117	05-4593	16.06	17.12
Signature Type V	100	130	05-3210	24.44	26.06
Tear Drop Small Shade B	100	117	05-3338	20.94	22.33
Maplwood Lantern Type III	100	110	05-3300	32.13	34.26
Villager Type III	100	117	05-3373	29.19	31.12
Tear Drop-Small Type III	100	130	05-7097	25.86	27.57
Acorn Decorative	150	177	05-0984	23.25	24.79
Acorn Scroll	150	171	05-0966	25.19	26.86
Architectural Type III	150	190	05-3222	21.56	22.99
Capitol Type V	150	171	05-3202	20.42	21.77
Cobra-Head	150	171	05-0941	10.25	10.93
Cobra-Head Cut-Off Type II	150	171	05-0994	13.91	14.83
Dayform Traditionaire Type III	150	171	05-3415	16.13	17.20
Deluxe Acorn	150	177	05-0968	19.43	20.72
Deluxe Acorn II Type V	150	171	05-3320	17.68	18.85
Edison III Type III	150	177	05-3326	18.80	20.05
Floodlight	150	171	05-0722, 05-0727	13.68	14.59
Franklin Park Type IV	150	171	05-4055	18.91	20.16
Hagerstown Type V	150	190	05-3192, 05-3193	24.65	26.28
Holophane RSL Type V	150	190	05-0931	21.56	22.99
Journal SQ 20" Globe Type V	150	190	05-4050	21.90	23.35
Liberty II Type V	150	171	05-3360	25.91	27.63
Old Boston Lantern Type II	150	171	05-3172	20.67	22.04

(Charges are for illustrative purposes only see Streetlight Appendix)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 180**

RATE SCHEDULE BPL
BODY POLITIC LIGHTING SERVICE
(Continued)

Standard Luminaires (continued)

High Pressure Sodium (cont'd) Luminaire Type	Lamp Wattage	Wattage Including Ballast	PSE&G Part Number	Charge	Charge Including SUT
Post-Top Acorn	150	177	05-0964	$ 18.78	$ 20.02
Post-Top Town & Country	150	171	05-0950	13.76	14.67
Shoe-Box-Small	150	171	05-0971	15.81	16.86
Signature Green Type V	150	171	05-3218	21.93	23.38
Signature Black Type V	150	190	05-3212	25.88	27.59
Trenton Type III	150	190	05-3263	21.58	23.01
Trenton Type V	150	190	05-3268	21.56	22.99
Villager Type III	150	171	05-3176	21.98	23.44
Acorn Scroll	150	171	05-0960	28.34	30.22
Vandal Resistant Type III	150	171	05-3501	14.13	15.07
Cobra-Head	250	300	05-0928	11.83	12.61
Cobra-Head Cut-Off	250	300	05-0993	14.36	15.31
Cobra-Head Vandal Resistant Shield	250	300	05-3502	17.37	18.52
Concourse Type IV	250	300	05-3017	15.13	16.13
Floodlight	250	300	05-0726	16.47	17.56
Shoe-Box-Large	250	300	05-0970	17.54	18.70
Shoe-Box-Small	250	300	05-0973	17.54	18.70
Signature Type V	250	300	05-3379	33.08	35.27
Trenton Type V	250	300	05-3270	18.45	19.67
Cobra-Head	400	450	05-0925	17.77	18.95
Cobra-Head Cut-Off	400	450	05-0929	17.32	18.47
Cobra-Head Type II	400	450	05-0933	17.77	18.95
Expressway Flood	400	450	05-1001	31.00	33.05
Floodlight	400	449	05-0725	21.04	22.43
Floodlight Bronze	400	449	05-0724	21.04	22.43
Shoe-Box-Large	400	470	05-0975	20.07	21.40
Shoe-Box-Small	400	450	05-0979	15.57	16.60
Tear Drop-Large Shade Type III	400	450	05-3336	24.38	26.00
Tear Drop-Large Type III	400	470	05-7096	28.90	30.81
Power Flood	750	839	05-0721	25.49	27.18
Induction					
Cobra-Head Type III	40	40	05-0901	8.89	9.48
Cobra-Head Type III	80	80	05-0902	9.08	9.68
Cobra-Head Type III	150	150	05-0903	12.96	13.82
Cobra-Head Type III	250	260	05-0904	14.50	15.46
Metal Halide					
Hagerstown Green Type V	100	130	05-3196	27.50	29.32
Capitol Black Type V	100	130	05-3206	27.81	29.65
Signature Black Type V	100	130	05-3215	28.27	30.14
Tear Drop – Type V	100	130	05-3281	27.50	29.32
Liberty I Type III	100	130	05-3351	26.57	28.33

(Charges are for illustrative purposes only see Streetlight Appendix)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 181**

RATE SCHEDULE BPL
BODY POLITIC LIGHTING SERVICE
(Continued)

Standard Luminaires (continued)

Metal Halide (cont'd) Luminaire Type	Lamp Wattage	Wattage Including Ballast	PSE&G Part Number	Charge	Charge Including SUT
Granville Black Type III	100	130	05-6038	$ 25.17	$ 26.84
Granville wR&B Type III	100	130	05-6040	25.56	27.25
Granville Type III	100	130	05-6042	25.72	27.42
Hallbrook – Type III	100	130	05-6056	28.99	30.91
Tear Drop – Type III	100	130	05-7102	27.50	29.32
Villager	150	170	05-8060	30.26	32.26
Contempo – Type II	150	170	05-8062	27.16	28.96
Imperial – Type III	150	170	05-8141	28.71	30.61
Hagerstown	150	170	05-8151	27.86	29.71
Capitol Type V	150	170	05-8162	28.71	30.61
Signature Black Type IV	150	165	05-8173	28.71	30.61
Architectural Type III	150	170	05-8181	26.93	28.71
Trenton Type V	150	170	05-8197	25.15	26.82
Tear Drop – Type III	150	170	05-8198	27.86	29.71
Granville Leaf Black Type III	150	170	05-8215	24.34	25.95
Deluxe Acorn	150	170	05-8224	25.38	27.06
Liberty I Type III	150	170	05-8230	26.93	28.71
Villager Type III	150	170	05-8252	30.26	32.26
Franklin Park Type V	150	170	05-8312	27.86	29.71
Pima	150	150	05-8393	26.93	28.71
Techtra – Type V	150	170	05-8441	30.72	32.76
Tear Drop – Type V	150	170	05-8658	27.86	29.71
New London Type III	150	170	05-8190	29.56	31.52
Contempo – Type V	250	280	05-8064	29.89	31.87
Signature Black Type III	250	275	05-8170	29.82	31.80
Tear Drop – Small	250	300	05-8211	28.96	30.88
Tear Drop – Type III	250	280	05-8622	29.12	31.05
Tear Drop – Type III	250	280	05-8664	31.44	33.52
Tear Drop – Large Type V	250	280	05-8668	31.05	33.11
Newarker – Type V	250	280	05-8680	29.82	31.80
Floodlight	320	350	05-8003	12.49	13.32
Cobra – Head Type III	320	350	05-8018	12.65	13.49
Tear Drop - Large Type III	320	350	05-8063	31.53	33.62
LED					
Floodlight	0	140	05-9900	16.31	17.39
Franklin Park	80	90	05-9999	31.86	33.97
Trenton	85	85	05-9930	28.61	30.51
Contempo – Type II	85	90	05-9940	31.55	33.64
Signature	85	100	05-9960	31.63	33.73
Newarker	85	95	05-9970	31.63	33.73
Franklin Park	86	90	05-9920	37.57	40.06
Tear Drop-Large w/Brim	125	90	05-9950	39.53	42.15
Tear Drop-Large	125	129	05-9951	30.47	32.49
Floodlight	129	141	05-0734	12.32	13.14

(Charges are for illustrative purposes only see Streetlight Appendix)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 182**

RATE SCHEDULE BPL
BODY POLITIC LIGHTING SERVICE
(Continued)

Specialty Luminaires

All luminaires not listed above as Standard Luminaires, all non-standard installations of Standard Luminaires, and any luminaire where the customer makes a contribution toward the total installed cost are deemed Specialty Luminaires. The Monthly Charge Per Unit for all Specialty Luminaires is equal to the sum of the Capital Recovery Charge and Maintenance Charge set forth as follows:

(1) A Capital Recovery Charge equal to the actual total installed cost less any customer contribution (net of tax gross up) times a factor equal to 1.554% (1.657% including SUT) for all Cobra-Head, Floodlights and Town and Country luminaires, and 1.171% (1.249% including SUT) for all other luminaire types. This Capital Recovery Charge will remain unchanged over the remaining life of the luminaire.

(2) A Maintenance Charge that varies by luminaire type and size and is equal to the following:

(2-a) **Applicable to Cobra Head, Floodlights And Town And Country Luminaires:**

Lamp Type	Lamp Wattage	Charge	Charge Including SUT
High Pressure Sodium	All wattages	$ 2.67	$ 2.85
Metal Halide	50 watts and 100 watts	3.27	3.49
	175 watts	3.98	4.24
	250 watts	4.07	4.34
	400 watts	3.58	3.82
	1000 watts	6.48	6.91
Mercury Vapor	All wattages	1.53	1.63
Induction	All wattages	1.28	1.37
LED	All wattages	1.10	1.17

(2-b) **Applicable to All Other Luminaire Types:**

Lamp Type	Lamp Wattage	Charge	Charge Including SUT
High Pressure Sodium	All wattages	$ 3.34	$ 3.56
Metal Halide	50 watts and 100 watts	3.94	4.20
	175 watts	4.64	4.95
	250 watts	4.74	5.05
	400 watts	4.25	4.53
	1000 watts	7.14	7.62
Mercury Vapor	All wattages	2.19	2.34
Induction	All wattages	1.28	1.37
LED	All wattages	1.10	1.17

(Charges are for illustrative purposes only see Streetlight Appendix)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 183**

RATE SCHEDULE BPL
BODY POLITIC LIGHTING SERVICE
(Continued)

Closed Luminaires

Luminaire Type	Lamp Wattage	Wattage including Ballast	PSE&G Part Number	Charge	Charge Including SUT
Filament					
1,000 Lumens NEMA Head	105	105	00-0052	$ 3.87	$ 4.13
2,500 Lumens NEMA Head	205	205	00-0054	5.81	6.19
4,000 Lumens NEMA Head	327	327	00-0055	6.36	6.78
6,000 Lumens NEMA Head	448	448	00-0056	6.43	6.86
10,000 Lumens NEMA Head	690	690	00-0057	5.88	6.27
15,000 Lumens NEMA Head	860	860	00-0058	8.24	8.79
High Pressure Sodium					
Offset Flood	250	300	05-1000	32.31	34.45
Metal Halide					
Hagerstown Black Type V	100	130	05-3195	25.13	26.79
Capitol Type V	175	210	05-3207	27.84	29.68
Hagerstown Type V	175	210	05-3197	27.97	29.82
Holophane GV Type III	175	210	05-3293	25.58	27.27
Old Boston Lantern Type II	175	210	05-3186	28.99	30.91
Post-Top Acorn	175	210	05-0965	19.39	20.67
Signature Type IV & Type V	175	210	05-3217	29.74	31.71
Signature Arch Green	175	210	05-3219	29.74	31.71
Trenton Type V	175	210	05-3272	23.59	25.15
Vero-Green (No Cage)	175	210	05-3545	25.49	27.18
Cobra-Head Vandal Resistant Shield	250	300	05-3503	23.56	25.12
Signature Type V	250	300	05-3213	30.99	33.04
Trenton Type III	250	300	05-3386	27.20	29.00
Cobra-Head Cut-Off	400	460	05-0930	17.58	18.74
Cobra-Head Type III	400	465	05-0916	17.58	18.74
Floodlight	400	460	05-0728	19.46	20.75
Gray Narrow Beam Floodlight	400	460	05-0729	19.46	20.75
Shoe-Box-Large	400	465	05-0976	20.89	22.27
Floodlight	1000	1080	05-0421	26.73	28.50
Mercury Vapor					
Cobra-Head	100	118	05-0921	5.93	6.32
Post-Top Town & Country	100	118	05-0935	5.93	6.32
Post-Top Town & Country Type IV	100	118	05-0936	5.93	6.32
Cobra-Head	175	210	05-0920	7.53	8.03
Post-Top Town & Country	175	210	05-0937	6.00	6.40
Post-Top Town & Country IV	175	210	05-0938	6.00	6.40
Cobra-Head	250	290	05-0919	9.32	9.94
Cobra-Head	400	432	05-0918	10.03	10.69
Floodlight	400	453	05-0422	14.61	15.58
Cobra-Head	1000	1085	05-0768	13.11	13.98
Floodlight	1000	1075	05-0420	23.10	24.63

(Charges are for illustrative purposes only see Streetlight Appendix)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 184**

RATE SCHEDULE BPL
BODY POLITIC LIGHTING SERVICE
(Continued)

DELIVERY CHARGES:

Distribution Charge per Kilowatt-hour:

Charge	Charge Including SUT
$ 0.006894	$ 0.007351

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 72 for details of these charges.

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Non-utility Generation Charge:

This charge shall recover above market costs associated with non-utility generation and other generation related costs as may be approved by the Board. Refer to the Non-utility Generation Charge sheet of this Tariff for the current charge.

Solar Pilot Recovery Charge:

This charge is designed to recover the revenue requirements associated with the Public Service Solar Pilot Program per the Board Order in Docket No. EO07040278 less the net proceeds from the sale of associated Solar Renewable Energy Certificates (SRECs) or cash received in lieu of SRECs. Refer to the Solar Pilot Recovery Charge sheet of this tariff for the current charge.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

Tax Adjustment Credit:

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current credit.

Zero Emission Certificate Recovery Charge:

This charge provides for the recovery of costs associated with the Zero Emission Certificate Program directed by the Board of Public Utilities ("BPU" or "Board"). Refer to the Zero Emission Certificate Recovery Charge sheet of this Tariff for the current charge.

Distribution Adjustment Charge:

This charge is designed to recover Board-approved costs. Refer to the Distribution Adjustment Charge sheet of this Tariff for the current charge.

The Distribution Charge, Societal Benefits Charge, Non-utility Generation Charge, the Solar Pilot Recovery Charge, the Green Programs Recovery Charge, the Tax Adjustment Credit, the Zero Emission Certificate Recovery Charge, and the Distribution Adjustment Charge shall be combined for billing.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 185**

RATE SCHEDULE BPL
BODY POLITIC LIGHTING SERVICE
(Continued)

ELECTRIC SUPPLY CHARGES:

A customer may choose to receive electric supply from either:
a) A TPS as described in Section 14 of this Tariff, or
b) Public Service through its Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP) default service.

Third Party Supply:

A customer that receives electric supply from a TPS will be charged for electric supply according to any agreement between the customer and the TPS. The customer will not be charged for electric supply by Public Service.

Basic Generation Service:

Customers that do not receive electric supply from a TPS will be supplied under the Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP) default service.

The BGS Energy Charge and the BGS Reconciliation Charge, as applicable, will be applied to all kilowatt-hours billed each month. Refer to the Basic Generation Service sheets of this Tariff for the current charges applicable to Rate Schedule BPL.

LIGHTING POLE AND MISCELLANEOUS DEVICE CHARGES (Monthly Charge Per Unit):

Only poles installed, owned and maintained by Public Service as part of the electric distribution system exclusively for the purpose of providing lighting service under Rate Schedules BPL or PSAL are designated as Lighting Poles.

Standard Lighting Poles

Pole Type	Style	Height	PSE&G Part Number	Charge	Charge Including SUT
Aluminum	Classic I Black	10 ft.	04-1292	$ 27.39	$ 29.20
Aluminum	Windsor Black	11.5 ft.	04-1269	28.16	30.02
Aluminum	Classic I Black	12 ft.	04-1280	26.37	28.12
Aluminum	Classic I Green	12 ft.	04-1290	29.35	31.29
Aluminum	Colonial Black	12 ft.	04-1264	20.96	22.34
Aluminum	Colonial Fluted Black	12 ft.	04-4036	22.39	23.88
Aluminum	Heritage Black	12 ft.	04-3499	29.95	31.93
Aluminum	Rockford Harbor Fluted Black	12 ft.	04-6015	30.86	32.90

(Charges are for illustrative purposes only see Streetlight Appendix)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 186**

RATE SCHEDULE BPL
BODY POLITIC LIGHTING SERVICE
(Continued)

Standard Lighting Poles – Continued

Pole Type	Style	Height	PSE&G Part Number	Charge	Charge Including SUT
Aluminum	Westwood Black	12 ft.	04-3260	$24.34	$25.95
Aluminum	Classic II	12 ft.	04-1285	36.35	38.76
Aluminum	Journal Square	12 ft.	04-4059	40.49	43.17
Aluminum	Colonial Fluted Black	13 ft.	04-4440	25.68	27.38
Aluminum	Classic I Black	14 ft.	04-1281	29.24	31.18
Aluminum	Classic I Green	14 ft.	04-1291	27.00	28.79
Aluminum	Classic II Black	14 ft.	04-1286	27.55	29.38
Aluminum	Colgate I Black	14 ft.	04-1262	26.87	28.65
Aluminum	Colonial Fluted Black	14 ft.	04-1261	20.80	22.17
Aluminum	Colonial Round Black	14 ft.	04-1265	21.78	23.22
Aluminum	Heritage Black	14 ft.	04-3500	30.16	32.16
Aluminum	Montclair Black	14 ft.	04-4085	29.44	31.39
Aluminum	Round Black	14 ft.	04-1284	25.66	27.36
Aluminum	Square Bronze	14 ft.	04-1251	18.57	19.80
Aluminum	Heritage Gray	14 ft.	04-3503	39.30	41.90
Aluminum	Classic I Black	14.5 ft.	04-1282	25.90	27.62
Aluminum	Classic II	15 ft.	04-1287	18.68	19.91
Aluminum	Classic I Black	16 ft.	04-1283	27.60	29.43
Aluminum	Colonial Fluted	16 ft.	04-1272	31.19	33.26
Aluminum	Colonial Fluted	16 ft.	04-4084	29.96	31.94
Aluminum	Contemporary Black	16 ft.	04-4073	33.16	35.36
Aluminum	Heritage Black	16 ft.	04-3501	39.53	42.15
Aluminum	Hudson Black	16 ft.	04-4083	37.57	40.06
Aluminum	Square Bronze	16 ft.	04-4006	23.80	25.38
Aluminum	Round	18 ft.	04-4017	31.63	33.73
Aluminum	Square 5 inch	20 ft.	04-1257	22.65	24.15
Aluminum	Tall Decorative	20 ft.	04-4091	41.60	44.36
Aluminum	Round	25 ft.	04-1211	33.68	35.91
Aluminum	Square Bronze	25 ft.	04-1258	26.08	27.81
Aluminum	Octagon Round	25 ft.	04-0198	55.08	58.73
Aluminum	Decorative Black	25 ft.	04-3262	44.26	47.19
Aluminum	Fluted	30 ft.	04-7098	64.33	68.59
Aluminum	Square Black	30 ft.	04-1254	33.29	35.50
Aluminum	Montclair Black	36 ft.	04-4090	36.84	39.28

(Charges are for illustrative purposes only see Streetlight Appendix)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 187**

RATE SCHEDULE BPL
BODY POLITIC LIGHTING SERVICE
(Continued)

Standard Lighting Poles - Continued

Pole Type	Style	Height	PSE&G Part Number	Charge	Charge Including SUT
Aluminum	Square Bronze	30 ft.	04-1250	$ 31.19	$ 33.26
Aluminum	Round	35 ft.	04-1230	27.33	29.14
Cast Aluminum	Colonial Fluted	12 ft.	04-1260	19.94	21.26
Fiberglass	Smooth Tapered Black	17 ft.	04-0201	*8.57	*9.14
Fiberglass	Round Bronze	20 ft.	04-0203	**9.00	**9.60
Fiberglass	Round Bronze	25 ft.	04-0204	19.39	20.67
Laminated Wood	Laminated Wood	30 ft.	04-0225	12.56	13.39
Laminated Wood	Laminated Wood Gray	30 ft.	04-0197	14.70	15.67
Pine	Center Bored	30 ft.	04-0350	8.00	8.53
Pine	Round	30 ft.	04-0302	*9.24	*9.85
Pine	Round	35 ft.	04-0304	*10.92	*11.64
Pine	Round Class IV	40 ft.	04-0306	***12.51	***13.34
Pine	Round Class III	45 ft.	04-0308	****13.33	****14.22

* The charge for indicated poles installed prior to August 1, 2003 is $0.00 ($0.00 including SUT).
** The charge for indicated poles installed prior to August 1, 2003 is $2.48 ($2.64 including SUT).
*** The charge for indicated poles installed prior to August 1, 2003 is $4.07 ($4.34 including SUT).
**** The charge for indicated poles installed prior to August 1, 2003 is $6.79 ($7.24 including SUT).

Specialty Lighting Poles and Miscellaneous Devices:

All poles not listed above as Standard Lighting Poles, all non-standard installations of standard lighting poles, any pole where the customer makes a contribution toward the total installed cost, and all shrouds, brackets and other miscellaneous devices are deemed Specialty Lighting Poles and Miscellaneous Devices. The Monthly Charge Per Unit for Specialty Lighting Poles and Miscellaneous Devices is equal to the sum of the Capital Recovery Charge and Maintenance Charge set forth as follows:

(1) A Capital Recovery Charge equal to the actual total installed cost less any customer contribution (net of tax gross up) times a factor equal to 1.097% (1.170% including SUT). This Capital Recovery Charge shall remain unchanged over the remaining life of the pole. In underground zones the total installed cost excludes the cost of underground conduits, conductors, manholes and handholes, but includes the cost of equivalent overhead conductors.

(2) A Maintenance Charge that varies by item type and is equal to the following:

(Charges are for illustrative purposes only see Streetlight Appendix)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 188**

RATE SCHEDULE BPL
BODY POLITIC LIGHTING SERVICE
(Continued)

Pole and Device Type	Charge	Charge Including SUT
Pine wood pole	$ 0.50	$ 0.54
Laminated wood pole	0.00	0.00
Aluminum pole	0.00	0.00
Fiberglass pole	0.00	0.00
Shrouds, Brackets & Other Miscellaneous Devices	0.00	0.00

BILLING DETERMINANTS:

Kilowatt-hours:

The kilowatt-hour estimate is determined for each lamp by dividing total wattage including ballast by 1,000 and multiplying the result by the monthly burning hours as follows:

January	447	July	281
February	374	August	312
February (leap-year)	387	September	343
March	372	October	397
April	317	November	421
May	292	December	456
June	263		

Generation Obligation:

The customer's Generation Obligation, in kilowatts, is determined by Public Service no less frequently than once a year. The Generation Obligation for existing customers or for new customers utilizing an existing building or premise is based upon the customer's share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM) as adjusted by PJM assigned capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions. The Generation Obligation for customers taking service in a new building or premise, as determined by Public Service, is based upon the load requirements, as estimated by Public Service, of the customer's building or premise. The Generation Obligation represents the generator capacity that PJM requires an electric supplier to have available to provide electric supply to a customer.

Transmission Obligation:

The customer's Transmission Obligation, in kilowatts, is determined in a similar manner to the Generation Obligation described above. The Transmission Obligation represents the level of transmission network service that must be procured by the Customer's electric supplier from PJM to provide service to the customer.

Costs associated with the Generation and Transmission Obligations are included in the charges for Basic Generation Service and may affect the price offered by a Third Party Supplier.

Allowance for Lamp Outages:

Charges reflect an outage allowance based upon normal and abnormal operating conditions. No further allowance will be made.

(Charges are for illustrative purposes only see Streetlight Appendix)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 189**

RATE SCHEDULE BPL
BODY POLITIC LIGHTING SERVICE
(Continued)

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill.

TERM:

For all Standard Luminaires and Standard Lighting Poles: One year and thereafter until terminated by five days' notice.

For all Specialty Luminaires and Specialty Lighting Poles and Miscellaneous Devices and all Underground Lighting Installations: Five years and thereafter until terminated by five days' notice. Customers shall be required to make a payment for all such lighting facilities removed prior to five years from the installation date equal to the cost of removal less salvage plus 75% of the original installed costs net of any customer contribution.

Customers who transfer from third party supply to Basic Generation Service may be subject to additional limitations regarding the term of Basic Generation Service as detailed in Section 14 of the Standard Terms and Conditions of this Tariff.

SPECIAL PROVISIONS:

(a) **Service to Customers:** Public Service will furnish and install the lamp, luminaire, bracket, pole, wiring and associated equipment, make necessary lamp renewals, otherwise maintain the installation, and repair or replace all equipment rendered inoperable whether or not due to willful or accidental damage. In the event of repeated damage to its facilities, whether willful or accidental, Public Service reserves the right to discontinue such lighting service or require the customer to be responsible for the continued cost of repair or replacement. Lighting service will be furnished only if practicable for installation and maintenance, safe from the standpoint of Public Service, and will not be supplied where the introduction of such lighting would create an unusual hazard.

(b) Underground Construction:

(b-1) Underground construction will be provided at no additional charge in underground zones designated by Public Service for all public street lighting applications and for nonpublic street lighting applications up to 100 feet distant from the public street as measured at right angles to the curb. Where underground construction is desired for all other applications and in other areas, the customer shall pay the cost of such underground construction for all conduits, conductors, manholes and handholes.

(b-2) In a underground zone designated by Public Service, a standard 30 foot aluminum street lighting pole, or credit equivalent, will be provided for each luminaire utilized for public street lighting by a body politic at no charge. The installation of these poles will be provided with a minimum space between poles of 150 feet when measured along the curb line.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 190**

RATE SCHEDULE BPL

BODY POLITIC LIGHTING SERVICE

(Continued)

(b-3) In subdivisions subject to the Regulations for Residential Electric Underground Extensions in N.J.A.C. 14:3-8 et seq., there will be no monthly charge to the local municipality for standard street lighting poles utilized for public street lighting that have been included in the charges paid by the developer of the subdivision as determined under tariff section Regulation for Residential Underground Extension.

(c) Changes in size, type or location:

(c-1) Customers may be required to make a payment toward the costs of installation, removal, relocation and/or changes in lamp size for conversion from one light source to another when the age of the luminaires to be converted is less than 20 years.

Payment shall be based on the unamortized installed cost plus the removal cost less salvage.

Customers will be required to make a payment based on actual cost of the requested work for the temporary replacement and/or relocation of an existing light to a new location and the subsequent movement of the light back to its old location.

(c-2) A request to install a new light at the same location within 12 months of the removal of an existing light will be considered a replacement of the existing light. A charge may be assessed for any lamp ordered reconnected or reinstalled when the elapsed time is less than 12 months from the request for disconnect.

(c-3) Public Service reserves the right to limit the number of lamp conversions in any year to no more than 5% of the total lamps served at the end of the previous year.

(d) **Replacement of Obsolete Equipment:** Public Service has the right to replace obsolete luminaires, poles and all other associated equipment with equivalent equipment without the consent of its customers.

(e) **Customer Contributions:** The making of a payment to Public Service shall not give the customer any interest in the facilities, the ownership being vested exclusively in Public Service.

Body Politic customers may elect to contribute to the total installed cost of Specialty Luminaires, Specialty Lighting Poles or Miscellaneous Devices in addition to that which may be required in accordance with Special Provision (b). Public Service may limit the contribution option between zero and the maximum contribution. Such contribution shall be up to a maximum of:

(e-1) The installed cost less $600.00, grossed up for income tax effects, of any luminaire with an installed cost greater than $1,200.00;

(e-2) The installed cost less $600.00, grossed up for income tax effects, of any pole with an installed cost greater than $1,200.00; or

(e-3) The installed cost, grossed up for income tax effects, of any shroud, bracket or other Miscellaneous Devices.

RATE SCHEDULE BPL

BODY POLITIC LIGHTING SERVICE

(Continued)

(f) **Unit Life:** Luminaires, poles and all other associated lighting equipment will be removed when replacement parts are required but no longer generally available. At that time the customer may elect for Public Service to install replacement equipment that will be considered as an installation of new facilities and priced at the then current applicable charges.

(g) **TPS Supply:** Customers who desire to purchase their electric supply from a TPS may request an enrollment package from Public Service that describes the process necessary for the customer to obtain a TPS for electric supply. This package will be provided to the customer at no charge by Public Service.

(g-1) The customer must contract with a TPS to arrange for deliveries to Public Service of the electric supply. A customer is limited to one TPS for electric supply for each account for which the customer receives delivery service.

(g-2) The customer's TPS is required to notify Public Service of the customer's selection prior to 13 days before the customer's scheduled Public Service meter reading date for deliveries to commence on such scheduled meter reading date, and such selection shall remain in effect for the entire billing month. Customer can change TPSs effective only on the date of the customer's scheduled Public Service meter reading date.

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 16 of the Standard Terms and Conditions for additional details and/or exceptions.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 192**
Original Sheet No. 193
Original Sheet No. 194

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 195**

RATE SCHEDULE BPL-POF
BODY POLITIC LIGHTING SERVICE FROM PUBLICLY OWNED FACILITIES

APPLICABLE TO USE OF SERVICE FOR:
This rate class is closed and in the process of elimination. Firm delivery service and maintenance for dusk to dawn street lighting and area lighting to a body politic served from Publicly-Owned Lighting Facilities. Customers may either purchase electric supply from a Third Party Supplier (TPS) or from Public Service's Basic Generation Service default service as detailed in this rate schedule.

MAINTENANCE CHARGES (Monthly Charge Per Unit):

Standard Luminaires

High Pressure Sodium

Luminaire Type	Lamp Wattage	Wattage including Ballast	Equivalent PSE&G Part Number	Charge	Charge Including SUT
Cobra-Head	50	58	05-0926	$ 1.87	$ 1.99
Cobra-Head Cut-Off Type IV	50	58	05-0990	1.87	1.99
Post-Top Town & Country	50	58	05-0946	1.87	1.99
Cobra-Head	100	117	05-0940	1.87	1.99
Post-Top Town & Country II	100	117	05-0948	1.87	1.99
Post-Top Town & Country IV	100	117	05-0949	1.87	1.99
Cobra-Head	150	171	05-0941	1.87	1.99
Post-Top Acorn	150	171	05-0964	2.61	2.78
Post-Top Town & Country II	150	171	05-0950	1.87	1.99
Shoe-Box-Large Round	150	171	05-0971	2.61	2.78
Shoe-Box-Large Square	150	171	05-0971	2.61	2.78
Cobra-Head	250	300	05-0928	1.87	1.99
Cobra-Head Cut-Off	250	300	05-0993	1.87	1.99
Shoe-Box-Large	250	300	05-0970	2.61	2.78
Shoe-Box-Large Round	250	300	05-0970	2.61	2.78
Shoe-Box-Large Square	250	300	05-0970	2.61	2.78
Cobra-Head Vandal Resistant Shield	250	300	05-3502	1.87	1.99
Cobra-Head	400	450	05-0925	1.87	1.99
Cobra-Head Cut-Off	400	450	05-0929	1.87	1.99
Shoe-Box-Large	400	470	05-0975	2.61	2.78

(Charges are for illustrative purposes only see Streetlight Appendix)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 196**

RATE SCHEDULE BPL-POF

BODY POLITIC LIGHTING SERVICE FROM PUBLICLY OWNED FACILITIES

(Continued)

Closed Luminaires

Filament Luminaire Type	Lamp Wattage	Wattage including Ballast	Equivalent PSE&G Part Number	Charge	Charge Including SUT
600 Lumens NEMA Head	58	58	N/A	$ 5.38	$ 5.74
1,000 Lumens NEMA Head	105	105	N/A	5.38	5.74
2,500 Lumens NEMA Head	205	205	N/A	5.38	5.74
4,000 Lumens NEMA Head	327	327	N/A	5.38	5.74
6,000 Lumens NEMA Head	448	448	N/A	5.38	5.74
10,000 Lumens NEMA Head	690	690	N/A	5.38	5.74
Metal Halide					
Acorn	175	210	N/A	4.06	4.33
Floodlight	1000	1080	N/A	6.11	6.51
Mercury Vapor					
Cobra-Head	175	210	N/A	1.08	1.15
Post-Top Town & Country Type IV	175	210	N/A	0.59	0.63
Cobra-Head	250	290	N/A	0.59	0.63
Cobra-Head	400	432	N/A	0.59	0.63

(Charges are for illustrative purposes only see Streetlight Appendix)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 197**

RATE SCHEDULE BPL-POF
BODY POLITIC LIGHTING SERVICE FROM PUBLICLY OWNED FACILITIES
(Continued)

DELIVERY CHARGES:

Distribution Charge per Kilowatt-hour:

Charge	Charge Including SUT
$ 0.006931	$ 0.007390

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 72 for details of these charges.

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Non-utility Generation Charge:

This charge shall recover above market costs associated with non-utility generation and other generation related costs as may be approved by the Board. Refer to the Non-utility Generation Charge sheet of this Tariff for the current charge.

Solar Pilot Recovery Charge:

This charge is designed to recover the revenue requirements associated with the Public Service Solar Pilot Program per the Board Order in Docket No. EO07040278 less the net proceeds from the sale of associated Solar Renewable Energy Certificates (SRECs) or cash received in lieu of SRECs. Refer to the Solar Pilot Recovery Charge sheet of this tariff for the current charge.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

Tax Adjustment Credit:

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current credit.

Zero Emission Certificate Recovery Charge:

This charge provides for the recovery of costs associated with the Zero Emission Certificate Program directed by the Board of Public Utilities ("BPU" or "Board"). Refer to the Zero Emission Certificate Recovery Charge sheet of this Tariff for the current charge.

Distribution Adjustment Charge:

This charge is designed to recover Board-approved costs. Refer to the Distribution Adjustment Charge sheet of this Tariff for the current charge.

The Distribution Charge, Societal Benefits Charge, Non-utility Generation Charge, the Solar Pilot Recovery Charge, the Green Programs Recovery Charge, the Tax Adjustment Credit, the Zero Emission Certificate Recovery Charge, and the Distribution Adjustment Charge shall be combined for billing.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 198**

RATE SCHEDULE BPL-POF

BODY POLITIC LIGHTING SERVICE FROM PUBLICLY OWNED FACILITIES

(Continued)

ELECTRIC SUPPLY CHARGES:

A customer may choose to receive electric supply from either:

a) A TPS as described in Section 14 of this Tariff, or
b) Public Service through its Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP) default service.

Third Party Supply:

A customer that receives electric supply from a TPS will be charged for electric supply according to any agreement between the customer and the TPS. The customer will not be charged for electric supply by Public Service.

Basic Generation Service:

Customers that do not receive electric supply from a TPS will be supplied under the Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP) default service.

The BGS Energy Charge and the BGS Reconciliation Charge, as applicable, will be applied to all kilowatt-hours billed each month. Refer to the Basic Generation Service sheets of this Tariff for the current charges applicable to Rate Schedule BPL-POF.

BILLING DETERMINANTS:

Kilowatt-hours:

The kilowatt-hour estimate is determined for each lamp by dividing total wattage including ballast by 1,000 and multiplying the result by the monthly burning hours as follows:

January	447	July	281
February	374	August	312
February (leap-year)	387	September	343
March	372	October	397
April	317	November	421
May	292	December	456
June	263		

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 199**

RATE SCHEDULE BPL-POF
BODY POLITIC LIGHTING SERVICE FROM PUBLICLY OWNED FACILITIES
(Continued)

Generation Obligation:

The customer's Generation Obligation, in kilowatts, is determined by Public Service no less frequently than once a year. The Generation Obligation for existing customers or for new customers utilizing an existing building or premise is based upon the customer's share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM) as adjusted by PJM assigned capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions. The Generation Obligation for customers taking service in a new building or premise, as determined by Public Service, is based upon the load requirements, as estimated by Public Service, of the customer's building or premise. The Generation Obligation represents the generator capacity that PJM requires an electric supplier to have available to provide electric supply to a customer.

Transmission Obligation:

The customer's Transmission Obligation, in kilowatts, is determined in a similar manner to the Generation Obligation described above. The Transmission Obligation represents the level of transmission network service that must be procured by the Customer's electric supplier from PJM to provide service to the customer.

Costs associated with the Generation and Transmission Obligations are included in the charges for Basic Generation Service and may affect the price offered by a Third Party Supplier.

Allowance for Lamp Outages:

Charges reflect an outage allowance based upon normal and abnormal operating conditions. No further allowance will be made.

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill.

TERM:

One year for all new lamps and thereafter until terminated by five days' notice.

Customers who transfer from third party supply to Basic Generation Service may be subject to additional limitations regarding the term of Basic Generation Service as detailed in Section 14 of the Standard Terms and Conditions of this Tariff.

SPECIAL PROVISIONS:

(a) **Service from Publicly-Owned Facilities:** Service under this Rate Schedule is only available where Public Service has paid no part of the cost of the distribution facilities, lamps, luminaires and all other associated equipment beyond the point of connection to the Public Service distribution system, such point of connection to be designated by Public Service. The complete lighting installation shall meet with the approval of Public Service for operation and maintenance. Public Service will clean refractors or globes, replace lamps, locate cable faults and make minor cable and socket repairs. Replacement of defective cable, painting or otherwise maintaining posts or luminaires or any other associated equipment shall be done only at the expense of the customer. In the event of repeated damage to the equipment, whether willful or accidental, Public Service reserves the right to discontinue such lighting service or require the customer to be responsible for the continued cost of repair or replacement.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 200**

RATE SCHEDULE BPL-POF

BODY POLITIC LIGHTING SERVICE FROM PUBLICLY OWNED FACILITIES

(Continued)

(b) **Service to Indicating Lamps:** Service to indicating lamps used for marking location of fire and police boxes, fixed warning or obstruction lights, or similar purposes will be provided where all necessary materials and labor for indicating lamp installations is furnished and installed by and at the expense of the customer. Service to indicating lamps will be furnished only if practicable and safe from the standpoint of Public Service.

(c) **TPS Supply:** Customers who desire to purchase their electric supply from a TPS may request an enrollment package from Public Service that describes the process necessary for the customer to obtain a TPS for electric supply. This package will be provided to the customer at no charge by Public Service.

(c-1) The customer must contract with a TPS to arrange for deliveries to Public Service of the electric supply. A customer is limited to one TPS for electric supply for each account for which the customer receives delivery service.

(c-2) The customer's TPS is required to notify Public Service of the customer's selection prior to 13 days before the customer's scheduled Public Service meter reading date for deliveries to commence on such scheduled meter reading date, and such selection shall remain in effect for the entire billing month. Customer can change TPSs effective only on the date of the customer's scheduled Public Service meter reading date.

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P. L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 16 of the Standard Terms and Conditions for additional details and/or exceptions.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 201**
Original Sheet No. 202

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 203**

RATE SCHEDULE PSAL

PRIVATE STREET AND AREA LIGHTING SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Luminaires, poles and appurtenances, maintenance and firm delivery service for dusk to dawn private street lighting and outdoor area lighting from Company owned lighting facilities. Customers may either purchase electric supply from a Third Party Supplier (TPS) or from Public Service's Basic Generation Service default service as detailed in this rate schedule.

LUMINAIRE CHARGES (Monthly Charge Per Unit):

Standard Luminaires

High Pressure Sodium

Luminaire Type	Lamp Wattage	Wattage Including Ballast	PSE&G Part Number	Charge	Charge Including SUT
Cobra-Head	50	58	05-0926	$ 8.72	$ 9.30
Cobra-Head Cut-Off	50	58	05-0990	9.34	9.95
Dayform Traditionaire Type III	50	58	05-3410	24.03	25.62
Post-Top Town & Country	50	58	05-0946	8.72	9.30
Post-Top Town & Country Black Type V	50	58	05-0947	8.72	9.30
Cobra-Head	70	83	05-0927	10.76	11.47
Traditional Bollard Type V	70	83	05-3400	23.12	24.65
Capitol Type V	100	130	05-3200	26.92	28.71
Cobra-Head Cut-Off Type III	100	117	05-0991	21.03	22.43
Cobra-Head	100	117	05-0940	12.86	13.71
Dayform Traditionaire Type III	100	117	05-3412	25.73	27.44
Deluxe Acorn	100	117	05-0967	22.55	24.05
Granville Black Type III	100	117	05-6037	27.88	29.73
Post-Top Acorn	100	117	05-0963	20.93	22.31
Post-Top Town & Country	100	117	05-0948	12.98	13.84
Post-Top Town & Country Type IV	100	117	05-0949	13.73	14.64
Profiler Type III	100	117	05-4593	21.69	23.13
Architectural Type III	150	190	05-3222	25.26	26.93
Cobra-Head	150	171	05-0941	13.16	14.03
Dayform Traditionaire Type III	150	171	05-3415	21.99	23.44
Dayform Traditionaire Type V	150	171	05-3317	27.17	28.97
Deluxe Acorn	150	177	05-0968	22.55	24.05
Edison III Type III	150	177	05-3326	26.88	28.66
Floodlight	150	171	05-0722, 05-0727	16.16	17.23
Franklin Park Type IV	150	177	05-4055	27.41	29.22
Old Boston Type V	150	171	05-0995	22.06	23.52
Post-Top Acorn	150	177	05-0964	22.04	23.50
Post-Top Town & Country	150	171	05-0950	16.10	17.16
Richmond Black Type III	150	177	05-4328	27.08	28.87
Shoe-Box-Small	150	171	05-0971	18.58	19.81
Signature Type V	150	171	05-3212	27.99	29.84
Trenton Type III	150	190	05-3263	25.26	26.93
Trenton Type V	150	177	05-3268	23.84	25.42
Hagerstown Type V	150	171	05-3192	33.45	35.67
Swan – Type V	150	177	05-4103	31.33	33.41
Cobra-Head	250	300	05-0928	14.43	15.39
Cobra-Head Cut-Off	250	300	05-0993	17.63	18.80
Floodlight	250	300	05-0723, 05-0726	19.60	20.90

(Charges are for illustrative purposes only see Streetlight Appendix)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

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RATE SCHEDULE PSAL
PRIVATE STREET AND AREA LIGHTING SERVICE
(Continued)

Standard Luminaires (continued)

Luminaire Type	Lamp Wattage	Wattage Including Ballast	PSE&G Part Number	Charge	Charge Including SUT
High Pressure Sodium (cont'd)					
Shoe-Box-Large	250	300	05-0970	$ 20.79	$ 22.17
Shoe-Box-Small	250	300	05-0973	20.79	22.17
Cobra-Head	400	450	05-0925	21.32	22.73
Cobra-Head Cut-Off	400	450	05-0929	20.75	22.13
Concourse Type III	400	450	05-3018	32.77	34.94
Expressway Flood	400	450	05-1001	36.63	39.06
Floodlight	400	449	05-0724,05-0725	26.32	28.06
Galleria Type AS	400	465	05-3111	32.02	34.15
Shoe Box-Large	400	470	05-0975	24.04	25.63
Shoe-Box-Small	400	450	05-0979	23.98	25.57
Power Flood	750	839	05-0721	34.02	36.27
Induction					
Cobra-Head Type III	40	40	05-0901	11.78	12.57
Cobra-Head Type III	80	80	05-0902	13.19	14.06
Cobra-Head Type III	150	150	05-0903	18.06	19.26
Cobra-Head Type III	250	260	05-0904	21.82	23.26
Metal Halide					
Signature Black Type V	100	130	05-3215	35.14	37.47
Classic Bollard	100	130	05-3423	41.08	43.80
Granville Black Type III	100	130	05-6038	31.29	33.36
Franklin Park Type V	150	170	05-8312	34.63	36.92
Hagarstown w/Cutoff	150	190	05-8316	36.18	38.58
Tear Drop - Type III	250	280	05-8664	38.90	41.48
Floodlight	320	350	05-8003	15.45	16.47
Cobra-Head Type III	320	350	05-8018	15.66	16.70
Profiler Type III	320	350	05-8550	28.55	30.44
LED					
Floodlight	0	140	05-9900	20.95	22.34
Floodlight	129	141	05-0734	15.97	17.03
Ecoform – Type III	158	173	05-6033	26.67	28.44

Specialty Luminaires

All luminaires not listed above as Standard Luminaires and all non-standard installations of Standard Luminaires are deemed Specialty Luminaires. The Monthly Charge Per Unit for all Specialty Luminaires is equal to the sum of the Capital Recovery Charge and Maintenance Charge set forth as follows:

(1) A Capital Recovery Charge equal to the actual total installed cost times a factor equal to 2.004% (2.137% including SUT) for all Cobrahead, Floodlights and Town and Country luminaires, and 1.634% (1.742% including SUT) for all other luminaire types. Customers requesting installation of lighting facilities related to construction

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(Continued)

projects where the customer of record and responsibility for the monthly payments will be transferred to a body politic upon completion of the project may elect to contribute to the total installed cost of Specialty Luminaires. These contributions, if made, are to be in accordance with Special Provisions (d) and the Capital Recovery Charge applicable is equal to the actual total installed cost less any customer contribution (net of tax gross up) times the applicable factor indicated herein. This Capital Recovery Charge will remain unchanged over the remaining life of the luminaire.

(2) A Maintenance Charge that varies by luminaire type and size and is equal to the following:

(2-a) **Applicable To Cobra Head, Floodlights And Town And Country Luminaires:**

Lamp Type	Lamp Wattage	Charge	Charge Including SUT
High Pressure Sodium	All wattages	$ 2.67	$ 2.85
Metal Halide	50 watts and 100 watts	3.27	3.49
	175 watts	3.98	4.24
	250 watts	4.07	4.34
	400 watts	3.58	3.82
	1000 watts	6.48	6.91
Mercury Vapor	All wattages	1.53	1.63
Induction	All wattages	1.28	1.37
LED	All wattages	1.10	1.17

(2-b) **Applicable To All Other Luminaire Types:**

Lamp Type	Lamp Wattage	Charge	Charge Including SUT
High Pressure Sodium	All wattages	$ 3.34	$ 3.56
Metal Halide	50 watts and 100 watts	3.94	4.20
	175 watts	4.64	4.95
	250 watts	4.74	5.05
	400 watts	4.25	4.53
	1000 watts	7.14	7.62
Mercury Vapor	All wattages	2.19	2.34
Induction	All wattages	1.28	1.37
LED	All wattages	1.10	1.17

(Charges are for illustrative purposes only see Streetlight Appendix)

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PRIVATE STREET AND AREA LIGHTING SERVICE

(Continued)

Closed Luminaires

Luminaire Type	Lamp Wattage	Wattage including Ballast	PSE&G Part Number	Charge	Charge Including SUT
Filament					
600 Lumens NEMA Head	58	58	00-0081	$ 4.42	$ 4.71
1,000 Lumens NEMA Head	105	105	00-0083	4.63	4.94
2,500 Lumens NEMA Head	205	205	00-0084	7.04	7.50
4,000 Lumens NEMA Head	327	327	00-0085	7.87	8.39
6,000 Lumens NEMA Head	448	448	00-0086	8.15	8.69
10,000 Lumens NEMA Head	690	690	00-0087	7.94	8.47
15,000 Lumens NEMA Head	860	860	00-0088	10.93	11.65
High Pressure Sodium					
Offset Flood	250	300	05-1000	36.84	39.28
Metal Halide					
Vandal Resistant Bollard Type V	100	130	05-3409	29.07	30.99
Bishop Crook	175	210	05-0911	36.42	38.83
Hagarstown w/ Cut-Off Type V	175	210	05-4072	37.65	40.15
Hagerstown Type V	175	210	05-3197	32.22	34.35
Manor Lantern Type III	175	210	05-3615	33.39	35.60
Post Top Acorn	175	210	05-0965	22.52	24.01
Signature Type IV & Type V	175	210	05-3217	34.22	36.49
Cobra Head Cut-Off	400	460	05-0930	21.17	22.57
Floodlight	400	460	05-0728	23.37	24.91
Gray Narrow Beam Floodlight	400	460	05-0729	23.37	24.91
Profiler Type III	400	465	05-5025	33.20	35.40
Shoe-Box-Large	400	465	05-0976	24.91	26.56
Floodlight	1000	1080	05-0421	31.89	34.00
Mercury Vapor					
Cobra-Head	100	118	05-0921	6.98	7.44
Post-Top Town & Country	100	118	05-0935	6.98	7.44
Post-Top Town & Country Type IV	100	118	05-0936	6.98	7.44
Cobra-Head	175	210	05-0920	8.99	9.59
Post-Top Town & Country	175	210	05-0937	8.03	8.56
Post-Top Town & Country Type IV	175	210	05-0938	8.03	8.56
Cobra-Head	250	290	05-0919	11.20	11.94
Cobra-Head	400	432	05-0918	12.50	13.33
Floodlight	400	453	05-0422	17.68	18.85
Cobra-Head	1000	1085	05-0768	17.12	18.26
Floodlight	1000	1075	05-0420	28.67	30.57

(Charges are for illustrative purposes only see Streetlight Appendix)

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PRIVATE STREET AND AREA LIGHTING SERVICE
(Continued)

DELIVERY CHARGES:

Distribution Charge per Kilowatt-hour:

Charge	Charge Including SUT
$ 0.007355	$ 0.007842

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 72 for details of these charges.

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Non-utility Generation Charge:

This charge shall recover above market costs associated with non-utility generation and other generation related costs as may be approved by the Board. Refer to the Non-utility Generation Charge sheet of this Tariff for the current charge.

Solar Pilot Recovery Charge:

This charge is designed to recover the revenue requirements associated with the Public Service Solar Pilot Program per the Board Order in Docket No. EO07040278 less the net proceeds from the sale of associated Solar Renewable Energy Certificates (SRECs) or cash received in lieu of SRECs. Refer to the Solar Pilot Recovery Charge sheet of this tariff for the current charge.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

Tax Adjustment Credit:

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current credit.

Zero Emission Certificate Recovery Charge:

This charge provides for the recovery of costs associated with the Zero Emission Certificate Program directed by the Board of Public Utilities ("BPU" or "Board"). Refer to the Zero Emission Certificate Recovery Charge sheet of this Tariff for the current charge.

Distribution Adjustment Charge:

This charge is designed to recover Board-approved costs. Refer to the Distribution Adjustment Charge sheet of this Tariff for the current charge.

The Distribution Charge, Societal Benefits Charge, Non-utility Generation Charge, the Solar Pilot Recovery Charge, the Green Programs Recovery Charge, the Tax Adjustment Credit, the Zero Emission Certificate Recovery Charge, and the Distribution Adjustment Charge shall be combined for billing.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

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RATE SCHEDULE PSAL

PRIVATE STREET AND AREA LIGHTING SERVICE

(Continued)

ELECTRIC SUPPLY CHARGES:

A customer may choose to receive electric supply from either:

a) A TPS as described in Section 14 of this Tariff, or
b) Public Service through its Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP) default service.

Third Party Supply:

A customer that receives electric supply from a TPS will be charged for electric supply according to any agreement between the customer and the TPS. The customer will not be charged for electric supply by Public Service.

Basic Generation Service:

Customers that do not receive electric supply from a TPS will be supplied under the Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP) default service.

For unmetered lighting, the BGS Energy Charge and the BGS Reconciliation Charge, as applicable, will be applied to all kilowatt-hours billed each month. Refer to the Basic Generation Service sheets of this Tariff for the current charges applicable to Rate Schedule PSAL.

For lighting and all other associated equipment in which Public Service has determined metering is required, the electric supply charges will be charged under Rate Schedule General Lighting and Power (GLP). The determination of the need for metering shall be at the sole discretion of Public Service giving due consideration to the particular service factors at issue, as well as, whether demand and usage is not constant on a monthly basis.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

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RATE SCHEDULE PSAL

PRIVATE STREET AND AREA LIGHTING SERVICE

(Continued)

LIGHTING POLE AND MISCELLANEOUS DEVICE CHARGES (Monthly Charge Per Unit):

Only poles installed, owned and maintained by Public Service as part of the electric distribution system exclusively for the purpose of providing lighting service under Rate Schedules BPL or PSAL are designated as Lighting Poles.

Standard Lighting Poles

Pole Type	Style	Height	PSE&G Part Number	Charge	Charge Including SUT
Aluminum	Windsor Black	11.5 ft.	04-1269	$ 31.26	$ 33.33
Aluminum	Classic I Black	12 ft.	04-1280	31.79	33.90
Aluminum	Classic II	12 ft.	04-1285	30.81	32.85
Aluminum	Colonial Fluted	12 ft.	04-1260	25.18	26.85
Aluminum	Contemporary Black	12 ft.	04-0353	30.77	32.81
Aluminum	Montclair Black	12 ft.	04-1273	34.75	37.05
Aluminum	Wadsworth Black	12 ft.	04-6011	26.35	28.09
Aluminum	Westwood Black	12 ft.	04-3260	24.34	25.95
Aluminum	Classic I Black	14 ft.	04-1281	32.04	34.17
Aluminum	Classic II Black	14 ft.	04-1286	32.73	34.90
Aluminum	Colgate I Black	14 ft.	04-1262	35.55	37.90
Aluminum	Colonial Fluted Black	14 ft.	04-1261	26.29	28.03
Aluminum	Colonial Round Black	14 ft.	04-1265	26.66	28.43
Aluminum	Heritage Black	14 ft.	04-3500	32.72	34.88
Aluminum	Square 5 inch	14 ft.	04-1256	27.35	29.16
Aluminum	Square Bronze	14 ft.	04-1251	22.29	23.77
Aluminum	Wadsworth Black	14 ft.	04-6009	26.78	28.55
Aluminum	Colonial Fluted	16 ft.	04-4084	34.14	36.40
Aluminum	Contemporary Black	16 ft.	04-4073	35.55	37.90
Aluminum	Heritage Black	16 ft.	04-3501	39.53	42.15
Aluminum	Square 5 inch	20 ft.	04-1257	28.66	30.56
Aluminum	Square Bronze	20 ft.	04-1252	24.21	25.82
Aluminum	Round	25 ft.	04-1211	33.68	35.91
Aluminum	Square Bronze	25 ft.	04-1258	33.07	35.26
Aluminum	Square Green 5 inch	25 ft.	04-5025	32.25	34.39
Aluminum	Square Bronze	30 ft.	04-1250	38.96	41.54
Aluminum	Round	35 ft.	04-1230	34.17	36.43
Aluminum	Colonial Fluted	10 ft.	04-1247	19.43	20.72
Aluminum	Classic 1 Black	14.5 ft.	04-1282	35.79	38.16
Fiberglass	Smooth Tapered Black	17 ft.	04-0201	8.57	9.14
Fiberglass	Round Bronze	20 ft.	04-0203	10.67	11.38
Fiberglass	Smooth Tapered Black	20 ft.	04-0205	31.66	33.76
Fiberglass	Round Bronze	25 ft.	04-0204	12.61	13.45
Laminated Wood	Natural	25 ft.	04-0195	13.25	14.13
Laminated Wood	Laminated Wood	30 ft.	04-0225	18.64	19.88
Laminated Wood	Laminated Wood Gray	30 ft.	04-0197	21.76	23.20
Pine	Center Bored	30 ft.	04-0350	17.25	18.40
Pine	Round	30 ft.	04-0302	9.24	9.85
Pine	Round	35 ft.	04-0304	10.92	11.64
Pine	Round Class IV	40 ft.	04-0306	13.96	14.88
Pine	Round Class III	45 ft.	04-0308	16.75	17.86

(Charges are for illustrative purposes only see Streetlight Appendix)

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PRIVATE STREET AND AREA LIGHTING SERVICE
(Continued)

Specialty Lighting Poles and Miscellaneous Devices

All poles not listed above as Standard Lighting Poles, all non-standard installations of standard lighting poles, and all shrouds, brackets and other miscellaneous devices are deemed Specialty Lighting Poles and Miscellaneous Devices. The Monthly Charge Per Unit for Specialty Lighting Poles and Miscellaneous Devices is equal to the sum of the Capital Recovery Charge and Maintenance Charge set forth as follows:

(1) A Capital Recovery Charge equal to the actual total installed cost times a factor equal to 1.635% (1.743% including SUT). Customers requesting installation of lighting facilities related to construction projects where the customer of record and responsibility for the monthly payments will be transferred to a body politic upon completion of the project may elect to contribute to the total installed cost of Specialty Lighting Poles and Miscellaneous Devices.

These contributions, if made, are to be in accordance with Special Provisions (d) and the Capital Recovery Charge applicable is equal to the actual total installed cost less any customer contribution (net of tax gross up) times the applicable factor indicated herein. This Capital Recovery Charge will remain unchanged over the remaining life of the pole.

(2) A Maintenance Charge that varies by item type and is equal to the following*:

Pole and Device Type	Charge	Charge Including SUT
Pine wood pole	$ 0.50	$ 0.54
Laminated wood pole	0.00	0.00
Aluminum pole	0.00	0.00
Fiberglass pole	0.00	0.00
Shrouds, Brackets & Other Miscellaneous Devices	0.00	0.00

* Maintenance Charges for poles and devices that are not otherwise described in (2) above, shall be determined by the Company on a case by case basis.

BILLING DETERMINANTS FOR UNMETERED LIGHTING:

Kilowatt-hours:

For lighting and all other associated equipment in which demand and usage are constant on a monthly basis, estimates of kilowatts and kilowatt-hours will be utilized. The kilowatt-hour estimate is determined for each lamp by dividing total wattage including ballast by 1,000 and multiplying the result by the monthly burning hours as follows:

January	447	July	281
February	374	August	312
February (leap-year)	387	September	343
March	372	October	397
April	317	November	421
May	292	December	456
June	263		

For lighting and all other associated equipment in which demand and usage are not constant on a monthly basis, the service will be metered and billed under Rate Schedule GLP unless Public Service at its sole discretion determines otherwise.

(Charges are for illustrative purposes only see Streetlight Appendix)

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RATE SCHEDULE PSAL
PRIVATE STREET AND AREA LIGHTING SERVICE
(Continued)

Generation Obligation:

For unmetered service, the customer's Generation Obligation, in kilowatts, is determined by Public Service no less frequently than once a year. The Generation Obligation for existing customers or for new customers utilizing an existing building or premise is based upon the customer's share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM) as adjusted by PJM assigned capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions. The Generation Obligation for customers taking service in a new building or premise, as determined by Public Service, is based upon the load requirements, as estimated by Public Service, of the customer's building or premise. The Generation Obligation represents the generator capacity that PJM requires an electric supplier to have available to provide electric supply to a customer.

Transmission Obligation:

For unmetered service, the customer's Transmission Obligation, in kilowatts, is determined in a similar manner to the Generation Obligation described above. The Transmission Obligation represents the level of transmission network service that must be procured by the Customer's electric supplier from PJM to provide service to the customer.

Costs associated with the Generation and Transmission Obligations are included in the charges for Basic Generation Service and may affect the price offered by a Third Party Supplier.

Allowance for Lamp Outages:

Charges reflect an outage allowance based upon normal and abnormal operating conditions. No further allowance will be made.

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill and subject to a late payment charge at the rate of 1.416% per monthly billing period in accordance with Section 9.12 of the Standard Terms and Conditions. Service to a body politic will not be subject to a late payment charge.

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RATE SCHEDULE PSAL

PRIVATE STREET AND AREA LIGHTING SERVICE

(Continued)

TERM:

For all Standard Luminaires and Standard Lighting Poles: One year and thereafter until terminated by five days' notice, unless underground construction is utilized, where the term shall be five years and thereafter until terminated by five days' notice.

For all Specialty Luminaires and Specialty Lighting Poles and Miscellaneous Devices and all Underground Lighting Installations: Ten years and thereafter until terminated by five days' notice. Customers shall be required to make a payment for all such lighting facilities removed prior to five years from the installation date equal to the cost of removal less salvage plus 75% of the original installed costs; for facilities removed from the fifth to tenth year after installation such payment shall equal the cost of removal less salvage plus 50% of the original installed costs.

Customers who transfer from third party supply to Basic Generation Service may be subject to additional limitations regarding the term of Basic Generation Service as detailed in Section 14 of the Standard Terms and Conditions of this Tariff.

SPECIAL PROVISIONS:

(a) **Service to Customers:** Public Service will furnish and install the lamp, luminaire, bracket, pole, wiring and associated equipment, make necessary lamp renewals, otherwise maintain the installation, and repair or replace all equipment rendered inoperable due to willful or accidental damage. In the event of repeated damage to its facilities, whether willful or accidental, Public Service reserves the right to discontinue such lighting service or require the customer to be responsible for the continued cost of repair or replacement.

Lighting service will be furnished only if practicable for installation and maintenance, safe from the standpoint of Public Service, and will not be supplied where the introduction of such lighting would create an unusual hazard.

(b) **Underground Construction:** Where underground construction is desired the customer shall pay the cost of such underground construction for all conduits, conductors, manholes and handholes. In designated underground zones, up to 100 feet of underground secondary service facilities as measured at right angles to the curb to the nearest pole utilized for lighting service under this Rate Schedule shall be exempt from this provision and will be provided by Public Service at no charge.

(c) Changes in size, type or location:

(c-1) Customers may be required to make a payment toward the costs of installation, removal, relocation and/or changes in lamp size for conversion from one light source to another when the age of the luminaires to be converted is less than 20 years.

Payment shall be based on the unamortized installed cost plus the removal cost less salvage.

Customers will be required to make a payment based on actual cost of the requested work for the temporary replacement and/or relocation of an existing light to a new location and the subsequent movement of the light back to its old location.

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RATE SCHEDULE PSAL

PRIVATE STREET AND AREA LIGHTING SERVICE

(Continued)

(c-2) A request to install a new light at the same location within 12 months of the removal of an existing light will be considered a replacement of the existing light. A charge may be assessed for any lamp ordered reconnected or reinstalled when the elapsed time is less than 12 months from the request for disconnect.

(c-3) Public Service reserves the right to limit the number of lamp conversions in any year to no more than 5% of the total lamps served at the end of the previous year.

(d) **Replacement of Obsolete Equipment:** Public Service has the right to replace obsolete luminaires, poles and all other associated equipment with equivalent equipment without the consent of its customers.

(e) **Customer Contributions:** The making of a payment to Public Service shall not give the customer any interest in the facilities, the ownership being vested exclusively in Public Service.

PSAL customers requesting installation of lighting facilities related to construction projects where the customer of record and responsibility for the monthly payments will be transferred to a Body Politic upon completion of the project may elect to contribute to the total installed cost of Specialty Luminaires, Specialty Lighting Poles or Maintenance Devices in addition to that which may be required in accordance with Special Provision (b). Public Service may limit the contribution option between zero and the maximum contribution. Such contribution shall be up to a maximum of:

(e-1) The installed cost less $600.00, grossed up for income tax effects, of any luminaire with an installed cost greater than $1,200.00;

(e-2) The installed cost less $600.00, grossed up for income tax effects, of any pole with an installed cost greater than $1,200.00; or

(e-3) The installed cost, grossed up for income tax effects, of any shroud, bracket or other Miscellaneous Devices.

(f) **Unit Life:** Luminaires, poles and all other associated lighting equipment will be removed when replacement parts are required but no longer generally available. At that time the customer may elect for Public Service to install replacement equipment that will be considered as an installation of new facilities and priced at the then current applicable charges.

(g) **TPS Supply:** Customers who desire to purchase their electric supply from a TPS may request an enrollment package from Public Service that describes the process necessary for the customer to obtain a TPS for electric supply. This package will be provided to the customer at no charge by Public Service.

(g-1) The customer must contract with a TPS to arrange for deliveries to Public Service of the electric supply. A customer is limited to one TPS for electric supply for each account for which the customer receives delivery service.

(g-2) The customer’s TPS is required to notify Public Service of the customer’s selection prior to 13 days before the customer’s scheduled Public Service meter reading date for deliveries to commence on such scheduled meter reading date, and such selection shall remain in effect for the entire billing month. Customer can change TPSs effective only on the date of the customer’s scheduled Public Service meter reading date.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 214**

RATE SCHEDULE PSAL

PRIVATE STREET AND AREA LIGHTING SERVICE

(Continued)

(h) **Metered Service:** Usage based charges for lighting and all other associated equipment in which Public Service has determined metering is required will be served under Rate Schedule General Lighting and Power (GLP). Associated luminaire and maintenance charges will continue to be served under this rate schedule. The determination of the need for metering shall be at the sole discretion of Public Service giving due consideration to the particular service factors at issue, as well as, whether demand and usage is not constant on a monthly basis.

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P. L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 16 of the Standard Terms and Conditions for additional details and/or exceptions.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff.

Item	Sheet No.		Description
Table of Contents	Original Sheet Nos. 2 to 3		Updated page numbers and inserted line for proposed new Distribution Adjustment Charge
Standard Terms & Conditions	Original Sheet No. 10		Updated the address for Board of Public Utilities.
			Updated methods for application of service
	Original Sheet No. 15		§ 3.7.1. (a) – Increased threshold for waiver of deposit requirement from $3,000 to $15,000
	Original Sheet No. 18		§ 3.8. – Corrected reference to §3.2. (f)
	Original Sheet No. 22		§ 7.1. Added opt-out provision for Advanced Metering Infrastructure (AMI)
	Original Sheet No. 24		§ 8.1. Added language explaining customer liability for changes in conditions without giving prior notice to the Company
	Original Sheet No. 25		§ 8.5. Added language specifying that preventative maintenance is customer's responsibility
	Original Sheet No. 28		§ 9.4.1. Deleted Remote Reading Device service fees
			Section now pertains to Remote Meter Reading (AMI) opt-out fees for meter change and monthly meter reading
			Removed additional obsolete language
	Original Sheet No. 29		Updated pricing for Data Pulses and removed obsolete language
			Updated language regarding customer access to meter data
	Original Sheet No. 32		§ 10.1. Added language addressing provision of Drivable Surfaces for Company vehicle access
	Original Sheet Nos. 32 to 34		Updated Discontinuance of Service language to reflect N.J.A.C. 14:3-3A
	Original Sheet No. 38		§ 14.5. – Struck obsolete language regarding manual data pull from interval meters
			§ 15.2. – Struck partial language referencing qualifications for Net Metering In addition, added limitations for participating in Community Solar
	Original Sheet No. 40		§ 15.8. – Program Availability for Net Metering
Regulation for Residential Underground Extension	Original Sheet No. 48		Corrected reference to § 3.7.2.
			Corrected item numbering under § B. Additional Charges
	Original Sheet No. 50		Updates to Unit Costs of Underground Construction – Single Phase
	Original Sheet No. 51		Updates to Unit Costs of Underground Construction – Three-Phase

Item	Sheet No.		Description
			Corrections to updates to Unit Costs of Underground Construction, specifically 5-inch and 6-inch conduit Correction to size of 700 kVa three-phase transformer. Actual size is 750 kVa.
	Original Sheet No. 52		Updates to Unit Costs of Underground Construction – Three-Phase Corrections to costs listed for transformers consistent with response to S-ENG-ELEC-74
Clauses			
Distribution Adjustment Charge	Original Sheet No. 67		Added the Distribution Adjustment Charge
Third Party Supplier			
	Original Sheet No. 87		Removed mention of facsimile and hand delivery
Delivery			
Rate Schedule RS	Original Sheet No. 93 for Future		Introduction of a new time-of-use rate schedule offering customers the choice of a two-peak rate or a three-peak rate (RS-TOU)
	Original Sheet No. 94		Added the Distribution Adjustment Charge to applicable clauses
	Original Sheet No. 95		Corrected language describing Minimum Charge
	Original Sheet No. 96 for Future		(a-8) Added terms for RS-TOU Program
	Original Sheet No. 97 for Future		Removed obsolete Special Provisions and replaced with (d) Special Provision for Residential Time of Use
	Original Sheet No. 98 for Future		Removed Special Provision (e-3)
Rate Schedule RHS	Original Sheet No. 100		Added the Distribution Adjustment Charge to applicable clauses
	Original Sheet No. 101		Corrected language describing Minimum Charge
Rate Schedule RLM	Original Sheet No. 105 for Future		Proposed closing this rate schedule with implementation of RS-TOU
	Original Sheet No. 106		Added the Distribution Adjustment Charge to applicable clauses
			Corrected language describing Minimum Charge
	Original Sheet No. 108 for Future		Added (a-8) and (a-9) Limitations on Service
Rate Schedule WH	Original Sheet No. 112		Added the Distribution Adjustment Charge to applicable clauses
Rate Schedule WHS	Original Sheet No. 118		Added the Distribution Adjustment Charge to applicable clauses
Rate Schedule HS	Original Sheet No. 124		Added the Distribution Adjustment Charge to applicable clauses
Rate Schedule GLP	Original Sheet No. 130		Added the Distribution Adjustment Charge to applicable clauses
	Original Sheet Nos. 134 to 135		Added provision for municipal or state public safety unmetered service
	Original Sheet No. 137		Proposed removing the special service charge

Item	**Sheet No.**		**Description**
			for Night Use as everyone will be on AMI meters
	Original Sheet No. 140		Corrected reference to New Jersey Statutes Annotated
	Original Sheet No. 141 for Future		Removed Special Provision for Distribution Demand Charge Rebate for DCFC customers
Rate Schedule LPL	Original Sheet No. 142		Carved out DCFC customers into a separate distribution-based rate structure
	Original Sheet No. 144		Added the Distribution Adjustment Charge to applicable clauses
	Original Sheet No. 153		Corrected reference to New Jersey Statutes Annotated
	Original Sheet No. 154		Removed Special Provision for Distribution Demand Charge Rebate for DCFC customers
Rate Schedule HTS	Original Sheet No. 157		Added the Distribution Adjustment Charge to applicable clauses
Rate Schedule BPL	Original Sheet No. 184		Added the Distribution Adjustment Charge to applicable clauses
Rate Schedule BPL-POF	Original Sheet No. 197		Added the Distribution Adjustment Charge to applicable clauses
Rate Schedule PSAL	Original Sheet No. 207		Added the Distribution Adjustment Charge to applicable clauses

TARIFF

FOR

ELECTRIC SERVICE

Applicable in

Territory served as shown on

Sheet Nos. 4 through 7 of this Tariff

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

GENERAL OFFICES

80 PARK PLAZA

NEWARK, NEW JERSEY 07102

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 2**

TABLE OF CONTENTS

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 3**

TABLE OF CONTENTS
(Continued)

Rate Schedules and Payment Schedule as listed below:

Other Services:

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 4**

TERRITORY SERVED

BERGEN COUNTY

Bergenfield, Borough of
Bogota, Borough of
Carlstadt, Borough of
Cliffside Park, Borough of
Dumont, Borough of
East Rutherford, Borough of
Edgewater, Borough of
Elmwood Park, Borough of
Emerson, Borough of
Englewood, City of
Englewood Cliffs, Borough of
Fair Lawn, Borough of
Fairview, Borough of
Fort Lee, Borough of
Garfield, City of
Glen Rock, Borough of
Hackensack, City of
Hasbrouck Heights, Borough of
Haworth, Borough of
Hillsdale, Borough of
Ho-Ho-Kus, Borough of
Leonia, Borough of
Little Ferry, Borough of
Lodi, Borough of
Lyndhurst, Township of
Maywood, Borough of
Midland Park, Borough of
Moonachie, Borough of
New Milford, Borough of
North Arlington, Borough of
Oakland, Borough of
Old Tappan, Borough of
Oradell, Borough of
Palisades Park, Borough of
Paramus, Borough of
Ridgefield, Borough of
Ridgefield Park, Village of
Ridgewood, Village of
River Edge, Borough of
River Vale, Township of
Rochelle Park, Township of
Rutherford, Borough of
Saddle Brook, Township of
Saddle River, Borough of
South Hackensack, Township of
Teaneck, Township of
Tenafly, Borough of
Teterboro, Borough of
Waldwick, Borough of
Wallington, Borough of
Washington, Township of
Westwood, Borough of
Woodcliff Lake, Borough of
Wood-Ridge, Borough of
Wyckoff, Township of

BURLINGTON COUNTY

Beverly, City of
Bordentown, City of
Bordentown, Township of
Burlington, City of
Burlington, Township of
Chesterfield, Township of
Cinnaminson, Township of
Delanco, Township of
Delran, Township of
Eastampton, Township of
Edgewater Park, Township of
Evesham, Township of
Fieldsboro, Borough of
Florence, Township of
Hainesport, Township of
Lumberton, Township of
Mansfield, Township of
Maple Shade, Township of
Medford, Township of
Medford Lakes, Borough of
Moorestown, Township of
Mount Holly, Township of
Mount Laurel, Township of
Palmyra, Borough of
Pemberton, Township of

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 5**

TERRITORY SERVED
(Continued)

BURLINGTON COUNTY (continued)

Riverside, Township of
Riverton, Borough of
Southampton, Township of
Springfield, Township of
Westamptown, Township of
Willingboro, Township of

CAMDEN COUNTY

Audubon, Borough of
Audubon Park, Borough of
Barrington, Borough of
Bellmawr, Borough of
Brooklawn Borough of
Camden, City of
Cherry Hill, Township of
Collingswood, Borough of
Gloucester, City of
Gloucester, Township of
Haddon, Township of
Haddonfield, Borough of
Haddon Heights, Borough of
Hi-Nella , Borough of
Lawnside, Borough of
Magnolia, Borough of
Merchantville, Borough of
Mount Ephraim, Borough of
Oaklyn, Borough of
Pennsauken, Township of
Runnemede, Borough of
Somerdale, Borough
Tavistock, Borough of
Voorhees, Township of
Wood-Lynne, Borough of

ESSEX COUNTY

Belleville, Town of
Bloomfield, Township of
Caldwell, Borough of
Cedar Grove, Township of
East Orange, City of
Essex Fells, Borough of
Fairfield, Township of
Glen Ridge, Borough of
Irvington, Township of
Livingston, Township of
Maplewood, Township of
Montclair, Township of
Newark, City of
North Caldwell, Borough of
Nutley, Township of
Orange, City of
Roseland, Borough of
South Orange Village, Township of
Verona, Township of
West Caldwell, Township of
West Orange, Township of

GLOUCESTER COUNTY

Deptford, Township of
National Park, Borough of
Washington, Township of
West Deptford, Township of
Westville, Borough of
Woodbury, City of
Woodbury Heights, Borough of

HUDSON COUNTY

Bayonne, City of
East Newark, Borough of
Guttenberg, Town of
Harrison, Town of
Hoboken, City of
Jersey City, City of
Kearny, Town of
North Bergen, Township of
Secaucus, Town of

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 6**

TERRITORY SERVED
(Continued)

HUDSON COUNTY (continued)

Union City, City of
Weehawken, Township of
West New York, Town of

MERCER COUNTY

Ewing, Township of
Hamilton, Township of
Hopewell, Borough of
Hopewell, Township of
Lawrence, Township of
Pennington, Borough of
Princeton, Borough of
Princeton, Township of
Robbinsville, Township of
Trenton, City of
West Windsor, Township of

MIDDLESEX COUNTY

Carteret, Borough of
Cranbury, Township of
Dunellen, Borough of
East Brunswick, Township of
Edison, Township of
Highland Park, Borough of
Metuchen, Borough of
Middlesex, Borough of
New Brunswick, City of
North Brunswick, Township of
Perth Amboy, City of
Piscataway, Township of
Plainsboro, Township of
South Brunswick, Township of
South Plainfield, Borough of
Woodbridge, Township of

MONMOUTH COUNTY

Allentown, Borough of
Upper Freehold, Township of

MORRIS COUNTY

Lincoln Park, Borough of

PASSAIC COUNTY

Clifton, City of
Haledon, Borough of
Hawthorne, Borough of
Little Falls, Township of
North Haledon, Borough of
Passaic, City of
Paterson, City of
Prospect Park, Borough of
Totowa, Borough of
Wayne, Township of
Woodland Park, Borough of

SOMERSET COUNTY

Bound Brook, Borough of
Branchburg, Township of
Bridgewater, Township of
Franklin, Township of
Green Brook, Township of
Hillsborough, Township of
Manville, Borough of
Millstone, Borough of
Montgomery, Township of
North Plainfield, Borough of
Raritan, Borough of
Rocky Hill, Borough of
Somerville, Borough of
South Bound Brook, Borough of
Warren, Township of
Watchung, Borough of

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 7**

TERRITORY SERVED
(Continued)

UNION COUNTY

Clark, Township of
Cranford, Township of
Elizabeth, City of
Fanwood, Borough of
Garwood, Borough of
Hillside, Township of
Kenilworth, Borough of
Linden, City of
Mountainside, Borough of
Plainfield, City of
Rahway, City of
Roselle, Borough of
Roselle Park, Borough of
Scotch Plains, Township of
Union, Township of
Westfield, Town of
Winfield, Township of

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 8**

STANDARD TERMS AND CONDITIONS – INDEX

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 9**

STANDARD TERMS AND CONDITIONS – INDEX
(Continued)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 10**

STANDARD TERMS & CONDITIONS

1. GENERAL

These Standard Terms and Conditions, filed as a part of the Electric Tariff of Public Service Electric and Gas Company, hereinafter referred to as "Public Service," set forth the terms and conditions under which electric service will be supplied and govern all classes of service to the extent applicable, and are made a part of all agreements for the supply of electric service unless specifically modified in a particular rate schedule.

No representative of Public Service has authority to modify any provision contained in this Tariff or to bind Public Service by any promise or representation contrary thereto.

Public Service will construct, own, and maintain distribution equipment located on land, streets, highways, rights of way acquired by Public Service, and on private property, used or usable as part of the distribution system of Public Service. Payment of monthly charges, or a deposit, or a contribution shall not give the customer, Applicant or depositor any interest in the facilities, the ownership being vested exclusively in Public Service.

Publications set forth by title in sections of these Standard Terms and Conditions are incorporated in this Tariff by reference.

This tariff is subject to the lawful orders of the Board of Public Utilities of the State of New Jersey. Complaints may be directed to: Board of Public Utilities, Division of Customer Assistance, 44 South Clinton Avenue, ~~Third Floor, Suite 314,~~ P.O. Box 350, Trenton, New Jersey, 08625-0350, 1-800-624-0241; www.nj.gov/bpu.

2. OBTAINING SERVICE

2.1. Application: An application for service may be made at any of the Customer Service Centers of Public Service in person, ~~by mail,~~ or by telephone, by the Company's website at www.pseg.com, ~~or by facsimile transmission~~ or electronic mail, where available. Forms for application for service, when required, together with terms and conditions and rate schedules, will be furnished upon request. All customers shall be given a copy of the Customer Bill of Rights, effective at the time of service initiation. Customer shall state, at the time of making application for service, the conditions under which service will be required and customer may be required to sign an agreement or other form then in use by Public Service covering special circumstances for the supply of electric service. Data requested from customers may include proof of identification as well as copies of leases, deeds and corporate charters, in accordance with N.J.A.C. 14:3-3.2(e) and (f). Such information shall be considered confidential.

Public Service may reject applications for service where such service is not available or where such service might affect the supply of electricity to other customers, or for failure of customer to agree to comply with any of these Standard Terms and Conditions.

See also Section 13, Service Limitations and Section 14, Third Party Supplier Service Provisions of these Standards Terms and Conditions.

2.2. Initial Selection of Rate Schedule: Public Service will assist in the selection of the available rate schedule, which is most favorable from the standpoint of the customer. Any advice given by Public Service will necessarily be based on customer's written statements detailing the customer's proposed operating conditions.

Customer may, upon written notice to Public Service within three months after service is begun, elect to change and to receive service under any other available rate schedule. Public Service will furnish service to and bill the customer under the rate schedule so selected from the date of last scheduled meter reading, but no further change will be allowed during the next twelve months.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 11**

STANDARD TERMS AND CONDITIONS
(Continued)

2.2.1. Change of Rate Schedule: Subsequent to initial selection of a rate schedule, customer shall notify Public Service in writing of any change in the customer's use of service which might affect the selection of a rate schedule or provision within a rate schedule. Any change in schedule or provision shall be applicable, if permitted, to the next regular billing subsequent to such notification.

2.3. Deposit and Guarantee: Public Service may require a reasonable deposit as a condition of supplying service, in accordance with the provisions as set forth in Board of Public Utility regulations.

A deposit may be required from a customer equal to the average monthly charge for a twelve-month period and one month's average bill. A customer taking service for a period of less than thirty days may be required to deposit an amount equal to the estimated bill for such temporary period.

Upon closing any account, the balance of any deposit remaining after the closing bill for service has been settled, shall be returned promptly to the customer with any interest due. The customer has the option of having the deposit refund applied to the account in the form of a credit or of having the deposit refunded by separate check in a period not to exceed one full billing cycle. Deposits shall cease to bear interest upon discontinuance of service.

Public Service shall review a residential customer's account at least once every year and a non-residential customer's account at least once every 2 years. If such review indicates that the customer has established credit satisfactory to Public Service, then the outstanding deposit shall be refunded to the customer. The customer has the option of having the deposit refund applied to the account in the form of a credit or of having the deposit refunded by separate check in a period not to exceed one billing cycle.

In accordance with N.J.A.C. 14:3-3.5(d), simple interest at a rate equal to the average yields on new six-month Treasury Bills for the twelve month period ending each September 30 shall be paid by Public Service on all deposits held by it, after notification by the BPU of the new effective rate. Said rate shall be determined by the Board of Public Utilities, and shall become effective on January 1 of the following year.

Interest payments shall be made at least once during each 12-month period in which a deposit is held and Public Service shall offer the customer the option of credits on bills toward utility service rendered or to be rendered or a separate check, in accordance with N.J.A.C. 14:3-3.5(h).

A deposit is not a payment or part payment of any bill for service, except that on discontinuance of service, Public Service may apply said deposit against unpaid bills for service, and only the remaining balance of the deposit will be refunded. Public Service shall promptly read the meters and ascertain that the obligations of the customer have been fully performed before being required to return any deposit. To have service resumed, a deposit may be required, but the deposit shall not be required prior to restoration of service. Public Service shall bill the customer for the deposit and allow at least 15 days after the billing for payment of deposit, or make other reasonable arrangements.

STANDARD TERMS AND CONDITIONS
(Continued)

2.4. Permits: Public Service, where necessary, will make application for any street opening permits for installing its service connections and shall not be required to furnish service until after such permits are granted. The Applicant may be required to pay the municipal charge, if any, for permission to open the street. The Applicant shall obtain and present to Public Service, for recording or for registration, all instruments providing for easements or rights of way, and all permits (except street opening permits), consents, and certificates necessary for the introduction of service.

2.5. Selection of Lighting Options: Public Service will assist in the selection of lighting options by making recommendations for the most appropriate option based on the customer's defined illumination needs. However, responsibility for the final selection shall, at all times, rest with the customer. Any advice given by Public Service will be based on the customer's statements and by giving such advice, Public Service assumes no responsibility, nor shall it incur liability.

3. CHARGES FOR SERVICE

3.1. General: Charges for electrical usage are set forth in the rate schedules included elsewhere in this Tariff. In addition to the charges for electrical usage, Public Service may require additional monthly charges, up-front contributions or deposits (including the gross-up for income tax effects) from an Applicant for providing Temporary Services, for certain Standard or Atypical Conditions, or for an Extension.

3.2. Definitions: The following are defined terms as used in this Tariff:

a) Applicant is the individual or entity, who may or may not be the ultimate customer, requesting new, additional, temporary, or upgraded electric service from Public Service.
b) Applicant For An Extension is an Applicant where Public Service has determined that an Extension is necessary to provide service.
c) N.J.A.C. is the New Jersey Administrative Code.
d) Distribution Revenue as used in this Section 3 means the total revenue, plus related New Jersey Sales and Use Tax (SUT), charged a customer by Public Service, minus the sum of Basic Generation Service charges including SUT, and, unless included with Basic Generation Service charges, Transmission Charges, including SUT, derived from FERC approved transmission charges; all assessed in accordance with this Tariff for Electric Service.
e) Temporary Service is where service is provided through an installation for a limited period and such installation is not permanent in nature.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 13**

STANDARD TERMS AND CONDITIONS
(Continued)

f) An Extension means the construction or installation of plant and/or facilities by Public Service used to convey service from existing or new plant and/or facilities to one or more new customers, and also means the plant and/or facilities themselves. An Extension includes all Public Service plant and/or facilities used for electric transmission (non-FERC jurisdictional) and/or distribution, whether located overhead or underground, on a public street or right of way, or on private property or private right of way, and includes the conductors, poles or supports, cable, conduit, rights of way, land, site restoration, handholes, manholes, vaults, line transformers, protection devices, metering equipment and other means of conveying service from existing plant and/or facilities to each unit or structure to be served. An Extension does not include equipment solely used for administrative purposes, such as office equipment used for administering a billing system.

An Extension begins at the existing Public Service infrastructure and ends at the point of connection with the customer's facilities, but also includes the meter. Details of the requirements for Service Connections and Service Entrance Installations are provided in Sections 5 and 6 of these Standard Terms and Conditions and in the New Jersey Uniform Construction Code. The new plant and/or facilities installed constituting an Extension must be nominally physically and electrically continuous from the beginning to the end of the Extension, but also includes the meter.

Plant and/or facilities installed to supply the increased load of existing non-residential customers are also considered an Extension where either: 1) Public Service facilities of the required voltage or number of phases did not previously exist, or 2) existing Public Service facilities are upgraded or replaced due to an Applicant's new or additional electrical load being greater than 50% of the total design capacity of the pre-existing facilities.

g) Cost means, with respect to the cost of construction of an Extension, actual and/or site-specific unitized expenses incurred by Public Service for materials and labor, including both internal and external labor, employed in the actual design, purchase, construction, and/or installation of the Extension, including overhead directly attributable to the work, as well as overrides or loading factors such as those for mapping and design. This term does not include expenses for clerical, dispatching, supervision, or general office functions. Costs shall be determined by the company and shall include all costs inclusive of upgrades to existing infrastructure as well as tax gross ups, inclusive of the applicable bonus depreciation credits. Costs related to plant and/or facilities installed to serve increased load from an existing customer are determined on a similar basis.

3.3. **Removal of Public Service Facilities:** There is normally no charge for the permanent removal of above ground Public Service facilities or the abandonment in place of underground Public Service facilities where an easement for such facilities does not exist. Where an easement exists, and when approved by Public Service, and unless preempted by statute, the requesting party shall be responsible for all costs related to the removal or abandonment of requested facilities and if necessary, the installation of all new facilities necessary to provide the same level of service to all other customers.

3.4. **Temporary Service:** Where Public Service provides Temporary Service, the customer will be required to pay to Public Service the cost of the installation and removal of facilities required to furnish service. The minimum period of temporary service for billing purposes shall be one month.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 14**

STANDARD TERMS AND CONDITIONS

(Continued)

After two years of service, a Temporary Service installation shall be eligible for refunds. Excluding the first two annual service periods, refunds equal to 10% of the Distribution Revenue received by Public Service during each annual service period shall be made at the end of such period. In no case shall the total amount refunded be in excess of the installation and removal cost paid by the customer, nor shall refunds be made for more than eight consecutive annual service periods.

Temporary service will be furnished only under Rate Schedules GLP, LPL, and HTS except that it will not be supplied for cogeneration or standby purposes under any rate schedule at locations where electric service is regularly supplied from another source, nor will it be supplied under Rate Schedules BPL, BPL-POF and PSAL.

3.5. **Provision of Service:** Electric service shall be supplied in accordance with these Standard Terms and Conditions and the applicable rate schedule and shall be based upon Applicant's anticipated load and upon plant facilities that are sufficient for safe, proper, and adequate service based upon Public Service's design standards and reliability criteria. Both the Applicant's anticipated load and sufficient plant facilities will be as determined by Public Service.

3.5.1. **Standard Conditions**: Overhead construction will be utilized for all distribution lines except in certain areas designated by Public Service as underground zones where underground construction will be utilized. An area is designated as an underground zone by Public Service based upon load density, area size, building occupation and the need for multiple and/or express circuits.

3.5.2. **Atypical Conditions:** When underground distribution lines or service connections in overhead zones are required due to conditions beyond the control of Public Service, or are requested by the Applicant and approved by Public Service, or are required due to local ordinance, the added cost of such underground construction over the estimated costs of equivalent overhead construction, such total grossed up for income tax effects, shall be paid by the Applicant as a non-refundable contribution.

Public Service may require agreements for a longer term than specified in the rate schedule, may require contributions toward the investment, and may establish such Minimum Charges, Facilities Charges, distribution capacity reservation charges or other charges as may be equitable under the circumstances involved where: (1) large or special investment is either necessary for the supply of service or is requested by the Applicant; (2) oversized transformers, feeders, or other special facilities are installed to serve an Applicant using equipment in such manner that the use of electric service is intermittent, momentary or subject to violent fluctuations; (3) capacity required to serve Applicant's equipment is out of proportion to the use of electric service for occasional or low load factor purposes, or is for short durations; or (4) service characteristics requested by Applicant differ from those normally supplied for a given size and type of load as specified in the current "Information and Requirements for Electric Service".

Unless there is a material change in the provision of service, once charges are established for a premises pursuant to this Section 3.5.2, they shall be used for all subsequent customers at that premises requesting such similar service, regardless of any lapse in the provision of such similar service characteristics to that premises.

Facility Charges will be assessed on a monthly basis equal to 1.45% (1.55% including SUT) times the total installed cost of the excess facilities.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 15**

STANDARD TERMS AND CONDITIONS

(Continued)

3.6. **Extensions – General Provisions:** Where it is necessary for Public Service to construct an Extension to serve the requirements of an Applicant, Public Service may require a deposit or contribution from the Applicant to cover all or part of the cost of the Extension, which is required to be paid to Public Service prior to any work being performed. Where a large portion of the cost of construction is related to the installation of underground facilities, the costs may be increased if severe conditions, such as excessive rock or other unknown conditions, are found during excavation.

3.7. **Charges for Extensions:** Applicants requesting service may be charged a deposit for service. Such deposit will be determined by Public Service by comparing the estimated Distribution Revenue to the applicable costs of the Extension. The detailed calculations of such deposits, if any, are contained in the remainder of Section 3.7 of these Standard Terms and Conditions.

3.7.1. **Individual Residential Customer**: Where application for service is made by an Applicant for individual residential use, and the service requested is not for a limited period of less than ten (10) years, the following shall apply:

a) Excess cost is defined as the total cost of the Extension less any contribution required for Atypical Conditions less ten times the estimated average annual Distribution Revenue, such result grossed up for income tax effects. The excess cost shall not be less than zero in any case.

Any excess cost shall be deposited and remain with Public Service without interest. Public Service will waive the deposit requirement where the excess cost is $~~3,000.00~~15,000.00 or less.

b) In each annual period from the date of connection, if the actual Distribution Revenue from the customer exceeds the greater of either: (1) the estimated annual Distribution Revenue used as the basis for the initial deposit, or (2) the highest actual Distribution Revenue from any prior year, there shall be returned to the Applicant an additional amount, equal to ten times such excess multiplied by the tax gross up factor used when the deposit was taken.

c) As additional customers not originally anticipated are supplied from this Extension and Public Service still holds at least some part of the deposit from the original Applicant, a reduction may be made to such remaining deposit. The cost of the Extension or cost for Increased Load for any such additional customer will be first compared to the estimated additional Distribution Revenue as detailed in the appropriate paragraph of this Section 3. Once any deposit requirement has been satisfied, any remaining Distribution Revenue credit will be applied toward the original customer's remaining deposit in an amount equal to ten times such excess Distribution Revenue multiplied by the tax gross up factor used when the deposit was taken.

d) In no event shall more than the original deposit be returned to the Applicant nor shall any part of the deposit remaining after ten years from the date of the original deposit be returned.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

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STANDARD TERMS AND CONDITIONS

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3.7.2. Multi-unit Developments: Where application for service is made for electric service to a multi-unit residential or multi-unit non-residential development, the following shall apply:

a) The Regulations on Residential Underground Extensions, New Jersey Administrative Code 14:5-4.1 *et seq.* shall apply regarding the installation of Public Service facilities within the boundaries of such applicable developments. Such charges, referred to hereafter as B.U.D. Charges, are included elsewhere in this Tariff and shall be treated as a non-refundable contribution.

b) Excess cost for an Applicant is defined as the total cost of the Extension less any contribution required for Atypical Conditions and, if applicable, B.U.D. Charges, such result grossed up for income tax effects.

Any excess cost shall be deposited and remain with Public Service without interest. Public Service will waive the deposit requirement where the excess cost is $3,000.00 or less, or where the ten times the estimated annual Distribution Revenue is greater than the excess costs and the excess cost is less than $20,000.00.

c) As each unit is connected, as determined by the setting and activation of the Public Service electric meter, there shall be returned to the Applicant an amount equal to ten times the estimated annual Distribution Revenue from that unit multiplied by the tax gross up factor used when the deposit was taken.

d) In each annual period from the date of deposit, if for all customers receiving service for the entire prior one year period the actual annual Distribution Revenue exceeds the greater of either: (1) the estimated annual Distribution Revenue, or (2) the highest actual Distribution Revenue from any prior year, there shall be returned to the Applicant an additional amount equal to ten times such excess multiplied by the tax gross up factor used when the deposit was taken.

e) As additional customers not originally anticipated are supplied from this Extension and Public Service still holds at least some part of the deposit from the original Applicant, a reduction may be made to such remaining deposit. The cost of the Extension or cost for Increased Load for any such additional customer will be first compared to the estimated additional Distribution Revenue as detailed in the appropriate paragraph of this Section 3. Once any deposit requirement has been satisfied, any remaining Distribution Revenue credit will be applied toward the original customer's remaining deposit in an amount equal to ten times such excess Distribution Revenue multiplied by the tax gross up factor used when the deposit was taken.

f) In no event shall more than the original deposit be returned to the Applicant nor shall any part of the deposit remaining after ten years from the date of the original deposit be returned.

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3.7.3. Individual Commercial and Industrial Customers: Where application for service is made for individual non-residential use, and the service requested is not for a limited period of less than ten (10) years, the following shall apply:

a) Excess cost for an Applicant is defined as the total cost of the Extension less any contribution required for Atypical Conditions, less ten times the estimated average annual distribution revenue, such result grossed up for income tax effects. The excess cost shall not be less than zero in any case.

Any excess cost shall be deposited and remain with Public Service without interest. Public Service will waive the deposit requirement where the excess cost is $3,000.00 or less, or where ten times the estimated annual Distribution Revenue is greater than the excess costs and the excess cost is less than $20,000.00.

b) As the Public Service electric meter is set, there shall be returned to the Applicant an amount equal to ten (10) times the estimated average annual Distribution revenue multiplied by the tax gross up factor used when the deposit was taken.

c) In each annual period from the date of deposit, if the actual Distribution Revenue from the customer exceeds the greater of: (1) the estimated annual Distribution Revenue used as the basis for the initial deposit computation, or (2) the highest actual Distribution Revenue from any prior year; there shall be returned to the Applicant an additional amount, equal to ten times such excess multiplied by the tax gross up factor used when the deposit was taken.

d) As additional customers not originally anticipated are supplied from this Extension and Public Service still holds at least some part of the deposit from the original Applicant, a reduction may be made to such remaining deposit. The cost of the Extension or cost for Increased Load for any such additional customer will be first compared to the estimated additional Distribution Revenue as detailed in the appropriate paragraph of this Section 3. Once any deposit requirement has been satisfied, any remaining Distribution Revenue credit will be applied toward the original customer's remaining deposit in an amount equal to ten times such excess Distribution Revenue multiplied by the tax gross up factor used when the deposit was taken.

e) In no event shall more than the original deposit be returned to the Applicant nor shall any part of the original deposit remaining after ten years from the date of the original deposit be returned.

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3.8. **Charges for Increased Load:** When it is necessary for Public Service to construct, upgrade, or install facilities necessary to service the additional requirements of existing customers and these facilities do not meet the definition of an Extension as defined in Section 3.2. (~~h~~f) of these Standard Terms and Conditions, the following shall apply:

a) Public Service may require a deposit from the customer to cover all or part of the investment necessary to supply service. Any such deposit will be calculated by comparing the estimated annual increase in Distribution Revenue as determined by Public Service to the total cost of the applicable work to determine if excess costs exist.

b) Excess cost is defined as the total cost of the applicable work less any contribution required for Atypical Conditions less the ten times the estimated average annual increase in Distribution Revenue, such result grossed up for income tax effects. The excess cost shall not be less than zero in any case.

c) Any excess cost shall be deposited and remain with Public Service without interest. Public Service will waive the deposit requirement where the excess cost is $3,000.00 or less.

d) In each annual period from the date of connection of such additional load, if the actual increase in Distribution Revenue from the customer exceeds the greater of either: (1) the estimated annual increase in Distribution Revenue used as the basis for the initial deposit computation, or (2) the highest increase in actual Distribution Revenue from any prior year, there shall be returned to the Applicant an additional amount, equal to ten times such excess multiplied by the tax gross up factor used when the deposit was taken.

e) In no event shall more than the original deposit be returned to the Applicant nor shall any part of the deposit remaining after ten years from the date of the original deposit be returned.

4. CHARACTERISTICS OF SERVICE

4.1. **General:** The standard service supply of Public Service is alternating current with a nominal frequency of 60 hertz (cycles per second). All types of service listed below are not available at all locations, and service from the primary distribution, subtransmission, transmission or high voltage system may be specified under special conditions, such as location, size, or type of load. The customer shall ascertain and comply with the service characteristics requirements of Public Service which are covered in detail in “Information and Requirements for Electric Service,” issued by Public Service and available on request.

Public Service must always be consulted to determine the type of service to be supplied to a particular installation. The type of service may govern the characteristics of equipment to be connected.

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4.2. **Types of Service:** Subject to the restrictions in Section 4.1, the types of service available, with their nominal voltages are:

Type of Service		Volts
Secondary Distribution Service	Single-phase, two-wire	120
	Single-phase, three wire	120/240
	Single-phase, three-wire	120/208
	Three-phase, three-wire	240
	Three-phase, four wire	120/240
	Three-phase, four wire	120/208
	Three-phase, four-wire	277/480
Primary Distribution Service	Three-phase, four wire	2,400/4,160
	Three-phase, four-wire	13,200
Subtransmission Service:	Three-phase, three-wire	26,400
	Three-phase, three-wire	69,000
High Voltage Service:	Three-phase, three-wire	138,000
	Three-phase, three-wire	230,000
Transmission Service	Three-phase, three-wire	69,000

4.3. **Losses:** Nominal electric losses and unaccounted for percentages:

Type of Service	Losses
Secondary Distribution Service:	5.8327%
Primary Distribution Service:	3.3153%
Subtransmission Service:	2.0472%
Transmission High Voltage Service:	0.8605%

5. SERVICE CONNECTIONS

5.1. **General:** The customer shall consult Public Service before starting work, to determine the type of service facilities involved, the exact location of the point of connection between customer's service entrance and Public Service's facilities and the construction to be installed by each.

Electric service will be supplied to each building or premises through a single service connection unless otherwise agreed in accordance with the detailed requirements of "Information and Requirements for Electric Service," Section 3.

Whenever conductors are required under or within a building to provide a continuous service run to the customer's entrance equipment, they shall be installed by Public Service at the expense of the customer.

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Where a customer is provided Subtransmission, Transmission or High Voltage Service, the customer's high side bus shall be considered part of the Public Service distribution system for operational purposes with no remuneration to the customer by Public Service.

5.2. **Overhead Service:** For overhead service in overhead zones, Public Service will furnish, install, and maintain the overhead service facilities to the point of connection to the customer's facilities. A deposit or non-refundable contribution may be required as provided in Section 3 of these Standard Terms and Conditions.

5.3. **Underground Service in Underground Zone:** For underground service in underground zones, Public Service will furnish, install, and maintain the underground service facilities to the point of connection to customer's facilities. A deposit or non-refundable contribution may be required as provided in Section 3 of these Standard Terms and Conditions.

5.4. **Underground Service in Overhead Zone:**

5.4.1. **Secondary Distribution Service**: Where underground service in an overhead zone is to be supplied, and secondary voltage supply from overhead facilities is inadequate for the size of customer's load, the customer shall furnish and install at its expense and in accordance with the specifications of Public Service the primary conduits and any necessary manholes, which will be maintained by Public Service. The customer shall also be required to furnish, install, and maintain all secondary conduits and conductors and provide space on its property for necessary transformation.

Where underground service in an overhead zone is to be supplied, and secondary voltage supply from overhead facilities is adequate for the size of customer's load, such service will be supplied under the following conditions:

At Request of Customer: The customer shall furnish and install the service facilities at its expense and in accordance with the specifications of Public Service. Public Service will connect the service conductors and maintain the service facilities without charge to the customer.

Operating Reasons Beyond the Control of Public Service: The customer shall furnish and install at its expense and in accordance with the specifications of Public Service the service conduit which will be maintained by Public Service. Public Service will furnish, install, and maintain the service conductors to the point of connection to customer's facilities.

5.4.2. **Primary Distribution Service:** Where underground service in an overhead zone is to be supplied, and primary voltage supply is required because of the size of the customer's load, such service will be supplied under the following condition:

At Request of Customer or for Operating Reasons Beyond the Control of Public Service: The customer shall furnish and install at its expense and in accordance with the specifications of Public Service the service conduit and any necessary manholes which will be maintained by Public Service. Public Service will furnish, install, and maintain the service conductors to the point of connection to customer's facilities.

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5.4.3. **Subtransmission Service:** Where underground service in an overhead zone is to be supplied, and subtransmission voltage supply is required because of the size of customer's load, such service will be supplied under the following condition:

At Request of Customer or for Operating Reasons Beyond the Control of Public Service: The customer shall furnish and install at its expense and in accordance with the specifications of Public Service, the service conduit and any necessary manholes which will be maintained by Public Service. Public Service will furnish, install, and maintain the service conductors to the point of connection to customer's facilities.

5.5. **Change in Location of Existing Service Line:** Any change requested by the customer in the location of the existing service line, if approved by Public Service, will be made at the expense of the customer. A request to install facilities for the same building within 12 months of the removal of similar facilities may be considered a relocation of the existing facilities if the load served is similar or lower and the building served is essentially the same.

6. SERVICE ENTRANCE INSTALLATIONS

6.1. **General:** The customer is required to furnish, install, and maintain the service entrance wiring and equipment on the customer's premises with the exception of transformers and network protectors for secondary service, and meters and metering equipment as enumerated in detail in the following paragraphs. All materials and equipment used shall be of a type approved by Public Service and must be installed according to the requirements of governmental authorities, Public Service, and the current edition of the National Electrical Code. The location of the service entrance installation must be designated by Public Service.

6.2. **Seals:** Public Service will seal or lock all meters and enclosures containing meters and associated metering equipment, service entrance interrupting devices acceptable to Public Service, or unmetered wiring. No person except a duly authorized employee of Public Service is permitted to break or remove a Public Service seal or lock.

6.3. **Secondary Distribution Service:** For new installations to be metered at voltages not exceeding 600 volts, meter-mounting equipment and, where required, current transformers, potential transformers, time switches, and associated unmetered wiring will be furnished without charge to the contractor, or may be furnished by the contractor at its expense if approved by Public Service. The contractor will install and wire this equipment as part of its contract with the customer. Public Service will furnish and install the meter.

For large secondary installations, the customer may be required to furnish a vault or space for a transformer mat, pad, manhole, or vault.

The customer shall ascertain and comply with the general requirements of Public Service for secondary installations, which are covered in detail in "Information and Requirements for Electric Service," issued by Public Service and available on request.

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6.4. Primary Distribution, Subtransmission, Transmission or High Voltage Service: For new installations to be metered at voltages exceeding 600 volts, meter-mounting equipment, current transformers, potential transformers, test switches, time switches, and associated unmetered wiring will be furnished without charge to the contractor, or may be furnished by the contractor at its expense if approved by Public Service. The contractor will install and wire this equipment as part of its contract with the customer. Public Service will furnish and install the meter.

Where service is received at primary distribution, subtransmission, transmission or high voltage entrance voltages, customer must furnish, install and maintain a service entrance interrupting device acceptable to Public Service and, where necessary, transformers and appurtenances.

The customer shall ascertain and comply with the general requirements of Public Service for primary distribution, subtransmission, transmission or high voltage service installations, which are covered in detail in "Information and Requirements for Electric Service," issued by Public Service and available on request.

Where subtransmission, transmission or high voltage service is supplied, it is necessary that the switching operations be controlled by Public Service; therefore, customer shall agree to abide by the operating instructions issued to customer by Public Service.

7. METERS AND OTHER EQUIPMENT

7.1. General: The installation of meters and connections shall be in accordance with N.J.A.C. 14:3-4.2.

Public Service will select the type and make of metering and its other equipment, and may, from time to time, change or alter such equipment; its sole obligation is to supply metering that will furnish accurate and adequate records for billing purposes.

Electric service normally will be supplied to each building or premises at a single metering point, by one watthour meter equipped, where necessary, with demand and recording devices. Additional meters will be installed (1) where, in the judgment of Public Service, the operating characteristics of its system require the installation of more than one meter, or (2) at the customer's request provided that the service measured by each meter shall be billed separately at an applicable rate schedule.

No person except a duly authorized employee or agent of Public Service is permitted to alter or change a meter or its connection.

When requested by a customer, equipment to provide ~~remote meter reading,~~ data pulses and/or advanced interval meter access may be installed, if feasible, at the expense of the customer. The payment shall not give the customer any interest in the equipment thus installed, the ownership being vested exclusively in Public Service.

A customer may choose to opt-out of remote meter reading and request a conventional meter and will be charged additional fees as detailed in Section 9.4.1.

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7.2. **Other Devices:** No branch circuits or devices are permitted on the supply side of the meter, except those for Police Recall or Fire Alarm System Service as provided in this Tariff.

Public Service will not permit the connection of the customer's ammeters, voltmeters, pilot lamps, or any other energy-using devices to the instrument transformers used in conjunction with its meter.

7.3. **Protection of Meters and Other Equipment:** Customer shall provide for the safekeeping of the meter and other equipment of Public Service, and shall not tamper with or remove such meter or other equipment, nor permit access thereto except by duly authorized employees or agents of Public Service. In case of loss or damage to the property of Public Service from the act or negligence of the customer or its agents or servants, or of failure to return equipment supplied by Public Service, customer shall pay to Public Service the amount of such loss or damage to the property. All equipment furnished at the expense of Public Service shall remain its property and may be replaced whenever deemed necessary and may be removed by it at any reasonable time after the discontinuance of service. In the case of defective service, the customer shall not interfere or tamper with the apparatus belonging to Public Service but shall immediately notify Public Service to have the defects remedied.

7.4. **Tampering:** In the event it is established that Public Service meters or other equipment on the customer's premises have been tampered with, and, such tampering results in incorrect measurement of the service supplied, the charges for such electric service under the applicable rate schedule including Basic Generation Service default service, exclusive of any reduction in charges for third party supplied electric services, based upon the Public Service estimate from available data and not registered by Public Service meters shall be paid by the beneficiary of such service. In the case of a residential customer, such unpaid service shall be limited to not more than one year prior to the date of correcting the tampered account and for no more than the unpaid service under the applicable rate schedule, exclusive of any reduction in charges for third party supplied electric services, alleged to be used by such customer. The beneficiary shall be the customer or other party who benefits from such tampering. The actual cost of investigation, inspection, and determination of such tampering, and other costs, such as but not limited to, the installation of protective equipment, legal fees, and other costs related to the administrative, civil or criminal proceedings, shall be billed to the responsible party. The responsible party shall be the party who either tampered with or caused the tampering with a meter or other equipment or knowingly received the benefit of tampering by or caused by another. In the event a residential customer unknowingly received the benefit of meter or equipment tampering, Public Service shall only seek from the benefiting customer the cost of the service provided under the applicable rate schedule including Basic Generation Service default service, exclusive of any reduction in charges for third party supplied electric services, but not the cost of investigation.

These provisions are subject to the customer's right to pursue a bill dispute proceeding pursuant to N.J.A.C. 14:3-7.6.

Tampering with Public Service facilities may be punishable by fine and/or imprisonment under the New Jersey Code of Criminal Justice.

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8. CUSTOMER'S INSTALLATION

8.1. **General:** Public Service makes no new electric installations on the customer's premises other than the installation of its services, meters and other equipment as set forth in these Standard Terms and Conditions except to continue a service run, a portion of which is installed under or within a building at the customer's expense. Public Service will assume no responsibility for the condition of customer's electric installation or for accidents, fires, or failures which may occur as the result of the condition of such electric installation. No material change in the size, total electrical capacity, or method of operation of customer's equipment shall be made without previous written notice to Public Service.

Failure of the Customer to give prior notice of changes in conditions as described above shall render the Customer responsible and liable for any personal injury and any property damage caused by the changed conditions, including damage to the Company's property and injury to its employees.

8.2. **Wiring:** Wiring installed on the customer's premises must conform to all requirements of governmental authorities and to the regulations set forth in the current edition of the National Electrical Code.

8.3. **Inspection and Acceptance:** The customer's service entrance installation must be inspected and approved by Public Service before service will be supplied. Public Service may refuse to connect with any customer's installation or make additions or alterations to the service connection when it is not in accordance with the National Electrical Code and with these Standard Terms and Conditions, and where a certificate approving the customer's electrical installation has not been issued by a county or a municipality or by any other organization authorized to perform such functions and services as may be designated and approved by the Board of Public Utilities. Information regarding the above inspection service is detailed in "Information and Requirements for Electric Service," issued by Public Service and available on request.

8.4. **Customer On-Site Generation:**

8.4.1. **General:** Electric service from a customer's on-site generation facility, or from sources other than that delivered by Public Service's system shall not be used for the operation of customer's electrical equipment without previous written notice to Public Service. The requirements in this Section 8.4.1 do not apply when the on-site generation facility is used exclusively as an emergency source of power during Public Service electric delivery service interruptions.

8.4.2. **Parallel Operation:** Customer may operate on-site generation facility in parallel with the service delivered by Public Service only with previous written notice to Public Service and written Public Service approval**,** and must conform with all applicable interconnection standards.

Public Service may re-energize the Public Service delivery service following an interruption without prior notice to the customer.

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8.5. **Maintenance of Customer's Installation:** Customer's entire electrical installation shall be maintained in the condition required by the electrical inspection agency having jurisdiction and by Public Service, and all repairs shall be made by the customer at their expense. Preventative and corrective maintenance on customer owned equipment is the responsibility of the customer. Further, customer electrical equipment under the operational control of Public Service shall be subject to Public Service's inspection and where necessary Public Service will advise the customer to make necessary repairs at customer expense. In the event PSE&G provides assistance in repairs or maintenance activities, customers will be responsible for those costs. If the customer fails to make the necessary repairs in a timely manner, then Public Service will have the repairs made and bill the customer.

8.6. **Electrical Equipment and Appliances:** Motors, welders, and other electrical equipment and appliances shall be so wired, connected, and operated as to produce no disturbing effects on the Public Service electrical system which will affect the adequacy or quality of service to other customers.

Where the use of electric service is to be intermittent, occasional or momentary, or subject to violent fluctuations, or for low load factor purposes or for short durations equipment shall not be connected without previous written notice to Public Service.

8.7. **Power Factor:** The average power factor under operating conditions of customer's load at the point where the electric service is metered shall not be less than 85%. Public Service may inspect customer's installed equipment and may place instruments for test purposes at its own expense on the premises of the customer.

Where neon, fluorescent, or other types of lighting or sign equipment having similar low power factor characteristics are installed or moved to a new location, the customer shall furnish, install, and maintain at its own expense corrective apparatus which will increase the power factor of the individual units or the entire lighting installation to not less than 90%.

8.8. **Liability for Customer's Installation:** Public Service will not be liable for damages or for injuries sustained by customers or others or by the equipment of customers or others by reason of the condition or character of customer's facilities or the equipment of others on customer's premises. Public Service will not be liable for the use, care or handling of the electric service delivered to the customer after same passes beyond the point at which the service facilities of Public Service connect to the customer's facilities.

8.9. **Replacement of Customer Owned Equipment Due to System Upgrades:** If customer owned communication equipment, such as relays, requires replacement in order to be compatible with PSE&G's system due to upgrade work being performed by PSE&G, the Company will provide the replacement at no cost to the Customer. Any equipment replaced by PSE&G under this section shall be owned by PSE&G. In all other circumstances including customer requirements or obsolescence, the equipment will be replaced at their expense and in accordance with other sections of this tariff.

9. METER READING AND BILLING

9.1. **Measurement of Electric Service:** Public Service will select the type and make of metering equipment and may, from time to time, change or alter such equipment; its sole obligation is to supply meters that will accurately and adequately furnish records for billing purposes.

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Where more than one meter is furnished and installed for Public Service operating reasons, as set forth in Section 7.1 of these Standard Terms and Conditions, the kilowatt-hour use measured by the meters will be combined for billing purposes at an applicable rate schedule selected by the customer.

When demand is measured, the customer's monthly maximum demand shall be the sum of the maximum kilowatt demands, determined in accordance with the provisions of the selected rate schedule, as recorded by the individual meters.

Where more than one meter is furnished and installed at the request of the customer, kilowatt-hour use and kilowatt demand measured by each meter will be billed separately at an applicable rate schedule selected by the customer.

Bills will be based upon registration of Public Service meters, except as otherwise provided for in this tariff.

The customer's Generation Obligation, in kilowatts, is determined by Public Service no less frequently than once a year. The Generation Obligation for existing customers or for new customers utilizing an existing building or premises is based upon the customer's share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM) as adjusted by PJM assigned capacity related factors. The Generation Obligation for customers taking service in a new facility, as determined by Public Service, is based upon the load requirements, as estimated by Public Service, of the customer's building or premises. More specifically the customer's Generation Obligation is established based upon the following: 1) an estimate of the customer's peak demand, based upon the load shape of a representative sample of customers served under the same rate schedule, in conjunction with the actual or estimated, as applicable, summer energy use of that customer, or on the customer's actual or estimated, as applicable, summer peak demand, depending upon the type of metering equipment installed by Public Service, and 2) the aforementioned PJM assigned capacity related factors which are established no less frequently than once a year.

The customer's Transmission Obligation, in kilowatts, is determined in a similar manner to the Generation Obligation described above.

9.2. Metering on Customer's Premises:

9.2.1. General: The service and supply of electrical energy by Public Service for the use of owners, landlords, tenants or occupants of newly constructed or renovated residential units will be furnished to them as customers of Public Service through Public Service individual meters.

The service and supply of electrical energy by Public Service to owners, landlords, tenants or occupants of industrial or commercial buildings or residential premises as noted below in Section 9.2.2 and not limited by the above paragraph may be further distributed to other users within such structures and such use and resultant charges, including reasonable administrative costs apportioned to such users. However, such charges shall not exceed the amount that Public Service would charge if the tenant were served and billed directly by Public Service on the most appropriate rate schedule. In no event will a customer buying electric service from Public Service be permitted to resell it for a profit.

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9.2.2. **Sub-Metering:** The practice where a customer of Public Service or a customer of record, through the use of direct metering devices, installed, maintained and operated at such customer's expense, monitors, evaluates or measures their own consumption of electrical energy or the consumption of a tenant for accounting or conservations purposes.

Sub-metering will be permitted in new or existing buildings or premises where the basic characteristic of use is industrial or commercial. Sub-metering will not be permitted in new or existing buildings or premises where the basic characteristic of use is residential, except where such buildings or premises are publicly financed or government owned; or are condominiums or cooperative housing; or are eleemosynary in nature. In the case of dwelling units, all electric consuming devices must be metered through a single sub-meter.

Sub-metering for the aforementioned purposes and applications shall not adversely affect the ability of Public Service to render service to any customer within the affected building or premises or any other customer. The ownership of all sub-metering devices is that of the customer, along with all incidents in connection with said ownership, including accuracy of the equipment, meter reading and billing, liability arising from the presence of the equipment and the maintenance and repair of the equipment. Any additional costs which may result from and are attributable to the installation of sub-metering devices shall be borne by the customer.

The customer shall be responsible for the accuracy of sub-metering equipment. In the event of a dispute involving such accuracy, the Public Service meter will be presumed correct, subject to test results.

9.3. **Testing of Meters:** At such times as Public Service may deem proper, or as the Board of Public Utilities may require, Public Service will test its meters in accordance with the standards and bases prescribed by the Board of Public Utilities.

Public Service shall, without charge, make a test of the accuracy of a meter(s) upon request of the customer, provided such customer does not make a request for test more frequently than once in 12 months. A report giving results of such tests shall be made to the customer, and a complete record of such tests shall be kept on file at the office of Public Service in conformance with the New Jersey Administrative Code.

9.4. **Metering Options:** The following optional metering services are available to customers and are subject to the charges as indicated in the following subsections:

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~~**9.4.1. Remote Reading Devices:** Public Service will install and maintain the necessary equipment to provide remote meter reading at the customer's request, at the applicable charges listed below. Customers requesting this service are subject to a minimum term of one year. This service is not available to customers with an interval meter installed.~~

~~Type of Service~~	~~Set-Up Charges~~	~~Set-Up Charges Including SUT~~	~~Monthly Charge~~
~~Single Phase~~	~~$ 110.00~~	~~$ 117.29~~	~~$ 1.00~~
~~Three Phase~~	~~190.00~~	~~202.59~~	~~2.00~~

9.4.~~2~~1. ~~Interval Metering~~Remote Meter Reading (AMI): In addition to the terms specified in Section 9, Meter Reading and Billing, of these Standard Terms and Conditions, Public Service currently provides remote capable AMI meters as the standard equipment. For residential customers only, a non-communicating meter can be installed at the customer's expense.

In the event the customer chooses not to have an interval meter/advanced meter installed on their premises, the following fees shall apply.~~interval meters to support billing and/or measurement of certain rate schedules and/or Special Provisions. For all other customers interval meters can be supplied, at the customer's option, at the applicable charges listed below. Customers requesting this service are subject to a minimum term of one year.~~

Type of Service	Set-Up Charge~~s~~	~~Set-Up~~ Charge~~s~~ Including SUT	Monthly Charge	Monthly Charge Including SUT
Meter Change (residential only)~~Single Phase~~	$45.00 ~~$ 450.00~~	$47.98 ~~$ 479.81~~	~~$ 31.00~~	
Monthly meter reading fee~~Three Phase~~	~~530.00~~	~~565.11~~	$12.00 ~~32.00~~	$12.79

~~If a customer elects to install its own telecommunications to support the interval meter(s), the installation is to be performed in accordance with Public Service's Standards for Telecommunications for Interval Meters, a copy of which is available upon request. If the customer elects to install its own telecommunications, the customer will be responsible for all monthly telephone charges. If the customer requests that Public Service provide the dedicated telephone line, Public Service may utilize an independent third party to install the telephone line and will bill the customer for the actual cost of the installation, which is in addition to the Set-Up Charges indicated above, as well as the actual monthly communications charges. The Set-Up Charge and telephone installation charge, if applicable, will be billed upon completion of the installation of the interval metering device and telecommunications (if applicable). The Monthly Charge, applied in accordance with Section 9, Meter Reading and Billing, shall commence on the date the meter is installed and will be included in the customer's regularly scheduled monthly Public Service bill.~~

~~If the telecommunications provided by a customer to an interval meter is not operable at the time of a monthly meter reading date, Public Service will notify the customer and manually obtain the data from the interval meter. If such a condition occurs for two consecutive meter reading dates, Public Service may charge the customer for the cost to manually obtain the interval data for the subsequent months' meter readings (after the second consecutive month) until the problem is remedied. The charge to provide this manual data collection is $50.00 ($53.31 including SUT) per month. If the customer does~~

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~~not remedy the telecommunications problem after four (4) consecutive meter reading dates, and the customer purchases its energy from a Third Party Supplier, Public Service, at its discretion, reserves the right to use load profile information for retail settlement until the telecommunication problem is remedied.~~

~~Customers that had an interval electric meter installed at their premises at Public Service expense and the meter is no longer required by Public Service for operating and billing purposes may choose to retain the installed meter. Customers that choose to retain the installed interval meter will be billed the Monthly Charge plus the telecommunications charge.~~

9.4.~~3~~2. Customer Access to Meter Data:

a) **Data Pulses:** Public Service will install and maintain the necessary equipment to supply data pulses for the customer's use at the customer's request, in accordance with the applicable charges listed below. Customers requesting these services are subject to a minimum term of one year.

Type of Service	Set-Up Charges	Set-Up Charges Including SUT	Monthly Charge
Single Phase	$ ~~80.00~~ 364.52	$ ~~85.30~~ 388.67	$ 1.00
Three Phase	~~280.00~~ 364.52	~~298.55~~ 388.67	2.00
Three Phase – time and data pulses	410.00	437.16	3.00

~~b) **Real Time Interval Meter Access:** Where Public Service has installed an interval meter, Public Service will maintain the necessary equipment to provide remote real time access to interval electric meter data at the customer's request. Customers requesting these services are subject to a minimum term of one year. The charges for this service shall include a set-up charge of $620.00 per meter ($661.08 including SUT), and a monthly charge of $32.00 per meter per month.~~

~~c) **Access to Historical Interval Usage Data**: Where Public Service has an interval meter installed, twelve months of historical interval usage, where available, will be provided upon request of the customer. The historical interval usage data will be provided based upon the measurement interval of the installed meter, and will be sent to the customer in an electronic format. The cost per meter, per request is $40.00.~~

b) **Access to Historical Interval Usage Data:** Where Public Service has an interval meter installed, Public Service will provide Internet access to customer historical interval usage data on a next-day basis through the customer account portal, including Green Button download.~~for those customers who request such service. The charges for this service shall include a set-up charge of $80.00 per meter, and a monthly charge of $17.00 per meter per month. Customer will be required to sign an Agreement for this service.~~

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9.5. **Billing Adjustments:** Whenever a meter is found to be registering fast by 2% or more, an adjustment of charges shall be made. When a meter is found to be registering slow by more than 2%, an adjustment of charges may be made in the case of meter tampering, non-register meters, or in circumstances in which a customer, other than RS, RHS or RLM, should reasonably have known that the bill did not accurately reflect the usage. Billing adjustments will be made in accordance with N.J.A.C. 14:3-4.6.

9.6. **Meter Reading and Billing Period:** All charges are stated on a monthly basis. The term "month" for billing purposes shall mean the period between any two consecutive regularly scheduled meter readings. Meter reading schedules provide for reading meters, in accordance with their geographic location, as nearly as may be practicable every thirty days. Schedules are prepared in advance by Public Service and are available for inspection.

9.7. **Proration of Monthly Charges:** For all billings for service, including initial bills, final bills, and bills for periods other than twenty-five to thirty-six days inclusive, except for temporary service accounts, the monthly charges will be prorated based on the number of days in the billing month. For temporary service accounts, the minimum period for billing purposes shall be one month.

9.8. **Averaged Bills:** Where Public Service is unable to read the meter, Public Service may estimate the amount of electric service supplied and submit an averaged bill, so marked, for customer's acceptance. Adjustments for averaged bills shall be made in accordance with N.J.A.C. 14:3-7.2. Adjustment of such customer's averaged use to actual use will be made after an actual meter reading is obtained.

Public Service reserves the right to discontinue electric service when a meter reading is not obtained for eight (8) consecutive billing periods (monthly accounts), and after written notice is sent to a customer on the fifth and seventh months explaining that a meter reading must be obtained. Public Service will take all reasonable means to obtain a meter reading during normal working hours, evening hours, or Saturdays before discontinuing service. After all reasonable means to obtain a meter reading have been exhausted, Public Service may discontinue service provided at least eight months have passed since the last meter reading was obtained, the Board of Public Utilities has been so notified and the customer has been properly notified by prior mailing.

9.9. **Budget Plan (Equal Payment Plan):** Customers billed under Rate Schedules RS or RHS or GLP (where GLP electric service is used for residential purposes in buildings of four or fewer units) shall have the option of paying for their Public Service charges in equal, estimated monthly installments. Budget plans for residential accounts shall be made in accordance with N.J.A.C. 14:3-7.5. The total Public Service charges for a twelve-month period will be averaged over twelve months and may be paid in twelve equal monthly installments. A review between the actual cost of service and the monthly budget amount will be made at least once in the budget plan year. A final bill for a budget plan year shall be issued at the end of the budget plan year and shall contain that month's monthly budget amount plus any adjustments will be made if actual charges are more or less than the budget amount billed.

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9.10. Billing of Charges in Tariff: Unless otherwise ordered by the Board of Public Utilities, the charges and the classification of service set forth in this Tariff or in amendments hereof shall apply to the first month's billing of service in the regular course on and after the effective date set forth in such Tariff covering the use of electric service subsequent to the scheduled meter reading date for the immediately preceding month.

9.11. Payment of Bills: At least 15 days time for payment shall be allowed after sending a bill. Bills are payable at any Customer Service Center of Public Service, or by mail, or to any collector or collection agency duly authorized by Public Service. Whenever a residential customer advises Public Service that the customer wishes to discuss a deferred payment agreement because the customer is presently unable to pay a total outstanding bill and/or deposit, Public Service will make a good-faith effort to allow a customer the opportunity to enter into a fair and reasonable deferred payment agreement, which takes into consideration the customer's financial situation. A residential electric or gas customer is not required to pay, as a down payment, more than 25% of the total outstanding bill due at the time of the agreement. Such agreements which extend more than 2 months must be in writing and shall provide that a customer who is presently unable to pay an outstanding debt for Public Service services may make reasonable periodic payments until the debt is liquidated, while continuing payment of current bills. While a deferred payment agreement for each separate service need not be entered into more than once a year, Public Service may offer more than one such agreement in a year. If the customer defaults on any of the terms of the agreement, Public Service may discontinue service after providing the customer with a notice of discontinuance. If a customer's service has been terminated for non-payment of bills, and has met all requirements for restoration of service, Public Service may require a deposit, but not prior to service restoration. Instead, Public Service will bill payment of the deposit, or make other reasonable arrangements. The amount of the deposit required for restoration of service will be determined in accordance with N.J.A.C. 14:3-3.4.

In the case of a residential customer who receives more than one utility service from Public Service and has entered into a separate agreement for each separate service, default on one such agreement shall constitute grounds for discontinuance of only that service.

9.12. Late Payment Charge: A late payment charge at the rate of 1.416% per monthly billing period shall be applied to the accounts of customers taking service under all rate schedules contained herein except for Rate Schedules RS, RHS, RLM, WH, WHS, BPL and BPL-POF. Service to a body politic will not be subject to a late payment charge. The charge will be applied to all amounts billed including accounts payable and unpaid finance charges applied to previous bills, and will not be applied sooner than 25 days after a bill is rendered, in accordance with N.J.A.C. 14:3-7.1(e). The amount of the finance charge to be added to the unpaid balance shall be calculated by multiplying the unpaid balance by the late payment charge rate. When payment is received by the Company from a customer who has an unpaid balance which includes charges for late payment, the payment shall be applied first to such charges and then to the remainder of the unpaid balance.

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9.13. Returned Check Charge: A $15.00 charge shall be applied to the accounts of customers who have checks to Public Service returned unhonored by the bank.

9.14. Field Collection Charge: A charge may be applied to the accounts of customers when it becomes necessary for Public Service to make a collection visit to the customer or premises. A charge of $30.00 may be applied to commercial and industrial accounts which include Rate Schedules GLP, LPL, PSAL, HS and HTS.

10. ACCESS TO CUSTOMER'S PREMISES

Public Service shall have the right of reasonable and safe access to customer's premises, and to all property furnished by Public Service, at all reasonable times for the purpose of inspection of customer's premises incident to the rendering of service, reading meters or inspecting, testing, or repairing its facilities used in connection with supplying the service, or for the removal of its property. The customer shall obtain, or cause to be obtained, all permits needed by Public Service for access to its facilities. Access to facilities of Public Service shall not be given except to authorized employees of Public Service or duly authorized government officials.

10.1. Drivable Surfaces: When a vehicle is needed to drive on customer's property to access Public Service facilities, the customer shall ensure that the path has a drivable surface that will prevent the vehicle from becoming disabled.

11. DISCONTINUANCE OF SERVICE

11.1. By Public Service: Public Service, upon ~~reasonable~~ notice, when it can be reasonably given, may suspend or curtail or discontinue service for the following reasons: (1) for the purpose of making permanent or temporary repairs, changes or improvements in any part of its system; (2) for compliance in good faith with any governmental order or directive notwithstanding such order or directive subsequently may be held to be invalid; (3) for any of the following acts or omissions on the part of the customer: (a) non-payment of a valid bill due for service furnished at a present or previous location, however, nonpayment~~.~~ ~~However, non-payment~~ for business service shall not be a reason for discontinuance of ~~residence~~ residential service except in cases of diversion of service pursuant to N.J.A.C. 14:3-7.8; (b) tampering with any facility of Public Service; (c) fraudulent representation in relation to the use of service; (d) customer moving from the premises, unless the customer requests that service be continued; (e) providing service to others without approval of Public Service except as permitted under Section 9.3 Metering on Customer's Premises of these Standard Terms and Conditions; (f) failure to make or increase an advance payment or deposit as provided for in these Standard Terms and Conditions; (g) refusal to contract for service where such contract is required; (h) connecting and operating equipment in such manner as to produce disturbing effects on the service of Public Service or other customers; (i) failure of the customer to comply with any of these Standard Terms and Conditions; (j) where the condition of the customer's installation presents a hazard to life or property; or (k) failure of customer to repair any faulty facility of the customer; (4) for refusal of reasonable and safe access to customer's premises for necessary purposes in connection with rendering of service, including meter installation, reading or testing, or the maintenance or removal of the property of Public Service.

Public Service~~The Company~~ shall apply the regulations set forth in N.J.A.C. 14:3.3A.2(a), and only discontinue service for non-payment of bills if one or both of the following criteria are met: 1) the customer's arrearage is more than $~~100~~200.00; and 2) the customer's account is more than 3 months in arrears.

Public Service may not discontinue service for non-payment of bills unless it gives the customer at least 10 days written notice of its intentions to discontinue service, 15 days if a

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landlord-tenant relationship is known to exist. The notice of discontinuance shall not be served until the expiration of the 15-day period indicated in Section 9.11 Payment of Bills of these Standard Terms and Conditions. No additional notice will be required when, in a response to a notice of discontinuance, payment by check is subsequently dishonored. However, in case of fraud, illegal use, or when it is clearly indicated that the customer is preparing to leave, immediate payment of accounts may be required.

Public Service may not discontinue service because of non-payment of bills in cases where a charge is in dispute, provided that the undisputed charges are paid and a request is made to the Board for investigation of the disputed charge. In such cases, Public Service shall notify the customer that unless steps are taken to invoke formal or informal Board action within 5 days, service will be discontinued for non-payment.

Public Service may not discontinue residential service involuntarily except between the hours of 8:00 A.M. ~~to~~ and 4:00 P.M., Monday through Thursday, unless there is a safety related emergency. There shall be no involuntary termination of service on Friday, Saturday, and Sunday or on the day before a holiday or a holiday, absent such emergency.

Subject to the conditions set forth below, d~~D~~iscontinuance of residential service for non-payment is prohibited if a medical emergency exists within the premises which would be aggravated by discontinuance of service. ~~and the customer gives reasonable proof of inability to pay.~~ Discontinuance shall be prohibited for a period of ~~up to~~ 90 days initially~~2 months~~ when a customer submits a licensed medical professional's~~physician's~~ statement in writing to Public Service as to the existence of the emergency, its nature and probable duration, and that termination of service will aggravate the medical emergency. Public Service may also require the customer to give reasonable proof of inability to pay. ~~Recertification by the physician as to continuance of the medical emergency shall be submitted to Public Service after 30 days.~~ However, at the end of such period of emergency, the customer shall still remain liable for payment of service(s) rendered, subject to the provisions of N.J.A.C. 14:3-7.~~7~~6.

1. The Board may extend the ~~60~~90-day period for good cause upon the receipt of a written request from the customer. ~~That~~ The written request shall be in accordance with the preceding terms. Pending the Board's consideration and decision regarding the request for extension, service shall not be discontinued.

2. Public Service may in its discretion, delay discontinuance of residential service for non-payment prior to submission of the licensed medical professional's~~physician's~~ statement required by this subsection when a medical emergency is known to exist.

If Public Service disconnects service to an unknown account and is notified that a medical emergency exists in the residential premises, Public Service shall: (1) restore service immediately; (2) allow 14 days to apply for service; and (3) allow 7 additional days following the service activation date or 21 days following the date it is notified of a medical emergency, whichever date is later, to submit a medical certification to Public Service written by a licensed medical professional in accordance with the preceding terms.

If a residential customer offers payment of the full amount or a reasonable portion of the amount due at the time of discontinuance, a Public Service representative shall accept payment without discontinuance of service. Whenever such payment is made, the representative shall provide the customer with a receipt showing the date, account number, customer's name and address and amount received.

Public Service shall make every reasonable effort to determine when a landlord-tenant relationship exists at residential premises being served. If such a relationship is known to exist, and if the tenants are not the customers of record but are end-users, service will not be ~~shut off~~discontinued unless Public Service has given a 15-day written notice to the owner of the premises or to the customer of record to whom the last preceding bill was rendered. Public Service will use its best efforts to provide discontinuance notices to all tenants, including providing tenants with a 15-day written notice, which will be ~~hand~~ hand-delivered, mailed or posted in a conspicuous area of the premises and in the common areas of multiple family premises.

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In addition, if posting is the method of notification used, Public Service will use its best efforts to place a copy of the notice on each tenant's car windshield or under the door of each tenant's dwelling. In the case of tenants of single and two-family dwellings, each tenant will be provided with a 15-day individual notice.

When a landlord-tenant relationship is known to exist, at the landlord's request, Public Service will provide the landlord with notice and/or have the service placed in the landlord's name if the tenant's service is being discontinued.

If Public Service disconnects service to a master metered premises in which the landlord is the actual customer of record and Public Service has been notified that a medical emergency exists by a tenant, Public Service shall restore service for a period of 7 days to allow the customer of record to resolve the nonpayment issue and to provide the tenant with time to make alternative arrangements.

Public Service shall not discontinue service during the period from November 15 through March 15, in accordance with N.J.A.C. 14:3-3A.5(a), unless otherwise ordered by the Board of Public Utilities, to those residential customers who demonstrate at the time of the intended termination that they are: (1) recipients of benefits ~~of: (1)~~under the Lifeline Credit Program; (2) recipients of benefits under the Federal Home Energy Assistance Program (HEAP), or certified as eligible therefor under standards set by the New Jersey Department of Human Services; (3) recipients of ~~); (3)~~ Temporary Assistance to Needy Families (TANF); (4) recipients of Federal Supplemental Security Income (SSI); (5) recipients of Pharmaceutical Assistance to the Aged and Disabled (PAAD); (6) recipients of General Assistance (GA) benefits; (7) recipients of the Universal Service Fund (USF); or (8) ~~Persons~~ persons unable to pay their utility bills because of circumstances beyond their control.

Public Service shall not discontinue service to any residential customer, for reasons of nonpayment, failure to pay a cash security deposit or guarantee, or failure to comply with the terms of a deferred payment plan, whenever the high temperature is forecast to be 32 degrees Fahrenheit or below during the next 24 hours, in accordance with N.J.A.C. 14:3-3A.2(e)1.

Public Service shall not discontinue service to any residential customer eligible for the Winter Termination Program, for reasons of nonpayment, failure to pay a cash security deposit or guarantee, or failure to comply with a deferred payment agreement, whenever the high temperature is forecast to be ~~95~~ 90 degrees Fahrenheit or more at any time during the following 48 hours, in accordance with N.J.A.C. 14:3-3A.2(e)3.

11.2. At Customer's Request: A customer wishing to discontinue service must give notice as provided in the applicable rate schedule. Within 48 hours of said notice, Public Service will discontinue service or obtain a meter reading for the purpose of calculating a final bill. Where such notice is not received by Public Service, customer shall be liable for service until final reading of the meter is taken. Notice to discontinue service will not relieve a customer from any minimum or guaranteed payment under any contract or rate schedule.

12. RECONNECTION CHARGE

A reconnection charge of $45.00 will be made for restoration of service when service has been suspended or discontinued for nonpayment of any bill due.

13. SERVICE LIMITATIONS

13.1. Continuity of Service: Public Service will use reasonable diligence to provide a regular and uninterrupted supply of service; but, should the supply be suspended, curtailed, or discontinued by Public Service for any of the reasons set forth in Section 11 of these Standard Terms and Conditions, or should the supply of service be interrupted, curtailed, deficient, defective, or fail, by reason of any act of God, accident, strike, legal process, governmental interference, or by reason of compliance in good faith with any governmental order or directive, notwithstanding such order or directive subsequently may be held to be invalid, Public Service shall not be liable for any loss or damage, direct or consequential, resulting from any such suspension, discontinuance, interruption, curtailment, deficiency, defect, or failure.

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13.2. Emergencies: Public Service may curtail or interrupt service or reduce voltage to any customer or customers in the event of an emergency threatening the integrity of its system or the systems to which it is directly or indirectly connected if, in its sole judgment, such action will prevent or alleviate the emergency condition.

In the event of an actual or threatened restriction of electric supplies available to its system or the systems to which it is directly or indirectly connected, Public Service may, after due notice to the Board, curtail or interrupt service or reduce voltage to any customer or customers if such action will prevent or alleviate the emergency condition.

13.3. Unusual Conditions: Public Service may place limitations on the amount and character of electric service it will supply and may refuse service to new customers or to existing customers for additional load if the necessary electric supply is unavailable or if Public Service is or will be unable to deliver, the necessary energy, or to obtain the necessary equipment and facilities to supply such service.

14. THIRD PARTY SUPPLIER SERVICE PROVISIONS

14.1. Third Party Supplier Electric Supply: Customers served on any of the applicable rate schedules of this Tariff for Electric Service and who desire to purchase their electric supply of capacity, transmission, and energy, hereinafter referenced as electric supply, from a Third Party Supplier (TPS) must provide appropriate authorization as required by the TPS. Customers who are not enrolled with a TPS will continue to receive Basic Generation Service electric supply.

A TPS is a retail energy and capacity provider that has been licensed by the Board and has executed a Third Party Supplier Agreement with Public Service so as to be eligible to furnish electric supply with delivery to the retail customer by Public Service. The customer may act as a third party supplier for its account if the customer meets all of the requirements of this Tariff.

14.1.1. Enrollment: Customers may request an enrollment package from Public Service which in addition to providing general information regarding electric supply, describes the process necessary for a customer to obtain a TPS for electric supply. This enrollment package will be provided to the customer at no charge and may be obtained by calling or writing Public Service or visiting a Customer Service Center.

14.2. Initiation of Service: In order to be eligible to receive electric supply from a TPS, the customer must contract with a TPS to obtain electric supply for delivery to the customer by Public Service. Delivery of electric supply to retail customers will be provided in accordance with the terms of the Third Party Supplier Agreement. The customer's designated TPS is required to notify Public Service of its selection as the customer's provider of electric supply. Initiation of service will become effective on the customer's next scheduled meter reading date that is at least thirteen (13) days following the receipt by Public Service from the TPS of the customer's selection.

Once Public Service has received the TPS notification for the initial, or subsequent, enrollment with a TPS, which process is as set forth in this subsection and in Section 14.1, Public Service will confirm the customer's selection of its designated TPS by sending a letter of confirmation to the customer. This letter of confirmation shall be provided within one day and shall include notification of the customer's right to rescind their contract with their designated TPS in accordance with Board established procedures. This right to rescind must be exercised within seven (7) days of mailing of the letter of confirmation. In the event of a dispute, assignment of a customer will not

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occur unless and until the dispute is resolved. Once assignment has occurred, the TPS will be required to provide all of the electric supply consumed on the Public Service customer's account (single point of delivery).

14.2.1. Customer Change of Third Party Supplier: If a customer subsequently elects to change its TPS, the customer must provide appropriate authorization as required by their TPS and as set forth in Section 14.1 and Section 14.2. Service from this alternate TPS will become effective on the customer's next scheduled meter reading date that is at least thirteen (13) days following the receipt by Public Service from the TPS of the customer's selection. Upon enrollment with a TPS, the customer may not change its TPS more frequently then once every billing month cycle.

14.2.2. Customer Return to Public Service Rate Schedule Electric Supply:

a) If the customer subsequently returns to Public Service as supplier of electric supply, the return to Public Service will become effective on the customer's next scheduled meter reading date that is at least thirteen (13) days following the receipt of customer notification by Public Service. Public Service shall confirm the customer's selection of Public Service as its provider of electric supply by sending a letter of confirmation to the customer and the customer shall have the right to rescind in accordance with Section 14.2, Initiation of Service, of these Standard Terms and Conditions.

b) If a customer's TPS no longer satisfies the requirements imposed on it by the Third Party Supplier Agreement, such customer shall immediately return to, and receive electric supply from Public Service under customer's applicable rate schedule unless and until customer selects another TPS in accordance with Section 14.2.1. The customer shall be advised by Public Service in writing of this change in supplier.

14.2.3. Third Party Supplier's Termination of Customer's Electric Supply: A TPS will not be permitted to physically connect or disconnect energy service to a customer.

14.3. Customer Billing Process: Public Service will provide one combined bill to the TPS's retail customer(s) containing both Public Service charges and TPS electric supply charges, providing the TPS executes and satisfies the terms of the Third Party Supplier Customer Account Services Master Service Agreement, and the retail customer(s) maintain a satisfactory bill payment history. Customer(s) may elect to receive a separate bill directly from its TPS for TPS services. If a customer requests and is permitted to receive a combined bill, but the customer's account subsequently becomes 120 days in arrears at any point in the future, such customer will thereafter be required to receive a separate bill directly from its TPS (including any subsequent TPS) for TPS services and will not be permitted to receive a combined bill from Public Service until such time the customer's arrearage is reduced to 60 days or less. Only Public Service owned, installed, and read meters will be used to determine customer usage for the purpose of calculating Public Service charges.

14.3.1. Payment of Bills: Payment of bills, including TPS's charges for electric supply if billed by Public Service, shall be made to Public Service and shall be in accordance with Section 9, Meter Reading and Billing, of these Standard Terms and Conditions. Any customer overpayment will be held in the customer's Public Service account to be applied against future customer bills or will be refunded to the customer at the customer's request.

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14.3.2. Late Payment Charges: A late payment charge in accordance with Section 9.12, Late Payment Charge, of these Standard Terms and Conditions is to be applicable to Public Service customer charges and TPS's charges for electric supply if billed by Public Service. Customer shut-offs in cases where there is non-payment to Public Service for its customer charges and TPS's charges for electric supply if billed by Public Service, are only performed in accordance with Section 11, Discontinuance of Service, of these Standard Terms and Conditions.

Billing Disputes: In the event of a billing dispute between the customer and the TPS, Public Service's sole duty is to verify its customer charges and billing determinants. Customer continues to remain responsible for the timely payment of all Public Service charges, and all undisputed TPS charges for electric supply if such charges are billed by Public Service, in accordance with Section 9, Meter Reading and Billing, and Section 14.3.1, Payment of Bills, of these Standard Terms and Conditions. All questions regarding TPS's charges or other terms of the customer's agreement with a TPS are to be resolved between the customer and its TPS. Public Service will not be responsible for the enforcement, intervention, mediation, or arbitration of agreements entered into between TPS customers and their TPS. Billing disputes that may arise regarding Public Service's charges shall be subject to Section 11, Discontinuance of Service, of these Standard Terms and Conditions.

14.4. Continuity of Service: In addition to the terms specified in Section 11, Discontinuance of Service, and Section 13, Service Limitations, of these Standard Terms and Conditions, Public Service shall have the right (i) to require a TPS's electric supply sources to be disconnected from Public Service's electrical system; (ii) to otherwise curtail, interrupt, or reduce a TPS's electric supply; or (iii) to disconnect a TPS's customer(s) whenever Public Service determines, or whenever Public Service is directed by PJM, that such a disconnection, curtailment, interruption or reduction is necessary to facilitate construction, installation, maintenance, repair, replacement or inspection of any of Public Service's or PJM members' facilities; to maintain the safety and reliability of Public Service's electrical system and any generation facilities attached thereto; or due to Emergencies, minimum generation ("light load") conditions, forced outages, potential overload of Public Service's or PJM's transmission and/or distribution circuits or events of Force Majeure including, but not limited to, those events specified in Section 13.1, Continuity of Service, of these Standard Terms and Conditions.

14.5. Interval Metering: In addition to the terms specified in Section 9, Meter Reading and Billing, of these Standard Terms and Conditions, customers being served by a TPS that have interval meters will be billed using the data obtained from those meters. If the interval meter is not operational, customer's hourly usage and demand, where applicable, will be determined by employing load profiling based upon the customer's rate schedule or historical customer usage and demand data, at the discretion of Public Service.

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~~If the telecommunications provided by a customer to an interval meter is not operable at the time of a monthly meter reading date, Public Service will notify the customer and manually obtain the data from the interval meter. If the telecommunications to an interval meter is not operable for two consecutive meter reading dates, Public Service may charge the customer for the cost to manually obtain the interval data for the subsequent months' meter readings (after the second consecutive month) until the problem is remedied. The charge to provide this manual data collection is $50.00 ($53.31 including SUT) per month. If the customer does not remedy the telecommunications problem after four (4) consecutive meter reading dates, Public Service reserves the right to bill third party supplied customers on the basis of a load profile for the customer's rate schedule or historical customer usage and demand data, at the discretion of Public Service, until the telecommunication problem is remedied.~~

15. NET METERING INSTALLATIONS

15.1. **General:** For the purpose of this Section of the Tariff for Electric Service a customer-generator is a customer that generates electricity using Class I renewable resources as defined in N.J.A.C. 14:8-1.2 on the customer's side of the meter. Net Metering provides for the billing or crediting, as applicable, of energy usage by measuring the difference between the amount of electricity delivered by Public Service to a Qualified Customer Generator, as defined in Section 15.2, in a given billing period and the electricity delivered by Qualified Customer Generator into the Public Service distribution system. Public Service will select and supply the type of meter(s) that will enable the measurement of the electricity for the billing or crediting of energy delivered as indicated above.

Customers qualified for Net Metering shall be responsible for all interconnection costs as defined in N.J.A.C. 14:8-4.1 *et seq*., which shall be in addition to any line or service extension charge required to meet service requirements. For customers eligible for Net Metering the term usage as applied in Section 3, Charges for Service, shall mean net usage as determined by Net Metering.

15.2. **Limitations and Qualifications for Net Metering:** To qualify for Net Metering, a customer-generator must generate Class I renewable energy as defined in N.J.A.C. 14:8-1.2. Further, to qualify for Net Metering, the capacity of the customer's generating system cannot exceed the amount of electricity supplied by the electric power supplier or basic generation service provider to the customer's residence or facility, as applicable, over an annualized period~~; or the customer's generating system is limited to a maximum size of 2 megawatts, whichever is less~~. Customer-generators that qualify for Net Metering shall be referred to as "Qualified Customer-Generators."

Additionally, customers participating in Community Solar cannot participate in Net Metering unless each project is metered separately.

15.3. **Installation Standards:** A Qualified Customer-Generator shall ascertain and comply with the requirements of Public Service which are covered in detail in the "Information and Requirements for Electric Service", available on www.pseg.com or by request as designated in Section 6.3, Secondary Distribution Service, of these Standard Terms and Conditions. In addition, the Qualified Customer-Generator shall be responsible for meeting all applicable safety and power quality standards as set forth below.

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STANDARD TERMS AND CONDITIONS
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Qualified Customer-Generator's generating system shall comply with all applicable safety and power quality standards specified by the National Electrical Code, Institute of Electrical and Electronics Engineers, accredited testing institutions, such as Underwriters Laboratories. The customer's installation should be made in accordance with the State of New Jersey Uniform Construction Code requirements for electrical installations, UL 1741 and the IEEE Standard 1547. Net Metering systems served by network distribution systems, shall comply to standards established by Public Service and approved by the New Jersey Board of Public Utilities ("Board") in addition to the aforementioned applicable safety and power quality standards and all other requirements in N.J.A.C. 14:8-4.1 *et seq*.

15.4. **Initiation of Service:** Prior to interconnecting with the Public Service distribution system the Qualified Customer-Generator is required to provide Public Service with an Interconnection Application provided by the Office of Clean Energy and pay all appropriate charges as detailed in the Interconnection Application Process. Additionally, Public Service may, at its option, inspect the interconnection prior to the initiation of Net Metering service for Qualified Customer-Generators.

Initiation of service will become effective on the Qualified Customer-Generator's first regularly scheduled meter reading date that is at least twenty (20) days after the customer elects this provision, by executing an Interconnection Application, but in no case prior to the installation of the necessary meter(s), and shall terminate at a regularly scheduled meter reading date that is at least twenty (20) days following the receipt of customer notification by Public Service. The Qualified Customer-Generator shall provide Public Service on a regular basis with access to the customer's telephone service when required for the purposes of acquiring metering data.

15.5. **Net Billing:** Where the amount of electricity delivered by the Qualified Customer-Generator plus any kilowatt-hour credits held over from the previous billing periods exceeds the electricity supplied by the Qualified Customer-Generator's electric supplier or basic generation service provider, as applicable, the Qualified Customer-Generator shall be credited for the excess kilowatt-hours to the next billing period. At the end of the annualized period the Qualified Customer-Generator will be compensated for any remaining credits by the Qualified Customer-Generator's electric supplier or basic generation service provider, as applicable, at their avoided cost of wholesale power.

A Qualified Customer-Generator shall have a one-time opportunity to select a monthly billing period as the start of the Qualified Customer-Generator's annualized period. This selection will become effective on the first regularly scheduled meter reading date that is at least twenty (20) days after the Qualified Customer-Generator notifies Public Service of the selection of their alternate monthly billing period. If a Qualified Customer-Generator initiating service after March 2, 2009 does not submit an annualized period selection they shall be assigned a default annualized period until such time as they notify Public Service of the selection of their alternate annualized period.

In the event that a Qualified Customer-Generator changes suppliers, the electric power supplier or basic service provider with whom service is terminated shall treat the end of the service period as if it were the end of the annualized period. Changes in supplier are to be in accordance with Section 14.2.1, Customer Change of Third Party Supplier, or Section 14.2.2, Customer Returns to Public Service Rate Schedule Electric Supply, of these Standard Terms and Conditions, as applicable.

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STANDARD TERMS AND CONDITIONS

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15.6. **Billing Adjustments:** In addition to Section 9.5, Billing Adjustments, of these Standard Terms and Conditions whenever a meter measuring energy delivered from a Qualified Customer-Generator to Public Service's distribution system is found to be registering slow by 2% or more an adjustment of the energy delivered shall be made and an adjustment may be made if the meter is found to be registering fast by more than 2%. The Qualified Customer-Generator's electric supplier or basic generation service provider, as applicable, will determine the applicability of this latter adjustment.

15.7. **Budget Plan (Equal Payment Plan):** The payment option described in Section 9.9, Budget Plan, is not available for customers taking service under this Section 15, Net Metering.

15.8. **Program Availability:** In accordance with N.J.S.A. 48:3-87(e)(1), Public Service may be authorized by the Board to cease offering net metering to customers that are not already net metered whenever the total rated generating capacity owned and operated by net metering customer-generators Statewide equals 5.8 percent of the total annual kilowatt-hours sold in this State by each electric power supplier and each basic generation service provider during the prior one-year period.~~Public Service may be authorized by the Board to cease offering net metering whenever the total rated generating capacity owned and operated by Qualified Customer-Generators Statewide equals 2.5 percent of the State's peak electricity demand.~~

16. NEW JERSEY AUTHORIZED TAXES

The following taxes are authorized by the State of New Jersey and are applied in accordance with P.L. 1997, c. 162 (the "Energy Tax Reform Statute"), as amended by P. L. 2006, c. 44, as amended by P.L. 2016, c. 57, and are included in the appropriate charges contained within this Tariff for Electric Service.

16.1. **New Jersey Sales and Use Tax:**
In accordance with P.L. 1997, c. 162, as amended by P. L. 2006, c. 44, as amended by P.L. 2016, c. 57, provision for the New Jersey Sales and Use Tax (SUT) has been included in all applicable charges by multiplying the charges that would apply before application of the SUT by the factor 1.06625.

16.1.1. The Energy Tax Reform Statute exempts the following customers from the SUT provision, and when billed to such customers, the charges otherwise applicable shall be reduced by the provision for the SUT included therein:

a) Franchised providers of utility services (gas, electricity, water, wastewater and telecommunications services provided by local exchange carriers) within the State of New Jersey.

b) Special contract customers for which a customer-specific tax classification was approved by a written Order of the New Jersey Board of Public Utilities prior to January 1, 1998.

c) Agencies or instrumentalities of the federal government.

d) International organizations of which the United States of America is a member.

e) Additional customers as authorized by the State of New Jersey Department of Treasury in accordance with the provisions of P.L. 1997, c. 162, as amended by P. L. 2006, c. 44, as amended by P.L. 2016, c. 57.

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16.1.2. The Business Retention and Relocation Assistance Act (P.L. 2004, c. 65) and subsequent amendment (P.L. 2005, c.374) exempts the following customers from the SUT provision, and when billed to such customers, the charges otherwise applicable shall be reduced by the provision for the SUT included therein:

a) A qualified business that employs at least 250 people within an enterprise zone, at least 50% of whom are directly employed in a manufacturing process, for the exclusive use or consumption of such business within an enterprise zone, and

b) A group of two or more persons:

(b-1) Each of which is a qualified business that are all located within a single redevelopment area adopted pursuant to the "Local Redevelopment and Housing Law," P.L.1992, c.79 (C.40A:12A-1 *et seq.*);
(b-2) That collectively employ at least 250 people within an enterprise zone, at least 50% of whom are directly employed in a manufacturing process;
(b-3) Are each engaged in a vertically integrated business, evidenced by the manufacture and distribution of a product or family of products that, when taken together, are primarily used, packaged and sold as a single product; and
(b-4) Collectively use the energy and utility service for the exclusive use or consumption of each of the persons that comprise a group within an enterprise zone.

c) A business facility located within a county that is designated for the 50% tax exemption under section 1 of P.L. 1993, c.373 (C.54:32B-8.45) provided that the business certifies that it employs at least 50 people at that facility, at least 50% of whom are directly employed in a manufacturing process, and provided that the energy and utility services are consumed exclusively at that facility.

A business that meets the requirements in (a), (b) or (c) above shall not be provided the exemption described in this section until it has complied with such requirements for obtaining the exemption as may be provided pursuant to P.L.1983, c.303 (C.52:27H-60 *et seq.*) and P.L.1966, c.30 (C.54:32B-1 *et seq.*) and Public Service has received a sales tax exemption letter issued by the New Jersey Department of Treasury, Division of Taxation.

16.2. **New Jersey Corporation Business Tax:**
In accordance with P.L. 1997, c. 162, provision for the New Jersey Corporation Business Tax (CBT) has been included in the Service Charge, Distribution Charge, and the Demand Charge.

16.2.1. The Energy Tax Reform Statute exempts the following customers from the CBT provision, and when billed to such customers, the charges otherwise applicable shall be reduced by the provision for the CBT (and related SUT) included therein.

a) Franchised providers of utility services (gas, electricity, water, wastewater and telecommunications services provided by local exchange carriers) within the State of New Jersey.

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b) Special contract customers for which a customer-specific tax classification was approved by a written Order of the New Jersey Board of Public Utilities prior to January 1, 1998.

c) Additional customers as authorized by the State of New Jersey Department of Treasury in accordance with the provisions of P.L. 1997, c. 162.

17. TERMINATION, CHANGE OR MODIFICATION OF PROVISIONS OF TARIFF

This tariff is subject to the lawful orders of the Board of Public Utilities of the State of New Jersey.

Public Service may at any time and in any manner permitted by law, and the applicable rules and regulations of the Board of Public Utilities of the State of New Jersey, terminate, or change or modify by revision, amendment, supplement, or otherwise, this Tariff or any part thereof, or any revision or amendment hereof or supplement hereto.

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RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

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REGULATION FOR RESIDENTIAL UNDERGROUND EXTENSIONS

The following are the charges applicable for certain residential underground extensions, in compliance with the Regulations on Residential Underground Extensions as per N.J.A.C. 14:3-8 et seq., and referenced in the Sections 3.~~8~~7.2. – Multi-unit Developments of the Standard Terms and Conditions of this tariff.

The Applicant will be charged for standard electric service as calculated in Section A – Base Charges and/or Section B – Additional Charges. The charges in Sections A and B will be adjusted for tax gross-up effects consistent with all applicable federal and state tax laws, including, but not limited to, the "Protecting Americans from Tax Hikes Act of 2015" ("the PATH Act"). For non-typical situations, including service to multiple family buildings and other situations as detailed below, such charges shall be equal to estimated cost of the underground construction less the total estimated costs of the otherwise applicable overhead construction, such result shall include the gross-up for income tax effects. Such cost estimates shall be based on the unit costs as detailed in Exhibits I to III and shall be based on the necessary construction to supply the same loads and locations utilizing Public Service's standard design and construction standards. Requests for additional facilities shall be considered as Atypical Conditions and other charges may apply in accordance with Section 3.5.2 of these Standard Terms and Conditions.

Charges for street and area lighting provided by Public Service under Rate Schedules PSAL or BPL are as indicated in Section C – Street and Area Lighting Charges.

A. Base Charges:

	Charge Per Building Lot	Charge Per Foot For Total Front Footage
1. Single-family	$ 529.43	$ 1.43
2. Duplex-family buildings, mobile homes, multiple occupancy buildings, three-phase, high capacity extensions, lots requiring primary extensions thereon, excess transformer capacity above 8.5 kVA, etc.	Charge to be based on differential cost according to unit costs specified in Exhibit I to III.	

B. Additional Charges:

	Item	Unit	Charge
1.	Primary termination	Each	$ 310.57
2.	Primary junction enclosure	Each	$ 1,639.80
3.	Excess service length over 50 feet	Per foot trench 100 & 150 amp	$ 5.47
4~~3~~.	Excess service length over 50 feet	Per foot trench 100 & 150 amp	$ 5.47
		Over 150 amp	$ 6.37
5~~3~~.	Excess service length over 50 feet	Per foot trench 100 & 150 amp	$ 5.47
6~~4~~.	Multi-phase constructions	Per foot per phase	$ (3.90)
7~~5~~.	Pavement cutting and restoration, rock removal, blasting, difficult digging and special backfill	At actual low bid cost with option of Applicant to contract for as limited by N.J.A.C. 14:5-2.4 et seq.	

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REGULATION FOR RESIDENTIAL UNDERGROUND EXTENSIONS
(Continued)

C. Street and Area Lighting Charges:

The Applicant shall pay the normal charges for all luminaires as indicated in the applicable street and area lighting rate schedule.

The monthly charge and up-front contribution for all lighting poles not installed on public streets shall be at the full charges indicated in the applicable street and area lighting rate schedule.

1. Street lighting~~Streetlighting~~ poles where spacing is equal to or greater than 200 feet.

   For street and area lighting poles installed on public streets, PSE&G will provide, as the standard lighting pole, a laminated wood pole (PSE&G part number W04-0197) at no up-front contribution or monthly charge. Requests for use of another type or size lighting pole shall be considered as a request for a Specialty Lighting Pole. In these cases, an up-front contribution credit equal to the installed cost of the standard lighting pole shall be provided by Public Service, with monthly charges calculated as per the applicable street and area lighting rate schedule.

2. Additional street lighting poles where spacing is less than 200 feet.

   The Applicant shall pay the full normal charges for lighting poles as indicated in the applicable street and area lighting rate schedule where the spacing of such lighting poles is less than 200 feet.

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REGULATION FOR RESIDENTIAL UNDERGROUND EXTENSIONS

(Continued)

EXHIBIT I - UNIT COSTS OF UNDERGROUND CONSTRUCTION - SINGLE PHASE

	Item	Unit	Total Charge*
1.	Trenching		
	Sole Trenching	Per foot	$ 2.22
	Joint Trenching**	Per foot	$ 1.28
2.	Primary cable (1/0 AWG Al.)	Per foot	$ 3.93~~2.30~~
3.	Secondary wire		
	2/0 AWG Cu	Per foot	$ 3.59
	350 kcmil Cu	Per foot	$ 10.75
4.	Services		
	50 feet complete - 100 & 150 amp	Each	$ 552.58~~491.02~~
	100 & 150 amp (#2 AWG Cu.)	Per foot	$11.05~~10.10~~
	50 feet complete - over 150 amp	Each	$ 675.06
	~~50 feet complete~~	~~Each~~	~~$ 491.02~~
	Service - over 150 amp (2/0 AWG Cu.)	Per foot	$13.50~~13.78~~
	~~50 feet complete~~	~~Each~~	~~$ 675.06~~
5.	Primary termination - branch	Each	$ 1,563.94~~232.81~~
6.	Primary junction enclosure - branch	Each	$ 2,294.67~~1,639.80~~
7.	Secondary enclosure	Each	$ 692.09
~~8.~~	~~Conduit~~		
	~~1 - 4 inch conduit~~	~~Per foot~~	~~$ 5.19~~
	~~2 - 4 inch conduits~~	~~Per foot~~	~~$ 6.62~~
	~~3 - 4 inch conduits~~	~~Per foot~~	~~$ 8.83~~
	~~4 - 4 inch conduits~~	~~Per foot~~	~~$ 11.03~~
~~9~~8.	Street light cable (#8 AWG Cu.)	Per foot	$ 4.32~~2.11~~
~~10~~9.	Transformers - including fiberglass pad		
	25 kVA - single-phase	Each	$1,376.93~~1,664.63~~
	50 kVA - single-phase	Each	$5,290.64~~1,879.14~~
	75 kVA - single-phase	Each	$5,645.29~~2,239.50~~
	100 kVA - single-phase	Each	$6,285.68~~2,417.06~~
	167 kVA - single-phase	Each	$3,632.41~~3,016.82~~
~~11~~10.	Street light poles (standard pole only)		
	30 foot ~~center bored pine wood pole~~laminated pole	Each	$1,100.00~~842.20~~

*Charges do not include costs for clerical, dispatching, supervision, or general office functions as, except for third-party damage or other actions by third-parties, those costs are considered legitimate costs of doing business and incurred as part of the Company's normal operations in meeting its regulatory duty to furnish service.

** Joint trench calculation: 0.5 (0.85 x $2.22) + 0.15 x $2.22 =$1.28

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REGULATION FOR RESIDENTIAL UNDERGROUND EXTENSIONS

(Continued)

EXHIBIT II - UNIT COSTS OF UNDERGROUND CONSTRUCTION - THREE-PHASE

	Item	Unit	Total Charge*
1.	Primary cable		
	750 kcmil Cu.	Per foot	$ 25.24
	500 kcmil Cu.	Per foot	$ 17.92
	4/0 AWG Al.	Per foot	$ 12.62
	1/0 AWG Al.	Per foot	$ 7.06
2.	Secondary 4-wire (350 kcmil Cu.)	Per foot	$ 11.34
~~3.~~	~~Service 4-wire (350 kcmil Cu.)~~	~~Per foot~~	~~$ 13.39~~
~~4~~3.	Primary Terminations		
	Main line (750 kcmil)	Set of 3	$3,387.34~~1,676.68~~
	Three phase branch (500 kcmil)	Set of 3	$ 785.25
	Two phase branch (4/0 AWG)	Set of 2	$ 425.38
~~5.~~	~~Three Phase Primary Switches~~		
	~~Switch with fused taps~~	~~Each~~	~~$ 15,918.85~~
	~~Junction with fused taps~~	~~Each~~	~~$ 9,410.52~~
	~~Junction without fused taps~~	~~Each~~	~~$ 6,304.55~~
~~6~~4.	5 inch conduit	Per foot	$ 5.87
	6 inch conduit	Per foot	$ 2.26
~~7~~5.	Transformers - including fiberglass pad		
	150 kVA - three-phase	Each	$11,158.06~~5,683.32~~
	225 kVA - three-phase	Each	$10,085.50~~7,697.69~~
	300 kVA - three-phase	Each	$20,902.25~~7,929.33~~
	500 kVA - three-phase	Each	$23,728.71~~9,833.99~~
	750 kVa - three-phase	Each	$ 22,574.76
	1000 kVa - three-phase	Each	$ 34,287.53
	1500 kVa - three-phase	Each	$ 38,672.75

*Charges do not include costs for clerical, dispatching, supervision, or general office functions as, except for third-party damage or other actions by third-parties, those costs are considered legitimate costs of doing business and incurred as part of the Company's normal operations in meeting its regulatory duty to furnish service.

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REGULATION FOR RESIDENTIAL UNDERGROUND EXTENSIONS

(Continued)

EXHIBIT III - UNIT COSTS OF OVERHEAD CONSTRUCTION

SINGLE-PHASE AND THREE-PHASE

	Item	Unit	Total Charge*
1.	Pole line - including 7-35 foot and 2-40 foot poles, anchors and guys per 1000 feet	Per foot	$ 6.48**
2.	Primary wire		
	1/0 AWG AAAC covered, one phase	Per foot	$ 7.25
	379.5 kcmil Al. covered, three phase	Per foot	$ 11.11
	1/0 AWG AAAC base, one phase	Per foot	$ 7.30
	379.5 kcmil Al. bare, three phase	Per foot	$ 10.85
3.	Primary wire neutral (1/0 AWG AAAC)	Per foot	$ 2.76
4.	Secondary cable		
	3 wire (2/0 AWG Al.)	Per foot	$ 5.16~~4.03~~
	4 wire (2/0 AWG Al.)	Per foot	$ 8.45~~4.63~~
5.	Services - single-phase		
	50 feet complete - 100 & 150 amp	Each	$ 259.25
	100 & 150 amp (#2 AWG Al.)	Per foot	$ 5.19
	~~50 feet complete~~	~~Each~~	~~$ 259.25~~
	50 feet complete - over 150 amp	Each	$ 379.01
	Over 150 amp (2/0 AWG Al.)	Per foot	$ 7.58
	~~50 feet complete~~	~~Each~~	~~$ 379.01~~
	Services - three-phase		
	up to 200 amp (2/0 AWG Al.)	Per foot	$ 7.76
	over 200 amp (397.5 kcmil Al.)	Per foot	$ 12.27
6.	Transformers		
	25 kVA - single-phase	Each	$ 1,353.88~~1,201.13~~
	50 kVA - single-phase	Each	$ 3,946.82~~1,356.16~~
	100 kVA - single-phase	Each	$ 5,247.55~~2,183.32~~
	3 - 25 kVA - three-phase	Per set	$ 4,061.65~~2,961.53~~
	3 - 50 kVA - three-phase	Per set	$ 11,840.85~~3,690.83~~
	3 - 100 kVA - three-phase	Per set	$ 15,742.65~~5,721.66~~

*Charges do not include costs for clerical, dispatching, supervision, or general office functions as, except for third-party damage or other actions by third-parties, those costs are considered legitimate costs of doing business and incurred as part of the Company's normal operations in meeting its regulatory duty to furnish service.

**Joint pole line cost to be used = $3.23

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RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

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SOCIETAL BENEFITS CHARGE

Cost Recovery (per kilowatt-hour)

Component:

Social Programs	$ 0.001728
Energy Efficiency and Renewable Energy Programs	0.003287
Manufactured Gas Plant Remediation	0.000471
Sub-total per kilowatt-hour	$ 0.005486

Charge including losses, USF and Lifeline:

	Loss Factor	Sub-total Including Losses	USF	Lifeline	Total Charge
Secondary Service	5.8327%	$ 0.005826	$ 0.001243	$ 0.000698	$ 0.007767
LPL Primary	3.3153%	0.005674	0.001243	0.000698	0.007615
HTS Subtransmission	2.0472%	0.005601	0.001243	0.000698	0.007542
HTS High Voltage & HTS Transmission	0.8605%	0.005534	0.001243	0.000698	0.007475

Charges including New Jersey Sales and Use Tax (SUT)

Secondary Service	$ 0.008282
LPL Primary	0.008119
HTS Subtransmission	0.008042
HTS High Voltage & HTS Transmission	0.007970

SOCIETAL BENEFITS CHARGE

This mechanism is designed to insure recovery of costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Actual costs incurred by the Company for each of these cost components will be subject to deferred accounting. Interest at the two-year constant maturity treasury rate plus 60 basis points will be accrued monthly on any under- or over-recovered balances for all components other than Manufactured Gas Plant Remediation. Interest at the seven-year constant maturity treasury rate plus 60 basis points will be accrued monthly on any under- or over-recovered balances for the Manufactured Gas Plant Remediation. The interest rates for all components other than USF and Lifeline shall change each August 1. The interest rates for the USF and Lifeline components shall be reset each month. In appropriate circumstances, the Board of Public Utilities may approve a discount from the Societal Benefits Charge.

(Charges are for illustrative purposes only and are based on the Tenth Revised Sheet No. 57 filed with the BPU on November 1, 2023)

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SOCIETAL BENEFITS CHARGE
(Continued)

SOCIAL PROGRAMS

This component shall recover costs associated with existing social programs. This includes but is not limited to uncollectible customers' accounts.

ENERGY EFFICIENCY AND RENEWABLES (EE&R) PROGRAMS

This factor is a recovery mechanism which will operate in accordance with the Demand Side Management (DSM) conservation incentive regulations and successor regulations. The factor has been used to recover past Core and Performance Program Costs and Performance Program Payments, payments for Large-Scale Conservation Investments, and all recoverable costs associated with the Board's Comprehensive Resource Analysis Orders, including but not limited to the low income Comfort Partners Program.

The New Jersey Clean Energy Program energy efficiency and renewable energy programs (formerly CRA Programs) are approved by the Board pursuant to N.J.S.A. 48:3-60(a)(3). They include energy efficiency programs, customer-sited renewable energy programs, grid supply renewable energy programs and any other programs the BPU may approve. These programs may be administered and or implemented by Public Service, the BPU, or a third party appointed by the BPU. New Jersey Clean Energy Program Costs consist of, but are not limited to, rebates, grants, payments to third parties for program implementation, direct marketing costs, energy efficiency and renewable energy hardware, administration, measurement and evaluation of energy efficiency and renewable energy programs, customer communication and education, market research, costs associated with developing, implementing and obtaining regulatory approval, costs of research and development activities associated with energy efficiency and renewable energy programs, applicable Lost Revenues, and New Jersey Clean Energy Program advertising costs.

MANUFACTURED GAS PLANT REMEDIATION

This factor shall recovery costs associated with addressing and resolving claims by and or requirements of governmental entities and private parties related to activities necessary to perform investigations and the remediation of environmental media.

UNIVERSAL SERVICE FUND

These factors shall recover costs associated with new or expanded social programs.

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NON-UTILITY GENERATION CHARGE

Cost Recovery (per kilowatt-hour)

	St Lawrence NYPA Credit RS, RHS and RLM	**Non-Utility Generation above market costs**	**Total**
Total Cost per kilowatt-hour		$0.000023	
Amount per kilowatt-hour of cost recovery after application of losses:			
RS, RHS & RLM (Loss Factor =5.8327%)	($ 0.000000)	$0.000024	$0.000024
Other Secondary (Loss Factor =5.8327%)		0.000024	0.000024
LPL Primary (Loss Factor =3.3153%)		0.000024	0.000024
HTS Subtransmission (Loss Factor =2.0472%)		0.000023	0.000023
HTS High Voltage & HTS Transmission (Loss Factor =0.8605%)		0.000023	0.000023
Charges including New Jersey Sales and Use Tax (SUT)			
RS, RHS & RLM	($ 0.000000)	$0.000026	$0.000026
Other Secondary Service		0.000026	0.000026
LPL Primary		0.000026	0.000026
HTS Subtransmission		0.000025	0.000025
HTS High Voltage & HTS Transmission		0.000025	0.000025

NON-UTILITY GENERATION CHARGE

This mechanism is designed to insure recovery of costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. This charge shall recover: 1) above market costs associated with non-regulated generation costs which are related to long-term contractual power purchase arrangements approved by the Board and/or established under requirements of the Public Utility Regulatory Policies Act of 1978 and 2) other generation costs as may be approved by the Board. Actual costs incurred by the Company will be subject to deferred accounting. The St. Lawrence New York Power Authority (NYPA) Annual Benefit Allocation credit reflects the annual Economic Benefit allocation for New Jersey's investor owned utilities to supply residential customers' load.

Interest at the two-year constant maturity treasury rate plus 60 basis points will be accrued monthly on any under- or over-recovered Non-utility Generation above market cost balances. This interest rate shall change each August 1.

(Charges are for illustrative purposes only and are based on the Sixth Revised Sheet No. 60 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 61**

ZERO EMISSION CERTIFICATE RECOVERY CHARGE

	Charge (per kilowatt-hour)
ZERO EMISSION CERTIFICATE RECOVERY CHARGE:	
Charge	$ 0.004000
Return of Excess Collections	$ 0.000000
Total Charge	$ 0.004000
Charge including New Jersey Sales and Use Tax (SUT)	$ 0.004265

ZERO EMISSION CERTIFICATE RECOVERY CHARGE

This charge provides for the recovery of costs associated with the Zero Emission Certificate Program directed by the Board of Public Utilities ("BPU" or "Board") as detailed below.
Pursuant to the BPU's Zero Emission Certificate Charge Order dated November 19, 2018 in Docket No. EO18091004, the Board approved the implementation of a non-bypassable, irrevocable ZEC Charge of $0.004000 per kWh for all customers. The ZEC Charge reflects the emission avoidance benefits of the continued operation of selected nuclear plants as determined in L. 2018, c. 16 ("ZEC Law"). The ZEC Charge has been set at the rate specified in the ZEC Law and may be adjusted periodically by the Board, in accordance with the methodology provided for in the ZEC Law.

In accordance with the ZEC Law, the proceeds of the ZEC Charge will be placed in a separate, interest-bearing account and will be used solely to purchase ZECs and to reimburse the Board for its reasonable, verifiable costs incurred to implement the ZEC program. Refunds will be provided to the customers served under each of the Company's rate schedules in proportion to the ZEC Charge revenues contributed by the rate schedule.

The ZEC Charge will become effective upon the issuance of the April 2019 Board Order in Docket No. EO18080899.

(Charges are for illustrative purposes only and are based on the Fourth Revised Sheet No. 61 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 62**
Original Sheet No. 63

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 64**

SOLAR PILOT RECOVERY CHARGE

Charge
(per kilowatt-hour)

SOLAR PILOT RECOVERY CHARGE:

Charge.. $ 0.000063

Charge including New Jersey Sales and Use Tax (SUT)... $ 0.000067

SOLAR PILOT RECOVERY CHARGE

This charge is designed to recover the revenue requirements associated with the Public Service Solar Pilot Program per the Board Order in Docket Nos. ER18010029, GR18010030, AX18010001 and ER18030231 EO07040278 less the net proceeds from the sale of associated Solar Renewable Energy Certificates (SRECs) or cash received in lieu of SRECs. The net recovery by the Company is subject to deferred accounting. Interest at the two-year constant maturity treasury rate plus 60 basis points will be accrued monthly on any under- or over-recovered balances. This interest rate shall change each August 1.

(Charges are for illustrative purposes only and are based on the Fifth Revised Sheet No. 64 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 65**

GREEN PROGRAMS RECOVERY CHARGE

Component:	Charge (per kilowatthour)
Carbon Abatement Program	($0.000010)
Energy Efficiency Economic Stimulus Program	0.000004
Solar Generation Investment Program	0.000297
Solar Loan II Program	0.000109
Energy Efficiency Economic Extension Program	0.000034
Solar Generation Investment Extension Program	(0.000222)
Solar Loan III Program	0.000015
Energy Efficiency Economic Extension Program II	0.000108
Solar Generation Investment Extension II Program	(0.000105)
Energy Efficiency 2017 Program	0.000268
Transition Renewable Energy Certificate Program	0.002480
Clean Energy Future - Energy Efficiency Program	0.001257
Successor Solar Incentive Program	0.000601
Community Solar Energy Program	0.000084
Sub-total per kilowatthour	$0.004920
Charge including New Jersey Sales and Use Tax (SUT)	$0.005246

GREEN PROGRAMS RECOVERY CHARGE

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs. The charge will be reset nominally on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under- or over- recovered balances. The interest rates shall be reset each month.

(Charges are for illustrative purposes only and are based on the Eighth Revised Sheet No. 61 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 66**

CONSERVATION INCENTIVE PROGRAM

CHARGE APPLICABLE TO RATE SCHEDULES RS, RHS, RLM, GLP, LPL-S

	Conservation Incentive Program	Conservation Incentive Program including SUT	
RS & RHS	$0.000271	$0.000289	Per kilowatt-hour
RLM	$0.000965	$0.001029	Per kilowatt-hour
GLP	$1.2193	$1.3001	Per kilowatt of monthly peak demand
LPL-S	$1.0290	$1.0972	Per kilowatt of monthly peak demand

Conservation Incentive Program

This charge shall be applicable to the rate schedules listed above. The Conservation Incentive Program shall be based on the differences between actual and allowed revenue per customer during the preceding annual period. The Conservation Incentive Program mechanism shall be determined as follows:

I. DEFINITION OF TERMS AS USED HEREIN

1. Actual Number of Customers
– the Actual Number of Customers (“ANC”) shall be determined on a monthly basis for each of the Customer Class Groups to which the Conservation Incentive Program (“CIP”) Clause applies. The ANC shall equal the aggregate actual monthly Service Charge revenue for each class of customers subject to the CIP as recorded on the Company’s books, divided by the service charge rate applicable to such class of customers in each Customer Class Group.

2. Actual Revenue Per Customer
– the Actual Revenue per Customer (“ARC”) shall be determined in dollars per customer on a monthly basis for each of the Customer Class Groups to which the CIP applies. The ARC shall equal the aggregate actual booked variable margin revenue per applicable rate schedule for the month as recorded on the Company’s books divided by the Actual Number of Customers for the corresponding month. Actual revenues shall include Distribution Kilowatt-hour and Distribution Kilowatt charges as well as any Infrastructure Investment Program revenues, and shall not include the Service Charge and any non-base rate charges such as the Societal Benefits, Non-Utility Generation Charge, Zero Emission Certificate Recovery Charge, Solar Pilot Recovery Charges, Green Programs Recovery Charges, or the Tax Adjustment Credit.

3. Adjustment Period
– shall be the year beginning immediately following the conclusion of the Annual Period.

4. Annual Period
– shall be the twelve consecutive months from June 1 of one calendar year through May 31 of the following calendar year.

5. Average 13 Month Common Equity Balance
– shall be the average of the beginning and ending common equity balances based on the latest publically available financials available before the end of the Annual Period. The Company shall provide the most recently available actual months plus forecasted data at the time of each Initial Filing. The forecasted data will be updated with actuals once the financial statements for the months have been disclosed.

(Charges are for illustrative purposes only and are based on the Third Revised Sheet No. 66 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 66A**

CONSERVATION INCENTIVE PROGRAM
(Continued)

6. Baseline Revenue per Customer
– the Baseline Revenue per Customer (“BRC”) shall be stated in dollars per customer on a monthly basis for each of the Customer Class Groups to which the CIP applies. The BRC shall be calculated as the current variable margin revenue per rate schedule, including any revenue from Infrastructure Investment Program rate adjustments, divided by the number of customers from the most recent approve base rate case for the rate schedule. Baseline revenues shall include Distribution Kilowatt-hour and Distribution Kilowatt charges, and shall not include the Service Charge and any non-base rate charges such as the Societal Benefits, Non-Utility Generation Charge, Zero Emission Certificate Recovery Charge, Solar Pilot Recovery Charges, Green Programs Recovery Charges, or the Tax Adjustment Credit.

7. Customer Class Group
– for purposes of determining and applying the CIP, customers shall be aggregated into four separate recovery class groups. The Customer Class Groups shall be as follows:

Group I:	RS & RHS
Group IA:	RLM
Group II:	GLP
Group III:	LPL-S

8. Forecast Annual Usage
– the Forecast Annual Usage (“FAU”) shall be the projected total annual throughput for all customers within the applicable Customer Class Group. The FAU shall be estimated based on normal weather.

9. Degree Days (DD)
– the difference between 65°F and the mean daily temperature. The mean daily temperature is the simple average of the 24 hourly temperature observations for a day. Heating Degree Days (HDD) are used to measure winter weather.

10. Temperature Humidity Index (THI)
– a measure of the degree of discomfort experienced by an individual in warm weather that includes temperature and humidity which is included by incorporating the dew point in the measure. The daily THI is the sum of the 24 hourly THI observations for a day. THI is used to measure summer weather.

11. Actual Calendar Month HDD and THI
– the accumulation of the actual HDD and THI for each day of a calendar month.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 66B**

CONSERVATION INCENTIVE PROGRAM
(Continued)

12. Normal Calendar Month HDD and THI
– the level of calendar month HDD and THI to which the weather portion of this CIP applies.

The normal calendar month HDD and THI will be based on the twenty-year average of the National Oceanic and Atmospheric Administration (NOAA) First Order Weather Observation Station hourly observations at the Newark airport and will be updated annually. The base level of normal HDD and THI for the defined winter and summer period months for the 2022-2023 Periods are set forth in the table below:

Month	Normal Heating Degree Days	Normal Temperature Humidity Index
January 2023	989	
February 2023	838	
March 2023	684	
April 2023	354	187
May 2023	128	931
June 2022		3,043
July 2022		5,624
August 2022		4,861
September 2022		2,237
October 2022	228	414
November 2022	523	
December 2022	816	

13. Winter Period
– shall be the eight consecutive calendar months from October of one calendar year through May of the following calendar year.

14. Summer Period
– shall be the seven consecutive calendar months from April of one calendar year through October of the calendar year.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 66C**

CONSERVATION INCENTIVE PROGRAM
(Continued)

15. Consumption Factors
– the use per HDD and THI component by month used in forecasting sales for the applicable rate schedules. These factors will be updated annually. Consumption Factors for the 2022-2023 Winter Period for HDD and 2022 Summer Period for THI are set forth below and presented as kWh per degree day:

	Consumption Factors (kWh per HDD and THI)					
	RS		RHS		RLM	
Month	HDD	THI	HDD	THI	HDD	THI
January 2023	469,298	150,909	11,303	409	6,341	1,577
February 2023	469,294	150,908	11,258	407	6,286	1,563
March 2023	469,288	150,906	11,276	408	6,207	1,543
April 2023	469,533	150,984	11,219	406	6,200	1,541
May 2023	469,777	151,063	11,163	404	6,193	1,540
June 2022	463,870	149,164	11,707	423	6,341	1,577
July 2022	461,601	148,434	11,568	418	6,287	1,563
August 2022	460,471	148,070	11,545	418	6,588	1,638
September 2022	461,466	148,390	11,469	415	6,061	1,507
October 2022	460,832	148,186	11,445	414	6,172	1,534
November 2022	461,133	148,283	11,350	410	6,412	1,594
December 2022	462,271	148,649	11,347	410	6,289	1,563

II. BASELINE REVENUE PER CUSTOMER

– the BRC for each Customer Class Group by month are as follows:

Month	RS & RHS	RLM	GLP	LPL-S
Jun	$32.30	$90.17	$130.32	$2,691.79
Jul	39.76	102.12	150.23	3,943.65
Aug	36.78	95.84	145.41	3,981.31
Sep	22.10	43.79	90.80	2,236.34
Oct	13.79	17.31	54.66	1,623.92
Nov	14.98	15.85	48.76	1,008.96
Dec	18.58	20.42	48.68	863.90
Jan	20.61	22.23	52.13	926.21
Feb	17.06	19.36	49.77	928.65
Mar	16.39	18.57	49.83	930.16
Apr	13.98	14.68	49.36	886.19
May	15.43	18.93	87.85	1,721.67
Total Annual	**$261.75**	**$479.26**	**$957.80**	**$21,742.74**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 66D**

CONSERVATION INCENTIVE PROGRAM
(Continued)

III. DETERMINATION OF THE CONSERVATION INCENTIVE PROGRAM

1. At the end of the Annual Period, a calculation shall be made that determines for each Customer Class Group the deficiency or excess to be surcharged or credited to customers pursuant to the CIP mechanism. The deficiency or excess shall be calculated each month by multiplying the result obtained from subtracting the Baseline Revenue per Customer from the Actual Revenue per Customer by the Actual Number of Customers.

2. The weather related change in customer usage shall be calculated as the difference between actual HDD and THI and the above HDD and THI multiplied by the consumption factors, and multiplying the result by the margin revenue factors as defined in Section I.10. of this rate schedule to determine the weather-related deficiency or excess. The weather-related amount will be subtracted from the total deficiency or excess to determine the non-weather related deficiency or excess.

3. Recovery of margin deficiency associated with non-weather related changes in customer usage will be subject to a BGS savings test and a Variable Margin Revenue recovery limitation (“recovery tests”). Recovery of non-weather related margin deficiency will be limited to the smaller of (1) the level of BGS savings achieved when such savings are less than 75 percent of the non-weather related margin deficiency, i.e. BGS savings test, and (2) 6.5 percent of variable margins for the CIP Annual Period, i.e., Variable Margin Revenue recovery limitation. Any amount that exceeds the above limitations may be deferred for future recovery and is subject to either or both of the recovery tests in a future year consistent with the amount by which either or both of the non-weather related margin deficiency exceeded the recovery tests. For the purposes of this calculation, the value of the weather related portion shall be calculated as set forth in Section III.2. of this rate schedule.

4. In addition, if the calculated ROE exceeds the allowed ROE from the utility's last base rate case by 50 basis points or more, recovery of lost revenues through the CIP shall not be allowed for the applicable filing period. For purposes of this section, the Company's rate of return on common equity shall be calculated by dividing the Company's net income for the applicable period as defined in the Average 13 Month Common Equity Balance by the Company's average common equity balance for the same period, all as reflected in the Company's monthly reports to the Board of Public Utilities. The Company's net income shall be calculated by subtracting from total operating income, any clause related Net Income, such as the Green Program’s Recovery Charge and interest expenses. The Company's Average 13 Month Common Equity Balance shall be the ratio of Electric Distribution Net Plant (including the Electric Distribution allocation of Common Plant) to total PSE&G Net Plant for the Average 13 Month Common Equity Balance period multiplied by the Company's total common equity for the same period.

5. The amount to be surcharged or credited shall equal the eligible aggregate deficiency or excess for all months during the Annual Period determined in accordance with the provisions herein, divided by the Forecast Annual Usage for the Customer Class Group.

IV. TRACKING THE OPERATION OF THE CONSERVATION INCENTIVE PROGRAM

The revenues billed, or credits applied, net of taxes and assessments, through the application of the Conservation Incentive Program Rate shall be accumulated for each month of the Adjustment Period and applied against the CIP excess or deficiency from the Annual Period and any cumulative balances remaining from prior periods.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 67**

DISTRIBUTION ADJUSTMENT CHARGE

	Charge (per kilowatthour)
Component:	
Storm Recovery Charge	$0.XXXXXX
COVID-19 Cost Recovery	0.XXXXXX
Distribution Adjustment Charge	$0.XXXXXX
Charge including New Jersey Sales and Use Tax (SUT)	$0.XXXXXX

DISTRIBUTION ADJUSTMENT CHARGE

This non-bypassable charge is designed to recover Board-approved costs. The charge will be reset nominally on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under- or over- recovered balances. The interest rates shall be reset each month.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **~~Original Sheet No. 67~~** **Original Sheet No. 68**

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 69**

TAX ADJUSTMENT CREDIT

Rate Schedule	Charge per kilowatt-hour	Charge per kilowatt-hour Including SUT
RS	($0.005250)	($0.005598)
RHS	($0.006603)	($0.007040)
RLM	($0.004760)	($0.005075)
WH	($0.000000)	($0.000000)
WHS	($0.000000)	($0.000000)
HS	($0.003743)	($0.003991)
GLP	($0.001622)	($0.001729)
LPL – Secondary	($0.000929)	($0.000991)
LPL – Primary	($0.000600)	($0.000640)
HTS – Subtransmission	($0.000563)	($0.000600)
HTS – High Voltage & HTS – Transmission	($0.000224)	($0.000239)
BPL	($0.000000)	($0.000000)
BPL-POF	($0.001418)	($0.001512)
PSAL	($0.000000)	($0.000000)

Tax Adjustment Credit

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month.

(Charges are for illustrative purposes only and are based on the Sixth Revised Sheet No. 69 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 70**

INFRASTRUCTURE IMPROVEMENT PROGRAM CHARGES

Rate Schedule		Base Distribution Charges Including SUT	Energy Strong II Charges	Energy Strong II Charges Including SUT	Total Charges Including SUT
RS					
Service Charge	per Month	$4.95	$0.00	$0.00	$4.95
Distribution 0-600, June-September	per kWhr	0.040752	0.007484	0.007980	0.048732
Distribution 0-600, October-May	per kWhr	0.035553	0.000000	0.000000	0.035553
Distribution over 600, June-September	per kWhr	0.044826	0.007484	0.007980	0.052806
Distribution over 600, October-May	per kWhr	0.035553	0.000000	0.000000	0.035553
RHS					
Service Charge	per Month	4.95	0.00	0.00	4.95
Distribution 0-600, June-September	per kWhr	0.051834	0.004222	0.004501	0.056335
Distribution 0-600, October-May	per kWhr	0.034956	0.001935	0.002063	0.037019
Distribution over 600, June-September	per kWhr	0.057058	0.004222	0.004502	0.061560
Distribution over 600, October-May	per kWhr	0.016190	0.001935	0.002063	0.018253
Common Use	per kWhr	0.057058	0.004222	0.004502	0.061560
RLM					
Service Charge	per Month	13.94	0.00	0.00	13.94
Distribution, June-September, On-Peak	per kWhr	0.075220	0.006391	0.006814	0.082034
Distribution, June-September, Off-Peak	per kWhr	0.015703	0.001335	0.001423	0.017126
Distribution, October-May, On-Peak	per kWhr	0.015703	0.001335	0.001423	0.017126
Distribution, October-May, Off-Peak	per kWhr	0.015703	0.001335	0.001423	0.017126
WH					
Distribution	per kWhr	0.050538	0.002084	0.002222	0.052760
WHS					
Service Charge	per Month	0.63	0.04	0.04	0.67
Distribution	per kWhr	0.001722	0.000310	0.000331	0.002053

(Charges are for illustrative purposes only and are based on the Fourth Revised Sheet No. 70 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 71**

INFRASTRUCTURE IMPROVEMENT PROGRAM CHARGES
(Continued)

Rate Schedule		Base Distribution Charges Including SUT	Energy Strong II Charges	Energy Strong II Charges Including SUT	Total Charges Including SUT
HS					
Service Charge	per Month	$3.74	$0.24	$0.26	$4.00
Distribution, June-September	per kWhr	0.102660	0.001730	0.001844	0.104504
Distribution, October-May	per kWhr	0.030703	0.000631	0.000672	0.031375
GLP					
Service Charge	per Month	4.77	0.31	0.33	5.10
Service Charge-Unmetered	per Month	2.21	0.13	0.14	2.35
Service Charge-Night Use	per Month	370.81	0.00	0.00	370.81
Annual Demand	per kW	3.9378	0.0729	0.0777	4.0155
Summer Demand, June-September	per kW	9.8746	0.1830	0.1952	10.0698
Distribution, June-September	per kWhr	0.003219	0.000060	0.000064	0.003283
Distribution, October-May	per kWhr	0.008217	0.000152	0.000162	0.008379
Distribution-Night Use, June-September	per kWhr	0.008217	0.000152	0.000162	0.008379
Distribution-Night Use, October-May	per kWhr	0.008217	0.000152	0.000162	0.008379
LPL-Secondary					
Service Charge	per Month	370.81	0.00	0.00	370.81
Annual Demand	per kW	3.7617	0.0944	0.1007	3.8624
Summer Demand, June-September	per kW	8.9495	0.2245	0.2393	9.1888
Distribution	per kWhr	0.000000	0.000000	0.000000	0.000000
LPL-Primary					
Service Charge	per Month	370.81	0.00	0.00	370.81
Service Charge-Primary Alternate	per Month	21.54	1.38	1.47	23.01
Annual Demand	per kW	1.7531	0.0443	0.0473	1.8004
Summer Demand, June-September	per kW	9.7321	0.2457	0.2620	9.9941
Distribution	per kWhr	0.000000	0.000000	0.000000	0.000000

(Charges are for illustrative purposes only and are based on the Fourth Revised Sheet No. 71 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 72**

INFRASTRUCTURE IMPROVEMENT PROGRAM CHARGES
(Continued)

Rate Schedule		Base Distribution Charges Including SUT	Energy Strong II Charges	Energy Strong II Charges Including SUT	Total Charges Including SUT
HTS-Subtransmission					
Service Charge	per Month	$2,038.02	$0.00	$0.00	$2,038.02
Annual Demand	per kW	1.1432	0.0720	0.0768	1.2200
Summer Demand, June-September	per kW	4.1326	0.2603	0.2775	4.4101
Distribution	per kWhr	0.000000	0.000000	0.000000	0.000000
HTS-High Voltage					
Service Charge	per Month	1,834.22	0.00	0.00	1,834.22
Annual Demand	per kW	0.6574	0.0156	0.0167	0.6741
Distribution	per kWhr	0.000000	0.000000	0.000000	0.000000
BPL					
Distribution	per kWhr	0.007181	0.000159	0.000170	0.007351
BPL-POF					
Distribution	per kWhr	0.007174	0.000203	0.000216	0.007390
PSAL					
Distribution	per kWhr	0.007660	0.000171	0.000182	0.007842

INFRASTRUCTURE IMPROVEMENT PROGRAM CHARGE

These charges are designed to recover the revenue requirements associated with the Company's Infrastructure Improvement Programs (IIPs) in accordance with the New Jersey Board of Public Utilities' rules on IIPs, N.J.A.C. 14:3-2A.

For detail concerning individual rate class base distribution charges, see individual rate class tariff sheets.

(Charges are for illustrative purposes only and are based on the Fourth Revised Sheet No. 72 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 73**

COMMERCIAL AND INDUSTRIAL ENERGY PRICING (CIEP) STANDBY FEE

APPLICABLE TO:

All kilowatt-hour usage under Rate Schedules LPL-Secondary (500 kilowatts or greater), LPL-Primary, HTS-Subtransmission, HTS-Transmission, HTS-High Voltage and all kilowatt-hour usage for customers under Rate Schedules HS, GLP and LPL-Secondary (less than 500 kilowatts) who have elected hourly energy pricing service from either BGS-CIEP or a Third Party Supplier.

	Charge (per kilowatt-hour)
Commercial and Industrial Energy Pricing (CIEP) Standby Fee	$ 0.000150
Charge including New Jersey Sales and Use Tax (SUT)	$ 0.000160

The above charges shall recover costs associated with the administration, maintenance and availability of the Basic Generation Service default electric supply service for applicable rate schedules. These charges shall be combined with the Distribution Kilowatt-hour Charges for billing.

Kilowatt threshold noted above is based upon the customer's Peak Load Share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM). See Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions of this Tariff.

(Charges are for illustrative purposes only and are based on the Original Sheet No. 73 filed with the BPU on November 1, 2023)

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 75**

BASIC GENERATION SERVICE – RESIDENTIAL SMALL COMMERCIAL PRICING (BGS-RSCP) ELECTRIC SUPPLY CHARGES

APPLICABLE TO:

Default electric supply service for Rate Schedules RS, RHS, RLM, WH, WHS, HS, BPL, BPL-POF, PSAL, GLP and LPL-Secondary (less than 500 kilowatts).

BGS ENERGY & CAPACITY CHARGES:

Applicable to Rate Schedules RS, RHS, RLM, WH, WHS, HS, BPL, BPL-POF and PSAL

Charges per kilowatt-hour:

	For usage in each of the months of October through May		For usage in each of the months of June through September	
Rate Schedule	Energy & Capacity Charges	Charges Including SUT	Energy & Capacity Charges	Charges Including SUT
RS – first 600 kWh	$ 0.075527	$ 0.080531	$ 0.072237	$ 0.077023
RS – in excess of 600 kWh	0.075527	0.080531	0.081381	0.086772
RHS – first 600 kWh	0.076746	0.081830	0.068808	0.073367
RHS – in excess of 600 kWh	0.076746	0.081830	0.081036	0.086405
RLM On-Peak	0.089221	0.095132	0.094156	0.100394
RLM Off-Peak	0.064475	0.068746	0.059459	0.063398
WH	0.068204	0.072723	0.066577	0.070988
WHS	0.066441	0.070843	0.066429	0.070830
HS	0.078509	0.083710	0.075325	0.080315
BPL	0.066509	0.070915	0.061239	0.065296
BPL-POF	0.066509	0.070915	0.061239	0.065296
PSAL	0.066509	0.070915	0.061239	0.065296

The above Basic Generation Service Energy Charges reflect costs for Energy, Generation Capacity, and Ancillary Services (including PJM Interconnection, L.L.C. (PJM) Administrative Charges).

Kilowatt threshold noted above is based upon the customer's Peak Load Share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM). See Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions of this Tariff.

(Charges are for illustrative purposes only and are based on the Fourteenth Revised Sheet No. 75 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 76**

BASIC GENERATION SERVICE – RESIDENTIAL SMALL COMMERCIAL PRICING (BGS-RSCP)
ELECTRIC SUPPLY CHARGES
(Continued)

BGS TRANSMISSION CHARGES:

Applicable to Rate Schedules RS, RHS, RLM, WH, WHS, HS, BPL, BPL-POF and PSAL

Charges per kilowatt-hour:

	For usage in all months	
Rate Schedule	Transmission Charges	Charges Including SUT
RS	$0.057428	$0.061233
RHS	0.037541	0.040028
RLM On-Peak	0.124829	0.133099
RLM Off-Peak	0.000000	0.000000
WH	0.000000	0.000000
WHS	0.000000	0.000000
HS	0.047976	0.051154
BPL	0.000000	0.000000
BPL-POF	0.000000	0.000000
PSAL	0.000000	0.000000

The above charges shall recover all costs related to the overall summer peak transmission load assigned to the Public Service Transmission Zone by the PJM Interconnection, L.L.C. (PJM) as adjusted by PJM assigned transmission capacity related factors and allocated to the above Rate Schedules. These charges will be changed from time to time on the effective date of such change to the PJM rate for charges for Network Integration Transmission Service, including the PJM Seams Elimination Cost Assignment Charges, the PJM Reliability Must Run Charge and PJM Transmission Enhancement Charges as approved by Federal Energy Regulatory Commission (FERC).

BGS ENERGY CHARGES:

Applicable to Rate Schedules GLP and LPL-Sec.

Charges per kilowatt-hour:

	For usage in each of the months of October through May		For usage in each of the months of June through September	
Rate Schedule	Charges	Charges Including SUT	Charges	Charges Including SUT
GLP	$0.067068	$0.071511	$0.067343	$0.071804
GLP Night Use	0.063526	0.067735	0.059237	0.063161
LPL-Sec. under 500 kW				
On-Peak	0.070936	0.075636	0.075223	0.080207
Off-Peak	0.063526	0.067735	0.059237	0.063161

The above Basic Generation Service Energy Charges reflect costs for Energy and Ancillary Services (including PJM Administrative Charges).

Kilowatt thresholds noted above are based upon the customer's Peak Load Share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM). See Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions of this Tariff.

(Charges are for illustrative purposes only and are based on the Fifteenth Revised Sheet No. 76 filed with the BPU on November 1, 2023)

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 79**

BASIC GENERATION SERVICE – RESIDENTIAL SMALL COMMERCIAL PRICING (BGS-RSCP)
ELECTRIC SUPPLY CHARGES
(Continued)

BGS CAPACITY CHARGES:

Applicable to Rate Schedules GLP and LPL-Sec.
Charges per kilowatt of Generation Obligation:

Charge applicable in the months of June through September .... $ 1.6327
Charge including New Jersey Sales and Use Tax (SUT) .... $ 1.7409

Charge applicable in the months of October through May .... $ 1.6327
Charge including New Jersey Sales and Use Tax (SUT) .... $ 1.7409

The above charges shall recover each customer’s share of the overall summer peak load assigned to the Public Service Transmission Zone by the PJM Interconnection, L.L.C. (PJM) as adjusted by PJM assigned capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions.

BGS TRANSMISSION CHARGES

Applicable to Rate Schedules GLP and LPL-Sec.
Charges per kilowatt of Transmission Obligation:

Currently effective Annual Transmission Rate for Network Integration Transmission Service for the Public Service Transmission Zone as derived from the FERC Electric Tariff of the PJM Interconnection, LLC .... $ 142,957.59 per MW per year
EL05-121 .... $ 77.54 per MW per month
FERC 680 & 715 Reallocation .... $ 0.00 per MW per month
PJM Seams Elimination Cost Assignment Charges .... $ 0.00 per MW per month
PJM Reliability Must Run Charge .... $ 0.00 per MW per month
PJM Transmission Enhancements
- Trans-Allegheny Interstate Line Company .... $ 52.61 per MW per month
- Virginia Electric and Power Company .... $ 63.65 per MW per month
- Potomac-Appalachian Transmission Highline L.L.C .... $ 0.49 per MW per month
- PPL Electric Utilities Corporation .... $ 181.69 per MW per month
- American Electric Power Service Corporation .... $ 17.58 per MW per month
- Atlantic City Electric Company .... $ 8.46 per MW per month
- Delmarva Power and Light Company .... $ 1.28 per MW per month
- Potomac Electric Power Company .... $ 2.70 per MW per month
- Baltimore Gas and Electric Company .... $ 3.89 per MW per month
- Jersey Central Power and Light .... $ 60.23 per MW per month
- Mid Atlantic Interstate Transmission .... $ 18.06 per MW per month
- PECO Energy Company .... $ 23.93 per MW per month
- Silver Run Electric, Inc .... $ 44.16 per MW per month
- Northern Indiana Public Service Company .... $ 0.73 per MW per month
- Commonwealth Edison Company .... $ 0.13 per MW per month
- South First Energy Operating Company .... $ 0.66 per MW per month
- Duquesne Light Company .... $ 0.33 per MW per month

Above rates converted to a charge per kW of Transmission Obligation, applicable in all months .... $ 12.4713
Charge including New Jersey Sales and Use Tax (SUT) .... $ 13.2975

The above charges shall recover each customer’s share of the overall summer peak transmission load assigned to the Public Service Transmission Zone by the PJM Interconnection, L.L.C. (PJM) as adjusted by PJM assigned transmission capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions. These charges will be changed from time to time on the effective date of such change to the PJM rate for charges for Network Integration Transmission Service, including the PJM Seams Elimination Cost Assignment Charges, the PJM Reliability Must Run Charge and PJM Transmission Enhancement Charges as approved by Federal Energy Regulatory Commission (FERC).

(Charges are for illustrative purposes only and are based on the Twenty-Third Revised Sheet No. 79 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 80**

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 81**

**BASIC GENERATION SERVICE – RESIDENTIAL SMALL COMMERCIAL PRICING (BGS-RSCP)
ELECTRIC SUPPLY CHARGES
(Continued)**

BGS RECONCILIATION CHARGES:

Charges per kilowatthour:

Basic Generation Service Reconciliation Charge .... $(0.006791)

Charge including New Jersey Sales and Use Tax (SUT).. $(0.007241)

The above charges shall recover the difference between the monthly amount paid to Basic Generation Service (BGS) suppliers and the total revenue from customers for BGS for the preceding months for the applicable BGS supply. These charges include all applicable taxes and are updated quarterly. These charges shall be combined with the BGS Energy Charges for billing.

(Charges are for illustrative purposes only and are based on the Fortieth Revised Sheet No. 81 filed with the BPU on August 15, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 82**

BASIC GENERATION SERVICE – COMMERCIAL AND INDUSTRIAL ENERGY PRICING (CIEP) ELECTRIC SUPPLY CHARGES

APPLICABLE TO:

Default electric supply service for Rate Schedules LPL-Secondary (500 kilowatts or greater), LPL-Primary, HTS-Subtransmission, HTS-Transmission, HTS-High Voltage and to customers served under Rate Schedules HS, GLP and LPL-Secondary (less than 500 kilowatts) who have elected BGS-CIEP as their default supply service.

BGS ENERGY CHARGES:

Charges per kilowatt-hour:

BGS Energy Charges are hourly and include PJM Locational Marginal Prices, and PJM Ancillary Services. The total BGS Energy Charges are based on the sum of the following:

- The real time PJM Load Weighted Average Residual Metered Load Aggregate Locational Marginal Prices for the Public Service Transmission Zone, adjusted for losses (tariff losses, as defined in Standard Terms and Conditions Section 4.3, adjusted to remove the mean hourly PJM marginal losses of 0.79690%), and adjusted for SUT, plus
- Ancillary Services (including PJM Administrative Charges) at the rate of $0.006000 per kilowatt-hour, adjusted for losses (tariff losses, as defined in Standard Terms and Conditions Section 4.3, adjusted to remove the mean hourly PJM marginal losses of 0.79690%), and adjusted for SUT, plus

BGS CAPACITY CHARGES:

Charges per kilowatt of Generation Obligation:

Charge applicable in the months of June through September $10.0663
Charge including New Jersey Sales and Use Tax (SUT) $10.7332

Charges applicable in the months of October through May $10.0663
Charges including New Jersey Sales and Use Tax (SUT)... $10.7332

The above charges shall recover each customer's share of the overall summer peak load assigned to the Public Service Transmission Zone by the PJM Interconnection, L.L.C. (PJM) as adjusted by PJM assigned capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions.

(Charges are for illustrative purposes only and are based on the Sixth Revised Sheet No. 82 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 83**

BASIC GENERATION SERVICE – COMMERCIAL AND INDUSTRIAL ENERGY PRICING (CIEP) ELECTRIC SUPPLY CHARGES (Continued)

BGS TRANSMISSION CHARGES

Charges per kilowatt of Transmission Obligation:

Currently effective Annual Transmission Rate for Network Integration Transmission Service for the Public Service Transmission Zone as derived from the FERC Electric Tariff of the PJM Interconnection, LLC	$ 142,957.59 per MW per year
EL05-121	$ 77.54 per MW per month
FERC 680 & 715 Reallocation	$ 0.00 per MW per month
PJM Seams Elimination Cost Assignment Charges	$ 0.00 per MW per month
PJM Reliability Must Run Charge	$ 0.00 per MW per month
PJM Transmission Enhancements	
Trans-Allegheny Interstate Line Company	$ 52.61 per MW per month
Virginia Electric and Power Company	$ 63.65 per MW per month
Potomac-Appalachian Transmission Highline L.L.C.	$ 0.49 per MW per month
PPL Electric Utilities Corporation	$ 181.69 per MW per month
American Electric Power Service Corporation	$ 17.58 per MW per month
Atlantic City Electric Company	$ 8.46 per MW per month
Delmarva Power and Light Company	$ 1.28 per MW per month
Potomac Electric Power Company	$ 2.70 per MW per month
Baltimore Gas and Electric Company	$ 3.89 per MW per month
Jersey Central Power and Light	$ 60.23 per MW per month
Mid Atlantic Interstate Transmission	$ 18.06 per MW per month
PECO Energy Company	$ 23.93 per MW per month
Silver Run Electric, Inc	$ 44.16 per MW per month
Northern Indiana Public Service Company	$ 0.73 per MW per month
Commonwealth Edison Company	$ 0.13 per MW per month
South First Energy Operating Company	$ 0.66 per MW per month
Duquesne Light Company	$ 0.33 per MW per month

Above rates converted to a charge per kW of Transmission Obligation, applicable in all months	$ 12.4713
Charge including New Jersey Sales and Use Tax (SUT)	$ 13.2975

The above charges shall recover each customer's share of the overall summer peak transmission load assigned to the Public Service Transmission Zone by the PJM Interconnection, L.L.C. (PJM) as adjusted by PJM assigned transmission capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions. These charges will be changed from time to time on the effective date of such charge to the PJM rate for charges for Network Integration Transmission Service, including the PJM Seams Elimination Cost Assignment Charges, the PJM Reliability Must Run Charge and PJM Transmission Enhancement Charges as approved by Federal Energy Regulatory Commission (FERC).

Kilowatt threshold noted above is based upon the customer's Peak Load Share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM). See Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions of this Tariff.

(Charges are for illustrative purposes only and are based on the Eighteenth Revised Sheet No. 83 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 84**

**BASIC GENERATION SERVICE – COMMERCIAL AND INDUSTRIAL ENERGY PRICING (CIEP)
ELECTRIC SUPPLY CHARGES
(Continued)**

BGS RECONCILIATION CHARGES:

Charges per kilowatthour:

Basic Generation Service Reconciliation Charge $0.003332

Charge including New Jersey Sales and Use Tax (SUT) $0.003553

The above charges shall recover the difference between the monthly amount paid to Basic Generation Service (BGS) suppliers and the total revenue from customers for BGS for the preceding months for the applicable BGS supply. These charges include all applicable taxes and are updated quarterly. These charges shall be combined with the BGS Energy Charges for billing.

(Charges are for illustrative purposes only and are based on the Fortieth Revised Sheet No. 84 filed with the BPU on August 15, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 85**
Original Sheet No. 86

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 87**

THIRD PARTY SUPPLIER

APPLICABLE TO:

A third party supplier is an entity that has executed a Third Party Supplier Agreement (Agreement) with Public Service so as to be eligible to furnish electric supply with delivery to the retail customer by Public Service. This Agreement sets forth the specific terms and conditions with which Third Party Suppliers must comply to use Public Service's distribution system to supply energy to retail customers in Public Service's service territory. This Agreement is standardized in form and will apply in an equal and uniform manner to all Third Party Suppliers requesting to provide competitive energy supply to retail customers in Public Service's service territory. The Agreement is hereby incorporated by reference herein, and similarly incorporates this Tariff for Electric Service in its terms.

All modifications to the Agreement must be approved by the Board, consistent with the process set forth below, prior to implementation. Any such modifications, other than Third Party Supplier fee changes, shall be undertaken in accordance with the following procedures. Specifically, Public Service may amend the Agreement by providing simultaneous written notice of such change, by regular mail, ~~facsimile, hand delivery,~~ or electronic means, to the Board of Public Utilities (Board), Division of Ratepayer Advocate (RPA), Jersey Central Power and Light, Atlantic City Electric Company, Rockland Electric and to Third Party Suppliers licensed as Electric Power Suppliers in New Jersey, a list of which will be provided by the Board. Within seventeen (17) days of such notice, the RPA or any New Jersey licensed Electric Power Supplier wishing to contest the amendment of the Agreement must submit in writing to the Board its reason for contesting the change, and must simultaneously provide a copy of such document to Public Service. Within forty-five (45) days of such notice, the Board may either (i) approve the amendment; (ii) determine through a suspension order that the proposed amendment needs further study, and thus place the request on hold pending future action by the Board; or (iii) take no action, in which case Public Service may implement the amendment at the conclusion of the forty-five (45) day period; provided, however, that the Board is not thereby precluded from taking action on the amendment in the future.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC

Original Sheet No. 88
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RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 93**

RATE SCHEDULE RS
RESIDENTIAL SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Delivery service for residential purposes. Customers may either purchase electric supply from a Third Party Supplier (TPS) or from Public Service's Basic Generation Service default service as detailed in this rate schedule.

DELIVERY CHARGES:

Service Charge:

$4.64 in each month [$4.95 including New Jersey Sales and Use Tax (SUT)].

Distribution Charges per Kilowatt-hour:

First 600 hours used in each of the months of:

October through May		June through September	
Charge	Charge Including SUT	Charge	Charge Including SUT
$ 0.033344	$ 0.035553	$ 0.045704	$ 0.048732

In excess of 600 hours used in each of the months of:

October through May		June through September	
Charge	Charge Including SUT	Charge	Charge Including SUT
$ 0.033344	$ 0.035553	$ 0.049525	$ 0.052806

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 70 for details of these charges.

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Non-utility Generation Charge:

This charge shall recover above market costs associated with non-utility generation costs and other generation related costs as may be approved by the Board. Refer to the Non-utility Generation Charge sheet of this Tariff for the current charge.

Solar Pilot Recovery Charge:

This charge is designed to recover the revenue requirements associated with the Public Service Solar Pilot Program per the Board Order in Docket Nos. ER18010029, GR18010030, AX18010001 and ER18030231 EO07040278 less the net proceeds from the sale of associated Solar Renewable Energy Certificates (SRECs) or cash received in lieu of SRECs. Refer to the Solar Pilot Recovery Charge sheet of this tariff for the current charge.

(Charges are for illustrative purposes only and are based on the Seventh Revised Sheet No. 93 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 93 for Future**

RATE SCHEDULE RS
RESIDENTIAL SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Delivery service for residential purposes. Customers may either purchase electric supply from a Third Party Supplier (TPS) or from Public Service's Basic Generation Service default service as detailed in this rate schedule.

DELIVERY CHARGES:

Service Charge:
$4.64 in each month [$4.95 including New Jersey Sales and Use Tax (SUT)].

Distribution Charges per Kilowatt-hour for RS non-Time of Use (TOU) customers:

First 600 hours used in each of the months of:

October through May		June through September	
Charge	Charge Including SUT	Charge	Charge Including SUT
$ 0.033344	$ 0.035553	$ 0.045704	$ 0.048732

In excess of 600 hours used in each of the months of:

October through May		June through September	
Charge	Charge Including SUT	Charge	Charge Including SUT
$ 0.033344	$ 0.035553	$ 0.049525	$ 0.052806

Distribution Charges per Kilowatt-hour for RS TOU customers (see Special Provision (a-8) for details)

For customers selecting two-period option (TOU-2P):

		June through September		October through May	
		Charges	Charges Including SUT	Charges	Charges Including SUT
On-Peak	4 pm - 9 pm (weekdays)*	$ X.XXXXXX	$ X.XXXXXX	$ X.XXXXXX	$ X.XXXXXX
Off-Peak	10 pm - 11 am	$ X.XXXXXX	$ X.XXXXXX	$ X.XXXXXX	$ X.XXXXXX

For customers selecting three-period option (TOU-3P):

		June through September		October through May	
		Charges	Charges Including SUT	Charges	Charges Including SUT
On-Peak	4 pm - 9 pm (weekdays)*	$ X.XXXXXX	$ X.XXXXXX	$ X.XXXXXX	$ X.XXXXXX
Mid-Peak	All other times	$ X.XXXXXX	$ X.XXXXXX	$ X.XXXXXX	$ X.XXXXXX
Off-Peak	Midnight - 6 am	$ X.XXXXXX	$ X.XXXXXX	$ X.XXXXXX	$ X.XXXXXX

* Weekdays exclude PJM holidays.

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 70 for details of these charges.

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Non-utility Generation Charge:

This charge shall recover above market costs associated with non-utility generation costs and other generation related costs as may be approved by the Board. Refer to the Non-utility Generation Charge sheet of this Tariff for the current charge.

Solar Pilot Recovery Charge:

This charge is designed to recover the revenue requirements associated with the Public Service Solar Pilot Program per the Board Order in Docket Nos. ER18010029, GR18010030, AX18010001 and ER18030231 EO07040278 less the net proceeds from the sale of associated Solar Renewable Energy Certificates (SRECs) or cash received in lieu of SRECs. Refer to the Solar Pilot Recovery Charge sheet of this tariff for the current charge.

(Charges are for illustrative purposes only and are based on the Seventh Revised Sheet No. 93 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 94**

RATE SCHEDULE RS
RESIDENTIAL SERVICE
(Continued)

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

Tax Adjustment Credit:

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current credit.

Zero Emission Certificate Recovery Charge:

This charge provides for the recovery of costs associated with the Zero Emission Certificate Program directed by the Board of Public Utilities ("BPU" or "Board"). Refer to the Zero Emission Certificate Recovery Charge sheet of this Tariff for the current charge.

Conservation Incentive Program Charge:

This mechanism provides for recovery of lost revenues associated with various energy efficiency programs. Refer to the Conservation Incentive Program sheet of this Tariff for the current charge.

Distribution Adjustment Charge:

This charge is designed to recover Board-approved costs. Refer to the Distribution Adjustment Charge sheet of this Tariff for the current charge.

The Distribution Charges, Societal Benefits Charge, Non-utility Generation Charge, the Solar Pilot Recovery Charge, the Green Programs Recovery Charge, the Tax Adjustment Credit, the Zero Emission Certificate Recovery Charge, ~~and~~ the Conservation Incentive Program Charge, and the Distribution Adjustment Charge shall be combined for billing.

ELECTRIC SUPPLY CHARGES:

A customer may choose to receive electric supply from either:

a) A TPS as described in Section 14 of this Tariff, or
b) Public Service through its Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP) default service.

Third Party Supply:

A customer that receives electric supply from a TPS will be charged for electric supply according to any agreement between the customer and the TPS. The customer will not be charged for electric supply by Public Service.

Basic Generation Service:

Customers that do not receive electric supply from a TPS will be supplied under the Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP) default service.

The BGS Energy Charges and the BGS Reconciliation Charge, as applicable, will be applied to all kilowatt-hours billed each month. Refer to the Basic Generation Service sheets of this Tariff for the current charges applicable to Rate Schedule RS.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 95**

RATE SCHEDULE RS
RESIDENTIAL SERVICE
(Continued)

MINIMUM CHARGE:

The minimum charge shall be equal to the monthly Service Charge.~~Where all or part of the electricity utilized by the customer is produced from on-site generation equipment and not delivered by Public Service, a Monthly Minimum charge of $2.95 ($3.15 including SUT) per kW of Measured Peak Demand The customer's Measured Peak Demand in any month shall be the greatest average number of kilowatts delivered by Public Service during any thirty-minute interval as registered by a demand meter furnished by Public Service. Revenue to satisfy the Monthly Minimum requirement shall be derived solely from Distribution Kilowatt-hour Charges.~~

~~This Minimum Charge shall not apply to Qualified Customer-Generators as defined in the Standard Terms and Conditions Section 15.2 in accordance with N.J.A.C. 14:8-4.3(n).~~

GENERATION CAPACITY AND TRANSMISSION OBLIGATIONS:

Generation Obligation:

The customer's Generation Obligation, in kilowatts, is determined by Public Service no less frequently than once a year. The Generation Obligation for existing customers or for new customers utilizing an existing building or premise is based upon the customer's share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM) as adjusted by PJM assigned capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions. The Generation Obligation for customers taking service in a new building or premise, as determined by Public Service, is based upon the load requirements, as estimated by Public Service, of the customer's building or premise. The Generation Obligation represents the generator capacity that PJM requires an electric supplier to have available to provide electric supply to a customer.

Transmission Obligation:

The customer's Transmission Obligation, in kilowatts, is determined in a similar manner to the Generation Obligation described above. The Transmission Obligation represents the level of transmission network service that must be procured by the customer's electric supplier from PJM to provide service to the customer.

Costs associated with the Generation and Transmission Obligations are included in the charges for Basic Generation Service and may affect the price offered by a Third Party Supplier.

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill.

TERM:

Customer may discontinue delivery service upon notice.

SPECIAL PROVISIONS:

(a) **Limitations on Service:** This rate schedule is available where all service is measured by one meter, except for service provided under Rate Schedules WH or WHS:

(a-1) In individual residences and appurtenant outbuildings;

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

RATE SCHEDULE RS
RESIDENTIAL SERVICE
(Continued)

(a-2) In residential premises where customer's use of electric service for purposes other than residential is incidental to its residential use;

(a-3) On residential farms;

(a-4) For rooming or boarding houses where the number of rented rooms does not exceed twice the number of bedrooms occupied by the customer;

(a-5) To a customer in a two- or three-family building who has the service for incidental common-use equipment registered on its meter;

(a-6) In individual flats or apartments in multiple-family buildings;

(a-7) In multiple-family buildings of two or more individual flats or apartments where electric service is furnished to the tenants or occupants of the flats or apartments by the owner without a specific charge for such service, provided that the number of kilowatt-hours in each block of the Distribution Charge are multiplied by the number of individual flats or apartments, whether occupied or not.

(b) **Resale:** Service under this rate schedule is not available for resale.

(c) **TPS Supply:** Customers who desire to purchase their electric supply from a TPS may request an enrollment package from Public Service that describes the process necessary for the customer to obtain a TPS for electric supply. This package will be provided to the customer at no charge by Public Service.

(c-1) The customer must contract with a TPS to arrange for deliveries to Public Service of the electric supply. A customer is limited to one TPS for electric supply for each account for which the customer receives delivery service.

(c-2) The customer's TPS is required to notify Public Service of the customer's selection prior to 13 days before the customer's scheduled Public Service meter reading date for deliveries to commence on such scheduled meter reading date, and such selection shall remain in effect for the entire billing month. Customer can change TPSs effective only on the date of the customer's scheduled Public Service meter reading date.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 96 for Future**

RATE SCHEDULE RS
RESIDENTIAL SERVICE
(Continued)

(a-2) In residential premises where customer's use of electric service for purposes other than residential is incidental to its residential use;

(a-3) On residential farms;

(a-4) For rooming or boarding houses where the number of rented rooms does not exceed twice the number of bedrooms occupied by the customer;

(a-5) To a customer in a two- or three-family building who has the service for incidental common-use equipment registered on its meter;

(a-6) In individual flats or apartments in multiple-family buildings;

(a-7) In multiple-family buildings of two or more individual flats or apartments where electric service is furnished to the tenants or occupants of the flats or apartments by the owner without a specific charge for such service, provided that the number of kilowatt-hours in each block of the Distribution Charge are multiplied by the number of individual flats or apartments, whether occupied or not~~.~~;

(a-8) In multiple-family buildings of two or more individual flats or apartments where a dedicated parking space is available and where a customer is served on a separate meter for electric vehicle charging use. This provision is only available to customers receiving this service under special provision (d);

(a-9) In detached garage on a residential parcel for the purposes of charging electric vehicles. This provision is only available to customers receiving this service under special provision (d);

(a-10) **Multi-Family Residential Electric Vehicle Charging:** Available to new and existing all Company-qualified Level 2 Electric Vehicle Charging Stations located at Multifamily Dwellings ("Multifamily Level 2 Electric Vehicle Charging Station") at a separately metered premise from the metering at the multifamily complex.

(b) **Resale:** Service under this rate schedule is not available for resale.

(c) **TPS Supply:** Customers who desire to purchase their electric supply from a TPS may request an enrollment package from Public Service that describes the process necessary for the customer to obtain a TPS for electric supply. This package will be provided to the customer at no charge by Public Service.

(c-1) The customer must contract with a TPS to arrange for deliveries to Public Service of the electric supply. A customer is limited to one TPS for electric supply for each account for which the customer receives delivery service.

(c-2) The customer's TPS is required to notify Public Service of the customer's selection prior to 13 days before the customer's scheduled Public Service meter reading date for deliveries to commence on such scheduled meter reading date, and such selection shall remain in effect for the entire billing month. Customer can change TPSs effective only on the date of the customer's scheduled Public Service meter reading date.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 97**

RATE SCHEDULE RS
RESIDENTIAL SERVICE
(Continued)

(d) **Electric Vehicle Distribution Only:** Based upon the following eligibility criteria, residential customers may elect to receive on-peak and off-peak distribution energy charges from the Residential Load Management (RLM) rate schedule exclusively for their electric vehicle usage. This option, upon Company approval into the program, will be issued as a credit on the customer bill on at least a quarterly basis, after the entire usage has been billed at the RS rate. All other provisions of this tariff will remain in effect.

(d-1) A customer taking service under this special provision must install or utilize PSE&G approved smart charging hardware and network technology. The customer must also agree to share the Electric Vehicle Charging Data with PSE&G in a manner specified by PSE&G. Data must be available to the Company and necessary billing system changes must be in place in order for these incentives to begin.

(d-2) The electric vehicle credit will be calculated by the Company’s program administrator at least quarterly using the electric vehicle usage at the Rate Schedule RLM distribution rates less the electric vehicle usage billed at Rate Schedule RS distribution rates for the corresponding billing period. If the credit calculation results in charges that would be in excess of the bill calculated using the RS distribution rates, no adjustment for the corresponding period will be applied.

(d-3) For ratemaking purposes, the electric vehicle RLM Distribution Only Provision credits associated with this special provision will be reflected as a reduction to the Rate Schedule RS distribution revenue. The credit will be applied at least quarterly to the customer bill and will indicate the corresponding period(s) for which the credit applies.

(d-4) This special provision will remain in effect until the conclusion of the Company’s Next Base Rate Case.

(e) **Electric Vehicle Basic Generation Supply (BGS) Customers Only**: Based upon the following eligibility criteria, residential customers who receive their electric supply via BGS may elect to receive on-peak and off-peak supply charges based on BGS rates applicable to Rate Schedule Residential Load Management (RLM) exclusively for their electric vehicle charging usage. This option, upon Company approval into the program, will be issued as a credit on the customer bill on at least a quarterly basis, after the entire usage has been billed at the BGS rates applicable to Rate Schedule RS. All other provisions of this tariff will remain in effect.

(e-1) A customer taking service under this special provision must install or utilize PSE&G approved smart charging hardware and network technology. The customer must also agree to share the Electric Vehicle Charging Data with PSE&G in a manner specified by PSE&G. Data must be available to the Company and necessary billing system changes must be in place in order for these incentives to begin.

(e-2) The electric vehicle credit will be calculated by the Company’s program administrator at least quarterly using the electric vehicle usage at the BGS rates applicable to Rate Schedule RLM less the electric vehicle usage billed at the BGS rates applicable to Rate Schedule RS for the corresponding billing period. If the credit calculation results in charges that would be in excess of the bill calculated using the BGS rates applicable to Rate Schedule RS, no adjustment for the corresponding period will be applied.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 97 for Future**

RATE SCHEDULE RS
RESIDENTIAL SERVICE
(Continued)

~~(d) **Electric Vehicle Distribution Only:** Based upon the following eligibility criteria, residential customers may elect to receive on-peak and off-peak distribution energy charges from the Residential Load Management (RLM) rate schedule exclusively for their electric vehicle usage. This option, upon Company approval into the program, will be issued as a credit on the customer bill on at least a quarterly basis, after the entire usage has been billed at the RS rate. All other provisions of this tariff will remain in effect.~~

~~(d-1) A customer taking service under this special provision must install or utilize PSE&G approved smart charging hardware and network technology. The customer must also agree to share the Electric Vehicle Charging Data with PSE&G in a manner specified by PSE&G. Data must be available to the Company and necessary billing system changes must be in place in order for these incentives to begin.~~

~~(d-2) The electric vehicle credit will be calculated by the Company's program administrator at least quarterly using the electric vehicle usage at the Rate Schedule RLM distribution rates less the electric vehicle usage billed at Rate Schedule RS distribution rates for the corresponding billing period. If the credit calculation results in charges that would be in excess of the bill calculated using the RS distribution rates, no adjustment for the corresponding period will be applied.~~

~~(d-3) For ratemaking purposes, the electric vehicle RLM Distribution Only Provision credits associated with this special provision will be reflected as a reduction to the Rate Schedule RS distribution revenue. The credit will be applied at least quarterly to the customer bill and will indicate the corresponding period(s) for which the credit applies.~~

~~(d-4) This special provision will remain in effect until the conclusion of the Company's Next Base Rate Case.~~

~~(e) **Electric Vehicle Basic Generation Supply (BGS) Customers Only**: Based upon the following eligibility criteria, residential customers who receive their electric supply via BGS may elect to receive on-peak and off-peak supply charges based on BGS rates applicable to Rate Schedule Residential Load Management (RLM) exclusively for their electric vehicle charging usage. This option, upon Company approval into the program, will be issued as a credit on the customer bill on at least a quarterly basis, after the entire usage has been billed at the BGS rates applicable to Rate Schedule RS. All other provisions of this tariff will remain in effect.~~

~~(e-1) A customer taking service under this special provision must install or utilize PSE&G approved smart charging hardware and network technology. The customer must also agree to share the Electric Vehicle Charging Data with PSE&G in a manner specified by PSE&G. Data must be available to the Company and necessary billing system changes must be in place in order for these incentives to begin.~~

~~(e-2) The electric vehicle credit will be calculated by the Company's program administrator at least quarterly using the electric vehicle usage at the BGS rates applicable to Rate Schedule RLM less the electric vehicle usage billed at the BGS rates applicable to Rate Schedule RS for the corresponding billing period. If the credit calculation results in charges that would be in excess of the bill calculated using the BGS rates applicable to Rate Schedule RS, no adjustment for the corresponding period will be applied.~~

(d) **Residential Time of Use**: RS customers may elect to take the RS TOU rate.

(d-1) Such customers will be required to stay on the RS TOU rate for a minimum of twelve (12) months.

(d-2) At the end of the initial 12-month period, the Company will provide the customer with reporting showing their 12-month bill on the new RS TOU rate and what their 12-month bill would have been on the non-TOU RS rate schedule. The customer will be offered a one-time refund of the difference if the 12 month bill on the RS TOU rate was higher compared to the RS rate schedule. This provision ~~applies~~is available only to customers who enroll in RS TOU rates during the first twenty-four (24) months ~~of the implementation of the RS TOU rate~~following the effective date of this tariff provision..

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

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RATE SCHEDULE RS
RESIDENTIAL SERVICE
(Continued)

(e-3) This special provision will remain in effect until the conclusion of the Company's Next Base Rate Case.

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 16 of the Standard Terms and Conditions for additional details and/or exceptions.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 98 for Future**

RATE SCHEDULE RS
RESIDENTIAL SERVICE
(Continued)

~~(e-3) This special provision will remain in effect until the conclusion of the Company's Next Base Rate Case.~~

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 16 of the Standard Terms and Conditions for additional details and/or exceptions.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 99**

RATE SCHEDULE RHS
RESIDENTIAL HEATING SERVICE

APPLICABLE TO USE OF SERVICE FOR:

This rate schedule is closed and is in the process of elimination. Delivery service under this rate schedule is limited to residential purposes where electricity is the sole source of space heating for customers at their current premise that are presently served under this rate schedule. Customers may either purchase electric supply from a Third Party Supplier (TPS) or from Public Service's Basic Generation Service default service as detailed in this rate schedule.

DELIVERY CHARGES:

Service Charge:

$4.64 in each month [$4.95 including New Jersey Sales and Use Tax (SUT)].

Distribution Charges per Kilowatt-hour:

First 600 hours used in each of the months of:

October through May		June through September	
Charge	Charge Including SUT	Charge	Charge Including SUT
$ 0.034719	$ 0.037019	$ 0.052835	$ 0.056335

In excess of 600 hours used in each of the months of:

October through May		June through September	
Charge	Charge Including SUT	Charge	Charge Including SUT
$ 0.017119	$ 0.018253	$ 0.057735	$ 0.061560

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 70 for details of these charges.

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Non-utility Generation Charge:

This charge shall recover above market costs associated with non-utility generation costs and other generation related costs as may be approved by the Board. Refer to the Non-utility Generation Charge sheet of this Tariff for the current charge.

Solar Pilot Recovery Charge:

This charge is designed to recover the revenue requirements associated with the Public Service Solar Pilot Program per the Board Order in Docket No. EO07040278 less the net proceeds from the sale of associated Solar Renewable Energy Certificates (SRECs) or cash received in lieu of SRECs. Refer to the Solar Pilot Recovery Charge sheet of this tariff for the current charge.

(Charges are for illustrative purposes only and are based on the Seventh Revised Sheet No. 99 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 100**

RATE SCHEDULE RHS
RESIDENTIAL HEATING SERVICE
(Continued)

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

Tax Adjustment Credit:

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current credit.

Zero Emission Certificate Recovery Charge:

This charge provides for the recovery of costs associated with the Zero Emission Certificate Program directed by the Board of Public Utilities ("BPU" or "Board"). Refer to the Zero Emission Certificate Recovery Charge sheet of this Tariff for the current charge.

Conservation Incentive Program Charge:

This mechanism provides for recovery of lost revenues associated with various energy efficiency programs. Refer to the Conservation Incentive Program sheet of this Tariff for the current charge.

Distribution Adjustment Charge:

This charge is designed to recover Board-approved costs. Refer to the Distribution Adjustment Charge sheet of this Tariff for the current charge.

The Distribution Charges, Societal Benefits Charge, Non-utility Generation Charge, the Solar Pilot Recovery Charge, the Green Programs Recovery Charge, the Tax Adjustment Credit, the Zero Emission Certificate Recovery Charge ~~and~~, the Conservation Incentive Program Charge, and the Distribution Adjustment Charge shall be combined for billing.

ELECTRIC SUPPLY CHARGES:

A customer may choose to receive electric supply from either:
a) A TPS as described in Section 14 of this Tariff, or
b) Public Service through its Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP) default service.

Third Party Supply:

A customer that receives electric supply from a TPS will be charged for electric supply according to any agreement between the customer and the TPS. The customer will not be charged for electric supply by Public Service.

Basic Generation Service:

Customers that do not receive electric supply from a TPS will be supplied under the Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP) default service.

The BGS Energy Charges and the BGS Reconciliation Charge, as applicable, will be applied to all kilowatt-hours billed each month. Refer to the Basic Generation Service sheets of this Tariff for the current charges applicable to Rate Schedule RHS.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 101**

RATE SCHEDULE RHS
RESIDENTIAL HEATING SERVICE
(Continued)

MINIMUM CHARGE:

The minimum charge shall be equal to the monthly Service Charge.~~Where all or part of the electricity utilized by the customer is produced from on-site generation equipment and not delivered by Public Service, a Monthly Minimum charge of $2.95 ($3.15 including SUT) per kW of Measured Peak Demand. The customer's Measured Peak Demand in any month shall be the greatest average number of kilowatts delivered by Public Service during any thirty-minute interval as registered by a demand meter furnished by Public Service. Revenue to satisfy the Monthly Minimum requirement shall be derived solely from Distribution Kilowatt-hour Charges.~~

~~This Minimum Charge shall not apply to Qualified Customer-Generators as defined in the Standard Terms and Conditions Section 15.2 in accordance with N.J.A.C. 14:8-4.3(n).~~

GENERATION CAPACITY AND TRANSMISSION OBLIGATIONS:

Generation Obligation:

The customer's Generation Obligation, in kilowatts, is determined by Public Service no less frequently than once a year. The Generation Obligation for existing customers or for new customers utilizing an existing building or premise is based upon the customer's share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM) as adjusted by PJM assigned capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions. The Generation Obligation for customers taking service in a new building or premise, as determined by Public Service, is based upon the load requirements, as estimated by Public Service, of the customer's building or premise. The Generation Obligation represents the generator capacity that PJM requires an electric supplier to have available to provide electric supply to a customer.

Transmission Obligation:

The customer's Transmission Obligation, in kilowatts, is determined in a similar manner to the Generation Obligation described above. The Transmission Obligation represents the level of transmission network service that must be procured by the customer's electric supplier from PJM to provide service to the customer.

Costs associated with the Generation and Transmission Obligations are included in the charges for Basic Generation Service and may affect the price offered by a Third Party Supplier.

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill.

TERM:

Customer may discontinue delivery service upon notice.

SPECIAL PROVISIONS:

(a) **General Limitations on Service:** This rate schedule is available where space heating equipment is permanently installed and is operated at not less than 208 volts and where all service is measured by one meter, except for service provided under Rate Schedules WH and WHS:

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 102**

RATE SCHEDULE RHS
RESIDENTIAL HEATING SERVICE
(Continued)

(a-1) In individual residences and appurtenant outbuildings;

(a-2) In individual apartments in a multiple-family building;

(a-3) In all-electric multiple-family building where electricity is furnished to the tenants as an incident to tenancy and is included in the rent, provided that the number of kilowatt-hours in each block of the Kilowatt-hour Charge are multiplied by the number of individual flats or apartments, whether occupied or not;

(a-4) Common-use equipment in an all electric multiple-family building in which each tenant is served individually under this rate schedule. The Distribution Charge for the kilowatt-hours used in each month shall be $0.057735 per kilowatt-hour ($0.061560 including SUT).

(b) **Limitations on Water Heating Service:** When electricity is used for water heating under this rate schedule, such service shall be to an automatic type water heater approved by Public Service; furthermore, if the water heater is equipped with more than one heating element, the thermostats controlling the heating elements shall be interlocked so that only one of such elements can operate at a time.

If water is centrally heated under (a-4), equipment shall be of an automatic type approved by Public Service, and billing under this rate schedule is not required.

(c) **Resale:** Service under this rate schedule is not available for resale.

(d) **TPS Supply:** Customers who desire to purchase their electric supply from a TPS may request an enrollment package from Public Service that describes the process necessary for the customer to obtain a TPS for electric supply. This package will be provided to the customer at no charge by Public Service.

(d-1) The customer must contract with a TPS to arrange for deliveries to Public Service of the electric supply. A customer is limited to one TPS for electric supply for each account for which the customer receives delivery service.

(d-2) The customer’s TPS is required to notify Public Service of the customer’s selection prior to 13 days before the customer’s scheduled Public Service meter reading date for deliveries to commence on such scheduled meter reading date, and such selection shall remain in effect for the entire billing month. Customer can change TPSs effective only on the date of the customer’s scheduled Public Service meter reading date.

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 16 of the Standard Terms and Conditions for additional details and/or exceptions.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff.

(Charges are for illustrative purposes only and are based on the Fifth Revised Sheet No. 102 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 103**
Original Sheet No. 104

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 105**

RATE SCHEDULE RLM
RESIDENTIAL LOAD MANAGEMENT SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Delivery service for residential purposes. Customers may either purchase electric supply from a Third Party Supplier (TPS) or from Public Service's Basic Generation Service default service as detailed in this rate schedule.

DELIVERY CHARGES:

Service Charge:

$13.07 in each month [$13.94 including New Jersey Sales and Use Tax (SUT)].

Distribution Charges per Kilowatt-hour:

	In each of the months of October through May		In each of the months of June through September	
	Charges	Charges Including SUT	Charges	Charges Including SUT
On-Peak	$ 0.016062	$ 0.017126	$ 0.076937	$ 0.082034
Off-Peak	$ 0.016062	$ 0.017126	$ 0.016062	$ 0.017126

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 70 for details of these charges.

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Non-utility Generation Charge:

This charge shall recover above market costs associated with non-utility generation costs and other generation related costs as may be approved by the Board. Refer to the Non-utility Generation Charge sheet of this Tariff for the current charge.

Solar Pilot Recovery Charge:

This charge is designed to recover the revenue requirements associated with the Public Service Solar Pilot Program per the Board Order in Docket No. EO07040278 less the net proceeds from the sale of associated Solar Renewable Energy Certificates (SRECs) or cash received in lieu of SRECs. Refer to the Solar Pilot Recovery Charge sheet of this tariff for the current charge.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

(Charges are for illustrative purposes only and are based on the Seventh Revised Sheet No. 105 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 105 for Future**

RATE SCHEDULE RLM
RESIDENTIAL LOAD MANAGEMENT SERVICE

APPLICABLE TO USE OF SERVICE FOR:

This rate schedule is closed and is in the process of elimination. Delivery service for residential purposes. Customers may either purchase electric supply from a Third Party Supplier (TPS) or from Public Service's Basic Generation Service default service as detailed in this rate schedule.

DELIVERY CHARGES:

Service Charge:

$13.07 in each month [$13.94 including New Jersey Sales and Use Tax (SUT)].

Distribution Charges per Kilowatt-hour:

	In each of the months of October through May		In each of the months of June through September	
	Charges	Charges Including SUT	Charges	Charges Including SUT
On-Peak	$ 0.016062	$ 0.017126	$ 0.076937	$ 0.082034
Off-Peak	$ 0.016062	$ 0.017126	$ 0.016062	$ 0.017126

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 70 for details of these charges.

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Non-utility Generation Charge:

This charge shall recover above market costs associated with non-utility generation costs and other generation related costs as may be approved by the Board. Refer to the Non-utility Generation Charge sheet of this Tariff for the current charge.

Solar Pilot Recovery Charge:

This charge is designed to recover the revenue requirements associated with the Public Service Solar Pilot Program per the Board Order in Docket No. EO07040278 less the net proceeds from the sale of associated Solar Renewable Energy Certificates (SRECs) or cash received in lieu of SRECs. Refer to the Solar Pilot Recovery Charge sheet of this tariff for the current charge.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

(Charges are for illustrative purposes only and are based on the Seventh Revised Sheet No. 105 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 106**

RATE SCHEDULE RLM

RESIDENTIAL LOAD MANAGEMENT SERVICE

(Continued)

Tax Adjustment Credit:

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current credit.

Zero Emission Certificate Recovery Charge:

This charge provides for the recovery of costs associated with the Zero Emission Certificate Program directed by the Board of Public Utilities ("BPU" or "Board"). Refer to the Zero Emission Certificate Recovery Charge sheet of this Tariff for the current charge.

Conservation Incentive Program Charge:

This mechanism provides for recovery of lost revenues associated with various energy efficiency programs. Refer to the Conservation Incentive Program sheet of this Tariff for the current charge.

Distribution Adjustment Charge:

This charge is designed to recover Board-approved costs. Refer to the Distribution Adjustment Charge sheet of this Tariff for the current charge.

The Distribution Charges, Societal Benefits Charge, Non-utility Generation Charge, the Solar Pilot Recovery Charge, the Green Programs Recovery Charge, the Tax Adjustment Credit, the Zero Emission Certificate Recovery Charge, ~~and~~ the Conservation Incentive Program Charge, and the Distribution Adjustment Charge shall be combined for billing.

ELECTRIC SUPPLY CHARGES:

A customer may choose to receive electric supply from either:

a) A TPS as described in Section 14 of this Tariff, or
b) Public Service through its Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP) default service.

Third Party Supply:

A customer that receives electric supply from a TPS will be charged for electric supply according to any agreement between the customer and the TPS. The customer will not be charged for electric supply by Public Service.

Basic Generation Service:

Customers that do not receive electric supply from a TPS will be supplied under the Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP) default service.

The BGS Energy Charges and the BGS Reconciliation Charge, as applicable, will be applied to all kilowatt-hours billed each month. Refer to the Basic Generation Service sheets of this Tariff for the current charges applicable to Rate Schedule RLM.

MINIMUM CHARGE:

The minimum charge shall be equal to the monthly Service Charge.~~Where all or part of the electricity utilized by the customer is produced from on-site generation equipment and not delivered by Public Service, a Monthly Minimum charge of $2.95 ($3.15 including SUT) per kW of Measured Peak Demand. The customer's Measured Peak Demand in any month shall be the greatest average number of kilowatts delivered by Public Service during any thirty-minute interval as registered by a demand meter furnished by Public Service. Revenue to satisfy the Monthly Minimum requirement shall be derived solely from Distribution Kilowatt-hour Charges.~~

~~This Minimum Charge shall not apply to Qualified Customer-Generators as defined in the Standard Terms and Conditions Section 15.2 in accordance with N.J.A.C. 14:8-4.3(n).~~

Date of Issue: Effective:

Issued by SCOTT S. JENNINGS, SVP – Finance, Planning & Strategy – PSE&G
80 Park Plaza, Newark, New Jersey 07102
Filed pursuant to Order of Board of Public Utilities dated
in Docket No.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 107**

RATE SCHEDULE RLM
RESIDENTIAL LOAD MANAGEMENT SERVICE
(Continued)

GENERATION CAPACITY AND TRANSMISSION OBLIGATIONS:

Generation Obligation:

The customer's Generation Obligation, in kilowatts, is determined by Public Service no less frequently than once a year. The Generation Obligation for existing customers or for new customers utilizing an existing building or premise is based upon the customer's share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM) as adjusted by PJM assigned capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions. The Generation Obligation for customers taking service in a new building or premise, as determined by Public Service, is based upon the load requirements, as estimated by Public Service, of the customer's building or premise. The Generation Obligation represents the generator capacity that PJM requires an electric supplier to have available to provide electric supply to a customer.

Transmission Obligation:

The customer's Transmission Obligation, in kilowatts, is determined in a similar manner to the Generation Obligation described above. The Transmission Obligation represents the level of transmission network service that must be procured by the customer's electric supplier from PJM to provide service to the customer.

Costs associated with the Generation and Transmission Obligations are included in the charges for Basic Generation Service and may affect the price offered by a Third Party Supplier.

TIME PERIODS:

The On-Peak time period shall be considered as the hours from 7 A.M. to 9 P.M. (EST) Monday through Friday. All other hours shall be considered the Off-Peak time period.

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill.

TERM:

The term for delivery service is one year and thereafter until terminated by five days notice.

SPECIAL PROVISIONS:

(a) **Limitations on Service:** This rate schedule is available where all service is measured by one meter, except for service provided under Rate Schedules WH or WHS:

(a-1) In individual residences and appurtenant outbuildings;

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 108**

RATE SCHEDULE RLM

RESIDENTIAL LOAD MANAGEMENT SERVICE

(Continued)

(a-2) In residential premises where customer's use of electric service for purposes other than residential is incidental to its residential use;

(a-3) On residential farms;

(a-4) For rooming or boarding houses where the number of rented rooms does not exceed twice the number of bedrooms occupied by the customer;

(a-5) To a customer in a two- or three-family building who has the service for incidental common-use equipment registered on its meter;

(a-6) In individual flats or apartments in multiple-family buildings;

(a-7) In multiple-family buildings of two or more individual flats or apartments where electric service is furnished to the tenants or occupants of the flats or apartments by the owner without a specific charge for such service;

(b) **Resale:** Service under this rate schedule is not available for resale.

(c) **TPS Supply:** Customers who desire to purchase their electric supply from a TPS may request an enrollment package from Public Service that describes the process necessary for the customer to obtain a TPS for electric supply. This package will be provided to the customer at no charge by Public Service.

(c-1) The customer must contract with a TPS to arrange for deliveries to Public Service of the electric supply. A customer is limited to one TPS for electric supply for each account for which the customer receives delivery service.

(c-2) The customer's TPS is required to notify Public Service of the customer's selection prior to 13 days before the customer's scheduled Public Service meter reading date for deliveries to commence on such scheduled meter reading date, and such selection shall remain in effect for the entire billing month. Customer can change TPSs effective only on the date of the customer's scheduled Public Service meter reading date.

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 16 of the Standard Terms and Conditions for additional details and/or exceptions.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 108 for Future**

RATE SCHEDULE RLM

RESIDENTIAL LOAD MANAGEMENT SERVICE

(Continued)

(a-2) In residential premises where customer's use of electric service for purposes other than residential is incidental to its residential use;

(a-3) On residential farms;

(a-4) For rooming or boarding houses where the number of rented rooms does not exceed twice the number of bedrooms occupied by the customer;

(a-5) To a customer in a two- or three-family building who has the service for incidental common-use equipment registered on its meter;

(a-6) In individual flats or apartments in multiple-family buildings;

(a-7) In multiple-family buildings of two or more individual flats or apartments where electric service is furnished to the tenants or occupants of the flats or apartments by the owner without a specific charge for such service;~~.~~

(a-8) In multiple-family buildings of two or more individual flats or apartments where a dedicated parking space is available and where a customer is served on a separate meter for electric vehicle charging use;

(a-9) In detached garage on a residential parcel for the purposes of charging electric vehicles.

(a-10) **Multi-Family Residential Electric Vehicle Charging:** Available to new and existing all Company-qualified Level 2 Electric Vehicle Charging Stations located at Multifamily Dwellings ("Multifamily Level 2 Electric Vehicle Charging Station") at a separately metered premise from the metering at the multifamily complex.

(b) **Resale:** Service under this rate schedule is not available for resale.

(c) **TPS Supply:** Customers who desire to purchase their electric supply from a TPS may request an enrollment package from Public Service that describes the process necessary for the customer to obtain a TPS for electric supply. This package will be provided to the customer at no charge by Public Service.

(c-1) The customer must contract with a TPS to arrange for deliveries to Public Service of the electric supply. A customer is limited to one TPS for electric supply for each account for which the customer receives delivery service.

(c-2) The customer's TPS is required to notify Public Service of the customer's selection prior to 13 days before the customer's scheduled Public Service meter reading date for deliveries to commence on such scheduled meter reading date, and such selection shall remain in effect for the entire billing month. Customer can change TPSs effective only on the date of the customer's scheduled Public Service meter reading date.

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 16 of the Standard Terms and Conditions for additional details and/or exceptions.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 109**
Original Sheet No. 110

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 111**

RATE SCHEDULE WH
WATER HEATING SERVICE

APPLICABLE TO USE OF SERVICE FOR:

This rate schedule is closed and is in the process of elimination. Delivery service under this rate schedule is limited to premises with controlled water heating installations that are presently served under this rate schedule. Customers may either purchase electric supply from a Third Party Supplier (TPS) or from Public Service's Basic Generation Service default service as detailed in this rate schedule.

DELIVERY CHARGES:

Distribution Charges per Kilowatt-hour:

For all use during the controlled heating period	
Charge	Charge Including SUT
$ 0.049482	$ 0.052760

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 70 for details of these charges.

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Non-utility Generation Charge:

This charge shall recover above market costs associated with non-utility generation costs and other generation related costs as may be approved by the Board. Refer to the Non-utility Generation Charge sheet of this Tariff for the current charge.

Solar Pilot Recovery Charge:

This charge is designed to recover the revenue requirements associated with the Public Service Solar Pilot Program per the Board Order in Docket No. EO07040278 less the net proceeds from the sale of associated Solar Renewable Energy Certificates (SRECs) or cash received in lieu of SRECs. Refer to the Solar Pilot Recovery Charge sheet of this tariff for the current charge.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

(Charges are for illustrative purposes only and are based on the Fifth Revised Sheet No. 111 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 112**

RATE SCHEDULE WH

WATER HEATING SERVICE

(Continued)

Tax Adjustment Credit:

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current credit.

Zero Emission Certificate Recovery Charge:

This charge provides for the recovery of costs associated with the Zero Emission Certificate Program directed by the Board of Public Utilities ("BPU" or "Board"). Refer to the Zero Emission Certificate Recovery Charge sheet of this Tariff for the current charge.

Distribution Adjustment Charge:

This charge is designed to recover Board-approved costs. Refer to the Distribution Adjustment Charge sheet of this Tariff for the current charge.

The Distribution Charges, Societal Benefits Charge, Non-utility Generation Charge, the Solar Pilot Recovery Charge, the Green Programs Recovery Charge, the Tax Adjustment Credit, ~~and~~ the Zero Emission Certificate Recovery Charge, and the Distribution Adjustment Charge shall be combined for billing.

ELECTRIC SUPPLY CHARGES:

A customer may choose to receive electric supply from either:

a) A TPS as described in Section 14 of this Tariff, or
b) Public Service through its Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP) default service.

Third Party Supply:

A customer that receives electric supply from a TPS will be charged for electric supply according to any agreement between the customer and the TPS. The customer will not be charged for electric supply by Public Service.

Basic Generation Service:

Customers that do not receive electric supply from a TPS will be supplied under the Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP) default service.

The BGS Energy Charges and the BGS Reconciliation Charge, as applicable, will be applied to all kilowatt-hours billed each month. Refer to the Basic Generation Service sheets of this Tariff for the current charges applicable to Rate Schedule WH.

GENERATION CAPACITY AND TRANSMISSION OBLIGATIONS:

Generation Obligation:

The customer's Generation Obligation, in kilowatts, is determined by Public Service no less frequently than once a year. The Generation Obligation for existing customers or for new customers utilizing an existing building or premise is based upon the customer's share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM) as adjusted by PJM assigned capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions. The Generation Obligation for customers taking service in a new building or premise, as determined by Public Service, is based upon the load requirements, as estimated by Public Service, of the customer's building or premise. The Generation Obligation represents the generator capacity that PJM requires an electric supplier to have available to provide electric supply to a customer.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 113**

RATE SCHEDULE WH
WATER HEATING SERVICE
(Continued)

Transmission Obligation:

The customer's Transmission Obligation, in kilowatts, is determined in a similar manner to the Generation Obligation described above. The Transmission Obligation represents the level of transmission network service that must be procured by the customer's electric supplier from PJM to provide service to the customer.

Costs associated with the Generation and Transmission Obligations are included in the charges for Basic Generation Service and may affect the price offered by a Third Party Supplier.

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill.

TERM:

Customer may discontinue delivery service upon notice.

SPECIAL PROVISIONS:

(a) **Limitations on Service:** Electric service will be furnished under this rate schedule during the controlled heating period under the following conditions:

(a-1) Line capacity at location is sufficient to supply water heating service;

(a-2) Customer shall be using service for some purpose other than water heating and water heating service shall be furnished through the same service connection which supplies such other service;

(a-3) Electricity used for water heating during periods other than the controlled heating periods shall be registered on the meter measuring customer's other use and shall be billed under the rate schedule applicable to such other service;

(a-4) Service for controlled water heating will be controlled by a time switch and registered on a separate meter furnished and installed by Public Service for that purpose;

(a-5) Service is to an automatic storage-type water heater approved by Public Service; if the water heater is equipped with more than one heating element, the thermostats controlling the heating elements shall be interlocked so that only one of such elements can operate at a time;

(a-6) Customer shall install, at its own expense, a separate circuit of approved standard wiring for such water heater including proper connections for the installation of the meter and time switch;

RATE SCHEDULE WH
WATER HEATING SERVICE
(Continued)

(a-7) Public Service shall furnish, install, and maintain a suitable time switch on the separate circuit for limiting to the controlled heating periods, hereinafter specified, the use of electric service at this rate schedule. The time switch shall remain the property of Public Service and shall be set and controlled exclusively by Public Service;

(a-8) The controlled heating period shall be normally from 11:00 P.M. of one day to 9:30 A.M. of the following day. Public Service may change such period depending upon load conditions on its system.

(b) **Resale:** Service under this rate schedule is not available for resale.

(c) **TPS Supply:** Customers who desire to purchase their electric supply from a TPS may request an enrollment package from Public Service that describes the process necessary for the customer to obtain a TPS for electric supply. This package will be provided to the customer at no charge by Public Service.

(c-1) The customer must contract with a TPS to arrange for deliveries to Public Service of the electric supply. A customer is limited to one TPS for electric supply for each account for which the customer receives delivery service.

(c-2) The customer's TPS is required to notify Public Service of the customer's selection prior to 13 days before the customer's scheduled Public Service meter reading date for deliveries to commence on such scheduled meter reading date, and such selection shall remain in effect for the entire billing month. Customer can change TPSs effective only on the date of the customer's scheduled Public Service meter reading date.

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 16 of the Standard Terms and Conditions for additional details and/or exceptions.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 115**
Original Sheet No. 116

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 117**

RATE SCHEDULE WHS
WATER HEATING STORAGE SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Delivery service for controlled water heating storage or for the electric heating elements of a water heating system connected to an active solar collection system. Customers may either purchase electric supply from a Third Party Supplier (TPS) or from Public Service's Basic Generation Service default service as detailed in this rate schedule.

DELIVERY CHARGES:

Service Charge:

$0.63 in each month [$0.67 including New Jersey Sales and Use Tax (SUT)].

Distribution Charges per Kilowatt-hour:

For all use during the controlled storage heating period	
Charge	Charge Including SUT
$ 0.001925	$ 0.002053

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 70 for details of these charges.

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Non-utility Generation Charge:

This charge shall recover above market costs associated with non-utility generation costs and other generation related costs as may be approved by the Board. Refer to the Non-utility Generation Charge sheet of this Tariff for the current charge.

Solar Pilot Recovery Charge:

This charge is designed to recover the revenue requirements associated with the Public Service Solar Pilot Program per the Board Order in Docket No. EO07040278 less the net proceeds from the sale of associated Solar Renewable Energy Certificates (SRECs) or cash received in lieu of SRECs. Refer to the Solar Pilot Recovery Charge sheet of this tariff for the current charge.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

(Charges are for illustrative purposes only and are based on the Fifth Revised Sheet No. 117 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 118**

RATE SCHEDULE WHS

WATER HEATING STORAGE SERVICE

(Continued)

Tax Adjustment Credit:

This mechanism is designed to return the Safe Harbor Adjusted Repair Expense (SHARE) deductions to customers net of any offsets for deferred storm and regulatory costs, IRS adjustments and adjust for any major tax changes, such as tax reform. Interest at the two-year treasury rate plus 60 basis points. Refer to the Tax Adjustment Credit sheet of this Tariff for the current credit.

Zero Emission Certificate Recovery Charge:

This charge provides for the recovery of costs associated with the Zero Emission Certificate Program directed by the Board of Public Utilities ("BPU" or "Board"). Refer to the Zero Emission Certificate Recovery Charge sheet of this Tariff for the current charge.

Distribution Adjustment Charge:

This charge is designed to recover Board-approved costs. Refer to the Distribution Adjustment Charge sheet of this Tariff for the current charge.

The Distribution Charges, Societal Benefits Charge, Non-utility Generation Charge, the Solar Pilot Recovery Charge, the Green Programs Recovery Charge, the Tax Adjustment Credit, ~~and~~ the Zero Emission Certificate Recovery Charge, and the Distribution Adjustment Charge shall be combined for billing.

ELECTRIC SUPPLY CHARGES:

A customer may choose to receive electric supply from either:
a) A TPS as described in Section 14 of this Tariff, or
b) Public Service through its Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP) default service.

Third Party Supply:

A customer that receives electric supply from a TPS will be charged for electric supply according to any agreement between the customer and the TPS. The customer will not be charged for electric supply by Public Service.

Basic Generation Service:

Customers that do not receive electric supply from a TPS will be supplied under the Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP) default service.

The BGS Energy Charges and the BGS Reconciliation Charge, as applicable, will be applied to all kilowatt-hours billed each month. Refer to the Basic Generation Service sheets of this Tariff for the current charges applicable to Rate Schedule WHS.

GENERATION CAPACITY AND TRANSMISSION OBLIGATIONS:

Generation Obligation:

The customer's Generation Obligation, in kilowatts, is determined by Public Service no less frequently than once a year. The Generation Obligation for existing customers or for new customers utilizing an existing building or premise is based upon the customer's share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM) as adjusted by PJM assigned capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions. The Generation Obligation for customers taking service in a new building or premise, as determined by Public Service, is based upon the load requirements, as estimated by Public Service, of the customer's building or premise. The Generation Obligation represents the generator capacity that PJM requires an electric supplier to have available to provide electric supply to a customer.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 119**

RATE SCHEDULE WHS

WATER HEATING STORAGE SERVICE

(Continued)

Transmission Obligation:

The customer's Transmission Obligation, in kilowatts, is determined in a similar manner to the Generation Obligation described above. The Transmission Obligation represents the level of transmission network service that must be procured by the customer's electric supplier from PJM to provide service to the customer.

Costs associated with the Generation and Transmission Obligations are included in the charges for Basic Generation Service and may affect the price offered by a Third Party Supplier.

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill.

TERM:

Customer may discontinue delivery service upon notice.

SPECIAL PROVISIONS:

(a) **Limitations on Service:** Electric service will be furnished under this rate schedule during the controlled storage heating period under the following conditions:

(a-1) Line capacity at location is sufficient to supply water heating service;

(a-2) Customer shall be using service for some purpose other than water heating and water heating service shall be furnished through the same service connection which supplies such other service;

(a-3) Water heating equipment shall be operated at not less than 208 volts;

(a-4) Service for all water heating use will be controlled by a time switch or other control device and registered on a separate meter furnished and installed by Public Service for that purpose;

(a-5) Service is to an automatic storage-type water heater approved by Public Service; if the water heater is equipped with more than one heating element, the thermostats controlling the heating elements shall be interlocked so that only one of such elements can operate at a time;

(a-6) Customer shall install, at its own expense, a separate circuit of approved standard wiring for such water heater including proper connections for the installation of the meter and time switch or other control device;

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 120**

RATE SCHEDULE WHS
WATER HEATING STORAGE SERVICE
(Continued)

(a-7) Where the water heater load does not preclude the use of a Public Service time switch or other control device, Public Service shall furnish, install, regulate and maintain a suitable time switch or other control device to limit the hours of energy available to the water heater. Where the water heater load does preclude the use of a Public Service time switch or other control device, the customer must furnish, install, and maintain a suitable relay, contact or other device which; in response to a Public Service signal, will energize the water heating installation;

(a-8) The controlled storage heating period shall be from 9 P.M. (EST) of one day to 7 A.M. (EST) of the following day. Public Service may change such period depending upon load conditions on its system.

(b) **Resale:** Service under this rate schedule is not available for resale.

(c) **TPS Supply:** Customers who desire to purchase their electric supply from a TPS may request an enrollment package from Public Service that describes the process necessary for the customer to obtain a TPS for electric supply. This package will be provided to the customer at no charge by Public Service.

(c-1) The customer must contract with a TPS to arrange for deliveries to Public Service of the electric supply. A customer is limited to one TPS for electric supply for each account for which the customer receives delivery service.

(c-2) The customer's TPS is required to notify Public Service of the customer's selection prior to 13 days before the customer's scheduled Public Service meter reading date for deliveries to commence on such scheduled meter reading date, and such selection shall remain in effect for the entire billing month. Customer can change TPSs effective only on the date of the customer's scheduled Public Service meter reading date.

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 16 of the Standard Terms and Conditions for additional details and/or exceptions.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 121**
Original Sheet No. 122

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 123**

RATE SCHEDULE HS
BUILDING HEATING SERVICE

APPLICABLE TO USE OF SERVICE FOR:

This rate schedule is closed and is in the process of elimination. Delivery service under this rate schedule is limited to permanently installed comfort building heating equipment in premises that are presently served under this rate schedule. Customers may either purchase electric supply from a Third Party Supplier (TPS) or from Public Service's Basic Generation Service default service as detailed in this rate schedule.

DELIVERY CHARGES:

Service Charge:

$3.75 in each month [$4.00 including New Jersey Sales and Use Tax (SUT)].

Distribution Charges per Kilowatt-hour:

In each of the months of October through May		In each of the months of June through September	
Charges	Charges Including SUT	Charges	Charges Including SUT
$ 0.029426	$ 0.031375	$ 0.098011	$ 0.104504

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 71 for details of these charges.

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Non-utility Generation Charge:

This charge shall recover above market costs associated with non-utility generation costs and other generation related costs as may be approved by the Board. Refer to the Non-utility Generation Charge sheet of this Tariff for the current charge.

Commercial and Industrial Energy Pricing (CIEP) Standby Fee:

Applicable to all kilowatt-hour usage for customers who have selected the option of hourly energy pricing service from either Basic Generation Service-Commercial and Industrial Energy Pricing (BGS-CIEP) or a Third Party Supplier. This charge shall recover costs associated with the administration, maintenance and availability of BGS-CIEP default supply service. Refer to the CIEP Standby Fee sheet of this Tariff for the current charge.

(Charges are for illustrative purposes only and are based on the Fifth Revised Sheet No. 123 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 124**

RATE SCHEDULE HS
BUILDING HEATING SERVICE
(Continued)

Solar Pilot Recovery Charge:

This charge is designed to recover the revenue requirements associated with the Public Service Solar Pilot Program per the Board Order in Docket No. EO07040278 less the net proceeds from the sale of associated Solar Renewable Energy Certificates (SRECs) or cash received in lieu of SRECs. Refer to the Solar Pilot Recovery Charge sheet of this tariff for the current charge.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

Tax Adjustment Credit:

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current credit.

Zero Emission Certificate Recovery Charge:

This charge provides for the recovery of costs associated with the Zero Emission Certificate Program directed by the Board of Public Utilities ("BPU" or "Board"). Refer to the Zero Emission Certificate Recovery Charge sheet of this Tariff for the current charge.

Distribution Adjustment Charge:

This charge is designed to recover Board-approved costs. Refer to the Distribution Adjustment Charge sheet of this Tariff for the current charge.

The Distribution Charges, Societal Benefits Charge, Non-utility Generation Charge, the Solar Pilot Recovery Charge, the Green Programs Recovery Charge, the Tax Adjustment Credit, ~~and~~ the Zero Emission Certificate Recovery Charge, and the Distribution Adjustment Charge shall be combined for billing. The CIEP Standby Fee shall also be combined with these charges where applicable.

ELECTRIC SUPPLY CHARGES:

A customer may choose to receive electric supply from either:
a) A TPS as described in Section 14 of this Tariff, or
b) Public Service through its Basic Generation Service.

Third Party Supply:

A customer that receives electric supply from a TPS will be charged for electric supply according to any agreement between the customer and the TPS. The customer will not be charged for electric supply by Public Service.

Basic Generation Service:

Customers that do not receive electric supply from a TPS will be supplied by Public Service through its Basic Generation Service - Residential Small Commercial Pricing (BGS-RSCP) default service. Customers may elect BGS-CIEP as their default supply but must notify Public Service of their election of BGS-CIEP as their default supply no later than the second business day in January of each year. Such election shall be effective June 1st of that year and BGS-CIEP will remain as the customer's default supply until they notify Public Service of their election of BGS-RSCP as their default supply no later than the second business day in January and their election of BGS-RSCP shall be effective June 1st of that year.
The BGS Energy Charges and the BGS Reconciliation Charge, as applicable, will be applied to all kilowatt-hours billed each month. Refer to the Basic Generation Service sheets of this Tariff for the current charges applicable to Rate Schedule HS.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 125**

RATE SCHEDULE HS

BUILDING HEATING SERVICE

(Continued)

GENERATION CAPACITY AND TRANSMISSION OBLIGATIONS:

Generation Obligation:

The customer's Generation Obligation, in kilowatts, is determined by Public Service no less frequently than once a year. The Generation Obligation for existing customers or for new customers utilizing an existing building or premise is based upon the customer's share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM) as adjusted by PJM assigned capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions. The Generation Obligation for customers taking service in a new building or premise, as determined by Public Service, is based upon the load requirements, as estimated by Public Service, of the customer's building or premise. The Generation Obligation represents the generator capacity that PJM requires an electric supplier to have available to provide electric supply to a customer.

Transmission Obligation:

The customer's Transmission Obligation, in kilowatts, is determined in a similar manner to the Generation Obligation described above. The Transmission Obligation represents the level of transmission network service that must be procured by the customer's electric supplier from PJM to provide service to the customer.

Costs associated with the Generation and Transmission Obligations are included in the charges for Basic Generation Service and may affect the price offered by a Third Party Supplier.

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill and subject to a late payment charge at the rate of 1.416% per monthly billing period in accordance with Section 9.12 of the Standard Terms and Conditions. Service to a body politic will not be subject to a late payment charge.

TERM:

The term for delivery service is one year and thereafter until terminated by five days notice.

Customers who transfer from third party supply to Basic Generation Service may be subject to additional limitations regarding the term of Basic Generation Service as detailed in Section 14 of the Standard Terms and Conditions of this Tariff.

SPECIAL PROVISIONS:

(a) **Limitations on Service:** This rate schedule is available for permanently installed comfort building heating where:

(a-1) Building heating equipment is operated at not less than 208 volts and has a total capacity of not less than five kilowatts;

(a-2) The wiring system metered under this rate schedule utilizes panels, troughs, conduit and wiring completely independent of the general lighting service for the building.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

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RATE SCHEDULE HS
BUILDING HEATING SERVICE
(Continued)

(b) **Resale:** Service under this rate schedule is not available for resale.

(c) **TPS Supply:** Customers who desire to purchase their electric supply from a TPS may request an enrollment package from Public Service that describes the process necessary for the customer to obtain a TPS for electric supply. This package will be provided to the customer at no charge by Public Service.

(c-1) The customer must contract with a TPS to arrange for deliveries to Public Service of the electric supply. A customer is limited to one TPS for electric supply for each account for which the customer receives delivery service.

(c-2) The customer's TPS is required to notify Public Service of the customer's selection prior to 13 days before the customer's scheduled Public Service meter reading date for deliveries to commence on such scheduled meter reading date, and such selection shall remain in effect for the entire billing month. Customer can change TPSs effective only on the date of the customer's scheduled Public Service meter reading date.

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P. L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 16 of the Standard Terms and Conditions for additional details and/or exceptions.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

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RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

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RATE SCHEDULE GLP
GENERAL LIGHTING AND POWER SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Delivery service for general purposes at secondary distribution voltages. Customers may either purchase electric supply from a Third Party Supplier (TPS) or from Public Service's Basic Generation Service default service as detailed in this rate schedule.

DELIVERY CHARGES:

Service Charge:

$4.78 in each month [$5.10 including New Jersey Sales and Use Tax (SUT)].

Distribution Kilowatt Charges:

Annual Demand Charge applicable in all months:

Charge	Charge Including SUT	
$ 3.7660	$ 4.0155	per kilowatt of Monthly Peak Demand

Summer Demand Charge applicable in the months of June through September:

Charge	Charge Including SUT	
$ 9.4441	$ 10.0698	per kilowatt of Monthly Peak Demand

Distribution Kilowatt-hour Charges:

In each of the months of October through May		In each of the Months of June through September		
Charge	Charge Including SUT	Charge	Charge Including SUT	
$ 0.007858	$ 0.008379	$ 0.003079	$ 0.003283	per kilowatt-hour

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 71 for details of these charges.

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Non-utility Generation Charge:

This charge shall recover above market costs associated with non-utility generation costs and other generation related costs as may be approved by the Board. Refer to the Non-utility Generation Charge sheet of this Tariff for the current charge.

(Charges are for illustrative purposes only and are based on the Fifth Revised Sheet No. 129 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

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RATE SCHEDULE GLP
GENERAL LIGHTING AND POWER SERVICE
(Continued)

Commercial and Industrial Energy Pricing (CIEP) Standby Fee:

Applicable to all kilowatt-hour usage for customers who have selected the option of hourly energy pricing service from either Basic Generation Service-Commercial and Industrial Energy Pricing (BGS-CIEP) or a Third Party Supplier. This charge shall recover costs associated with the administration, maintenance and availability of BGS-CIEP default supply service. Refer to the CIEP Standby Fee sheet of this Tariff for the current charge.

Solar Pilot Recovery Charge:

This charge is designed to recover the revenue requirements associated with the Public Service Solar Pilot Program per the Board Order in Docket No. EO07040278 less the net proceeds from the sale of associated Solar Renewable Energy Certificates (SRECs) or cash received in lieu of SRECs. Refer to the Solar Pilot Recovery Charge sheet of this tariff for the current charge.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

Tax Adjustment Credit:

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current credit.

Zero Emission Certificate Recovery Charge:

This charge provides for the recovery of costs associated with the Zero Emission Certificate Program directed by the Board of Public Utilities ("BPU" or "Board"). Refer to the Zero Emission Certificate Recovery Charge sheet of this Tariff for the current charge.

Conservation Incentive Program Charge:

This mechanism provides for recovery of lost revenues associated with various energy efficiency programs. Refer to the Conservation Incentive Program sheet of this Tariff for the current charge.

Distribution Adjustment Charge:

This charge is designed to recover Board-approved costs. Refer to the Distribution Adjustment Charge sheet of this Tariff for the current charge.

The Distribution Kilowatt-hour Charge, the Non-utility Generation Charge, the Solar Pilot Recovery Charge, the Green Programs Recovery Charge, the Tax Adjustment Credit, ~~and~~ the Zero Emission Certificate Recovery Charge, and the Distribution Adjustment Charge shall be combined for billing. The CIEP Standby Fee shall also be combined with these charges where applicable.

The Distribution Kilowatt Charge and the Conservation Incentive Program Charge shall be combined for billing.

ELECTRIC SUPPLY CHARGES:

A customer may choose to receive electric supply from either:
a) A TPS as described in Section 14 of this Tariff, or
b) Public Service through its Basic Generation Service.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

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RATE SCHEDULE GLP

GENERAL LIGHTING AND POWER SERVICE

(Continued)

Third Party Supply:

A customer that receives electric supply from a TPS will be charged for electric supply according to any agreement between the customer and the TPS. The customer will not be charged for electric supply by Public Service.

Basic Generation Service:

Customers that do not receive electric supply from a TPS will be supplied by Public Service through its Basic Generation Service - Residential Small Commercial Pricing (BGS-RSCP) default service. Customers may elect BGS-CIEP as their default supply but must notify Public Service of their election of BGS-CIEP as their default supply no later than the second business day in January of each year. Such election shall be effective June 1st of that year and BGS-CIEP will remain as the customer's default supply until they notify Public Service of their election of BGS-RSCP as their default supply no later than the second business day in January and their election of BGS-RSCP shall be effective June 1st of that year.

The BGS Energy Charges, BGS Capacity Charge, BGS Transmission Charge and BGS Reconciliation Charge are applicable. Refer to the Basic Generation Service sheets of this Tariff for the current charges applicable to Rate Schedule GLP.

MINIMUM CHARGE:

Where the use of electricity is for seldom used applications, an Annual Minimum charge may be applied. Such Annual Minimum charge shall equal the diversified connected load of the electric service, in kW, times the Annual Demand Charge times 6. Revenue to satisfy the Annual Minimum requirement shall be derived solely from Distribution Kilowatt Charges and Distribution Kilowatt-hour Charges.

BILLING DETERMINANTS:

Monthly Peak Demand:

The Monthly Peak Demand shall be determined either by the registration of a demand meter furnished by Public Service or by estimate.

Where a demand meter is installed, the customer's Monthly Peak Demand in any month shall be the greatest average number of kilowatts delivered by Public Service during any thirty-minute interval.

Where no demand meter is installed, the customer's Monthly Peak Demand shall be determined by estimate by dividing the kilowatt-hours by 100 for the applicable billing period.

New Customer: Where a new customer applying for service has an anticipated maximum Monthly Peak Demand of 10 kilowatts or more, that customer's Monthly Peak Demand shall be determined by measurement. If the anticipated maximum Monthly Peak Demand is less than 10 kilowatts, the demand may be determined by estimate or measurement.

Existing Customer: Where an existing customer's Monthly Peak Demand is determined, for billing, by measurement and is 10 kilowatts or greater in any of the preceding 12 months, the customer will continue to have their Monthly Peak Demand determined by measurement and is not eligible for determination by estimate.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

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RATE SCHEDULE GLP
GENERAL LIGHTING AND POWER SERVICE
(Continued)

Where an existing customer's Monthly Peak Demand is determined, for billing, by estimate and their monthly billed kilowatt-hours in any of the preceding 12 months exceeds 1,000 kilowatt-hours, or their Monthly Peak Demand exceeds 10 kilowatts by actual measurement, the customer will be converted to have their Monthly Peak Demand, for billing, determined by measurement. If customer's usage is always less than 1,000 kilowatt-hours per month, the customer may be billed under estimated or measured demand.

Self-Generation Customer: For customers with operational self-generation units: 1) with a combined maximum net kilowatt output rating equal to or greater than 50% of their Annual Peak Demand; or, 2) whose premise was served on the former special provision for Standby Service of this rate schedule on July 31, 2003; or 3) who have been granted all necessary air permits by August 1, 2004 for a new or expanded self-generation facility: The Monthly Peak Demand used in the determination of the Summer Demand Charges shall be equal to the greatest average number of kilowatts delivered by Public Service during any thirty-minute interval that occur during the single hour of monthly maximum peak demand of the Public Service distribution system for the applicable summer billing month. For self-generation customers served under this standby provision, the Annual Demand Charge will be applied to the customer's Annual Peak Demand in lieu of the Monthly Peak Demand.

Annual Peak Demand:

The customer's Annual Peak Demand in kilowatts shall be the highest Monthly Peak Demand occurring in any time period of the current month and the preceding 11 months.

Generation Obligation:

The customer's Generation Obligation, in kilowatts, is determined by Public Service no less frequently than once a year. The Generation Obligation for existing customers or for new customers utilizing an existing building or premise is based upon the customer's share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM) as adjusted by PJM assigned capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions. The Generation Obligation for customers taking service in a new building or premise, as determined by Public Service, is based upon the load requirements, as estimated by Public Service, of the customer's building or premise. The Generation Obligation represents the generator capacity that PJM requires an electric supplier to have available to provide electric supply to a customer.

Transmission Obligation:

The customer's Transmission Obligation, in kilowatts, is determined in a similar manner to the Generation Obligation described above. The Transmission Obligation represents the level of transmission network service that must be procured by the customer's electric supplier from PJM to provide service to the customer.

Generation and Transmission Obligations are used in the determination of the customer's charges for Basic Generation Service and may affect the price offered by a Third Party Supplier.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

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RATE SCHEDULE GLP

GENERAL LIGHTING AND POWER SERVICE

(Continued)

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill and subject to a late payment charge at the rate of 1.416% per monthly billing period in accordance with Section 9.12 of the Standard Terms and Conditions. Service to a body politic will not be subject to a late payment charge.

TERM:

The term for delivery service is one year and thereafter until terminated by five days notice.

Customers who transfer from third party supply to Basic Generation Service may be subject to additional limitations regarding the term of Basic Generation Service as detailed in Section 14 of the Standard Terms and Conditions of this Tariff.

SPECIAL PROVISIONS:

(a) **Limitations on Service:** Service under this rate schedule will not be supplied where:

(a-1) The customers' Monthly Peak Demand exceeds 150 kilowatts in any month;

(a-2) The customer is presently served under Rate Schedule LPL-secondary and their Monthly Peak Demand has exceeded 100 kilowatts in any of the prior 24 consecutive months;

(a-3) The electrical capacity installed by Public Service exceeds 400 kilowatts.

Customers receiving service on the Building Heating Special Provision in July 2003 are exempt from the above limitation (a-1) and (a-3), where in any of the months of October through May the Monthly Peak Demand may exceed 150 kilowatts.

(b) **Resale:** Service under this rate schedule is not available for resale.

(c) **Police Recall or Fire Alarm System Service:** Unmetered police recall or fire alarm system service will be furnished for signaling lamps, bells, or horns with an individual rating not greater than 100 watts or 1/8-horsepower, as rated by Public Service, at a charge of $0.180 ($0.192 including SUT) per month for each signaling lamp, bell, or horn connected, but the total charge shall in no case be less than $1.80 ($1.92 including SUT) per month. No other energy-using devices shall be connected to the police recall or fire alarm system. The customer shall provide, at its own expense, all necessary equipment and wiring, including the service connection. This Special Provision is only available with electric supply furnished by Public Service.

(d) **Religious Houses of Worship Service:** Where electric supply is provided by Public Service to a customer where the primary use of service is for public religious services and customer applies for and is eligible for such service, the customer's monthly bill will be subject to a credit of $0.0500 ($0.0533 including SUT) per kilowatt-hour but not to exceed $50.00 ($53.31 including SUT) in any billing period.

The customer will be required to sign an Application for Religious Houses of Worship Service certifying eligibility. Upon request by Public Service, the customer shall furnish satisfactory proof of eligibility for service under this Special Provision.

(Charges are for illustrative purposes only and are based on the Original Sheet No. 133 filed with the BPU on November 1, 2018)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

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RATE SCHEDULE GLP
GENERAL LIGHTING AND POWER SERVICE
(Continued)

(e) **Unmetered Service:** Unmetered service will be supplied, at the discretion of Public Service, where estimates of kilowatts and kilowatt-hours are based upon information supplied by the customer and agreed to by Public Service. Such estimates of demand and usage shall be constant on a monthly basis. ~~Customers taking service under this Special Provision shall be subject to a monthly Unmetered Service Charge of $ 2.20 ($2.35 including SUT) in lieu of the Service Charge hereinbefore set forth.~~

Unmetered service for automated license plate readers (ALPR) and/or closed-circuit television cameras (CCTV) or similar pole attachments used for body politic-affiliated safety activities may be supplied at the direction of Public Service. Unmetered service to ALPR and CCTV devices shall be based on estimates of kilowatts and kilowatt-hours based upon information supplied by the customer, including any available manufacturer specifications regarding power requirements of these devices. At the discretion of Public Service, the estimates for unmetered service to ALPR or CCTV or similar pole attachment devices may require the assumption that the devices are operate at 100 percent load factor based upon their maximum kilowatt rating.

Customer shall notify Public Service in writing at any time as to changes in conditions or operation of the equipment which may affect estimates of demand or use. Public Service reserves the right to meter any and all such installations where customer does not comply, and customer will no longer be eligible for service under this Special Provision. (See Section 7.1 of the Standard Terms and Conditions.) The customer may be required to furnish and install, at its own expense, a load-limiting device approved by Public Service, which shall be maintained by Public Service at customer's expense.

Customers taking service under this Special Provision shall be subject to a monthly Unmetered Service Charge of $2.20 ($2.35 including SUT) in lieu of the Service Charge hereinbefore set forth.

(f) **Area Development Service:** Where a new or existing customer takes service under this rate schedule at a single service connection located within the municipal boundaries of the cities of Newark, Jersey City, Paterson, Elizabeth, Camden, Trenton, East Orange, Hoboken, Union City, Plainfield, Gloucester City, Passaic City, Weehawken, Kearny, or Orange, service will be supplied under this provision subject to the following conditions:

(f-1) Each customer will be required to sign an Application for Area Development Service under this rate schedule. Public Service shall define a customer as new or existing for purposes of this application. In the case of existing customers, the base year period twelve Monthly Peak Demands in kilowatts shall be specified by Public Service and agreed to by the customer prior to institution of any credits.

(f-2) Customers shall be eligible for credits under this Special Provision only to the extent that they have signed an Application for Area Development Service and meet the minimum load conditions. For new customers, the minimum load must be no less than 25 kilowatts of the applicable Monthly Peak Demand. For existing customers, the average twelve-month minimum load must be no less than 50 kilowatts of applicable Monthly Peak Demand during the previous twelve months. In addition, during any three consecutive months subsequent to an acceptance of the application by Public Service, existing customer applicable Monthly Peak Demands must be at least 125%, or for customers under the minimum load an addition of at least 50 kilowatts, of applicable Monthly Peak Demands in comparable months of the previous 36 months to qualify for credits. Credits for new and existing customers shall commence in the first month subsequent to such qualification.

In no case shall any customer receive credits under this Special Provision who has previously applied for electric service at the same or new location in excess of 300 kilowatts which has been approved for service by Public Service 90 days from the effective date of this Special Provision for the original nine cities and 90 days from the effective date of the modified Special Provision for any additional cities.

(Charges are for illustrative purposes only and are based on the Fifth Revised Sheet No. 134 filed with the BPU on November 1, 2023)

RATE SCHEDULE GLP

GENERAL LIGHTING AND POWER SERVICE

(Continued)

(f-3) A credit of $2.69 ($2.87 including SUT) per kilowatt of Monthly Peak Demand shall apply to all kilowatts so measured for new customers. A new customer, for purposes of this Special Provision, shall be defined either as a customer taking service in a new or renovated building or premise, or a customer taking service in an existing building or premise whose activities or use of electric service is substantially different from that of the previous customer. Where no business has been conducted at a building or premise for at least three months, any customer shall be considered a new customer for purposes of this Special Provision.

(f-4) A credit of $2.69 ($2.87 including SUT) per kilowatt of Monthly Peak Demand shall apply only to those kilowatts so measured for existing customers which are in excess of comparable demands in the same month established in a base year period, which period shall be defined as the twelve calendar months immediately preceding the first month of qualification. An existing customer, for purposes of this Special Provision, shall be defined as a customer whose activities or use of electric service is substantially the same as that of the previous customer, except that such customer shall be eligible for this Special Provision to the extent that the previous customer was so eligible, and for the remainder of the previous customer's term.

(f-5) Where a customer signs an Application for Area Development Service and elects to be billed under this Special Provision, the term of service shall be seven years in lieu of the term stated in this rate schedule. For new customers, the term shall commence with the first month following qualification and, for existing customers, beginning with the first month following the three-month qualification period. In no case shall the term of service commence prior to the completion of the Application for Area Development Service by the customer and acceptance by Public Service.

Credits under (f-3) or (f-4) will be available to qualifying customers during the first five years of the term. Subsequently, such credits will be reduced by 50% during the final two years of the term.

(f-6) Public Service reserves the right to reject Applications for Area Development Service where the cost of facilities to supply new or existing customers is, in its judgment, excessive or might affect the supply of service to other customers.

(g) **Duplicate Service:** Where, at request of a customer, either: a) an additional source or sources of Public Service distribution supply is provided to serve all or part of their load when the principal Public Service distribution source or sources (termed the Normal Service) are unavailable, or b) where such additional sources are supplied as part of standard supply configuration provided by Public Service and such additional source is provided from a different substation or switching station than as determined by Public Service, such service is termed Duplicate Service. Duplicate Service will be furnished only if practical and safe from the standpoint of Public Service and will not be supplied where it would create an unusual hazard or interfere with the provision of service to other customers.

(Charges are for illustrative purposes only and are based on the Original Sheet No. 135 filed with the BPU on November 1, 2018)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

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RATE SCHEDULE GLP

GENERAL LIGHTING AND POWER SERVICE

(Continued)

(g-1) **Duplicate Service Capacity:** The maximum electrical requirement, in kilowatts, needed by the customer at any time on the Duplicate Service is defined as Duplicate Service Capacity. The value of the Duplicate Service Capacity will initially be determined by the customer and shall be used by Public Service as the design criteria in construction of the Duplicate Service. The Duplicate Service Capacity shall be reviewed periodically and shall be the greater of the then requested Duplicate Service Capacity, or the highest actual peak demand established in the prior 24 month period on the Duplicate Service or the Normal Service.

(g-2) **Duplicate Service Charges:** Duplicate service charges will be established for each Duplicate Service based on the sum of the following:

(g-2a) A monthly facilities charge as set forth in Section 3.5.2. of these Standard Terms and Conditions calculated as the Facilities Charge Rate times the total costs of any service or line work required to supply Duplicate Service, including extending or reinforcing Public Service distribution facilities and any distribution transformer or metering costs.

Once a facilities charge is established for a facility or premise and there is no material change in the Duplicate Service Capacity to be provided, the basis for the facilities charge shall remain the same as long as the Public Service facilities remain in service and shall be used for all subsequent customers at that facility requesting Duplicate Service, regardless of any lapse in the provision of Duplicate Service to that facility.

(g-2b) Charges for the kilowatts of Duplicate Service Capacity of:

Duplicate Service Capacity Charges		Applicable in all months
Charge	Charge Including SUT	
$ 2.22	$ 2.37	per kilowatt of Duplicate Service Capacity supplied from the same substation as the Normal Service
$ 3.20	$ 3.41	per kilowatt of Duplicate Service Capacity supplied from a different substation than the Normal Service

(g-3) **Metering and Billing:** Where separate metering is provided, all usage on the duplicate service will be combined for billing purposes with usage on the Normal Service meter.

(Charges are for illustrative purposes only and are based on the Original Sheet No. 136 filed with the BPU on November 1, 2018)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

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RATE SCHEDULE GLP

GENERAL LIGHTING AND POWER SERVICE

(Continued)

(g-4) **Changes in Duplicate Service Capacity**: Any material increase in the Duplicate Service Capacity that requires a change in the facilities related to extending Public Service facilities to the customer or the costs of reinforcing related Public Service facilities may require an increase in the monthly facilities charge. Any material decrease in the Duplicate Service Capacity shall not change the monthly facilities charge.

All initial requests or requests for an increase in Duplicate Service Capacity in excess of 5 megawatts shall require the customer to deposit with Public Service the first five year's facilities charges and applicable Duplicate Service Charges on a non-refundable basis prior to the start of any work by Public Service to supply such Duplicate Service. The monthly charges for Duplicate Service shall be applied against the deposited amount in lieu of being billed to the customer until such time as the customer's deposited amount is exhausted, at which time such charges shall be included in the customer's monthly bill. In no event shall any part of the deposit remaining after five years be returned or credited to the customer in any manner.

(h) **Night Use:** Where a customer has requested Public Service to install a time of day meter for billing under this Special Provision, the following shall apply:

~~(h-1) A Service Charge of $347.77 ($370.81 including SUT) in lieu of the otherwise applicable Service Charge and a Distribution Kilowatt-hour Charge of $0.007858 ($0.008379 including SUT) for kilowatt-hour usage during the Night Period.~~

(h-1~~2~~) The Summer Demand Charge will be applicable only to the kilowatts of Day Period Monthly Peak Demand during the months of June through September.

(h-2~~3~~) A Term of Service on this Special Provision of two years and thereafter until terminated by five days notice.

(h-3~~4~~) The Day Period shall be considered as the hours of 8 A.M. to 8 P.M. Monday through Friday. All other hours shall be considered the Night Period.

(i) **Curtailable Electric Service:** Curtailable Electric Service will be furnished when and where available so as to preserve the reliability of the Public Service distribution system. Those customers that receive electric supply from a third party supplier may continue to receive service under this Special Provision. If a third party supplied customer chooses to no longer participate, or alternatively, a customer is disqualified for this Special Provision because of continued failure to meet agreed upon load reductions, the customer will be required to pay Public Service, in accordance with Standard Terms and Conditions, Section 9.4.2, Metering, for the installed interval metering device if the customer chooses to retain the installed interval meter and the meter is not otherwise required for service. Curtailable Electric Service will be furnished under the following conditions:

(Charges are for illustrative purposes only and are based on the Fifth Revised Sheet No. 137 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

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RATE SCHEDULE GLP
GENERAL LIGHTING AND POWER SERVICE
(Continued)

(i-1) A customer agrees to take service under this rate schedule at a single service connection and agrees to curtail its load during times of curtailment by the amount stated in the customer's Application/Agreement. A credit of $6.11 ($6.51 including SUT) per kilowatt of average actual curtailed demand for each curtailment period will be applied to the customer's bill in a succeeding month. The curtailed demands will be measured as the difference, for each hour, between a customer-specific hourly load curve developed by Public Service for customer's normal business operation and the actual recorded hourly load during the curtailment period. The curtailment period will commence a minimum of one hour from the time of notification and end at the time indicated in the restoration call but not later than 8:00 P.M. as indicated in (i-3) below. For each applicable calendar month, the customer's individual curtailment period results will be summed to determine the appropriate credit. There will be no penalty for failure to curtail load or meet the agreed upon load reduction when notified. Continued failure by a customer to meet agreed upon load reduction, however, will result in customer's disqualification for this Special Provision and Public Service may remove from the customer's premises the interval metering device installed solely for this Special Provision.

(i-1a) In the event that a customer-specific hourly load curve for customer's normal business operation cannot be developed by Public Service, the curtailed demands will be measured as the difference between the actual hourly load at the time of notification and the actual recorded hourly load for each hour during the curtailment period. Payment will be subject to a maximum equal to the estimated amount of load customer will curtail during curtailments in (i-2).

(i-2) A customer will be required to sign an Application/Agreement for Curtailable Electric Service under this rate schedule. The Application/Agreement will specify the estimated amount of load customer will curtail during curtailments. Curtailment payments will be subject to a maximum of 150% of the estimated amount of load customer will curtail during curtailments. The maximum shall apply subsequent to the customer's first curtailment after election to take service under this Special Provision. The minimum curtailable load is 100 kilowatts. The advanced notification period is a minimum of one hour.

(i-3) This Special Provision will be in effect for the four summer months June through September and apply on weekdays only, excluding holidays, and the potential daily curtailment period shall be the hours between 12:00 Noon and 8:00 P.M. Public Service agrees to limit curtailments, as described in this Special Provision, to a maximum of 120 total hours and a maximum of 15 curtailments during the calendar year.

(i-4) Public Service will contact the customer by telephone or otherwise of the need to curtail load under this Special Provision. The customer shall designate personnel who will accept notification of curtailment on summer weekdays from 9:00 A.M. to 8:00 P.M. Where necessary, Public Service will install and maintain suitable metering at its meter locations for verification of customer compliance with the curtailment and notification agreement.

(Charges are for illustrative purposes only and are based on the Original Sheet No. 138 filed with the BPU on November 1, 2018)

RATE SCHEDULE GLP
GENERAL LIGHTING AND POWER SERVICE
(Continued)

(i-5) When a customer signs an Application/Agreement for Curtailable Electric Service and elects to be billed under this Special Provision, the term of service will be for two years in lieu of the term stated in this rate schedule, with periodic review of curtailable demand not to exceed twelve months. Public Service reserves the right to determine whether successive terms may be negotiated and under what conditions curtailable demand may be changed.

(i-6) In the event of an emergency condition which occurs outside the period specified in (i-3) above and which threatens the integrity of the Public Service system or the systems to which Public Service is directly or indirectly connected, Public Service may contact customer of the need to curtail load. There will be no penalty for failure to curtail load or meet the agreed upon load reduction. Customers who are able to curtail load will have a credit applied to their bill.

(j) **TPS Supply:** Customers who desire to purchase their electric supply from a TPS may request an enrollment package from Public Service that describes the process necessary for the customer to obtain a TPS for electric supply. This package will be provided to the customer at no charge by Public Service.

(j-1) The customer must contract with a TPS to arrange for deliveries to Public Service of the electric supply. A customer is limited to one TPS for electric supply for each account for which the customer receives delivery service.

(j-2) The customer's TPS is required to notify Public Service of the customer's selection prior to 13 days before the customer's scheduled Public Service meter reading date for deliveries to commence on such scheduled meter reading date, and such selection shall remain in effect for the entire billing month. Customer can change TPSs effective only on the date of the customer's scheduled Public Service meter reading date.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 140**

RATE SCHEDULE GLP

GENERAL LIGHTING AND POWER SERVICE

(Continued)

(k) **Veterans' Organization Service:** Pursuant to N.J.S.A. 48:2-21.41, when electric service is delivered to a customer that is a Veterans' Organization, serving the needs of veterans of the armed forces, the customer may apply and be eligible for billing under this Special Provision.

(k-1) Each customer shall be eligible for billing under this Special Provision upon submitting an Application for Veterans' Organization Service under this rate schedule and by qualifying as a Veterans' Organization as defined by N.J.S.A. 48:2-21.41 as "an organization dedicated to serving the needs of veterans of the armed forces that: is chartered under federal law, qualifies as a tax exempt organization under paragraph (19) of subsection (c) of section 501 of the federal Internal Revenue Code of 1986, 26 U.S.C. s.501 (c)(19), or that is organized as a corporation under the 'New Jersey Nonprofit Corporation Act,' N.J.S.~~15~~A. 15:1-1 et seq." Under N.J.S.A. 48:2-21.41, a qualified Veterans' Organization shall be charged the residential rate for service delivered to the property where the Veterans' Organization primarily operates, if the residential rate is lower than the commercial rate for service at that property.

The customer shall furnish satisfactory proof of eligibility of service under this Special Provision to the Company. Once proof of eligibility is determined by the Company, service under this Special Provision shall begin with the next billing cycle following receipt of the Application.

(k-2) The customer will continue to be billed on this rate schedule. At least once annually, the Company shall review eligible customers' delivery charges under this Special Provision for all relevant periods. If the comparable delivery charges under the Residential Service (RS) rate schedule are lower than the delivery charges under its current rate schedule, a credit in the amount of the difference will be applied to the customer's next bill.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 141**

RATE SCHEDULE GLP

GENERAL LIGHTING AND POWER SERVICE

(Continued)

(I) **Distribution Demand Charge Rebate:** A customer under this rate schedule whose sole usage is for Direct Current Fast Charging (DCFC) Electric Vehicle charging and ancillary energy consumption (communications, area lighting, etc.) and who meets all of the requirements of this special provision, will qualify for a Distribution Demand Charge Rebate. This rebate will remain in effect until the N.J.B.P.U approved $5 million program total has been reached or an electric vehicle specific tariff rate is established in a future rate proceeding.

(I-1) To qualify for the Demand Charge Rebate, a DCFC customer must agree to provide electric vehicle charging data to PSE&G in accordance with the approved program rules.

(I-2) Qualifying customers, upon Company approval into the program, will be issued an off bill rebate quarterly that will indicate the corresponding period(s) for which the credit applies, and that will apply to the portion of the approved demand charges set forth in (I-3) below. All rebates are contingent on timely availability of electric vehicle charging data for rebate calculation.

(I-3) As long as rebate funds are available, the following discounts will apply: For years one and two of the program, the monthly distribution demand charges will be rebated by 75% from the approved rates during the period being calculated. For years three and until new rates become effective following the Company's Next Base Rate Case, monthly distribution demand charges will be rebated by 50% from those in effect during the period being calculated.

(I-4) Both new and existing DCFC Charging Locations are eligible for this rebate.

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 16 of the Standard Terms and Conditions for additional details and/or exceptions.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 141 for Future**

RATE SCHEDULE GLP
GENERAL LIGHTING AND POWER SERVICE
(Continued)

~~**(I) Distribution Demand Charge Rebate:** A customer under this rate schedule whose sole usage is for Direct Current Fast Charging (DCFC) Electric Vehicle charging and ancillary energy consumption (communications, area lighting, etc.) and who meets all of the requirements of this special provision, will qualify for a Distribution Demand Charge Rebate. This rebate will remain in effect until the N.J.B.P.U approved $5 million program total has been reached or an electric vehicle specific tariff rate is established in a future rate proceeding.~~

~~(I-1) To qualify for the Demand Charge Rebate, a DCFC customer must agree to provide electric vehicle charging data to PSE&G in accordance with the approved program rules.~~

~~(I-2) Qualifying customers, upon Company approval into the program, will be issued an off bill rebate quarterly that will indicate the corresponding period(s) for which the credit applies, and that will apply to the portion of the approved demand charges set forth in (I-3) below. All rebates are contingent on timely availability of electric vehicle charging data for rebate calculation.~~

~~(I-3) As long as rebate funds are available, the following discounts will apply: For years one and two of the program, the monthly distribution demand charges will be rebated by 75% from the approved rates during the period being calculated. For years three and until new rates become effective following the Company's Next Base Rate Case, monthly distribution demand charges will be rebated by 50% from those in effect during the period being calculated.~~

~~(I-4) Both new and existing DCFC Charging Locations are eligible for this rebate.~~

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 16 of the Standard Terms and Conditions for additional details and/or exceptions.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

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RATE SCHEDULE LPL

LARGE POWER AND LIGHTING SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Delivery service for general purposes at secondary distribution voltages where the customer's measured peak demand exceeds 150 kilowatts in any month and also at primary distribution voltages. Customers may either purchase electric supply from a Third Party Supplier (TPS) or from Public Service's Basic Generation Service default service as detailed in this rate schedule.

DELIVERY CHARGES FOR SERVICE AT SECONDARY DISTRIBUTION VOLTAGES (excluding Direct Current Fast Charging [DCFC] customers):

Service Charge:

$347.77 in each month [$370.81 including New Jersey Sales and Use Tax (SUT)].

Distribution Kilowatt Charges:

Annual Demand Charge applicable in all months:

Charge	Charge Including SUT	
$ 3.6224	$ 3.8624	per kilowatt of highest Monthly Peak Demand in any time period

Summer Demand Charge applicable in the months of June through September:

Charge	Charge Including SUT	
$ 8.6179	$ 9.1888	per kilowatt of On-Peak Monthly Peak Demand

~~**Distribution Kilowatt-hour Charges:**~~

~~All Use~~

~~Charge~~	~~Charge Including SUT~~	
~~$0.000000~~	~~$0.000000~~	~~per kilowatt-hour~~

~~Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 71 for details of these charges.~~

DELIVERY CHARGES FOR SERVICE AT SECONDARY DISTRIBUTION VOLTAGES FOR DCFC CUSTOMERS ONLY:

Service Charge:

$347.77 in each month [$370.81 including New Jersey Sales and Use Tax (SUT)].

Distribution Kilowatt-hour Charges:

All Use

Charge	Charge Including SUT	
$0.XXXXXX	$X.XXXXXX	per kilowatt-hour

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 71 for details of these charges.

(Charges are for illustrative purposes only and are based on the Fifth Revised Sheet No. 142 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

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RATE SCHEDULE LPL
LARGE POWER AND LIGHTING SERVICE
(Continued)

DELIVERY CHARGES FOR SERVICE AT PRIMARY DISTRIBUTION VOLTAGES:

Service Charge:

$347.77 in each month [$370.81 including New Jersey Sales and Use Tax (SUT)].

Distribution Kilowatt Charges:

Annual Demand Charge applicable in all months:

Charge	Charge Including SUT	
$ 1.6885	$ 1.8004	per kilowatt of highest Monthly Peak Demand in any time period

Summer Demand Charge applicable in the months of June through September:

Charge	Charge Including SUT	
$ 9.3731	$ 9.9941	per kilowatt of On-Peak Monthly Peak Demand

Distribution Kilowatt-hour Charges:

All Use

Charge	Charge Including SUT	
$0.000000	$0.000000	per kilowatt-hour

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 71 for details of these charges.

DELIVERY CHARGES FOR SERVICE AT SECONDARY AND PRIMARY DISTRIBUTION VOLTAGES:

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Non-utility Generation Charge:

This charge shall recover above market costs associated with non-utility generation costs and other generation related costs as may be approved by the Board. Refer to the Non-utility Generation Charge sheet of this Tariff for the current charge.

Commercial and Industrial Energy Pricing (CIEP) Standby Fee:

Applicable to all kilowatt-hour usage for customers who have selected the hourly energy pricing service from either Basic Generation Service - Commercial and Industrial Energy Pricing (BGS-CIEP) or a Third Party Supplier. This charge shall recover costs associated with the administration, maintenance and availability of BGS–CIEP default supply service. Refer to the CIEP Standby Fee sheet of this Tariff for the current charge.

(Charges are for illustrative purposes only and are based on the Seventh Revised Sheet No. 143 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 144**

RATE SCHEDULE LPL
LARGE POWER AND LIGHTING SERVICE
(Continued)

Solar Pilot Recovery Charge:

This charge is designed to recover the revenue requirements associated with the Public Service Solar Pilot Program per the Board Order in Docket No. EO07040278 less the net proceeds from the sale of associated Solar Renewable Energy Certificates (SRECs) or cash received in lieu of SRECs. Refer to the Solar Pilot Recovery Charge sheet of this tariff for the current charge.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

Tax Adjustment Credit:

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current credit.

Zero Emission Certificate Recovery Charge:

This charge provides for the recovery of costs associated with the Zero Emission Certificate Program directed by the Board of Public Utilities ("BPU" or "Board"). Refer to the Zero Emission Certificate Recovery Charge sheet of this Tariff for the current charge.

Conservation Incentive Program Charge:

This charge is applicable only to LPL customers for service at secondary distribution voltages. This mechanism provides for recovery of lost revenues associated with various energy efficiency programs. Refer to the Conservation Incentive Program sheet of this Tariff for the current charge.

Distribution Adjustment Charge:

This charge is designed to recover Board-approved costs. Refer to the Distribution Adjustment Charge sheet of this Tariff for the current charge.

The Distribution Kilowatt-hour Charge, the Non-utility Generation Charge, the Solar Pilot Recovery Charge, the Green Programs Recovery Charge, the Tax Adjustment Credit, ~~and~~ the Zero Emission Certificate Recovery Charge, and the Distribution Adjustment Charge shall be combined for billing. The CIEP Standby Fee shall also be combined with these charges where applicable.

The Distribution Kilowatt Charge and the Conservation Incentive Program Charge shall be combined for billing.

ELECTRIC SUPPLY CHARGES:

A customer may choose to receive electric supply from either:
a) A TPS as described in Section 14 of this Tariff, or
b) Public Service through its Basic Generation Service.

Third Party Supply:

A customer that receives electric supply from a TPS will be charged for electric supply according to any agreement between the customer and the TPS. The customer will not be charged for electric supply by Public Service.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 145**

RATE SCHEDULE LPL
LARGE POWER AND LIGHTING SERVICE
(Continued)

Basic Generation Service:

A customer's Peak Load Share (PLS), with adjustments, is the basis for the customer's Generation Obligation. A customer's PLS in effect November 1 of a given year will determine the customer's default service type eligibility effective June 1 of the following year [Basic Generation Service - Residential Small Commercial Pricing (BGS-RSCP) or Basic Generation Service-Commercial and Industrial Pricing (BGS-CIEP)].

Customers that do not receive electric supply from a TPS will be supplied by Public Service through its BGS-RSCP default service for LPL-Secondary customers with a PLS less than 500 kilowatts or BGS-CIEP default service for LPL-Secondary customers with a PLS equal to or greater than 500 kilowatts and LPL-Primary. LPL-Secondary customers with a PLS less than 500 kilowatts may elect BGS-CIEP as their default supply but must notify Public Service of their election of BGS-CIEP as their default supply no later than the second business day in January of each year. Such election shall be effective June 1st of that year and BGS-CIEP will remain as the customer's default supply until they notify Public Service of their election of BGS-RSCP as their default supply no later than the second business day in January and their election of BGS-RSCP shall be effective June 1st of that year.

The BGS Energy Charges, BGS Capacity Charge, BGS Transmission Charge and BGS Reconciliation Charge are applicable. Refer to the Basic Generation Service sheets of this Tariff for the current charges applicable to Rate Schedule LPL for secondary or primary service.

MINIMUM CHARGE:

Where the use of electricity is for seldom used applications, an Annual Minimum charge may be applied. Such Annual Minimum charge shall equal the diversified connected load of the electric service, in kilowatts, times the Annual Demand Charge times 6. Revenue to satisfy the Annual Minimum requirement shall be derived solely from Distribution Kilowatt Charges and Distribution Kilowatt-hour Charges.

BILLING DETERMINANTS:

Monthly Peak Demand:

The Monthly Peak Demand for each time period shall be determined by the registration of a demand meter furnished by Public Service. The customer's Monthly Peak Demand in any month for each time period shall be the greatest average number of kilowatts delivered by Public Service during any thirty-minute interval for secondary distribution voltage customers and during any fifteen-minute interval for primary distribution voltage customers. Where the use of electric service is intermittent or subject to violent fluctuations, Public Service may base the customer's Monthly Peak Demand for each time period upon five-minute intervals in lieu of intervals hereinbefore set forth.

Where electric service is supplied for traction power to a rail rapid-transit system, for the purpose of determination of Monthly Peak Demands, the hours 8 A.M. to 10 A.M. and 4 P.M. to 7 P.M. shall be included in the Off-Peak time period, and Public Service shall base the customer's Monthly Peak Demand for each time period upon the greatest average number of kilowatts delivered by Public Service during any single coincident hour-ended sixty-minute interval during each time period, in lieu of fifteen minute intervals.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

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RATE SCHEDULE LPL
LARGE POWER AND LIGHTING SERVICE
(Continued)

Self-Generation Customer:

For customers with operational self-generation units: 1) with a combined maximum net kilowatt output rating equal to or greater than 50% of their Annual Peak Demand; or, 2) whose premise was served on the former special provision for Standby Service of this rate schedule on July 31, 2003; or 3) who have been granted all necessary air permits by August 1, 2004 for a new or expanded self-generation facility: the On-Peak Monthly Peak Demand used in the determination of the Summer Demand Charges shall be equal to the greatest average number of kilowatts delivered by Public Service during any thirty-minute interval for secondary distribution voltage customers, and during any fifteen-minute interval for primary distribution voltage customers, that occur during the single hour of monthly maximum peak demand of the Public Service distribution system for the applicable summer billing month. For self-generation customers served under this standby provision, the Annual Demand Charge will be applied to the customer's Annual Peak Demand in lieu of the Monthly Peak Demand.

Annual Peak Demand:

The customer's Annual Peak Demand in kilowatts shall be the highest Monthly Peak Demand occurring in any time period of the current month and the preceding 11 months.

Generation Obligation:

The customer's Generation Obligation, in kilowatts, is determined by Public Service no less frequently than once a year. The Generation Obligation for existing customers or for new customers utilizing an existing building or premise is based upon the customer's share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM) as adjusted by PJM assigned capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions. The Generation Obligation for customers taking service in a new building or premise, as determined by Public Service, is based upon the load requirements, as estimated by Public Service, of the customer's building or premise. The Generation Obligation represents the generator capacity that PJM requires an electric supplier to have available to provide electric supply to a customer.

Transmission Obligation:

The customer's Transmission Obligation, in kilowatts, is determined in a similar manner to the Generation Obligation described above. The Transmission Obligation represents the level of transmission network service that must be procured by the customer's electric supplier from PJM to provide service to the customer.

Generation and Transmission Obligations are used in the determination of the customer's charges for Basic Generation Service and may affect the price offered by a Third Party Supplier.

TIME PERIODS:

The On-Peak time period shall be considered as the hours from 8 A.M. to 10 P.M. Monday through Friday. All other hours shall be considered the Off-Peak time period.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

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RATE SCHEDULE LPL
LARGE POWER AND LIGHTING SERVICE
(Continued)

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill and subject to a late payment charge at the rate of 1.416% per monthly billing period in accordance with Section 9.12 of the Standard Terms and Conditions. Service to a body politic will not be subject to a late payment charge.

TERM:

The term for delivery service is one year and thereafter until terminated by five days notice.

Customers who transfer from third party supply to Basic Generation Service may be subject to additional limitations regarding the term of Basic Generation Service as detailed in Section 14 of the Standard Terms and Conditions of this Tariff.

SPECIAL PROVISIONS:

(a) **Primary Distribution Alternate Service Charge:** Customers taking service at primary distribution voltage, who were billed the under 100 kilowatt Service Charge in July 2003, and whose Monthly Peak Demand has not exceeded 100 kilowatts in any subsequent month shall be subject to a monthly Service Charge of $21.58 ($23.01 including SUT) in lieu of the otherwise applicable Service Charge.

(b) **Substation Service-Individual Customer:** Where special conditions such as location, size or type of load require that customer be supplied at a subtransmission voltage or at high-voltage as designated in Standard Terms and Conditions, Section 4.2., High Voltage Service, and customer and Public Service agree that Public Service will furnish, install, and maintain a substation solely to serve customer from the secondary side of the transformers at nominal voltages of 4,160 volts, 13,200 volts, or 26,400 volts, such service shall be considered as secondary distribution service. Customer may be required to sell or lease a site for the location of the substation. Public Service may require a guaranteed annual payment and a termination agreement.

This provision is closed and is in the process of elimination and is limited to premises presently served under this provision.

(c) **Resale:** Service under this rate schedule is not available for resale.

(d) **Area Development Service:** Where a new or existing customer takes service under this rate schedule at a single service connection located within the municipal boundaries of the cities of Newark, Jersey City, Paterson, Elizabeth, Camden, Trenton, East Orange, Hoboken, Union City, Plainfield, Gloucester City, Passaic City, Weehawken, Kearny, or Orange, service will be supplied under this provision subject to the following conditions:

(d-1) Each customer will be required to sign an Application for Area Development Service under this rate schedule. Public Service shall define a customer as new or existing for purposes of this application. In the case of existing customers, the base year period twelve Monthly Peak Demands in kilowatts shall be specified by Public Service and agreed to by the customer prior to institution of any credits.

(Charges are for illustrative purposes only and are based on the Fifth Revised Sheet No. 147 filed with the BPU on November 1, 2023)

RATE SCHEDULE LPL
LARGE POWER AND LIGHTING SERVICE
(Continued)

(d-2) Customers shall be eligible for credits under this Special Provision only to the extent that they have signed an Application for Area Development Service and meet the minimum load conditions. For new customers, the minimum load must be no less than 25 kilowatts of the applicable Monthly Peak Demand. For existing customers, the average twelve-month minimum load must be no less than 50 kilowatts of applicable Monthly Peak Demand during the previous twelve months. In addition, during any three consecutive months subsequent to an acceptance of the application by Public Service, existing customer applicable Monthly Peak Demands must be at least 125%, or for customers under the minimum load an addition of at least 50 kilowatts, of applicable Monthly Peak Demands in comparable months of the previous 36 months to qualify for credits. Credits for new and existing customers shall commence in the first month subsequent to such qualification.

In no case shall any customer receive credits under this Special Provision who has previously applied for electric service at the same or new location in excess of 300 kilowatts which has been approved for service by Public Service 90 days from the effective date of this Special Provision for the original nine cities and 90 days from the effective date of the modified Special Provision for any additional cities.

(d-3) A credit of $2.69 ($2.87 including SUT) per kilowatt of Monthly Peak Demand shall apply to all kilowatts so measured for new customers. A new customer, for purposes of this Special Provision, shall be defined either as a customer taking service in a new or renovated building or premise, or a customer taking service in an existing building or premise whose activities or use of electric service is substantially different from that of the previous customer. Where no business has been conducted at a building or premise for at least three months, any customer shall be considered a new customer for purposes of this Special Provision.

(d-4) A credit of $2.69 ($2.87 including SUT) per kilowatt of Monthly Peak Demand shall apply only to those kilowatts so measured for existing customers which are in excess of comparable demands in the same month established in a base year period, which period shall be defined as the twelve calendar months immediately preceding the first month of qualification. An existing customer, for purposes of this Special Provision, shall be defined as a customer whose activities or use of electric service is substantially the same as that of the previous customer, except that such customer shall be eligible for this Special Provision to the extent that the previous customer was so eligible, and for the remainder of the previous customer's term.

(d-5) Where a customer signs an Application for Area Development Service and elects to be billed under this Special Provision, the term of service shall be seven years in lieu of the term stated in this rate schedule. For new customers, the term shall commence with the first month following qualification and, for existing customers, beginning with the first month following the three-month qualification period. In no case shall the term of service commence prior to the completion of the Application for Area Development Service by the customer and acceptance by Public Service.

(Charges are for illustrative purposes only and are based on the Original Sheet No. 148 filed with the BPU on November 1, 2018)

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RATE SCHEDULE LPL

LARGE POWER AND LIGHTING SERVICE

(Continued)

Credits under (d-3) or (d-4) will be available to qualifying customers during the first five years of the term. Subsequently, such credits will be reduced by 50% during the final two years of the term.

(d-6) Public Service reserves the right to reject Applications for Area Development Service where the cost of facilities to supply new or existing customers is, in its judgment, excessive or might affect the supply of service to other customers.

(e) **Duplicate Service:** Where, at request of a customer, either: a) an additional source or sources of Public Service distribution supply is provided to serve all or part of their load when the principal Public Service distribution source or sources (termed the Normal Service) are unavailable, or b) where such additional sources are supplied as part of standard supply configuration provided by Public Service and such additional source is provided from a different substation or switching station than as determined by Public Service, such service is termed Duplicate Service. Duplicate Service will be furnished only if practical and safe from the standpoint of Public Service and will not be supplied where it would create an unusual hazard or interfere with the provision of service to other customers.

(e-1) **Duplicate Service Capacity:** The maximum electrical requirement, in kilowatts, needed by the customer at any time on the Duplicate Service is defined as Duplicate Service Capacity. The value of the Duplicate Service Capacity will initially be determined by the customer and shall be used by Public Service as the design criteria in construction of the Duplicate Service. The Duplicate Service Capacity shall be reviewed periodically and shall be the greater of the then requested Duplicate Service Capacity, or the highest actual peak demand established in the prior 24 month period on the Duplicate Service or the Normal Service.

(e-2) **Duplicate Service Charges**: Duplicate service charges will be established for each Duplicate Service based on the sum of the following:

(e-2a) A monthly facilities charge as set forth in Section 3.5.2 of these Standard Terms and Conditions calculated as the Facilities Charge Rate times the total costs of any service or line work required to supply Duplicate Service, including extending or reinforcing Public Service distribution facilities and any distribution transformer or metering costs.

Once a facilities charge is established for a facility or premise and there is no material change in the Duplicate Service Capacity to be provided, the basis for the facilities charge shall remain the same as long as the Public Service facilities remain in service and shall apply to all subsequent customers at that facility requesting Duplicate Service, regardless of any lapse in the provision of Duplicate Service to that facility.

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RATE SCHEDULE LPL
LARGE POWER AND LIGHTING SERVICE
(Continued)

(e-2b) Charges for the kilowatts of Duplicate Service Capacity of:

Duplicate Service Capacity Charges		Applicable in all months
Charge	Charge Including SUT	
$ 2.22	$ 2.37	per kilowatt of Duplicate Service Capacity supplied from the same substation as the Normal Service
$ 3.20	$ 3.41	per kilowatt of Duplicate Service Capacity supplied from a different substation than the Normal Service

(e-3) **Metering and Billing:** Where separate metering is provided, all usage on the duplicate service will be combined for billing purposes with usage on the Normal Service meter.

(e-4) **Changes in Duplicate Service Capacity:** Any material increase in the Duplicate Service Capacity that requires a change in the facilities related to extending Public Service facilities to the customer or the costs of reinforcing related Public Service facilities may require an increase in the monthly facilities charge. Any material decrease in the Duplicate Service Capacity shall not change the monthly facilities charge.

All initial requests or requests for an increase in Duplicate Service Capacity in excess of 5 megawatts shall require the customer to deposit with Public Service the first five year's facilities charges and applicable Duplicate Service Charges on a non-refundable basis prior to the start of any work by Public Service to supply such Duplicate Service. The monthly charges for Duplicate Service shall be applied against the deposited amount in lieu of being billed to the customer until such time as the customer's deposited amount is exhausted, at which time such charges shall be included in the customer's monthly bill. In no event shall any part of the deposit remaining after five years be returned or credited to the customer in any manner.

(f) **Curtailable Electric Service:** Curtailable Electric Service will be furnished when and where available so as to preserve the reliability of the Public Service distribution system. Those customers that receive electric supply from a third party supplier may continue to receive service under this Special Provision. If a third party supplied customer chooses to no longer participate, or alternatively, a customer is disqualified for this Special Provision because of continued failure to meet agreed upon load reductions, the customer will be required to pay Public Service, in accordance with Standard Terms and Conditions, Section 9.4.2, Metering, for the installed interval metering device if the customer chooses to retain the installed interval meter and the meter is not otherwise required for service. Curtailable Electric Service will be furnished under the following conditions:

(Charges are for illustrative purposes only and are based on the Original Sheet No. 150 filed with the BPU on November 1, 2018)

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RATE SCHEDULE LPL

LARGE POWER AND LIGHTING SERVICE

(Continued)

(f-1) A customer agrees to take service under this rate schedule at a single service connection and agrees to curtail its load during times of curtailment by the amount stated in the customer's Application/Agreement. A credit of $6.11 ($6.51 including SUT) per kilowatt of average actual curtailed demand for each curtailment period will be applied to the customer's bill in a succeeding month. The curtailed demands will be measured as the difference, for each hour, between a customer-specific hourly load curve developed by Public Service for customer's normal business operation and the actual recorded hourly load during the curtailment period. The curtailment period will commence a minimum of one hour from the time of notification and end at the time indicated in the restoration call but not later than 8:00 P.M. as indicated in (f-3) below. For each applicable calendar month, the customer's individual curtailment period results will be summed to determine the appropriate credit. There will be no penalty for failure to curtail load or meet the agreed upon load reduction when notified. Continued failure by a customer to meet agreed upon load reduction, however, will result in customer's disqualification for this Special Provision and Public Service may remove from the customer's premises the interval metering device installed solely for this Special Provision.

(f-1a) In the event that a customer-specific hourly load curve for customer's normal business operation cannot be developed by Public Service, the curtailed demands will be measured as the difference between the actual hourly load at the time of notification and the actual recorded hourly load for each hour during the curtailment period. Payment will be subject to a maximum equal to the estimated amount of load customer will curtail during curtailments in (f-2).

(f-2) A customer will be required to sign an Application/Agreement for Curtailable Electric Service under this rate schedule. The Application/Agreement will specify the estimated amount of load customer will curtail during curtailments. Curtailment payments will be subject to a maximum of 150% of the estimated amount of load customer will curtail during curtailments. The maximum shall apply subsequent to the customer's first curtailment after election to take service under this Special Provision. The minimum curtailable load is 100 kilowatts. The advanced notification period is a minimum of one hour.

(f-3) This Special Provision will be in effect for the four summer months June through September and apply on weekdays only, excluding holidays, and the potential daily curtailment period shall be the hours between 12:00 Noon and 8:00 P.M. Public Service agrees to limit curtailments, as described in this Special Provision, to a maximum of 120 total hours and a maximum of 15 curtailments during the calendar year.

(f-4) Public Service will contact the customer by telephone or otherwise of the need to curtail load under this Special Provision. The customer shall designate personnel who will accept notification of curtailment on summer weekdays from 9:00 A.M. to 8:00 P.M. Where necessary, Public Service will install and maintain suitable metering at its meter locations for verification of customer compliance with the curtailment and notification agreement.

(Charges are for illustrative purposes only and are based on the Original Sheet No. 151 filed with the BPU on November 1, 2018)

RATE SCHEDULE LPL
LARGE POWER AND LIGHTING SERVICE
(Continued)

(f-5) When a customer signs an Application/Agreement for Curtailable Electric Service and elects to be billed under this Special Provision, the term of service will be for two years in lieu of the term stated in this rate schedule, with periodic review of curtailable demand not to exceed twelve months. Public Service reserves the right to determine whether successive terms may be negotiated and under what conditions curtailable demand may be changed.

(f-6) In the event of an emergency condition which occurs outside the period specified in (f-3) above and which threatens the integrity of the Public Service system or the systems to which Public Service is directly or indirectly connected, Public Service may contact customer of the need to curtail load. There will be no penalty for failure to curtail load or meet the agreed upon load reduction. Customers who are able to curtail load will have a credit applied to their bill.

(g) **TPS Supply:** Customers who desire to purchase their electric supply from a TPS may request an enrollment package from Public Service that describes the process necessary for the customer to obtain a TPS for electric supply. This package will be provided to the customer at no charge by Public Service.

(g-1) The customer must contract with a TPS to arrange for deliveries to Public Service of the electric supply. A customer is limited to one TPS for electric supply for each account for which the customer receives delivery service.

(g-2) The customer’s TPS is required to notify Public Service of the customer’s selection prior to 13 days before the customer’s scheduled Public Service meter reading date for deliveries to commence on such scheduled meter reading date, and such selection shall remain in effect for the entire billing month. Customer can change TPSs effective only on the date of the customer’s scheduled Public Service meter reading date.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 153**

RATE SCHEDULE LPL
LARGE POWER AND LIGHTING SERVICE
(Continued)

(h) **Veterans' Organization Service:** Pursuant to N.J.S.A. 48:2-21.41, when electric service is delivered to a customer that is a Veterans' Organization, serving the needs of veterans of the armed forces, the customer may apply and be eligible for billing under this Special Provision.

(h-1) Each customer shall be eligible for billing under this Special Provision upon submitting an Application for Veterans' Organization Service under this rate schedule and by qualifying as a Veterans' Organization as defined by N.J.S.A. 48:2-21.41 as "an organization dedicated to serving the needs of veterans of the armed forces that: is chartered under federal law, qualifies as a tax exempt organization under paragraph (19) of subsection (c) of section 501 of the federal Internal Revenue Code of 1986, 26 U.S.C. s.501 (c)(19), or that is organized as a corporation under the 'New Jersey Nonprofit Corporation Act,' N.J.S. ~~15~~A. 15:1-1 et seq." Under N.J.S.A. 48: 2-21.41, a qualified Veterans' Organization shall be charged the residential rate for service delivered to the property where the Veterans' Organization primarily operates, if the residential rate is lower than the commercial rate for service at that property.

The customer shall furnish satisfactory proof of eligibility of service under this Special Provision to the Company. Once proof of eligibility is determined by the Company, service under this Special Provision shall begin with the next billing cycle following receipt of the Application.

(h-2) The customer will continue to be billed on this rate schedule. At least once annually, the Company shall review eligible customers' delivery charges under this Special Provision for all relevant periods. If the comparable delivery charges under the Residential Service (RS) rate schedule are lower than the delivery charges under its current rate schedule, a credit in the amount of the difference will be applied to the customer's next bill.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

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RATE SCHEDULE LPL

LARGE POWER AND LIGHTING SERVICE

(Continued)

~~**(i) Distribution Demand Charge Rebate:** A customer under this rate schedule, receiving service at secondary voltage levels and whose sole usage is for DCFC Electric Vehicle charging and ancillary energy consumption (communications, area lighting, etc.) and who meets all of the requirements of this special provision, will qualify for a Distribution Demand Charge Rebate. This rebate will remain in effect until the N.J.B.P.U approved $5 million program total has been reached or an electric vehicle specific tariff rate is established in a future rate proceeding.~~

~~(i-1) To qualify for the Demand Charge Rebate, a DCFC customer must agree to provide electric vehicle charging data to PSE&G in accordance with the approved program rules.~~

~~(i-2) Qualifying customers, upon Company approval into the program, will be issued an off bill rebate quarterly that will indicate the corresponding period(s) for which the credit applies, and that will apply to the portion of the approved demand charges set forth in (i-3) below. All rebates are contingent on timely availability of electric vehicle charging data for rebate calculation.~~

~~(i-3) As long as rebate funds are available, the following discounts will apply: For years one and two of the program, the monthly distribution demand charges will be rebated by 75% from the approved rates during the period being calculated. For years three and until new rates become effective following the Company's Next Base Rate Case, monthly distribution demand charges will be rebated by 50% from those in effect during the period being calculated.~~

~~(i-4) Both new and existing DCFC Charging Locations are eligible for this rebate.~~

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 16 of the Standard Terms and Conditions for additional details and/or exceptions.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 155**

RATE SCHEDULE HTS
HIGH TENSION SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Delivery service for general purposes at subtransmission, transmission and high voltages. Customers may either purchase electric supply from a Third Party Supplier (TPS) or from Public Service's Basic Generation Service default service as detailed in this rate schedule.

DELIVERY CHARGES FOR SERVICE AT SUBTRANSMISSION VOLTAGES:

Service Charge:

$1,911.39 in each month [$2,038.02 including New Jersey Sales and Use Tax (SUT)].

Distribution Kilowatt Charges:

Annual Demand Charge applicable in all months:

Charge	Charge Including SUT	
$ 1.1442	$ 1.2200	per kilowatt of Annual Peak Demand

Summer Demand Charge applicable in the months of June through September:

Charge	Charge Including SUT	
$ 4.1361	$ 4.4101	per kilowatt of On-Peak Monthly Peak Demand

Distribution Kilowatt-hour Charges:

All Use

Charge	Charge Including SUT	
$0.000000	$0.000000	per kilowatt-hour

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 72 for details of these charges.

DELIVERY CHARGES FOR SERVICE AT TRANSMISSION VOLTAGES:

Customers historically served under rate schedule HTS-High Voltage currently receiving service at lower voltage levels on facilities under FERC jurisdiction as a result of system modifications mandated by the Company but have not changed their usage characteristics will continue to be billed as High Voltage customers by having their usage adjusted solely by a factor based upon the current Subtransmission and High Voltage Losses as detailed in the Standard Terms and Conditions, Section 4.3. The current adjustment factor for Subtransmission to High Voltage usage is 1.01212%.

(Charges are for illustrative purposes only and are based on the Fifth Revised Sheet No. 155 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 156**

RATE SCHEDULE HTS
HIGH TENSION SERVICE
(Continued)

DELIVERY CHARGES FOR SERVICE AT HIGH VOLTAGE:

Service Charge:

$1,720.25 in each month [$1,834.22 including New Jersey Sales and Use Tax (SUT)].

Distribution Kilowatt Charges:

Annual Demand Charge applicable in all months:

Charge	Charge Including SUT	
$ 0.6322	$ 0.6741	per kilowatt of Annual Peak Demand

Distribution Kilowatt-hour Charges:

All Use

Charge	Charge Including SUT	
$0.000000	$0.000000	per kilowatt-hour

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 72 for details of these charges.

DELIVERY CHARGES FOR SERVICE AT SUBTRANSMISSION, TRANSMISSION AND HIGH VOLTAGES:

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Non-utility Generation Charge:

This charge shall recover above market costs associated with non-utility generation costs and other generation related costs as may be approved by the Board. Refer to the Non-utility Generation Charge sheet of this Tariff for the current charge.

Commercial and Industrial Energy Pricing (CIEP) Standby Fee:

Applicable to all kilowatt-hour usage under this rate schedule. This charge shall recover costs associated with the administration, maintenance and availability of the Basic Generation Service default supply service. Refer to the CIEP Standby Fee sheet of this Tariff for the current charge.

Solar Pilot Recovery Charge:

This charge is designed to recover the revenue requirements associated with the Public Service Solar Pilot Program per the Board Order in Docket No. EO07040278 less the net proceeds from the sale of associated Solar Renewable Energy Certificates (SRECs) or cash received in lieu of SRECs. Refer to the Solar Pilot Recovery Charge sheet of this tariff for the current charge.

(Charges are for illustrative purposes only and are based on the Sixth Revised Sheet No. 156 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

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RATE SCHEDULE HTS
HIGH TENSION SERVICE
(Continued)

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

Tax Adjustment Credit:

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current credit.

Zero Emission Certificate Recovery Charge:

This charge provides for the recovery of costs associated with the Zero Emission Certificate Program directed by the Board of Public Utilities ("BPU" or "Board"). Refer to the Zero Emission Certificate Recovery Charge sheet of this Tariff for the current charge.

Distribution Adjustment Charge:

This charge is designed to recover Board-approved costs. Refer to the Distribution Adjustment Charge sheet of this Tariff for the current charge.

The Distribution Kilowatt-hour Charge, the Non-utility Generation Charge, the Solar Pilot Recovery Charge, the Green Programs Recovery Charge, the Tax Adjustment Credit, the Zero Emission Certificate Recovery Charge, the Distribution Adjustment Charge, and the CIEP Standby Fee shall be combined for billing.

ELECTRIC SUPPLY CHARGES:

A customer may choose to receive electric supply from either:
a) A TPS as described in Section 14 of this Tariff, or
b) Public Service through its Basic Generation Service – Commercial and Industrial Energy Pricing (BGS – CIEP) default service.

Third Party Supply:

A customer that receives electric supply from a TPS will be charged for electric supply according to any agreement between the customer and the TPS. The customer will not be charged for electric supply by Public Service.

Basic Generation Service:

Customers that do not receive electric supply from a TPS will be supplied under the Basic Generation Service - Commercial and Industrial Energy Pricing (BGS – CIEP) default service.

The BGS Energy Charges, BGS Capacity Charge, BGS Transmission Charge and BGS Reconciliation Charge are applicable. Refer to the Basic Generation Service sheets of this Tariff for the current charges applicable to Rate Schedule HTS for subtransmission, transmission or high voltage service.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 158**

RATE SCHEDULE HTS
HIGH TENSION SERVICE
(Continued)

MINIMUM CHARGE:

Where the use of electricity is for seldom used applications, an Annual Minimum charge may be applied. Such Annual Minimum charge shall equal the diversified connected load of the electric service, in kilowatts, times the Annual Demand Charge times 12. Revenue to satisfy the Annual Minimum requirement shall be derived solely from Distribution Kilowatt Charges and Distribution Kilowatt-hour Charges.

BILLING DETERMINANTS:

Monthly Peak Demand:

The Monthly Peak Demand for each time period shall be determined by the registration of a demand meter furnished by Public Service. The customer's Monthly Peak Demand in any month for each time period shall be the greatest average number of kilowatts delivered by Public Service during any fifteen-minute interval. Where the use of electric service is intermittent or subject to violent fluctuations, Public Service may base the customer's Monthly Peak Demand for each time period upon five-minute intervals in lieu of intervals hereinbefore set forth.

Where electric service is supplied for traction power to a rail rapid-transit system, for the purpose of determination of Monthly Peak Demands the hours 8 A.M. to 10 A.M. and 4 P.M. to 7 P.M. shall be included in the Off-Peak time period, and Public Service shall base the customer's Monthly Peak Demand for each time period upon the greatest average number of kilowatts delivered by Public Service during any single coincident hour-ended sixty-minute interval during each time period, in lieu of fifteen-minute intervals. Where traction power is supplied at high voltage (230,000 volts) and such power is being provided during a limited period to supplant power normally supplied by another utility, that limited period shall be excluded for the purpose of determining Monthly Peak Demand.

Self-Generation Customer:

For customers with operational self-generation units: 1) with a combined maximum net kilowatt output rating equal to or greater than 50% of their Annual Peak Demand; or, 2) whose premise was served on the former special provision for Standby Service of this rate schedule on July 31, 2003; or 3) who have been granted all necessary air permits by August 1, 2004 for a new or expanded self-generation facility: the On-Peak Monthly Peak Demand used in the determination of the Summer Demand Charges shall be equal to the greatest average number of kilowatts delivered by Public Service during any fifteen-minute interval that occur during the single hour of monthly maximum peak demand of the Public Service distribution system for the applicable summer billing month.

Annual Peak Demand:

The customer's Annual Peak Demand in kilowatts shall be the highest Monthly Peak Demand occurring in any time period of the current month and the preceding 11 months.

RATE SCHEDULE HTS
HIGH TENSION SERVICE
(Continued)

Generation Obligation:

The customer's Generation Obligation, in kilowatts, is determined by Public Service no less frequently than once a year. The Generation Obligation for existing customers or for new customers utilizing an existing building or premise is based upon the customer's share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM) as adjusted by PJM assigned capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions. The Generation Obligation for customers taking service in a new building or premise, as determined by Public Service, is based upon the load requirements, as estimated by Public Service, of the customer's building or premise. The Generation Obligation represents the generator capacity that PJM requires an electric supplier to have available to provide electric supply to a customer.

Transmission Obligation:

The customer's Transmission Obligation, in kilowatts, is determined in a similar manner to the Generation Obligation described above. The Transmission Obligation represents the level of transmission network service that must be procured by the customer's electric supplier from PJM to provide service to the customer.

Generation and Transmission Obligations are used in the determination of the customer's charges for Basic Generation Service and may affect the price offered by a Third Party Supplier.

TIME PERIODS:

The On-Peak time period shall be considered as the hours from 8 A.M. to 10 P.M. Monday through Friday. All other hours shall be considered the Off-Peak time period.

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill and subject to a late payment charge at the rate of 1.416% per monthly billing period in accordance with Section 9.12 of the Standard Terms and Conditions. Service to a body politic will not be subject to a late payment charge.

TERM:

The term for delivery service is one year and thereafter until terminated by five days notice.

Customers who transfer from third party supply to Basic Generation Service may be subject to additional limitations regarding the term of Basic Generation Service as detailed in Section 14 of the Standard Terms and Conditions of this Tariff.

SPECIAL PROVISIONS:

(a) **Limitations on Loads Served at 138,000 Volts or Higher:** Customer may be required to supply advance information as to conditions affecting its load as an aid to Public Service in load scheduling. Public Service shall not, without prior written acceptance, be obligated to deliver at a single service location an amount of power in excess of a maximum demand of 50,000 kilowatts at 85% power factor.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

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RATE SCHEDULE HTS
HIGH TENSION SERVICE
(Continued)

(b) **Termination of Service by Customer:** Where a customer, served at 138,000 volts or higher, terminates service prior to fifteen years from the initial date of service, customer shall be obligated to pay Public Service that part of the total actual cost of any of the 138,000 volt or higher facilities, land, easements, interests, or rights of way used in rendering such service, under the following schedules:

(b-1) Actual cost of facilities through the first year; thence such actual cost reduced by 5% quarterly during the next succeeding year; thence reduced by 1-1/4% quarterly during the next succeeding six years; thence reduced by 1-3/4% quarterly during the next succeeding six years; and then reduced by 2% quarterly during the remaining year.

(b-2) Actual cost of land, easements, interest, or rights of way through the first year; thence at 80% of actual cost during any of the next succeeding nine years; thence reduced by 4% quarterly during the remaining five years.

(b-3) In the event that Public Service determines to serve other load from or otherwise use the aforesaid facilities, lands, easements, interests, or rights of way, then their cost shall be allocated on an equitable basis for the determination of the termination payment reflecting the difference between the actual cost and the allocated cost.

(c) **Resale**: Service under this rate schedule is not available for resale.

(d) **Area Development Service**: Where a new or existing customer takes service under this rate schedule at a single service connection located within the municipal boundaries of the cities of Newark, Jersey City, Paterson, Elizabeth, Camden, Trenton, East Orange, Hoboken, Union City, Plainfield, Gloucester City, Passaic City, Weehawken, Kearny, or Orange, service will be supplied under this provision subject to the following conditions:

(d-1) Each customer will be required to sign an Application for Area Development Service under this rate schedule. Public Service shall define a customer as new or existing for purposes of this application. In the case of existing customers, the base year period twelve Monthly Peak Demands in kilowatts shall be specified by Public Service and agreed to by the customer prior to institution of any credits.

(d-2) Customers shall be eligible for credits under this Special Provision only to the extent that they have signed an Application for Area Development Service and meet the minimum load conditions. For new customers, the minimum load must be no less than 25 kilowatts of the applicable Monthly Peak Demand. For existing customers, the average twelve-month minimum load must be no less than 50 kilowatts of applicable Monthly Peak Demand during the previous twelve months. In addition, during any three consecutive months subsequent to an acceptance of the application by Public Service, existing customer applicable Monthly Peak Demands must be at least 110%, or for customers under the minimum load an addition of at least 50 kilowatts, of applicable Monthly Peak Demands in comparable months of the previous 36 months to qualify for credits. Credits for new and existing customers shall commence in the first month subsequent to such qualification.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 161**

RATE SCHEDULE HTS
HIGH TENSION SERVICE
(Continued)

In no case shall any customer receive credits under this Special Provision who has previously applied for electric service at the same or new location in excess of 300 kilowatts which has been approved for service by Public Service 90 days from the effective date of this Special Provision for the original nine cities and 90 days from the effective date of the modified Special Provision for any additional cities.

(d-3) A credit of $1.79 ($1.91 including SUT) per kilowatt of Monthly Peak Demand shall apply to all kilowatts so measured for new customers. A new customer, for purposes of this Special Provision, shall be defined either as a customer taking service in a new or renovated building or premise, or a customer taking service in an existing building or premise whose activities or use of electric service is substantially different from that of the previous customer. Where no business has been conducted at a building or premise for at least three months, any customer shall be considered a new customer for purposes of this Special Provision.

(d-4) A credit of $1.79 ($1.91 including SUT) per kilowatt of Monthly Peak Demand shall apply only to those kilowatts so measured for existing customers which are in excess of comparable demands in the same month established in a base year period, which period shall be defined as the twelve calendar months immediately preceding the first month of qualification. An existing customer, for purposes of this Special Provision, shall be defined as a customer whose activities or use of electric service is substantially the same as that of the previous customer, except that such customer shall be eligible for this Special Provision to the extent that the previous customer was so eligible, and for the remainder of the previous customer's term.

(d-5) Where a customer signs an Application for Area Development Service and elects to be billed under this Special Provision, the term of service shall be seven years in lieu of the term stated in this rate schedule. For new customers, the term shall commence with the first month following qualification and, for existing customers, beginning with the first month following the three-month qualification period. In no case shall the term of service commence prior to the completion of the Application for Area Development Service by the customer and acceptance by Public Service.

Credits under (d-3) or (d-4) will be available to qualifying customers during the first five years of the term. Subsequently, such credits will be reduced by 50% during the final two years of the term.

(d-6) Public Service reserves the right to reject Applications for Area Development Service where the cost of facilities to supply new or existing customers is, in its judgment, excessive or might affect the supply of service to other customers.

(Charges are for illustrative purposes only and are based on the Original Sheet No. 161 filed with the BPU on November 1, 2018)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 162**

RATE SCHEDULE HTS
HIGH TENSION SERVICE
(Continued)

(e) **Duplicate Service:** Where, at request of a subtransmission customer, either: a) an additional source or sources of Public Service distribution supply is provided to serve all or part of their load when the principal Public Service distribution source or sources (termed the Normal Service) are unavailable, or b) where such additional sources are supplied as part of standard supply configuration provided by Public Service and such additional source is provided from a different substation or switching station than as determined by Public Service, such service is termed Duplicate Service. Duplicate Service will be furnished only if practical and safe from the standpoint of Public Service and will not be supplied where it would create an unusual hazard or interfere with the provision of service to other customers.

(e-1) **Duplicate Service Capacity:** The maximum electrical requirement, in kilowatts, needed by the customer at any time on the Duplicate Service is defined as Duplicate Service Capacity. The value of the Duplicate Service Capacity will initially be determined by the customer and shall be used by Public Service as the design criteria in construction of the Duplicate Service. The Duplicate Service Capacity shall be reviewed periodically and shall be the greater of the then requested Duplicate Service Capacity, or the highest actual peak demand established in the prior 24 month period on the Duplicate Service or the Normal Service.

(e-2) **Duplicate Service Charges:** Duplicate service charges will be established for each Duplicate Service based on the sum of the following:

(e-2a) A monthly facilities charge as set forth in Section 3.5.2 of these Standard Terms and Conditions calculated as the Facilities Charge Rate times the total costs of any service or line work required to supply Duplicate Service, including extending or reinforcing Public Service distribution facilities and any distribution transformer or metering costs.

Once a facilities charge is established for a facility or premise and there is no material change in the Duplicate Service Capacity to be provided, the basis for the facilities charge shall remain the same as long as the Public Service facilities remain in service and shall apply to all subsequent customers at that facility requesting Duplicate Service, regardless of any lapse in the provision of Duplicate Service to that facility.

(e-2b) Charges for the kilowatts of Duplicate Service Capacity of:

Duplicate Service Capacity Charges		Applicable in all months
Charge	Charge Including SUT	
$ 1.83	$ 1.95	per kilowatt of Duplicate Service Capacity supplied from the same substation or switching station as the Normal Service
$ 2.20	$ 2.35	per kilowatt of Duplicate Service Capacity supplied from a different substation or switching station than the Normal Service

(Charges are for illustrative purposes only and are based on the Original Sheet No. 162 filed with the BPU on November 1, 2018)

Date of Issue: Effective:

Issued by SCOTT S. JENNINGS, SVP – Finance, Planning & Strategy – PSE&G
80 Park Plaza, Newark, New Jersey 07102
Filed pursuant to Order of Board of Public Utilities dated
in Docket No.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 163**

RATE SCHEDULE HTS
HIGH TENSION SERVICE
(Continued)

(e-3) **Metering and Billing:** Where separate metering is provided, all usage on the duplicate service will be combined for billing purposes with usage on the Normal Service meter.

(e-4) **Changes in Duplicate Service Capacity:** Any material increase in the Duplicate Service Capacity that requires a change in the facilities related to extending Public Service facilities to the customer or the costs of reinforcing related Public Service facilities may require an increase in the monthly facilities charge. Any material decrease in the Duplicate Service Capacity shall not change the monthly facilities charge.

All initial requests or requests for an increase in Duplicate Service Capacity in excess of 5 megawatts shall require the customer to deposit with Public Service the first five year's facilities charges and applicable Duplicate Service Charges on a non-refundable basis prior to the start of any work by Public Service to supply such Duplicate Service. The monthly charges for Duplicate Service shall be applied against the deposited amount in lieu of being billed to the customer until such time as the customer's deposited amount is exhausted, at which time such charges shall be included in the customer's monthly bill. In no event shall any part of the deposit remaining after five years be returned or credited to the customer in any manner.

(f) **Curtailable Electric Service:** Curtailable Electric Service will be furnished when and where available so as to preserve the reliability of the Public Service distribution system. Those customers that receive electric supply from a third party supplier may continue to receive service under this Special Provision. If a third party supplied customer chooses to no longer participate, or alternatively, a customer is disqualified for this Special Provision because of continued failure to meet agreed upon load reductions, the customer will be required to pay Public Service, in accordance with Standard Terms and Conditions, Section 9.4.2, Metering, for the installed interval metering device if the customer chooses to retain the installed interval meter and the meter is not otherwise required for service. Curtailable Electric Service will be furnished under the following conditions:

(f-1) A customer agrees to take service under this rate schedule at a single service connection and agrees to curtail its load during times of curtailment by the amount stated in the customer's Application/Agreement. A credit of $6.11 ($6.51 including SUT) per kilowatt of average actual curtailed demand for each curtailment period will be applied to the customer's bill in a succeeding month. The curtailed demands will be measured as the difference, for each hour, between a customer-specific hourly load curve developed by Public Service for customer's normal business operation and the actual recorded hourly load during the curtailment period. The curtailment period will commence a minimum of one hour from the time of notification and end at the time indicated in the restoration call but not later than 8:00 P.M. as indicated in (f-3) below. For each applicable calendar month, the customer's individual curtailment period results will be summed to determine the appropriate credit. There will be no penalty for failure to curtail load or meet the agreed upon load reduction when notified. Continued failure by a customer to meet agreed upon load reduction, however, will result in customer's disqualification for this Special Provision and Public Service may remove from the customer's premises the interval metering device installed solely for this Special Provision.

(Charges are for illustrative purposes only and are based on the Original Sheet No. 163 filed with the BPU on November 1, 2018)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 164**

RATE SCHEDULE HTS
HIGH TENSION SERVICE
(Continued)

(f-1a) In the event that a customer-specific hourly load curve for customer's normal business operation cannot be developed by Public Service, the curtailed demands will be measured as the difference between the actual hourly load at the time of notification and the actual recorded hourly load for each hour during the curtailment period. Payment will be subject to a maximum equal to the estimated amount of load customer will curtail during curtailments in (f-2).

(f-2) A customer will be required to sign an Application/Agreement for Curtailable Electric Service under this rate schedule. The Application/Agreement will specify the estimated amount of load customer will curtail during curtailments. Curtailment payments will be subject to a maximum of 150% of the estimated amount of load customer will curtail during curtailments. The maximum shall apply subsequent to the customer's first curtailment after election to take service under this Special Provision. The minimum curtailable load is 100 kilowatts. The advanced notification period is a minimum of one hour.

(f-3) This Special Provision will be in effect for the four summer months June through September and apply on weekdays only, excluding holidays, and the potential daily curtailment period shall be the hours between 12:00 Noon and 8:00 P.M. Public Service agrees to limit curtailments, as described in this Special Provision, to a maximum of 120 total hours and a maximum of 15 curtailments during the calendar year.

(f-4) Public Service will contact the customer by telephone or otherwise of the need to curtail load under this Special Provision. The customer shall designate personnel who will accept notification of curtailment on summer weekdays from 9:00 A.M. to 8:00 P.M. Where necessary, Public Service will install and maintain suitable metering at its meter locations for verification of customer compliance with the curtailment and notification agreement.

(f-5) When a customer signs an Application/Agreement for Curtailable Electric Service and elects to be billed under this Special Provision, the term of service will be for two years in lieu of the term stated in this rate schedule, with periodic review of curtailable demand not to exceed twelve months. Public Service reserves the right to determine whether successive terms may be negotiated and under what conditions curtailable demand may be changed.

(f-6) In the event of an emergency condition which occurs outside the period specified in (f-3) above and which threatens the integrity of the Public Service system or the systems to which Public Service is directly or indirectly connected, Public Service may contact customer of the need to curtail load. There will be no penalty for failure to curtail load or meet the agreed upon load reduction. Customers who are able to curtail load will have a credit applied to their bill.

(g) **TPS Supply:** Customers who desire to purchase their electric supply from a TPS may request an enrollment package from Public Service that describes the process necessary for the customer to obtain a TPS for electric supply. This package will be provided to the customer at no charge by Public Service.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 165**

RATE SCHEDULE HTS
HIGH TENSION SERVICE
(Continued)

(g-1) The customer must contract with a TPS to arrange for deliveries to Public Service of the electric supply. A customer is limited to one TPS for electric supply for each account for which the customer receives delivery service.

(g-2) The customer's TPS is required to notify Public Service of the customer's selection prior to 13 days before the customer's scheduled Public Service meter reading date for deliveries to commence on such scheduled meter reading date, and such selection shall remain in effect for the entire billing month. Customer can change TPSs effective only on the date of the customer's scheduled Public Service meter reading date.

(h) **Special Provision per Docket No. EO16080788**: This provision of the HTS tariff applies to substation-related service provided to a rail-rapid transit traction power customer that currently subscribes to High Tension Service (HTS) traction power service delivered at 230 kV to an existing multi-substation facility that has been rebuilt by Public Service based upon the approval of the Board of Public Utilities where such approval permits Public Service to own and operate the multi-substation facility and recover the costs of the multi-substation through the traction power customer and distribution rates. In addition, the multi-substation shall provide unique operational characteristics where in disaster or storm events, in which the bulk electric system is inoperable, the multi-substation can operate in isolation to facilitate a microgrid type contingency scheme.

(h-1) The service provided herein shall be the provision of power to a multi- substation facility (meeting the eligibility requirement described herein) owned by Public Service that transforms and delivers power for a traction service HTS customer at voltage levels from 230 kV to 55kV, 27kV, and 12kV. Public Service and the customer will be required to enter into a protocols and operational responsibility agreement that addresses the maintenance and operational responsibilities for the substation. Unless the protocols and operational agreement specifically state otherwise, the terms and conditions of Public Service's tariff shall apply.

(h-2) A customer that is provided this service shall be subject to the requirements of this service tariff as applicable for service delivered at the 230 kV level. All service provided to the substation shall be metered at 230 kV and billed at the 230 kV service rate for traction power service as set forth in the HTS service tariff, except for power delivered to the substation under standard tariff provisions for 13kV which will be billed under the LPL-P tariff.

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P. L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 16 of the Standard Terms and Conditions for additional details and/or exceptions.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC

Original Sheet No. 166
Original Sheet No. 167
Original Sheet No. 168
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Original Sheet No. 175

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 176**

PAYMENT SCHEDULE PEP
PURCHASED ELECTRIC POWER

APPLICABLE TO:

Electricity produced from a Qualifying Facility as defined in Section 210 of the Public Utility Regulatory Policies Act of 1978, with net capacity no greater than 20 MW and delivered by the Seller to Public Service lines.

RATE:

Service Charge:

$5.00 in each month for installations with a three time period watthour meter, or $30.00 in each month for installations with a recording demand meter.

Energy Payment:

The energy payment in any month for energy received by Public Service shall be based upon the avoided energy cost by time period or by hour, as applicable, in that month (defined as the load weighted average Residual Metered Load Aggregate Locational Marginal Price (LMP) for the Public Service Transmission Zone). Historical LMP data may be found on the Pennsylvania-Jersey-Maryland Independent System Operator (PJM) web site at www.pjm.com.

Capacity Payment:

Purchases from a Qualifying Facility that also qualifies as a PJM Installed Capacity Resource, may receive a capacity payment when the capacity exceeds 100 kilowatts and that capacity meets certain reliability criteria as established from time to time by PJM. Capacity payments or charges, if applicable, will be based on the revenue received by Public Service for selling such capacity in the final PJM capacity auction prior to delivery, adjusted for all penalties and other charges assessed to Public Service by PJM related to the non-performance or unavailability of such capacity.

TIME PERIODS:

The On-Peak time period shall be considered as the hours from 7 A.M. to 9 P.M. (EST) Monday through Friday. All other hours shall be considered the Off-Peak time period.

TERMS OF PAYMENT:

For any month payment to the Seller shall be the energy payment plus a capacity payment and/or capacity penalties, if applicable, less the Service Charge. Payment to the Seller shall be within approximately 90 days from the customer's meter reading date.

SPECIAL PROVISIONS:

(a) Seller shall pay all connection charges that are incurred by Public Service in excess of the costs for supplying the Qualifying Facility's maximum expected distribution delivery requirements including the costs of any required studies. Such charges may also include charges assessed by PJM.

(b) Seller's installation shall conform to Public Service specifications for interconnections as outlined in the applicable standards, and such installation is also subject to any applicable PJM requirements.

(Charges are for illustrative purposes only and are based on the Original Sheet No. 176 filed with the BPU on November 1, 2018)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 177**

PAYMENT SCHEDULE PEP
PURCHASED ELECTRIC POWER
(Continued)

(c) The Seller shall sign an application for Purchased Electric Power.

(d) All Sellers are required to execute an Operations Coordination and Interconnection Agreement with Public Service and comply with all then current PJM generator interconnection and operational standards. Additional information regarding current PJM generator interconnection standards and procedures may be found on the PJM web site at www.pjm.com.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 178**

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 179**

RATE SCHEDULE BPL
BODY POLITIC LIGHTING SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Luminaires, poles and appurtenances, maintenance and firm delivery service for dusk to dawn street lighting and area lighting to a body politic served from Company owned lighting facilities. Customers may either purchase electric supply from a Third Party Supplier (TPS) or from Public Service's Basic Generation Service default service as detailed in this rate schedule.

LUMINAIRE CHARGES (Monthly Charge Per Unit):

Standard Luminaires

High Pressure Sodium Luminaire Type	Lamp Wattage	Wattage Including Ballast	PSE&G Part Number	Charge	Charge Including SUT
Cobra-Head	50	58	05-0926	$ 7.49	$ 7.99
Cobra-Head Cut-Off	50	58	05-0990	8.02	8.55
Post-Top Town & Country	50	58	05-0946, 05-0947	7.35	7.84
Cobra-Head	70	83	05-0927	9.22	9.83
Franklin Park Type V	70	83	05-4054	20.08	21.41
Acorn Decorative	100	117	05-0969	21.13	22.53
Cobra-Head	100	117	05-0940	9.91	10.57
Cobra-Head Cut-Off Type III	100	117	05-0991	15.16	16.16
Deluxe Acorn	100	117	05-0967	19.43	20.72
Franklin Park Type IV	100	117	05-3328	21.87	23.32
Hagerstown Type V	100	130	05-3190	23.06	24.59
New Oxford Black Type III	100	117	05-3260	22.29	23.77
Post-Top Acorn	100	117	05-0963	17.91	19.10
Post-Top Town & Country	100	117	05-0948	11.07	11.80
Post-Top Town & Country	100	117	05-0949	11.67	12.44
Profiler Type III	100	117	05-4593	16.06	17.12
Signature Type V	100	130	05-3210	24.44	26.06
Tear Drop Small Shade B	100	117	05-3338	20.94	22.33
Maplwood Lantern Type III	100	110	05-3300	32.13	34.26
Villager Type III	100	117	05-3373	29.19	31.12
Tear Drop-Small Type III	100	130	05-7097	25.86	27.57
Acorn Decorative	150	177	05-0984	23.25	24.79
Acorn Scroll	150	171	05-0966	25.19	26.86
Architectural Type III	150	190	05-3222	21.56	22.99
Capitol Type V	150	171	05-3202	20.42	21.77
Cobra-Head	150	171	05-0941	10.25	10.93
Cobra-Head Cut-Off Type II	150	171	05-0994	13.91	14.83
Dayform Traditionaire Type III	150	171	05-3415	16.13	17.20
Deluxe Acorn	150	177	05-0968	19.43	20.72
Deluxe Acorn II Type V	150	171	05-3320	17.68	18.85
Edison III Type III	150	177	05-3326	18.80	20.05
Floodlight	150	171	05-0722, 05-0727	13.68	14.59
Franklin Park Type IV	150	171	05-4055	18.91	20.16
Hagerstown Type V	150	190	05-3192, 05-3193	24.65	26.28
Holophane RSL Type V	150	190	05-0931	21.56	22.99
Journal SQ 20” Globe Type V	150	190	05-4050	21.90	23.35
Liberty II Type V	150	171	05-3360	25.91	27.63
Old Boston Lantern Type II	150	171	05-3172	20.67	22.04

(Charges are for illustrative purposes only see Streetlight Appendix)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 180**

RATE SCHEDULE BPL
BODY POLITIC LIGHTING SERVICE
(Continued)

Standard Luminaires (continued)

Luminaire Type	Lamp Wattage	Wattage Including Ballast	PSE&G Part Number	Charge	Charge Including SUT
High Pressure Sodium (cont'd)					
Post-Top Acorn	150	177	05-0964	$ 18.78	$ 20.02
Post-Top Town & Country	150	171	05-0950	13.76	14.67
Shoe-Box-Small	150	171	05-0971	15.81	16.86
Signature Green Type V	150	171	05-3218	21.93	23.38
Signature Black Type V	150	190	05-3212	25.88	27.59
Trenton Type III	150	190	05-3263	21.58	23.01
Trenton Type V	150	190	05-3268	21.56	22.99
Villager Type III	150	171	05-3176	21.98	23.44
Acorn Scroll	150	171	05-0960	28.34	30.22
Vandal Resistant Type III	150	171	05-3501	14.13	15.07
Cobra-Head	250	300	05-0928	11.83	12.61
Cobra-Head Cut-Off	250	300	05-0993	14.36	15.31
Cobra-Head Vandal Resistant Shield	250	300	05-3502	17.37	18.52
Concourse Type IV	250	300	05-3017	15.13	16.13
Floodlight	250	300	05-0726	16.47	17.56
Shoe-Box-Large	250	300	05-0970	17.54	18.70
Shoe-Box-Small	250	300	05-0973	17.54	18.70
Signature Type V	250	300	05-3379	33.08	35.27
Trenton Type V	250	300	05-3270	18.45	19.67
Cobra-Head	400	450	05-0925	17.77	18.95
Cobra-Head Cut-Off	400	450	05-0929	17.32	18.47
Cobra-Head Type II	400	450	05-0933	17.77	18.95
Expressway Flood	400	450	05-1001	31.00	33.05
Floodlight	400	449	05-0725	21.04	22.43
Floodlight Bronze	400	449	05-0724	21.04	22.43
Shoe-Box-Large	400	470	05-0975	20.07	21.40
Shoe-Box-Small	400	450	05-0979	15.57	16.60
Tear Drop-Large Shade Type III	400	450	05-3336	24.38	26.00
Tear Drop-Large Type III	400	470	05-7096	28.90	30.81
Power Flood	750	839	05-0721	25.49	27.18
Induction					
Cobra-Head Type III	40	40	05-0901	8.89	9.48
Cobra-Head Type III	80	80	05-0902	9.08	9.68
Cobra-Head Type III	150	150	05-0903	12.96	13.82
Cobra-Head Type III	250	260	05-0904	14.50	15.46
Metal Halide					
Hagerstown Green Type V	100	130	05-3196	27.50	29.32
Capitol Black Type V	100	130	05-3206	27.81	29.65
Signature Black Type V	100	130	05-3215	28.27	30.14
Tear Drop – Type V	100	130	05-3281	27.50	29.32
Liberty I Type III	100	130	05-3351	26.57	28.33

(Charges are for illustrative purposes only see Streetlight Appendix)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 181**

RATE SCHEDULE BPL
BODY POLITIC LIGHTING SERVICE
(Continued)

Standard Luminaires (continued)

Metal Halide (cont'd) Luminaire Type	Lamp Wattage	Wattage Including Ballast	PSE&G Part Number	Charge	Charge Including SUT
Granville Black Type III	100	130	05-6038	$ 25.17	$ 26.84
Granville wR&B Type III	100	130	05-6040	25.56	27.25
Granville Type III	100	130	05-6042	25.72	27.42
Hallbrook – Type III	100	130	05-6056	28.99	30.91
Tear Drop – Type III	100	130	05-7102	27.50	29.32
Villager	150	170	05-8060	30.26	32.26
Contempo – Type II	150	170	05-8062	27.16	28.96
Imperial – Type III	150	170	05-8141	28.71	30.61
Hagerstown	150	170	05-8151	27.86	29.71
Capitol Type V	150	170	05-8162	28.71	30.61
Signature Black Type IV	150	165	05-8173	28.71	30.61
Architectural Type III	150	170	05-8181	26.93	28.71
Trenton Type V	150	170	05-8197	25.15	26.82
Tear Drop – Type III	150	170	05-8198	27.86	29.71
Granville Leaf Black Type III	150	170	05-8215	24.34	25.95
Deluxe Acorn	150	170	05-8224	25.38	27.06
Liberty I Type III	150	170	05-8230	26.93	28.71
Villager Type III	150	170	05-8252	30.26	32.26
Franklin Park Type V	150	170	05-8312	27.86	29.71
Pima	150	150	05-8393	26.93	28.71
Techtra – Type V	150	170	05-8441	30.72	32.76
Tear Drop – Type V	150	170	05-8658	27.86	29.71
New London Type III	150	170	05-8190	29.56	31.52
Contempo – Type V	250	280	05-8064	29.89	31.87
Signature Black Type III	250	275	05-8170	29.82	31.80
Tear Drop – Small	250	300	05-8211	28.96	30.88
Tear Drop – Type III	250	280	05-8622	29.12	31.05
Tear Drop – Type III	250	280	05-8664	31.44	33.52
Tear Drop – Large Type V	250	280	05-8668	31.05	33.11
Newarker – Type V	250	280	05-8680	29.82	31.80
Floodlight	320	350	05-8003	12.49	13.32
Cobra – Head Type III	320	350	05-8018	12.65	13.49
Tear Drop - Large Type III	320	350	05-8063	31.53	33.62
LED					
Floodlight	0	140	05-9900	16.31	17.39
Franklin Park	80	90	05-9999	31.86	33.97
Trenton	85	85	05-9930	28.61	30.51
Contempo – Type II	85	90	05-9940	31.55	33.64
Signature	85	100	05-9960	31.63	33.73
Newarker	85	95	05-9970	31.63	33.73
Franklin Park	86	90	05-9920	37.57	40.06
Tear Drop-Large w/Brim	125	90	05-9950	39.53	42.15
Tear Drop-Large	125	129	05-9951	30.47	32.49
Floodlight	129	141	05-0734	12.32	13.14

(Charges are for illustrative purposes only see Streetlight Appendix)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 182**

RATE SCHEDULE BPL

BODY POLITIC LIGHTING SERVICE

(Continued)

Specialty Luminaires

All luminaires not listed above as Standard Luminaires, all non-standard installations of Standard Luminaires, and any luminaire where the customer makes a contribution toward the total installed cost are deemed Specialty Luminaires. The Monthly Charge Per Unit for all Specialty Luminaires is equal to the sum of the Capital Recovery Charge and Maintenance Charge set forth as follows:

(1) A Capital Recovery Charge equal to the actual total installed cost less any customer contribution (net of tax gross up) times a factor equal to 1.554% (1.657% including SUT) for all Cobra-Head, Floodlights and Town and Country luminaires, and 1.171% (1.249% including SUT) for all other luminaire types. This Capital Recovery Charge will remain unchanged over the remaining life of the luminaire.

(2) A Maintenance Charge that varies by luminaire type and size and is equal to the following:

(2-a) **Applicable to Cobra Head, Floodlights And Town And Country Luminaires:**

Lamp Type	Lamp Wattage	Charge	Charge Including SUT
High Pressure Sodium	All wattages	$ 2.67	$ 2.85
Metal Halide	50 watts and 100 watts	3.27	3.49
	175 watts	3.98	4.24
	250 watts	4.07	4.34
	400 watts	3.58	3.82
	1000 watts	6.48	6.91
Mercury Vapor	All wattages	1.53	1.63
Induction	All wattages	1.28	1.37
LED	All wattages	1.10	1.17

(2-b) **Applicable to All Other Luminaire Types:**

Lamp Type	Lamp Wattage	Charge	Charge Including SUT
High Pressure Sodium	All wattages	$ 3.34	$ 3.56
Metal Halide	50 watts and 100 watts	3.94	4.20
	175 watts	4.64	4.95
	250 watts	4.74	5.05
	400 watts	4.25	4.53
	1000 watts	7.14	7.62
Mercury Vapor	All wattages	2.19	2.34
Induction	All wattages	1.28	1.37
LED	All wattages	1.10	1.17

(Charges are for illustrative purposes only see Streetlight Appendix)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 183**

RATE SCHEDULE BPL

BODY POLITIC LIGHTING SERVICE

(Continued)

Closed Luminaires

Luminaire Type	Lamp Wattage	Wattage including Ballast	PSE&G Part Number	Charge	Charge Including SUT
Filament					
1,000 Lumens NEMA Head	105	105	00-0052	$ 3.87	$ 4.13
2,500 Lumens NEMA Head	205	205	00-0054	5.81	6.19
4,000 Lumens NEMA Head	327	327	00-0055	6.36	6.78
6,000 Lumens NEMA Head	448	448	00-0056	6.43	6.86
10,000 Lumens NEMA Head	690	690	00-0057	5.88	6.27
15,000 Lumens NEMA Head	860	860	00-0058	8.24	8.79
High Pressure Sodium					
Offset Flood	250	300	05-1000	32.31	34.45
Metal Halide					
Hagerstown Black Type V	100	130	05-3195	25.13	26.79
Capitol Type V	175	210	05-3207	27.84	29.68
Hagerstown Type V	175	210	05-3197	27.97	29.82
Holophane GV Type III	175	210	05-3293	25.58	27.27
Old Boston Lantern Type II	175	210	05-3186	28.99	30.91
Post-Top Acorn	175	210	05-0965	19.39	20.67
Signature Type IV & Type V	175	210	05-3217	29.74	31.71
Signature Arch Green	175	210	05-3219	29.74	31.71
Trenton Type V	175	210	05-3272	23.59	25.15
Vero-Green (No Cage)	175	210	05-3545	25.49	27.18
Cobra-Head Vandal Resistant Shield	250	300	05-3503	23.56	25.12
Signature Type V	250	300	05-3213	30.99	33.04
Trenton Type III	250	300	05-3386	27.20	29.00
Cobra-Head Cut-Off	400	460	05-0930	17.58	18.74
Cobra-Head Type III	400	465	05-0916	17.58	18.74
Floodlight	400	460	05-0728	19.46	20.75
Gray Narrow Beam Floodlight	400	460	05-0729	19.46	20.75
Shoe-Box-Large	400	465	05-0976	20.89	22.27
Floodlight	1000	1080	05-0421	26.73	28.50
Mercury Vapor					
Cobra-Head	100	118	05-0921	5.93	6.32
Post-Top Town & Country	100	118	05-0935	5.93	6.32
Post-Top Town & Country Type IV	100	118	05-0936	5.93	6.32
Cobra-Head	175	210	05-0920	7.53	8.03
Post-Top Town & Country	175	210	05-0937	6.00	6.40
Post-Top Town & Country IV	175	210	05-0938	6.00	6.40
Cobra-Head	250	290	05-0919	9.32	9.94
Cobra-Head	400	432	05-0918	10.03	10.69
Floodlight	400	453	05-0422	14.61	15.58
Cobra-Head	1000	1085	05-0768	13.11	13.98
Floodlight	1000	1075	05-0420	23.10	24.63

(Charges are for illustrative purposes only see Streetlight Appendix)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 184**

RATE SCHEDULE BPL
BODY POLITIC LIGHTING SERVICE
(Continued)

DELIVERY CHARGES:

Distribution Charge per Kilowatt-hour:

Charge	Charge Including SUT
$ 0.006894	$ 0.007351

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 72 for details of these charges.

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Non-utility Generation Charge:

This charge shall recover above market costs associated with non-utility generation and other generation related costs as may be approved by the Board. Refer to the Non-utility Generation Charge sheet of this Tariff for the current charge.

Solar Pilot Recovery Charge:

This charge is designed to recover the revenue requirements associated with the Public Service Solar Pilot Program per the Board Order in Docket No. EO07040278 less the net proceeds from the sale of associated Solar Renewable Energy Certificates (SRECs) or cash received in lieu of SRECs. Refer to the Solar Pilot Recovery Charge sheet of this tariff for the current charge.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

Tax Adjustment Credit:

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current credit.

Zero Emission Certificate Recovery Charge:

This charge provides for the recovery of costs associated with the Zero Emission Certificate Program directed by the Board of Public Utilities ("BPU" or "Board"). Refer to the Zero Emission Certificate Recovery Charge sheet of this Tariff for the current charge.

Distribution Adjustment Charge:

This charge is designed to recover Board-approved costs. Refer to the Distribution Adjustment Charge sheet of this Tariff for the current charge.

The Distribution Charge, Societal Benefits Charge, Non-utility Generation Charge, the Solar Pilot Recovery Charge, the Green Programs Recovery Charge, the Tax Adjustment Credit, ~~and~~ the Zero Emission Certificate Recovery Charge, and the Distribution Adjustment Charge shall be combined for billing.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 185**

RATE SCHEDULE BPL
BODY POLITIC LIGHTING SERVICE
(Continued)

ELECTRIC SUPPLY CHARGES:

A customer may choose to receive electric supply from either:

a) A TPS as described in Section 14 of this Tariff, or
b) Public Service through its Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP) default service.

Third Party Supply:

A customer that receives electric supply from a TPS will be charged for electric supply according to any agreement between the customer and the TPS. The customer will not be charged for electric supply by Public Service.

Basic Generation Service:

Customers that do not receive electric supply from a TPS will be supplied under the Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP) default service.

The BGS Energy Charge and the BGS Reconciliation Charge, as applicable, will be applied to all kilowatt-hours billed each month. Refer to the Basic Generation Service sheets of this Tariff for the current charges applicable to Rate Schedule BPL.

LIGHTING POLE AND MISCELLANEOUS DEVICE CHARGES (Monthly Charge Per Unit):

Only poles installed, owned and maintained by Public Service as part of the electric distribution system exclusively for the purpose of providing lighting service under Rate Schedules BPL or PSAL are designated as Lighting Poles.

Standard Lighting Poles

Pole Type	Style	Height	PSE&G Part Number	Charge	Charge Including SUT
Aluminum	Classic I Black	10 ft.	04-1292	$ 27.39	$ 29.20
Aluminum	Windsor Black	11.5 ft.	04-1269	28.16	30.02
Aluminum	Classic I Black	12 ft.	04-1280	26.37	28.12
Aluminum	Classic I Green	12 ft.	04-1290	29.35	31.29
Aluminum	Colonial Black	12 ft.	04-1264	20.96	22.34
Aluminum	Colonial Fluted Black	12 ft.	04-4036	22.39	23.88
Aluminum	Heritage Black	12 ft.	04-3499	29.95	31.93
Aluminum	Rockford Harbor Fluted Black	12 ft.	04-6015	30.86	32.90

(Charges are for illustrative purposes only see Streetlight Appendix)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 186**

RATE SCHEDULE BPL
BODY POLITIC LIGHTING SERVICE
(Continued)

Standard Lighting Poles – Continued

Pole Type	Style	Height	PSE&G Part Number	Charge	Charge Including SUT
Aluminum	Westwood Black	12 ft.	04-3260	$24.34	$25.95
Aluminum	Classic II	12 ft.	04-1285	36.35	38.76
Aluminum	Journal Square	12 ft.	04-4059	40.49	43.17
Aluminum	Colonial Fluted Black	13 ft.	04-4440	25.68	27.38
Aluminum	Classic I Black	14 ft.	04-1281	29.24	31.18
Aluminum	Classic I Green	14 ft.	04-1291	27.00	28.79
Aluminum	Classic II Black	14 ft.	04-1286	27.55	29.38
Aluminum	Colgate I Black	14 ft.	04-1262	26.87	28.65
Aluminum	Colonial Fluted Black	14 ft.	04-1261	20.80	22.17
Aluminum	Colonial Round Black	14 ft.	04-1265	21.78	23.22
Aluminum	Heritage Black	14 ft.	04-3500	30.16	32.16
Aluminum	Montclair Black	14 ft.	04-4085	29.44	31.39
Aluminum	Round Black	14 ft.	04-1284	25.66	27.36
Aluminum	Square Bronze	14 ft.	04-1251	18.57	19.80
Aluminum	Heritage Gray	14 ft.	04-3503	39.30	41.90
Aluminum	Classic I Black	14.5 ft.	04-1282	25.90	27.62
Aluminum	Classic II	15 ft.	04-1287	18.68	19.91
Aluminum	Classic I Black	16 ft.	04-1283	27.60	29.43
Aluminum	Colonial Fluted	16 ft.	04-1272	31.19	33.26
Aluminum	Colonial Fluted	16 ft.	04-4084	29.96	31.94
Aluminum	Contemporary Black	16 ft.	04-4073	33.16	35.36
Aluminum	Heritage Black	16 ft.	04-3501	39.53	42.15
Aluminum	Hudson Black	16 ft.	04-4083	37.57	40.06
Aluminum	Square Bronze	16 ft.	04-4006	23.80	25.38
Aluminum	Round	18 ft.	04-4017	31.63	33.73
Aluminum	Square 5 inch	20 ft.	04-1257	22.65	24.15
Aluminum	Tall Decorative	20 ft.	04-4091	41.60	44.36
Aluminum	Round	25 ft.	04-1211	33.68	35.91
Aluminum	Square Bronze	25 ft.	04-1258	26.08	27.81
Aluminum	Octagon Round	25 ft.	04-0198	55.08	58.73
Aluminum	Decorative Black	25 ft.	04-3262	44.26	47.19
Aluminum	Fluted	30 ft.	04-7098	64.33	68.59
Aluminum	Square Black	30 ft.	04-1254	33.29	35.50
Aluminum	Montclair Black	36 ft.	04-4090	36.84	39.28

(Charges are for illustrative purposes only see Streetlight Appendix)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 187**

RATE SCHEDULE BPL
BODY POLITIC LIGHTING SERVICE
(Continued)

Standard Lighting Poles - Continued

Pole Type	Style	Height	PSE&G Part Number	Charge	Charge Including SUT
Aluminum	Square Bronze	30 ft.	04-1250	$ 31.19	$ 33.26
Aluminum	Round	35 ft.	04-1230	27.33	29.14
Cast Aluminum	Colonial Fluted	12 ft.	04-1260	19.94	21.26
Fiberglass	Smooth Tapered Black	17 ft.	04-0201	*8.57	*9.14
Fiberglass	Round Bronze	20 ft.	04-0203	**9.00	**9.60
Fiberglass	Round Bronze	25 ft.	04-0204	19.39	20.67
Laminated Wood	Laminated Wood	30 ft.	04-0225	12.56	13.39
Laminated Wood	Laminated Wood Gray	30 ft.	04-0197	14.70	15.67
Pine	Center Bored	30 ft.	04-0350	8.00	8.53
Pine	Round	30 ft.	04-0302	*9.24	*9.85
Pine	Round	35 ft.	04-0304	*10.92	*11.64
Pine	Round Class IV	40 ft.	04-0306	***12.51	***13.34
Pine	Round Class III	45 ft.	04-0308	****13.33	****14.22

* The charge for indicated poles installed prior to August 1, 2003 is $0.00 ($0.00 including SUT).
** The charge for indicated poles installed prior to August 1, 2003 is $2.48 ($2.64 including SUT).
*** The charge for indicated poles installed prior to August 1, 2003 is $4.07 ($4.34 including SUT).
**** The charge for indicated poles installed prior to August 1, 2003 is $6.79 ($7.24 including SUT).

Specialty Lighting Poles and Miscellaneous Devices:

All poles not listed above as Standard Lighting Poles, all non-standard installations of standard lighting poles, any pole where the customer makes a contribution toward the total installed cost, and all shrouds, brackets and other miscellaneous devices are deemed Specialty Lighting Poles and Miscellaneous Devices. The Monthly Charge Per Unit for Specialty Lighting Poles and Miscellaneous Devices is equal to the sum of the Capital Recovery Charge and Maintenance Charge set forth as follows:

(1) A Capital Recovery Charge equal to the actual total installed cost less any customer contribution (net of tax gross up) times a factor equal to 1.097% (1.170% including SUT). This Capital Recovery Charge shall remain unchanged over the remaining life of the pole. In underground zones the total installed cost excludes the cost of underground conduits, conductors, manholes and handholes, but includes the cost of equivalent overhead conductors.

(2) A Maintenance Charge that varies by item type and is equal to the following:

(Charges are for illustrative purposes only see Streetlight Appendix)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 188**

RATE SCHEDULE BPL
BODY POLITIC LIGHTING SERVICE
(Continued)

Pole and Device Type	Charge	Charge Including SUT
Pine wood pole	$ 0.50	$ 0.54
Laminated wood pole	0.00	0.00
Aluminum pole	0.00	0.00
Fiberglass pole	0.00	0.00
Shrouds, Brackets & Other Miscellaneous Devices	0.00	0.00

BILLING DETERMINANTS:

Kilowatt-hours:

The kilowatt-hour estimate is determined for each lamp by dividing total wattage including ballast by 1,000 and multiplying the result by the monthly burning hours as follows:

January	447	July	281
February	374	August	312
February (leap-year)	387	September	343
March	372	October	397
April	317	November	421
May	292	December	456
June	263		

Generation Obligation:

The customer's Generation Obligation, in kilowatts, is determined by Public Service no less frequently than once a year. The Generation Obligation for existing customers or for new customers utilizing an existing building or premise is based upon the customer's share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM) as adjusted by PJM assigned capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions. The Generation Obligation for customers taking service in a new building or premise, as determined by Public Service, is based upon the load requirements, as estimated by Public Service, of the customer's building or premise. The Generation Obligation represents the generator capacity that PJM requires an electric supplier to have available to provide electric supply to a customer.

Transmission Obligation:

The customer's Transmission Obligation, in kilowatts, is determined in a similar manner to the Generation Obligation described above. The Transmission Obligation represents the level of transmission network service that must be procured by the Customer's electric supplier from PJM to provide service to the customer.

Costs associated with the Generation and Transmission Obligations are included in the charges for Basic Generation Service and may affect the price offered by a Third Party Supplier.

Allowance for Lamp Outages:

Charges reflect an outage allowance based upon normal and abnormal operating conditions. No further allowance will be made.

(Charges are for illustrative purposes only see Streetlight Appendix)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 189**

RATE SCHEDULE BPL

BODY POLITIC LIGHTING SERVICE

(Continued)

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill.

TERM:

For all Standard Luminaires and Standard Lighting Poles: One year and thereafter until terminated by five days' notice.

For all Specialty Luminaires and Specialty Lighting Poles and Miscellaneous Devices and all Underground Lighting Installations: Five years and thereafter until terminated by five days' notice. Customers shall be required to make a payment for all such lighting facilities removed prior to five years from the installation date equal to the cost of removal less salvage plus 75% of the original installed costs net of any customer contribution.

Customers who transfer from third party supply to Basic Generation Service may be subject to additional limitations regarding the term of Basic Generation Service as detailed in Section 14 of the Standard Terms and Conditions of this Tariff.

SPECIAL PROVISIONS:

(a) **Service to Customers:** Public Service will furnish and install the lamp, luminaire, bracket, pole, wiring and associated equipment, make necessary lamp renewals, otherwise maintain the installation, and repair or replace all equipment rendered inoperable whether or not due to willful or accidental damage. In the event of repeated damage to its facilities, whether willful or accidental, Public Service reserves the right to discontinue such lighting service or require the customer to be responsible for the continued cost of repair or replacement. Lighting service will be furnished only if practicable for installation and maintenance, safe from the standpoint of Public Service, and will not be supplied where the introduction of such lighting would create an unusual hazard.

(b) Underground Construction:

(b-1) Underground construction will be provided at no additional charge in underground zones designated by Public Service for all public street lighting applications and for nonpublic street lighting applications up to 100 feet distant from the public street as measured at right angles to the curb. Where underground construction is desired for all other applications and in other areas, the customer shall pay the cost of such underground construction for all conduits, conductors, manholes and handholes.

(b-2) In a underground zone designated by Public Service, a standard 30 foot aluminum street lighting pole, or credit equivalent, will be provided for each luminaire utilized for public street lighting by a body politic at no charge. The installation of these poles will be provided with a minimum space between poles of 150 feet when measured along the curb line.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 190**

RATE SCHEDULE BPL
BODY POLITIC LIGHTING SERVICE
(Continued)

(b-3) In subdivisions subject to the Regulations for Residential Electric Underground Extensions in N.J.A.C. 14:3-8 et seq., there will be no monthly charge to the local municipality for standard street lighting poles utilized for public street lighting that have been included in the charges paid by the developer of the subdivision as determined under tariff section Regulation for Residential Underground Extension.

(c) Changes in size, type or location:

(c-1) Customers may be required to make a payment toward the costs of installation, removal, relocation and/or changes in lamp size for conversion from one light source to another when the age of the luminaires to be converted is less than 20 years.

Payment shall be based on the unamortized installed cost plus the removal cost less salvage.

Customers will be required to make a payment based on actual cost of the requested work for the temporary replacement and/or relocation of an existing light to a new location and the subsequent movement of the light back to its old location.

(c-2) A request to install a new light at the same location within 12 months of the removal of an existing light will be considered a replacement of the existing light. A charge may be assessed for any lamp ordered reconnected or reinstalled when the elapsed time is less than 12 months from the request for disconnect.

(c-3) Public Service reserves the right to limit the number of lamp conversions in any year to no more than 5% of the total lamps served at the end of the previous year.

(d) **Replacement of Obsolete Equipment:** Public Service has the right to replace obsolete luminaires, poles and all other associated equipment with equivalent equipment without the consent of its customers.

(e) **Customer Contributions:** The making of a payment to Public Service shall not give the customer any interest in the facilities, the ownership being vested exclusively in Public Service.

Body Politic customers may elect to contribute to the total installed cost of Specialty Luminaires, Specialty Lighting Poles or Miscellaneous Devices in addition to that which may be required in accordance with Special Provision (b). Public Service may limit the contribution option between zero and the maximum contribution. Such contribution shall be up to a maximum of:

(e-1) The installed cost less $600.00, grossed up for income tax effects, of any luminaire with an installed cost greater than $1,200.00;

(e-2) The installed cost less $600.00, grossed up for income tax effects, of any pole with an installed cost greater than $1,200.00; or

(e-3) The installed cost, grossed up for income tax effects, of any shroud, bracket or other Miscellaneous Devices.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 191**

RATE SCHEDULE BPL

BODY POLITIC LIGHTING SERVICE

(Continued)

(f) **Unit Life:** Luminaires, poles and all other associated lighting equipment will be removed when replacement parts are required but no longer generally available. At that time the customer may elect for Public Service to install replacement equipment that will be considered as an installation of new facilities and priced at the then current applicable charges.

(g) **TPS Supply:** Customers who desire to purchase their electric supply from a TPS may request an enrollment package from Public Service that describes the process necessary for the customer to obtain a TPS for electric supply. This package will be provided to the customer at no charge by Public Service.

(g-1) The customer must contract with a TPS to arrange for deliveries to Public Service of the electric supply. A customer is limited to one TPS for electric supply for each account for which the customer receives delivery service.

(g-2) The customer's TPS is required to notify Public Service of the customer's selection prior to 13 days before the customer's scheduled Public Service meter reading date for deliveries to commence on such scheduled meter reading date, and such selection shall remain in effect for the entire billing month. Customer can change TPSs effective only on the date of the customer's scheduled Public Service meter reading date.

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 16 of the Standard Terms and Conditions for additional details and/or exceptions.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 192**
Original Sheet No. 193
Original Sheet No. 194

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 195**

RATE SCHEDULE BPL-POF
BODY POLITIC LIGHTING SERVICE FROM PUBLICLY OWNED FACILITIES

APPLICABLE TO USE OF SERVICE FOR:
This rate class is closed and in the process of elimination. Firm delivery service and maintenance for dusk to dawn street lighting and area lighting to a body politic served from Publicly-Owned Lighting Facilities. Customers may either purchase electric supply from a Third Party Supplier (TPS) or from Public Service's Basic Generation Service default service as detailed in this rate schedule.

MAINTENANCE CHARGES (Monthly Charge Per Unit):

Standard Luminaires

High Pressure Sodium

Luminaire Type	Lamp Wattage	Wattage including Ballast	Equivalent PSE&G Part Number	Charge	Charge Including SUT
Cobra-Head	50	58	05-0926	$ 1.87	$ 1.99
Cobra-Head Cut-Off Type IV	50	58	05-0990	1.87	1.99
Post-Top Town & Country	50	58	05-0946	1.87	1.99
Cobra-Head	100	117	05-0940	1.87	1.99
Post-Top Town & Country II	100	117	05-0948	1.87	1.99
Post-Top Town & Country IV	100	117	05-0949	1.87	1.99
Cobra-Head	150	171	05-0941	1.87	1.99
Post-Top Acorn	150	171	05-0964	2.61	2.78
Post-Top Town & Country II	150	171	05-0950	1.87	1.99
Shoe-Box-Large Round	150	171	05-0971	2.61	2.78
Shoe-Box-Large Square	150	171	05-0971	2.61	2.78
Cobra-Head	250	300	05-0928	1.87	1.99
Cobra-Head Cut-Off	250	300	05-0993	1.87	1.99
Shoe-Box-Large	250	300	05-0970	2.61	2.78
Shoe-Box-Large Round	250	300	05-0970	2.61	2.78
Shoe-Box-Large Square	250	300	05-0970	2.61	2.78
Cobra-Head Vandal Resistant Shield	250	300	05-3502	1.87	1.99
Cobra-Head	400	450	05-0925	1.87	1.99
Cobra-Head Cut-Off	400	450	05-0929	1.87	1.99
Shoe-Box-Large	400	470	05-0975	2.61	2.78

(Charges are for illustrative purposes only see Streetlight Appendix)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 196**

RATE SCHEDULE BPL-POF
BODY POLITIC LIGHTING SERVICE FROM PUBLICLY OWNED FACILITIES
(Continued)

Closed Luminaires

Luminaire Type	Lamp Wattage	Wattage including Ballast	Equivalent PSE&G Part Number	Charge	Charge Including SUT
Filament					
600 Lumens NEMA Head	58	58	N/A	$ 5.38	$ 5.74
1,000 Lumens NEMA Head	105	105	N/A	5.38	5.74
2,500 Lumens NEMA Head	205	205	N/A	5.38	5.74
4,000 Lumens NEMA Head	327	327	N/A	5.38	5.74
6,000 Lumens NEMA Head	448	448	N/A	5.38	5.74
10,000 Lumens NEMA Head	690	690	N/A	5.38	5.74
Metal Halide					
Acorn	175	210	N/A	4.06	4.33
Floodlight	1000	1080	N/A	6.11	6.51
Mercury Vapor					
Cobra-Head	175	210	N/A	1.08	1.15
Post-Top Town & Country Type IV	175	210	N/A	0.59	0.63
Cobra-Head	250	290	N/A	0.59	0.63
Cobra-Head	400	432	N/A	0.59	0.63

(Charges are for illustrative purposes only see Streetlight Appendix)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 197**

RATE SCHEDULE BPL-POF
BODY POLITIC LIGHTING SERVICE FROM PUBLICLY OWNED FACILITIES
(Continued)

DELIVERY CHARGES:

Distribution Charge per Kilowatt-hour:

Charge	Charge Including SUT
$ 0.006931	$ 0.007390

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 72 for details of these charges.

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Non-utility Generation Charge:

This charge shall recover above market costs associated with non-utility generation and other generation related costs as may be approved by the Board. Refer to the Non-utility Generation Charge sheet of this Tariff for the current charge.

Solar Pilot Recovery Charge:

This charge is designed to recover the revenue requirements associated with the Public Service Solar Pilot Program per the Board Order in Docket No. EO07040278 less the net proceeds from the sale of associated Solar Renewable Energy Certificates (SRECs) or cash received in lieu of SRECs. Refer to the Solar Pilot Recovery Charge sheet of this tariff for the current charge.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

Tax Adjustment Credit:

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current credit.

Zero Emission Certificate Recovery Charge:

This charge provides for the recovery of costs associated with the Zero Emission Certificate Program directed by the Board of Public Utilities ("BPU" or "Board"). Refer to the Zero Emission Certificate Recovery Charge sheet of this Tariff for the current charge.

Distribution Adjustment Charge:

This charge is designed to recover Board-approved costs. Refer to the Distribution Adjustment Charge sheet of this Tariff for the current charge.

The Distribution Charge, Societal Benefits Charge, Non-utility Generation Charge, the Solar Pilot Recovery Charge, the Green Programs Recovery Charge, the Tax Adjustment Credit, ~~and~~ the Zero Emission Certificate Recovery Charge, and the Distribution Adjustment Charge shall be combined for billing.

RATE SCHEDULE BPL-POF

BODY POLITIC LIGHTING SERVICE FROM PUBLICLY OWNED FACILITIES

(Continued)

ELECTRIC SUPPLY CHARGES:

A customer may choose to receive electric supply from either:

a) A TPS as described in Section 14 of this Tariff, or
b) Public Service through its Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP) default service.

Third Party Supply:

A customer that receives electric supply from a TPS will be charged for electric supply according to any agreement between the customer and the TPS. The customer will not be charged for electric supply by Public Service.

Basic Generation Service:

Customers that do not receive electric supply from a TPS will be supplied under the Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP) default service.

The BGS Energy Charge and the BGS Reconciliation Charge, as applicable, will be applied to all kilowatt-hours billed each month. Refer to the Basic Generation Service sheets of this Tariff for the current charges applicable to Rate Schedule BPL-POF.

BILLING DETERMINANTS:

Kilowatt-hours:

The kilowatt-hour estimate is determined for each lamp by dividing total wattage including ballast by 1,000 and multiplying the result by the monthly burning hours as follows:

January	447	July	281
February	374	August	312
February (leap-year)	387	September	343
March	372	October	397
April	317	November	421
May	292	December	456
June	263		

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 199**

RATE SCHEDULE BPL-POF
BODY POLITIC LIGHTING SERVICE FROM PUBLICLY OWNED FACILITIES
(Continued)

Generation Obligation:

The customer's Generation Obligation, in kilowatts, is determined by Public Service no less frequently than once a year. The Generation Obligation for existing customers or for new customers utilizing an existing building or premise is based upon the customer's share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM) as adjusted by PJM assigned capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions. The Generation Obligation for customers taking service in a new building or premise, as determined by Public Service, is based upon the load requirements, as estimated by Public Service, of the customer's building or premise. The Generation Obligation represents the generator capacity that PJM requires an electric supplier to have available to provide electric supply to a customer.

Transmission Obligation:

The customer's Transmission Obligation, in kilowatts, is determined in a similar manner to the Generation Obligation described above. The Transmission Obligation represents the level of transmission network service that must be procured by the Customer's electric supplier from PJM to provide service to the customer.

Costs associated with the Generation and Transmission Obligations are included in the charges for Basic Generation Service and may affect the price offered by a Third Party Supplier.

Allowance for Lamp Outages:

Charges reflect an outage allowance based upon normal and abnormal operating conditions. No further allowance will be made.

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill.

TERM:

One year for all new lamps and thereafter until terminated by five days' notice.

Customers who transfer from third party supply to Basic Generation Service may be subject to additional limitations regarding the term of Basic Generation Service as detailed in Section 14 of the Standard Terms and Conditions of this Tariff.

SPECIAL PROVISIONS:

(a) **Service from Publicly-Owned Facilities:** Service under this Rate Schedule is only available where Public Service has paid no part of the cost of the distribution facilities, lamps, luminaires and all other associated equipment beyond the point of connection to the Public Service distribution system, such point of connection to be designated by Public Service. The complete lighting installation shall meet with the approval of Public Service for operation and maintenance. Public Service will clean refractors or globes, replace lamps, locate cable faults and make minor cable and socket repairs. Replacement of defective cable, painting or otherwise maintaining posts or luminaires or any other associated equipment shall be done only at the expense of the customer. In the event of repeated damage to the equipment, whether willful or accidental, Public Service reserves the right to discontinue such lighting service or require the customer to be responsible for the continued cost of repair or replacement.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 200**

RATE SCHEDULE BPL-POF

BODY POLITIC LIGHTING SERVICE FROM PUBLICLY OWNED FACILITIES

(Continued)

(b) **Service to Indicating Lamps:** Service to indicating lamps used for marking location of fire and police boxes, fixed warning or obstruction lights, or similar purposes will be provided where all necessary materials and labor for indicating lamp installations is furnished and installed by and at the expense of the customer. Service to indicating lamps will be furnished only if practicable and safe from the standpoint of Public Service.

(c) **TPS Supply:** Customers who desire to purchase their electric supply from a TPS may request an enrollment package from Public Service that describes the process necessary for the customer to obtain a TPS for electric supply. This package will be provided to the customer at no charge by Public Service.

(c-1) The customer must contract with a TPS to arrange for deliveries to Public Service of the electric supply. A customer is limited to one TPS for electric supply for each account for which the customer receives delivery service.

(c-2) The customer's TPS is required to notify Public Service of the customer's selection prior to 13 days before the customer's scheduled Public Service meter reading date for deliveries to commence on such scheduled meter reading date, and such selection shall remain in effect for the entire billing month. Customer can change TPSs effective only on the date of the customer's scheduled Public Service meter reading date.

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P. L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 16 of the Standard Terms and Conditions for additional details and/or exceptions.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 201**
Original Sheet No. 202

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 203**

RATE SCHEDULE PSAL

PRIVATE STREET AND AREA LIGHTING SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Luminaires, poles and appurtenances, maintenance and firm delivery service for dusk to dawn private street lighting and outdoor area lighting from Company owned lighting facilities. Customers may either purchase electric supply from a Third Party Supplier (TPS) or from Public Service's Basic Generation Service default service as detailed in this rate schedule.

LUMINAIRE CHARGES (Monthly Charge Per Unit):

Standard Luminaires

High Pressure Sodium Luminaire Type	Lamp Wattage	Wattage Including Ballast	PSE&G Part Number	Charge	Charge Including SUT
Cobra-Head	50	58	05-0926	$ 8.72	$ 9.30
Cobra-Head Cut-Off	50	58	05-0990	9.34	9.95
Dayform Traditionaire Type III	50	58	05-3410	24.03	25.62
Post-Top Town & Country	50	58	05-0946	8.72	9.30
Post-Top Town & Country Black Type V	50	58	05-0947	8.72	9.30
Cobra-Head	70	83	05-0927	10.76	11.47
Traditional Bollard Type V	70	83	05-3400	23.12	24.65
Capitol Type V	100	130	05-3200	26.92	28.71
Cobra-Head Cut-Off Type III	100	117	05-0991	21.03	22.43
Cobra-Head	100	117	05-0940	12.86	13.71
Dayform Traditionaire Type III	100	117	05-3412	25.73	27.44
Deluxe Acorn	100	117	05-0967	22.55	24.05
Granville Black Type III	100	117	05-6037	27.88	29.73
Post-Top Acorn	100	117	05-0963	20.93	22.31
Post-Top Town & Country	100	117	05-0948	12.98	13.84
Post-Top Town & Country Type IV	100	117	05-0949	13.73	14.64
Profiler Type III	100	117	05-4593	21.69	23.13
Architectural Type III	150	190	05-3222	25.26	26.93
Cobra-Head	150	171	05-0941	13.16	14.03
Dayform Traditionaire Type III	150	171	05-3415	21.99	23.44
Dayform Traditionaire Type V	150	171	05-3317	27.17	28.97
Deluxe Acorn	150	177	05-0968	22.55	24.05
Edison III Type III	150	177	05-3326	26.88	28.66
Floodlight	150	171	05-0722, 05-0727	16.16	17.23
Franklin Park Type IV	150	177	05-4055	27.41	29.22
Old Boston Type V	150	171	05-0995	22.06	23.52
Post-Top Acorn	150	177	05-0964	22.04	23.50
Post-Top Town & Country	150	171	05-0950	16.10	17.16
Richmond Black Type III	150	177	05-4328	27.08	28.87
Shoe-Box-Small	150	171	05-0971	18.58	19.81
Signature Type V	150	171	05-3212	27.99	29.84
Trenton Type III	150	190	05-3263	25.26	26.93
Trenton Type V	150	177	05-3268	23.84	25.42
Hagerstown Type V	150	171	05-3192	33.45	35.67
Swan – Type V	150	177	05-4103	31.33	33.41
Cobra-Head	250	300	05-0928	14.43	15.39
Cobra-Head Cut-Off	250	300	05-0993	17.63	18.80
Floodlight	250	300	05-0723, 05-0726	19.60	20.90

(Charges are for illustrative purposes only see Streetlight Appendix)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 204**

RATE SCHEDULE PSAL
PRIVATE STREET AND AREA LIGHTING SERVICE
(Continued)

Standard Luminaires (continued)

Luminaire Type	Lamp Wattage	Wattage Including Ballast	PSE&G Part Number	Charge	Charge Including SUT
High Pressure Sodium (cont'd)					
Shoe-Box-Large	250	300	05-0970	$ 20.79	$ 22.17
Shoe-Box-Small	250	300	05-0973	20.79	22.17
Cobra-Head	400	450	05-0925	21.32	22.73
Cobra-Head Cut-Off	400	450	05-0929	20.75	22.13
Concourse Type III	400	450	05-3018	32.77	34.94
Expressway Flood	400	450	05-1001	36.63	39.06
Floodlight	400	449	05-0724,05-0725	26.32	28.06
Galleria Type AS	400	465	05-3111	32.02	34.15
Shoe Box-Large	400	470	05-0975	24.04	25.63
Shoe-Box-Small	400	450	05-0979	23.98	25.57
Power Flood	750	839	05-0721	34.02	36.27
Induction					
Cobra-Head Type III	40	40	05-0901	11.78	12.57
Cobra-Head Type III	80	80	05-0902	13.19	14.06
Cobra-Head Type III	150	150	05-0903	18.06	19.26
Cobra-Head Type III	250	260	05-0904	21.82	23.26
Metal Halide					
Signature Black Type V	100	130	05-3215	35.14	37.47
Classic Bollard	100	130	05-3423	41.08	43.80
Granville Black Type III	100	130	05-6038	31.29	33.36
Franklin Park Type V	150	170	05-8312	34.63	36.92
Hagarstown w/Cutoff	150	190	05-8316	36.18	38.58
Tear Drop - Type III	250	280	05-8664	38.90	41.48
Floodlight	320	350	05-8003	15.45	16.47
Cobra-Head Type III	320	350	05-8018	15.66	16.70
Profiler Type III	320	350	05-8550	28.55	30.44
LED					
Floodlight	0	140	05-9900	20.95	22.34
Floodlight	129	141	05-0734	15.97	17.03
Ecoform – Type III	158	173	05-6033	26.67	28.44

Specialty Luminaires

All luminaires not listed above as Standard Luminaires and all non-standard installations of Standard Luminaires are deemed Specialty Luminaires. The Monthly Charge Per Unit for all Specialty Luminaires is equal to the sum of the Capital Recovery Charge and Maintenance Charge set forth as follows:

(1) A Capital Recovery Charge equal to the actual total installed cost times a factor equal to 2.004% (2.137% including SUT) for all Cobrahead, Floodlights and Town and Country luminaires, and 1.634% (1.742% including SUT) for all other luminaire types. Customers requesting installation of lighting facilities related to construction

(Charges are for illustrative purposes only see Streetlight Appendix)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 205**

RATE SCHEDULE PSAL

PRIVATE STREET AND AREA LIGHTING SERVICE

(Continued)

projects where the customer of record and responsibility for the monthly payments will be transferred to a body politic upon completion of the project may elect to contribute to the total installed cost of Specialty Luminaires. These contributions, if made, are to be in accordance with Special Provisions (d) and the Capital Recovery Charge applicable is equal to the actual total installed cost less any customer contribution (net of tax gross up) times the applicable factor indicated herein. This Capital Recovery Charge will remain unchanged over the remaining life of the luminaire.

(2) A Maintenance Charge that varies by luminaire type and size and is equal to the following:

(2-a) **Applicable To Cobra Head, Floodlights And Town And Country Luminaires:**

Lamp Type	Lamp Wattage	Charge	Charge Including SUT
High Pressure Sodium	All wattages	$ 2.67	$ 2.85
Metal Halide	50 watts and 100 watts	3.27	3.49
	175 watts	3.98	4.24
	250 watts	4.07	4.34
	400 watts	3.58	3.82
	1000 watts	6.48	6.91
Mercury Vapor	All wattages	1.53	1.63
Induction	All wattages	1.28	1.37
LED	All wattages	1.10	1.17

(2-b) **Applicable To All Other Luminaire Types:**

Lamp Type	Lamp Wattage	Charge	Charge Including SUT
High Pressure Sodium	All wattages	$ 3.34	$ 3.56
Metal Halide	50 watts and 100 watts	3.94	4.20
	175 watts	4.64	4.95
	250 watts	4.74	5.05
	400 watts	4.25	4.53
	1000 watts	7.14	7.62
Mercury Vapor	All wattages	2.19	2.34
Induction	All wattages	1.28	1.37
LED	All wattages	1.10	1.17

(Charges are for illustrative purposes only see Streetlight Appendix)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 206**

RATE SCHEDULE PSAL
PRIVATE STREET AND AREA LIGHTING SERVICE
(Continued)

Closed Luminaires

Luminaire Type	Lamp Wattage	Wattage including Ballast	PSE&G Part Number	Charge	Charge Including SUT
Filament					
600 Lumens NEMA Head	58	58	00-0081	$ 4.42	$ 4.71
1,000 Lumens NEMA Head	105	105	00-0083	4.63	4.94
2,500 Lumens NEMA Head	205	205	00-0084	7.04	7.50
4,000 Lumens NEMA Head	327	327	00-0085	7.87	8.39
6,000 Lumens NEMA Head	448	448	00-0086	8.15	8.69
10,000 Lumens NEMA Head	690	690	00-0087	7.94	8.47
15,000 Lumens NEMA Head	860	860	00-0088	10.93	11.65
High Pressure Sodium					
Offset Flood	250	300	05-1000	36.84	39.28
Metal Halide					
Vandal Resistant Bollard Type V	100	130	05-3409	29.07	30.99
Bishop Crook	175	210	05-0911	36.42	38.83
Hagarstown w/ Cut-Off Type V	175	210	05-4072	37.65	40.15
Hagerstown Type V	175	210	05-3197	32.22	34.35
Manor Lantern Type III	175	210	05-3615	33.39	35.60
Post Top Acorn	175	210	05-0965	22.52	24.01
Signature Type IV & Type V	175	210	05-3217	34.22	36.49
Cobra Head Cut-Off	400	460	05-0930	21.17	22.57
Floodlight	400	460	05-0728	23.37	24.91
Gray Narrow Beam Floodlight	400	460	05-0729	23.37	24.91
Profiler Type III	400	465	05-5025	33.20	35.40
Shoe-Box-Large	400	465	05-0976	24.91	26.56
Floodlight	1000	1080	05-0421	31.89	34.00
Mercury Vapor					
Cobra-Head	100	118	05-0921	6.98	7.44
Post-Top Town & Country	100	118	05-0935	6.98	7.44
Post-Top Town & Country Type IV	100	118	05-0936	6.98	7.44
Cobra-Head	175	210	05-0920	8.99	9.59
Post-Top Town & Country	175	210	05-0937	8.03	8.56
Post-Top Town & Country Type IV	175	210	05-0938	8.03	8.56
Cobra-Head	250	290	05-0919	11.20	11.94
Cobra-Head	400	432	05-0918	12.50	13.33
Floodlight	400	453	05-0422	17.68	18.85
Cobra-Head	1000	1085	05-0768	17.12	18.26
Floodlight	1000	1075	05-0420	28.67	30.57

(Charges are for illustrative purposes only see Streetlight Appendix)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 207**

RATE SCHEDULE PSAL
PRIVATE STREET AND AREA LIGHTING SERVICE
(Continued)

DELIVERY CHARGES:

Distribution Charge per Kilowatt-hour:

Charge	Charge Including SUT
$ 0.007355	$ 0.007842

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 72 for details of these charges.

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Non-utility Generation Charge:

This charge shall recover above market costs associated with non-utility generation and other generation related costs as may be approved by the Board. Refer to the Non-utility Generation Charge sheet of this Tariff for the current charge.

Solar Pilot Recovery Charge:

This charge is designed to recover the revenue requirements associated with the Public Service Solar Pilot Program per the Board Order in Docket No. EO07040278 less the net proceeds from the sale of associated Solar Renewable Energy Certificates (SRECs) or cash received in lieu of SRECs. Refer to the Solar Pilot Recovery Charge sheet of this tariff for the current charge.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

Tax Adjustment Credit:

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current credit.

Zero Emission Certificate Recovery Charge:

This charge provides for the recovery of costs associated with the Zero Emission Certificate Program directed by the Board of Public Utilities ("BPU" or "Board"). Refer to the Zero Emission Certificate Recovery Charge sheet of this Tariff for the current charge.

Distribution Adjustment Charge:

This charge is designed to recover Board-approved costs. Refer to the Distribution Adjustment Charge sheet of this Tariff for the current charge.

The Distribution Charge, Societal Benefits Charge, Non-utility Generation Charge, the Solar Pilot Recovery Charge, the Green Programs Recovery Charge, the Tax Adjustment Credit, ~~and~~ the Zero Emission Certificate Recovery Charge, and the Distribution Adjustment Charge shall be combined for billing.

Date of Issue: Effective:

Issued by SCOTT S. JENNINGS, SVP – Finance, Planning & Strategy – PSE&G
80 Park Plaza, Newark, New Jersey 07102
Filed pursuant to Order of Board of Public Utilities dated
in Docket No.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 208**

RATE SCHEDULE PSAL
PRIVATE STREET AND AREA LIGHTING SERVICE
(Continued)

ELECTRIC SUPPLY CHARGES:

A customer may choose to receive electric supply from either:

a) A TPS as described in Section 14 of this Tariff, or
b) Public Service through its Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP) default service.

Third Party Supply:

A customer that receives electric supply from a TPS will be charged for electric supply according to any agreement between the customer and the TPS. The customer will not be charged for electric supply by Public Service.

Basic Generation Service:

Customers that do not receive electric supply from a TPS will be supplied under the Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP) default service.

For unmetered lighting, the BGS Energy Charge and the BGS Reconciliation Charge, as applicable, will be applied to all kilowatt-hours billed each month. Refer to the Basic Generation Service sheets of this Tariff for the current charges applicable to Rate Schedule PSAL.

For lighting and all other associated equipment in which Public Service has determined metering is required, the electric supply charges will be charged under Rate Schedule General Lighting and Power (GLP). The determination of the need for metering shall be at the sole discretion of Public Service giving due consideration to the particular service factors at issue, as well as, whether demand and usage is not constant on a monthly basis.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 209**

RATE SCHEDULE PSAL

PRIVATE STREET AND AREA LIGHTING SERVICE

(Continued)

LIGHTING POLE AND MISCELLANEOUS DEVICE CHARGES (Monthly Charge Per Unit):

Only poles installed, owned and maintained by Public Service as part of the electric distribution system exclusively for the purpose of providing lighting service under Rate Schedules BPL or PSAL are designated as Lighting Poles.

Standard Lighting Poles

Pole Type	Style	Height	PSE&G Part Number	Charge	Charge Including SUT
Aluminum	Windsor Black	11.5 ft.	04-1269	$ 31.26	$ 33.33
Aluminum	Classic I Black	12 ft.	04-1280	31.79	33.90
Aluminum	Classic II	12 ft.	04-1285	30.81	32.85
Aluminum	Colonial Fluted	12 ft.	04-1260	25.18	26.85
Aluminum	Contemporary Black	12 ft.	04-0353	30.77	32.81
Aluminum	Montclair Black	12 ft.	04-1273	34.75	37.05
Aluminum	Wadsworth Black	12 ft.	04-6011	26.35	28.09
Aluminum	Westwood Black	12 ft.	04-3260	24.34	25.95
Aluminum	Classic I Black	14 ft.	04-1281	32.04	34.17
Aluminum	Classic II Black	14 ft.	04-1286	32.73	34.90
Aluminum	Colgate I Black	14 ft.	04-1262	35.55	37.90
Aluminum	Colonial Fluted Black	14 ft.	04-1261	26.29	28.03
Aluminum	Colonial Round Black	14 ft.	04-1265	26.66	28.43
Aluminum	Heritage Black	14 ft.	04-3500	32.72	34.88
Aluminum	Square 5 inch	14 ft.	04-1256	27.35	29.16
Aluminum	Square Bronze	14 ft.	04-1251	22.29	23.77
Aluminum	Wadsworth Black	14 ft.	04-6009	26.78	28.55
Aluminum	Colonial Fluted	16 ft.	04-4084	34.14	36.40
Aluminum	Contemporary Black	16 ft.	04-4073	35.55	37.90
Aluminum	Heritage Black	16 ft.	04-3501	39.53	42.15
Aluminum	Square 5 inch	20 ft.	04-1257	28.66	30.56
Aluminum	Square Bronze	20 ft.	04-1252	24.21	25.82
Aluminum	Round	25 ft.	04-1211	33.68	35.91
Aluminum	Square Bronze	25 ft.	04-1258	33.07	35.26
Aluminum	Square Green 5 inch	25 ft.	04-5025	32.25	34.39
Aluminum	Square Bronze	30 ft.	04-1250	38.96	41.54
Aluminum	Round	35 ft.	04-1230	34.17	36.43
Aluminum	Colonial Fluted	10 ft.	04-1247	19.43	20.72
Aluminum	Classic 1 Black	14.5 ft.	04-1282	35.79	38.16
Fiberglass	Smooth Tapered Black	17 ft.	04-0201	8.57	9.14
Fiberglass	Round Bronze	20 ft.	04-0203	10.67	11.38
Fiberglass	Smooth Tapered Black	20 ft.	04-0205	31.66	33.76
Fiberglass	Round Bronze	25 ft.	04-0204	12.61	13.45
Laminated Wood	Natural	25 ft.	04-0195	13.25	14.13
Laminated Wood	Laminated Wood	30 ft.	04-0225	18.64	19.88
Laminated Wood	Laminated Wood Gray	30 ft.	04-0197	21.76	23.20
Pine	Center Bored	30 ft.	04-0350	17.25	18.40
Pine	Round	30 ft.	04-0302	9.24	9.85
Pine	Round	35 ft.	04-0304	10.92	11.64
Pine	Round Class IV	40 ft.	04-0306	13.96	14.88
Pine	Round Class III	45 ft.	04-0308	16.75	17.86

(Charges are for illustrative purposes only see Streetlight Appendix)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 210**

RATE SCHEDULE PSAL
PRIVATE STREET AND AREA LIGHTING SERVICE
(Continued)

Specialty Lighting Poles and Miscellaneous Devices

All poles not listed above as Standard Lighting Poles, all non-standard installations of standard lighting poles, and all shrouds, brackets and other miscellaneous devices are deemed Specialty Lighting Poles and Miscellaneous Devices. The Monthly Charge Per Unit for Specialty Lighting Poles and Miscellaneous Devices is equal to the sum of the Capital Recovery Charge and Maintenance Charge set forth as follows:

(1) A Capital Recovery Charge equal to the actual total installed cost times a factor equal to 1.635% (1.743% including SUT). Customers requesting installation of lighting facilities related to construction projects where the customer of record and responsibility for the monthly payments will be transferred to a body politic upon completion of the project may elect to contribute to the total installed cost of Specialty Lighting Poles and Miscellaneous Devices.

These contributions, if made, are to be in accordance with Special Provisions (d) and the Capital Recovery Charge applicable is equal to the actual total installed cost less any customer contribution (net of tax gross up) times the applicable factor indicated herein. This Capital Recovery Charge will remain unchanged over the remaining life of the pole.

(2) A Maintenance Charge that varies by item type and is equal to the following*:

Pole and Device Type	Charge	Charge Including SUT
Pine wood pole	$ 0.50	$ 0.54
Laminated wood pole	0.00	0.00
Aluminum pole	0.00	0.00
Fiberglass pole	0.00	0.00
Shrouds, Brackets & Other Miscellaneous Devices	0.00	0.00

* Maintenance Charges for poles and devices that are not otherwise described in (2) above, shall be determined by the Company on a case by case basis.

BILLING DETERMINANTS FOR UNMETERED LIGHTING:

Kilowatt-hours:

For lighting and all other associated equipment in which demand and usage are constant on a monthly basis, estimates of kilowatts and kilowatt-hours will be utilized. The kilowatt-hour estimate is determined for each lamp by dividing total wattage including ballast by 1,000 and multiplying the result by the monthly burning hours as follows:

January	447	July	281
February	374	August	312
February (leap-year)	387	September	343
March	372	October	397
April	317	November	421
May	292	December	456
June	263		

For lighting and all other associated equipment in which demand and usage are not constant on a monthly basis, the service will be metered and billed under Rate Schedule GLP unless Public Service at its sole discretion determines otherwise.

(Charges are for illustrative purposes only see Streetlight Appendix)

RATE SCHEDULE PSAL
PRIVATE STREET AND AREA LIGHTING SERVICE
(Continued)

Generation Obligation:

For unmetered service, the customer's Generation Obligation, in kilowatts, is determined by Public Service no less frequently than once a year. The Generation Obligation for existing customers or for new customers utilizing an existing building or premise is based upon the customer's share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM) as adjusted by PJM assigned capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions. The Generation Obligation for customers taking service in a new building or premise, as determined by Public Service, is based upon the load requirements, as estimated by Public Service, of the customer's building or premise. The Generation Obligation represents the generator capacity that PJM requires an electric supplier to have available to provide electric supply to a customer.

Transmission Obligation:

For unmetered service, the customer's Transmission Obligation, in kilowatts, is determined in a similar manner to the Generation Obligation described above. The Transmission Obligation represents the level of transmission network service that must be procured by the Customer's electric supplier from PJM to provide service to the customer.

Costs associated with the Generation and Transmission Obligations are included in the charges for Basic Generation Service and may affect the price offered by a Third Party Supplier.

Allowance for Lamp Outages:

Charges reflect an outage allowance based upon normal and abnormal operating conditions. No further allowance will be made.

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill and subject to a late payment charge at the rate of 1.416% per monthly billing period in accordance with Section 9.12 of the Standard Terms and Conditions. Service to a body politic will not be subject to a late payment charge.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

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RATE SCHEDULE PSAL

PRIVATE STREET AND AREA LIGHTING SERVICE

(Continued)

TERM:

For all Standard Luminaires and Standard Lighting Poles: One year and thereafter until terminated by five days' notice, unless underground construction is utilized, where the term shall be five years and thereafter until terminated by five days' notice.

For all Specialty Luminaires and Specialty Lighting Poles and Miscellaneous Devices and all Underground Lighting Installations: Ten years and thereafter until terminated by five days' notice. Customers shall be required to make a payment for all such lighting facilities removed prior to five years from the installation date equal to the cost of removal less salvage plus 75% of the original installed costs; for facilities removed from the fifth to tenth year after installation such payment shall equal the cost of removal less salvage plus 50% of the original installed costs.

Customers who transfer from third party supply to Basic Generation Service may be subject to additional limitations regarding the term of Basic Generation Service as detailed in Section 14 of the Standard Terms and Conditions of this Tariff.

SPECIAL PROVISIONS:

(a) **Service to Customers:** Public Service will furnish and install the lamp, luminaire, bracket, pole, wiring and associated equipment, make necessary lamp renewals, otherwise maintain the installation, and repair or replace all equipment rendered inoperable due to willful or accidental damage. In the event of repeated damage to its facilities, whether willful or accidental, Public Service reserves the right to discontinue such lighting service or require the customer to be responsible for the continued cost of repair or replacement.

Lighting service will be furnished only if practicable for installation and maintenance, safe from the standpoint of Public Service, and will not be supplied where the introduction of such lighting would create an unusual hazard.

(b) **Underground Construction:** Where underground construction is desired the customer shall pay the cost of such underground construction for all conduits, conductors, manholes and handholes. In designated underground zones, up to 100 feet of underground secondary service facilities as measured at right angles to the curb to the nearest pole utilized for lighting service under this Rate Schedule shall be exempt from this provision and will be provided by Public Service at no charge.

(c) Changes in size, type or location:

(c-1) Customers may be required to make a payment toward the costs of installation, removal, relocation and/or changes in lamp size for conversion from one light source to another when the age of the luminaires to be converted is less than 20 years.

Payment shall be based on the unamortized installed cost plus the removal cost less salvage.

Customers will be required to make a payment based on actual cost of the requested work for the temporary replacement and/or relocation of an existing light to a new location and the subsequent movement of the light back to its old location.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 213**

RATE SCHEDULE PSAL

PRIVATE STREET AND AREA LIGHTING SERVICE

(Continued)

(c-2) A request to install a new light at the same location within 12 months of the removal of an existing light will be considered a replacement of the existing light. A charge may be assessed for any lamp ordered reconnected or reinstalled when the elapsed time is less than 12 months from the request for disconnect.

(c-3) Public Service reserves the right to limit the number of lamp conversions in any year to no more than 5% of the total lamps served at the end of the previous year.

(d) **Replacement of Obsolete Equipment:** Public Service has the right to replace obsolete luminaires, poles and all other associated equipment with equivalent equipment without the consent of its customers.

(e) **Customer Contributions:** The making of a payment to Public Service shall not give the customer any interest in the facilities, the ownership being vested exclusively in Public Service.

PSAL customers requesting installation of lighting facilities related to construction projects where the customer of record and responsibility for the monthly payments will be transferred to a Body Politic upon completion of the project may elect to contribute to the total installed cost of Specialty Luminaires, Specialty Lighting Poles or Maintenance Devices in addition to that which may be required in accordance with Special Provision (b). Public Service may limit the contribution option between zero and the maximum contribution. Such contribution shall be up to a maximum of:

(e-1) The installed cost less $600.00, grossed up for income tax effects, of any luminaire with an installed cost greater than $1,200.00;

(e-2) The installed cost less $600.00, grossed up for income tax effects, of any pole with an installed cost greater than $1,200.00; or

(e-3) The installed cost, grossed up for income tax effects, of any shroud, bracket or other Miscellaneous Devices.

(f) **Unit Life:** Luminaires, poles and all other associated lighting equipment will be removed when replacement parts are required but no longer generally available. At that time the customer may elect for Public Service to install replacement equipment that will be considered as an installation of new facilities and priced at the then current applicable charges.

(g) **TPS Supply:** Customers who desire to purchase their electric supply from a TPS may request an enrollment package from Public Service that describes the process necessary for the customer to obtain a TPS for electric supply. This package will be provided to the customer at no charge by Public Service.

(g-1) The customer must contract with a TPS to arrange for deliveries to Public Service of the electric supply. A customer is limited to one TPS for electric supply for each account for which the customer receives delivery service.

(g-2) The customer's TPS is required to notify Public Service of the customer's selection prior to 13 days before the customer's scheduled Public Service meter reading date for deliveries to commence on such scheduled meter reading date, and such selection shall remain in effect for the entire billing month. Customer can change TPSs effective only on the date of the customer's scheduled Public Service meter reading date.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 214**

RATE SCHEDULE PSAL
PRIVATE STREET AND AREA LIGHTING SERVICE
(Continued)

(h) **Metered Service:** Usage based charges for lighting and all other associated equipment in which Public Service has determined metering is required will be served under Rate Schedule General Lighting and Power (GLP). Associated luminaire and maintenance charges will continue to be served under this rate schedule. The determination of the need for metering shall be at the sole discretion of Public Service giving due consideration to the particular service factors at issue, as well as, whether demand and usage is not constant on a monthly basis.

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P. L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 16 of the Standard Terms and Conditions for additional details and/or exceptions.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff.

TARIFF

FOR

GAS SERVICE

Applicable in

Territory served as shown on

Sheet Nos. 3 through 6 of this Tariff

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

GENERAL OFFICES

80 PARK PLAZA

NEWARK, NEW JERSEY 07102

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 2**

TABLE OF CONTENTS

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

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TERRITORY SERVED

BERGEN COUNTY

Allendale, Borough of
Alpine, Borough of
Bergenfield, Borough of
Bogota, Borough of
Carlstadt, Borough of
Cliffside Park, Borough of
Closter, Borough of
Cresskill, Borough of
Demarest, Borough of
Dumont, Borough of
East Rutherford, Borough of
Edgewater, Borough of
Elmwood Park, Borough of
Emerson, Borough of
Englewood, City of
Englewood Cliffs, Borough of
Fair Lawn, Borough of
Fairview, Borough of
Fort Lee, Borough of
Franklin Lakes, Borough of
Garfield, City of
Glen Rock, Borough of
Hackensack, City of
Harrington Park, Borough of
Hasbrouck Heights, Borough of
Haworth, Borough of
Hillsdale, Borough of
Ho-Ho-Kus, Borough of
Leonia, Borough of
Little Ferry, Borough of
Lodi, Borough of
Lyndhurst, Township of
Mahwah, Township of
Maywood, Borough of
Midland Park, Borough of
Montvale, Borough of
Moonachie, Borough of
New Milford, Borough of
North Arlington, Borough of
Northvale, Borough of
Norwood, Borough of
Oakland, Borough of
Old Tappan, Borough of
Oradell, Borough of
Palisades Park, Borough of
Paramus, Borough of
Park Ridge, Borough of
Ramsey, Borough of
Ridgefield, Borough of
Ridgefield Park, Village of
Ridgewood, Village of
River Edge, Borough of
River Vale, Township of
Rochelle Park, Township of
Rockleigh, Borough of
Rutherford, Borough of
Saddle Brook, Township of
Saddle River, Borough of
South Hackensack, Township of
Teaneck, Township of
Tenafly, Borough of
Teterboro, Borough of
Upper Saddle River, Borough of
Waldwick, Borough of
Wallington, Borough of
Washington, Township of
Westwood, Borough of
Woodcliff Lake, Borough of
Wood-Ridge, Borough of
Wyckoff, Township of

BURLINGTON COUNTY

Beverly, City of
Bordentown, City of
Bordentown, Township of
Burlington, City of
Burlington, Township of

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 4**

TERRITORY SERVED
(Continued)

BURLINGTON COUNTY (continued)

Chesterfield, Township of
Cinnaminson, Township of
Delanco, Township of
Delran, Township of
Eastampton, Township of
Edgewater Park, Township of
Evesham, Township of
Fieldsboro, Borough of
Florence, Township of
Hainesport, Township of
Lumberton, Township of
Mansfield, Township of
Maple Shade, Township of
Medford, Township of
Moorestown, Township of
Mount Holly, Township of
Mount Laurel, Township of
New Hanover, Township of
North Hanover, Township of
Palmyra, Borough of
Pemberton, Borough of
Pemberton, Township of
Riverside, Township of
Riverton, Borough of
Southampton, Township of
Springfield, Township of
Westampton, Township of
Willingboro, Township of
Woodland, Township of
Wrightstown, Borough of

CAMDEN COUNTY

Audubon, Borough of
Audubon Park, Borough of
Barrington, Borough of
Bellmawr, Borough of
Brooklawn Borough of
Camden, City of
Cherry Hill, Township of
Collingswood, Borough of
Gloucester, City of
Haddon, Township of
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Haddon Heights, Borough of
Lawnside, Borough of
Merchantville, Borough of
Mount Ephraim, Borough of
Oaklyn, Borough of
Pennsauken, Township of
Tavistock, Borough of
Woodlynne, Borough of

ESSEX COUNTY

Belleville, Town of
Bloomfield, Township of
Caldwell, Borough of
Cedar Grove, Township of
East Orange, City of
Essex Fells, Borough of
Fairfield, Township of
Glen Ridge, Borough of
Irvington, Township of
Livingston, Township of
Maplewood, Township of
Millburn, Township of
Montclair, Township of
Newark, City of
North Caldwell, Borough of
Nutley, Township of
Orange, City of
Roseland, Borough of
South Orange Village, Township of
Verona, Township of
West Caldwell, Township of
West Orange, Township of

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 5**

TERRITORY SERVED
(Continued)

GLOUCESTER COUNTY

Deptford, Township of
National Park, Borough of
West Deptford, Township of
Westville, Borough of
Woodbury, City of

HUDSON COUNTY

Bayonne, City of
East Newark, Borough of
Guttenberg, Town of
Harrison, Town of
Hoboken, City of
Jersey City, City of
Kearny, Town of
North Bergen, Township of
Secaucus, Town of
Union City, City of
Weehawken, Township of
West New York, Town of

HUNTERDON COUNTY

East Amwell, Township of
Readington, Township of
Tewksbury, Township of

MERCER COUNTY

East Windsor, Township of
Ewing, Township of
Hamilton, Township of
Hightstown, Borough of
Lawrence, Township of
Princeton, Borough of
Princeton, Township of
Robbinsville, Township of
Trenton, City of
West Windsor, Township of

MIDDLESEX COUNTY

Cranbury, Township of
Dunellen, Borough of
East Brunswick, Township of
Edison, Township of
Helmetta, Borough of
Highland Park, Borough of
Jamesburg, Borough of
Middlesex, Borough of
Milltown, Borough of
Monroe, Township of
New Brunswick, City of
North Brunswick, Township of
Old Bridge, Township of
Piscataway, Township of
Plainsboro, Township of
Sayreville, Borough of
South Amboy, City of
South Brunswick, Township of
South Plainfield, Borough of
South River, Borough of
Spotswood, Borough of

MONMOUTH COUNTY

Allentown, Borough of
Millstone, Township of
Roosevelt, Borough of
Upper Freehold, Township of

MORRIS COUNTY

Butler, Borough of
Chatham, Borough of
Chatham, Township of
Chester, Borough of
Chester, Township of
Denville, Township of
East Hanover, Township of
Florham Park, Borough of

Date of Issue: Effective:
Issued by SCOTT S. JENNINGS, SVP – Finance, Planning & Strategy – PSE&G
80 Park Plaza, Newark, New Jersey 07102
Filed pursuant to Order of Board of Public Utilities dated
in Docket No.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 6**

TERRITORY SERVED
(Continued)

MORRIS COUNTY (continued)

Hanover, Township of
Harding, Township of
Jefferson, Township of
Kinnelon, Borough of
Long Hill, Township of
Madison, Borough of
Mendham, Borough of
Mendham, Township of
Morris, Township of
Morris Plains, Borough of
Morristown, Town of
Parsippany-Troy Hills, Township of
Pequannock, Township of
Randolph, Township of
Riverdale, Borough of

OCEAN COUNTY

Plumsted, Township of

PASSAIC COUNTY

Bloomingdale, Borough of
Clifton, City of
Haledon, Borough of
Hawthorne, Borough of
Little Falls, Township of
North Haledon, Borough of
Passaic, City of
Paterson, City of
Pompton Lakes, Borough of
Prospect Park, Borough of
Ringwood, Borough of
Totowa, Borough of
Wanaque, Borough of
Wayne, Township of
West Milford, Township of
Woodland Park, Borough of

SOMERSET COUNTY

Bedminster, Township of
Bernards, Township of
Bernardsville, Borough of
Bound Brook, Borough of
Branchburg, Township of
Bridgewater, Township of
Far Hills, Borough of
Franklin, Township of
Green Brook, Township of
Hillsborough, Township of
Manville, Borough of
Millstone, Borough of
Montgomery, Township of
North Plainfield, Borough of
Peapack-Gladstone, Borough of
Raritan, Borough of
Rocky Hill, Borough of
Somerville, Borough of
South Bound Brook, Borough of
Warren, Township of
Watchung, Borough of

UNION COUNTY

Berkeley Heights, Township of
New Providence, Borough of
Plainfield, City of
Springfield, Township of
Summit, City of

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 7**

STANDARD TERMS AND CONDITIONS - INDEX

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 8**

STANDARD TERMS AND CONDITIONS – INDEX
(Continued)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 9**

STANDARD TERMS AND CONDITIONS

1. GENERAL

These Standard Terms and Conditions, filed as part of the Gas Tariff of Public Service Electric and Gas Company, hereinafter referred to as "Public Service", set forth the terms and conditions under which gas service will be supplied and govern all classes of service to the extent applicable, and are made a part of all agreements for the supply of gas service unless specifically modified in a particular rate schedule.

No representative of Public Service has authority to modify any provision contained in this Tariff or to bind Public Service by any promise or representation contrary thereto.

Public Service will construct, own, and maintain distribution mains and services located on land, streets, highways, rights of way acquired by Public Service, and on private property, used or usable as part of the distribution system of Public Service. Payment of monthly charges, or a deposit or a contribution shall not give the customer, Applicant or depositor any interest in the facilities, the ownership being vested exclusively in Public Service.

Publications set forth by title in sections of these Standard Terms and Conditions are incorporated in this Tariff by reference.

This tariff is subject to the lawful orders of the Board of Public Utilities of the State of New Jersey. Complaints may be directed to: Board of Public Utilities, Division of Customer Assistance, 44 South Clinton Avenue, P.O. Box 350, Trenton, New Jersey, 08625-0350 or 1-800-624-0241; www.nj.gov/bpu.

2. OBTAINING SERVICE

2.1. Application: An application for service may be made at any of the Customer Service Centers of Public Service in person, or by telephone, by the Company's website at www.pseg.com, or electronic mail, where available. Forms for application for service, when required, together with terms and conditions and rate schedules, will be furnished upon request. All customers shall be given a copy of the Customer Bill of Rights, effective at the time of service initiation. Customer shall state, at the time of making application for service, the conditions under which service will be required and customer may be required to sign an agreement or other form then in use by Public Service covering special circumstances for the supply of gas service. Data requested from customers may include proof of identification as well as copies of leases, deeds and corporate charters in accordance with N.J.A.C. 14:3-3.2 (e) and (f). Such information shall be considered confidential.

Public Service may reject applications for service where such service is not available or where such service might affect the supply of gas to other customers, or for failure of customer to agree to comply with any of these Standard Terms and Conditions.

See also Section 13 Service Limitations, of these Standard Terms and Conditions.

2.2. Initial Selection of Rate Schedule: Public Service will assist in the selection of the available rate schedule which is most favorable from the standpoint of the customer. Any advice given by Public Service will necessarily be based on customer's written statements detailing the customer's proposed operating conditions.

Customers may, upon written notice to Public Service within three months after service has begun, elect to change and to receive service under any other available rate schedule. Public Service will furnish service to and bill the customer under the rate schedule so selected from the date of last scheduled meter reading, but no further change will be allowed during the next twelve months.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 10**

STANDARD TERMS AND CONDITIONS
(Continued)

2.2.1. Change of Rate Schedule: Subsequent to initial selection of a rate schedule, customer shall notify Public Service in writing of any change in the customer's use of service which might affect the selection of a rate schedule or provision within a rate schedule. Any change in schedule or provision shall be applicable, if permitted, to the next regular billing subsequent to such notification.

2.3. Deposit and Guarantee: Public Service may require a reasonable deposit as a condition of supplying service, in accordance with the provisions as set forth in Board of Public Utility regulations.

A deposit may be required from a customer equal to the average monthly charge for a twelve-month period and one month's average bill. A customer taking service for a period of less than thirty days may be required to deposit an amount equal to the estimated bill for such temporary period.

Upon closing any account, the balance of any deposit remaining after the closing bill for service has been settled, shall be returned promptly to the customer with any interest due. The customer has the option of having the deposit refund applied to the account in the form of a credit or of having the deposit refunded by separate check in a period not to exceed one full billing cycle.

Public Service shall review a residential customer's account at least once every year and a non-residential customer's account at least once every 2 years. If such review indicates that the customer has established credit satisfactory to Public Service, then the outstanding deposit shall be refunded to the customer. The customer has the option of having the deposit refund applied to the account in the form of a credit or of having the deposit refunded by separate check in a period not to exceed one billing cycle.

In accordance with N.J.A.C. 14:3-3.5(d), simple interest at a rate equal to the average yields on new six-month Treasury Bills for the twelve month period ending each September 30 shall be paid by Public Service on all deposits held by it after notification by the BPU of the new effective rate. Said rate shall be determined by the Board of Public Utilities ("Board"), and shall become effective on January 1 of the following year.

For residential customers, interest payments shall be made at least once during each 12-month period in which a deposit is held. Residential customers shall have the option of a credit to the customer's account or a separate check.

A deposit is not a payment or part payment of any bill for service, except that on discontinuance of service Public Service may apply said deposit against unpaid bills for service, and only the remaining balance of the deposit will be refunded. Public Service shall promptly read the meters and ascertain that the obligations of the customer have been fully performed before being required to return any deposit. To have service resumed, a deposit may be required, but the deposit shall not be required prior to restoration of service. Public Service shall bill the customer for the deposit and allow at least 15 days after the billing for payment of deposit, or make other reasonable arrangements.

STANDARD TERMS AND CONDITIONS
(Continued)

2.4. **Permits**: Public Service, where necessary, will make application for any street opening permits for installing its gas facilities necessary to provide new or upgraded service to a customer and shall not be required to furnish service until after such permits are granted. The Applicant may be required to pay the municipal charge, if any, for permission to open the street. The Applicant shall obtain and present to Public Service, for recording or for registration, all instruments providing for easements or rights of way, and all permits (except street opening permits), consents, and certificates necessary for the introduction of service.

2.5. **Service Connections:** The customer may be required to make a contribution toward the cost of installing a service connection as set forth in Section 5 of these Standard Terms and Conditions.

2.6. **Temporary Service:** Where service is to be used at an installation for a limited period and such installation is not permanent in nature, the use of service shall be classified as temporary. In such cases, the customer may be required to pay to Public Service the cost of the facilities required to furnish service. The minimum period of temporary service for billing purposes shall be one month.

After two years of service a temporary service installation shall be eligible for refunds. Excluding the first two annual service periods, refunds equal to 10% of the revenue from Service Charges, Distribution Charges and Demand Charges received by Public Service during an annual service period shall be made at the end of such period. In no case shall the total amount refunded be in excess of the installation cost paid by the customer, nor shall refunds be made for more than eight consecutive annual service periods.

3. CHARGES FOR SERVICE

3.1. **General:** Charges for gas usage are set forth in the rate schedules included elsewhere in this Tariff. In addition to the charges for gas usage, Public Service may require additional monthly charges, up-front contributions or deposits (including the gross-up for income tax effects) from an Applicant for providing Temporary Services, for certain Standard and Atypical Conditions, or for an Extension.

3.2. **Definitions:** The following are defined terms as used in this Tariff:

a) Applicant is the individual or entity, who may or may not be the ultimate customer, requesting new, additional, temporary, or upgraded gas service from Public Service.

b) Applicant For An Extension is an Applicant where Public Service has determined that an Extension is necessary to provide service.

c) N.J.A.C. is the New Jersey Administrative Code.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

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STANDARD TERMS AND CONDITIONS
(Continued)

d) Distribution Revenue as used in this Section 3 means the total revenue, plus related New Jersey Sales and Use Tax (SUT), charged a customer by Public Service, minus Basic Gas Supply Service charges including SUT, assessed in accordance with this Tariff for Gas Service. For Rate CIG the Basic Gas Supply Service Charges is the Estimated Average Commodity Cost plus Losses and applicable SUT.

e) Temporary Service is where service is provided through an installation for a limited period and such installation is not permanent in nature.

f) An Extension means the construction or installation of plant and/or facilities by Public Service used to convey service from existing or new plant and/or facilities to one or more new customers, and also means the plant and/or facilities themselves. An Extension includes all Public Service plant and/or facilities used for gas transmission (non-FERC jurisdictional) and/or distribution, whether located on a public street or right of way, or on private property or private right of way, and includes the pipe, rights of way, land, valves, site restoration, regulators and metering equipment and other means of conveying service from existing plant and/or facilities to each unit or structure to be served. An Extension does not include equipment solely used for administrative purposes, such as office equipment used for administering a billing system.

An Extension begins at the existing Public Service infrastructure and ends at the meter and includes the meter. The new plant and/or facilities installed constituting an Extension must be nominally physically continuous from the beginning to the end of the Extension.

Plant and/or facilities installed to supply the increased load of existing non-residential customers are also considered an Extension where existing Public Service facilities are upgraded or replaced due to an Applicant's new or additional gas load being greater than 50% of the total design capacity of the pre-existing facilities.

g) Cost means, with respect to the cost of construction of an Extension, actual and/or site-specific unitized expenses incurred by Public Service for materials and labor, including both internal and external labor, employed in the actual design, purchase, construction, and/or installation of the Extension, including overhead directly attributable to the work, as well as overrides or loading factors such as those for mapping and design. This term does not include expenses for clerical, dispatching, supervision, or general office functions. Costs shall be determined by the Company and shall include all costs inclusive of upgrades to existing infrastructure as well as tax gross ups, inclusive of the applicable bonus depreciation credits. Costs related to plant and/or facilities installed to serve increased load from an existing customer are determined on a similar basis.

3.3. **Removal of Public Service Facilities:** There is normally no charge for the permanent removal of above ground Public Service facilities or the abandonment in place of underground Public Service facilities where an easement for such facilities does not exist. Where an easement exists, and when approved by Public Service, and unless preempted by statute, the requesting party shall be responsible for all costs related to the removal or abandonment of requested facilities and if necessary, the installation of all new facilities necessary to provide the same level of service to all other customers.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 13**

STANDARD TERMS AND CONDITIONS
(Continued)

3.4. **Temporary Service**: Where Public Service provides Temporary Service, the customer will be required to pay to Public Service the cost of the installation and removal of facilities required to furnish service. The minimum period of temporary service for billing purposes shall be one month.

After two years of service, a Temporary Service installation shall be eligible for refunds. Excluding the first two annual service periods, refunds equal to 10% of the Distribution Revenue received by Public Service during each annual service period shall be made at the end of such period. In no case shall the total amount refunded be in excess of the installation and removal cost paid by the customer, nor shall refunds be made for more than eight consecutive annual service periods.

Temporary service will not be supplied under Rate Schedule SLG.

3.5. **Provision of Service:** Gas service shall be supplied in accordance with these Standard Terms and Conditions and the applicable rate schedule and shall be based upon customer's anticipated load and upon plant facilities that are sufficient for safe, proper, and adequate service based upon Public Service's design standards and reliability criteria. Both the Applicant's anticipated load and sufficient plant facilities will be as determined by Public Service.

3.5.1. **Standard Conditions:** Underground construction is the standard for all gas mains and services. Metering and regulating facilities are normally located above ground outside of buildings, unless required by Public Service operating conditions in which case they will be located inside.

3.5.2. **Atypical Conditions:** When special facilities are required due to conditions beyond the control of Public Service, or are requested by the Applicant and approved by Public Service, or are required due to local ordinance, the added cost of such special facilities, grossed up for income tax effects, shall be paid by the Applicant as a non-refundable contribution.

Public Service may require agreements for a longer term than specified in the rate schedule, may require contributions toward the investment, and may establish such Minimum Charges and Facilities Charges as may be equitable under the circumstances involved where: (1) large or special investment is necessary for the supply of service; (2) capacity required to serve Rate Schedules GSG or LVG customer's weather-sensitive or dual-fueled equipment is out of proportion to the use of gas service for occasional, intermittent, or low load factor purposes, or is for short durations. The assessment of any Minimum Charges will be based upon a minimum use requirement of 850 therms per year for each therm of applicable connected load. To the extent that total annual therm usage is less than 850 therms per therm of connected load, any deficiency will be assessed a Minimum Charge of $0.25 ($0.27 including SUT) per therm.

Unless there is a material change in the provision of service, once charges are established for a premises pursuant to this Section 3.5.2, they shall be used for all subsequent customers at that premises requesting such similar service, regardless of any lapse in the provision of such similar service characteristics to that premises.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 14**

STANDARD TERMS AND CONDITIONS
(Continued)

3.6. Extensions – General Provisions: Where it is necessary for Public Service to construct an Extension to serve the requirements of an Applicant, Public Service may require a deposit or contribution from the customer to cover all or part of the cost of the Extension, which is required to be paid to Public Service prior to any work being performed. The costs will be estimated based upon normal conditions, and may be increased if severe conditions, such as excessive rock or other unknown conditions, are found during excavation.

3.7. Charges for Extensions: Applicants requesting service may be charged a deposit for service. Such deposit will be determined by Public Service by comparing the estimated Distribution Revenue to the applicable costs of the Extension. The detailed calculations of such deposits, if any, are contained in the remainder of Section 3.7 of these Standard Terms and Conditions.

3.7.1. Individual Residential Customer: Where application for service is made by an Applicant for individual residential use, and the service requested is not for a limited period of less than ten (10) years, the following shall apply:

a) Excess cost is defined as the total cost of the Extension less any contribution required for Atypical Conditions less ten times the estimated average annual Distribution Revenue, such result grossed up for income tax effects. The excess cost shall not be less than zero in any case.

Any excess cost shall be deposited and remain with Public Service without interest. Public Service will waive the deposit requirement where the excess cost is $3,000.00 or less.

b) In each annual period from the date of connection, if the actual Distribution Revenue from the customer exceeds the greater of either: (1) the estimated annual Distribution Revenue used as the basis for the initial deposit computation, or (2) the highest actual Distribution Revenue from any prior year, there shall be returned to the Applicant an additional amount, equal to ten times such excess multiplied by the tax gross up factor used when the deposit was taken.

c) As additional customers not originally anticipated are supplied from this Extension and Public Service still holds at least some part of the deposit from the original Applicant, a reduction may be made to such remaining deposit. The cost of the Extension or cost for Increased Load for any such additional customer will be first compared to the estimated additional Distribution Revenue as detailed in the appropriate paragraph of this Section 3. Once any deposit requirement has been satisfied, any remaining Distribution Revenue credit will be applied toward the original customer's remaining deposit in an amount equal to ten times such excess Distribution Revenue multiplied by the tax gross up factor used when the deposit was taken.

d) In no event shall more than the original deposit be returned to the Applicant nor shall any part of the deposit remaining after ten years from the date of the original deposit be returned.

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3.7.2. Multi-unit Developments: Where application for service is made for gas service to a multi-unit residential or multi-unit non-residential development, the following shall apply:

a) Excess cost for an Applicant is defined as the total cost of the Extension less any contribution required for Atypical Conditions, such result grossed up for income tax effects.

Any excess cost shall be deposited and remain with Public Service with interest. Public Service will waive the deposit, requirement where the excess cost is $3,000.00 or less, or where ten times the estimated annual Distribution Revenue is greater than the excess costs and the excess cost is less than $20,000.00.

b) As each unit is connected, as determined by the setting and activation of the Public Service gas meter, there shall be returned to the Applicant an amount equal to ten times the estimated annual Distribution Revenue from that unit multiplied by the tax gross up factor used when the deposit was taken.

c) In each annual period from the date of deposit, if for all customers receiving service for the entire prior one year period the actual annual Distribution Revenue exceeds the greater of either: (1) the estimated annual Distribution Revenue, or (2) the highest actual Distribution Revenue from any prior year, there shall be returned to the Applicant an additional amount equal to ten times such excess multiplied by the tax gross up factor used when the deposit was taken.

d) As additional customers not originally anticipated are supplied from this Extension and Public Service still holds at least some part of the deposit from the original Applicant, a reduction may be made to such remaining deposit. The cost of the Extension or cost for Increased Load for any such additional customer will be first compared to the estimated additional Distribution Revenue as detailed in the appropriate paragraph of this Section 3. Once any deposit requirement has been satisfied, any remaining Distribution Revenue credit will be applied toward the original customer's remaining deposit in an amount equal to ten times such excess Distribution Revenue multiplied by the tax gross up factor used when the deposit was taken.

e) In no event shall more than the original deposit be returned to the Applicant nor shall any part of the deposit remaining after ten years from the date of the original deposit be returned.

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3.7.3. Individual Commercial and Industrial Customers: Where application for service is made for individual non-residential use, and the service requested is not for a limited period of less than ten (10) years, the following shall apply:

a) Excess cost for an Applicant is defined as the total cost of the Extension less any contribution required for Atypical Conditions less ten times the estimated average annual Distribution Revenue, such result grossed up for income tax effects. The excess cost shall not be less than zero in any case.

Any excess cost shall be deposited and remain with Public Service with interest. Public Service will waive the deposit requirement where the excess cost is $3,000.00 or less, or where ten times the estimated annual Distribution Revenue is greater than the excess costs and the excess cost is less than $20,000.00.

b) As the Public Service gas meter is set, there shall be returned to the Applicant an amount equal to ten (10) times the estimated average annual Distribution revenue multiplied by the tax gross up factor used when the deposit was taken.

c) In each annual period from the date of deposit, if the actual Distribution Revenue from the customer exceeds the greater of: (1) the estimated annual Distribution Revenue used as the basis for the initial deposit, or (2) the highest actual Distribution Revenue from any prior year; there shall be returned to the Applicant an additional amount, equal to ten times such excess multiplied by the tax gross up factor used when the deposit was taken.

d) As additional customers not originally anticipated are supplied from this Extension and Public Service still holds at least some part of the deposit from the original Applicant, a reduction may be made to such remaining deposit. The cost of the Extension or cost for Increased Load for any such additional customer will be first compared to the estimated additional Distribution Revenue as detailed in the appropriate paragraph of this Section 3. Once any deposit requirement has been satisfied, any remaining Distribution Revenue credit will be applied toward the original customer’s remaining deposit in an amount equal to ten times such excess Distribution Revenue multiplied by the tax gross up factor used when the deposit was taken.

e) In no event shall more than the original deposit be returned to the Applicant nor shall any part of the original deposit remaining after ten years from the date of the original deposit be returned.

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3.8. **Charges for Increased Load:** When it is necessary for Public Service to construct, upgrade, or install facilities necessary to service the additional requirements of existing customers and these facilities do not meet the definition of an Extension as defined in Section 3.2 (f) of these Standard Terms and Conditions, the following shall apply:

a) Public Service may require a deposit from the customer to cover all or part of the investment necessary to supply service. Any such deposit will be calculated by comparing the estimated annual increase in Distribution Revenue as determined by Public Service to the total cost of the applicable work to determine if excess costs exist.

b) Excess cost is defined as the total cost of the applicable work less any contribution required for Atypical Conditions less the ten times the estimated average annual increase in Distribution Revenue, such result grossed up for income tax effects. The excess cost shall not be less than zero in any case.

c) Any excess cost shall be deposited and remain with Public Service without interest. Public Service will waive the deposit requirement where the excess cost is $3,000.00 or less.

d) In each annual period from the date of connection of such additional load, if the actual increase in Distribution Revenue from the customer exceeds the greater of either: (1) the estimated annual increase in Distribution Revenue used as the basis for the initial deposit, or (2) the highest increase in actual Distribution Revenue from any prior year, there shall be returned to the Applicant an additional amount, equal to ten times such excess multiplied by the tax gross up factor used when the deposit was taken.

e) In no event shall more than the original deposit be returned to the Applicant nor shall any part of the deposit remaining after ten years from the date of the original deposit be returned.

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4. CHARACTERISTICS OF SERVICE

4.1. Standard Service Supply: Public Service may commingle gas supplies from several sources. All gas delivered to any customer may be a mixture of gas manufactured or derived from natural sources, altered to remove impurities and to add desirable constituents. The heat content of delivered gas may vary between 950 and 1,150 Btu per cubic foot. The character of the gas will be of a nature which will allow an atmospheric burner to operate without repeated adjustment.

4.2. Heat Measurement and Billing Units: For billing purposes, the customer's gas use in cubic feet will be converted to therms, using the actual weighted average heating value, on a dry basis, of the gas distributed in the second preceding calendar month, where a therm is a unit of heat energy equivalent to 100,000 British thermal units (Btu). Metered usage in cubic feet at standard pressure will be corrected to atmospheric pressure by application of a 1.012 multiplier. Metered usage at higher than standard pressure will be corrected to atmospheric pressure by application of appropriate multipliers.

4.3. Standard Pressure: The standard pressure supplied at the meter outlet will be within the range of 4 to 7 inches water column pressure.

5. SERVICE CONNECTIONS

5.1. General: The Applicant shall consult Public Service as to the exact point at which the meter set will be located and connection to customer piping will be made before installing interior gas piping or starting any other work dependent upon the location of the service pipe.

Public Service will determine the location of the service pipe depending upon existing facilities in the street and other practical considerations.

Gas service will be supplied to each building or premises through a single service pipe except where, in the judgment of Public Service, its economic considerations; conditions on its distribution system; improvement of service conditions; or volume of the customer's requirements, make it desirable to install more than one service pipe.

5.2. Change in Location of Existing Service Pipe: Any change requested by the customer in the location of the existing service pipe, if approved by Public Service, will be made at the expense of the customer. A request to install facilities for the same building within 12 months of the removal of similar facilities may be considered a relocation of the existing facilities if the load served is similar or lower and the building served is essentially the same.

6. METERS AND ASSOCIATED EQUIPMENT

6.1. General: A single meter will be furnished and installed by Public Service for each separately billed rate schedule under which a customer receives service. Public Service shall be consulted regarding meter locations. Meter installations shall be in conformance

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with the standards of the fuel gas subcode of the “Uniform Construction Code” and the “General Criteria for Installation of Gas Appliances and Gas Piping,” issued by Public Service and available on request. Where permitted, the meter shall be located outside. If the meter is not located outside solely due to the request of the customer, Public Service reserves the right to install remote metering equipment at the customer’s expense. See Section 8.5 of these Standard Terms and Conditions. The installation of meters and connections shall be in accordance with N.J.A.C. 14:3-4.2.

When requested by a customer, remote meter reading equipment may be installed, if feasible, at the expense of the customer. The payment shall not give the customer any interest in the equipment thus installed, the ownership being vested exclusively in Public Service.

Additional meters will be installed only where, in the judgment of Public Service, its economic considerations; conditions on its distribution system; improvement of service conditions; or the volume of the customer’s requirements, make it desirable to install such additional meters.

6.2. **Seals:** Public Service may seal or lock any meters or enclosures containing meters and associated metering equipment. No person except a duly authorized employee of Public Service shall break or remove a Public Service seal or lock.

6.3. **Protection of Meter and Service Equipment:** Customer shall furnish and maintain a suitable space for the meter and associated equipment. Such space shall be as near as practicable to the point of entrance of the gas service pipe, adequately ventilated, dry (inside installation only) and free from corrosive vapors, not subject to extreme temperatures, readily accessible to duly authorized employees or agents of Public Service and shall otherwise conform to the standards of the fuel gas subcode of the “Uniform Construction Code” and to the “General Criteria for Installation of Gas Appliances and Gas Piping,” issued by Public Service and available on request. The gas meter cannot be located behind fences or gates unless no other practical location can be identified. Customer shall not tamper with or remove meters or other equipment, nor permit access thereto except by duly authorized employees or agents of Public Service. In case of loss or damage to the property of Public Service from the act or negligence of the customer or the customer’s agents or servants, or of failure to return equipment supplied by Public Service, customer shall pay to Public Service the amount of such loss or damage to the property. All equipment furnished at the expense of Public Service shall remain its property and may be replaced whenever deemed necessary and may be removed by it at any reasonable time after the discontinuance of service. In the case of defective service, the customer shall not interfere or tamper with the apparatus belonging to Public Service but shall immediately notify Public Service to have the defects remedied.

6.4. **Public Service to Turn on Gas:** No person other than a duly authorized employee or agent of Public Service shall turn gas into any new system of piping or into any old system of piping from which the use of gas had been discontinued.

6.5. **Change in Location of Meters and Associated Equipment:** Any change requested by the customer in the existing location of meters and associated equipment, if approved by Public Service, will be made at the expense of the customer.

6.6. **Tampering:** In the event it is established that Public Service meters or other equipment on the customer’s premises have been tampered with, and, such tampering results in incorrect measurement of the service supplied, the charges for such gas service under the applicable rate schedule including Basic Gas Supply Service default service, based

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upon the Public Service estimate from available data and not registered by Public Service meters shall be paid by the beneficiary of such service. In the case of a residential customer, such unpaid service shall be limited to not more than one year prior to the date of correcting the tampered account and for no more than the unpaid service alleged to be used by such customer. The beneficiary shall be the customer or other party who benefits from such tampering. The actual cost of investigation, inspection, and determination of such tampering, and other costs, such as but not limited to, the installation of protective equipment, legal fees, and other costs related to the administrative, civil or criminal proceedings, shall be billed to the responsible party. The responsible party shall be the party who either tampered with or caused the tampering with a meter or other equipment or knowingly received the benefit of tampering by or caused by another. In the event a residential customer unknowingly received the benefit of meter or equipment tampering, Public Service shall only seek from the benefiting customer the cost of the service provided under the applicable rate schedule including Basic Gas Supply Service default service but not the cost of investigation.

These provisions are subject to the customer's right to pursue a bill dispute proceeding pursuant to N.J.A.C. 14:3-7.6.

Tampering with Public Service facilities may be punishable by fine and/or imprisonment under the New Jersey Code of Criminal Justice.

7. CUSTOMER'S INSTALLATION

7.1. **General:** No material change in the total input rating, or method of operation of customer's equipment shall be made without previous written notice to Public Service. For the purpose of this paragraph a material change in total input rating is defined as a change of 50,000 Btu per hour input or 10%, whichever is larger. A material change in method of operation is defined as a 50% change in the customer's total annual gas consumption.

7.2. **Piping:** Gas piping installed on the customer's premises must conform to all requirements of municipal or other properly constituted public authorities, the most current edition of the standards of the fuel gas subcode of the "Uniform Construction Code", and to the regulations set forth in "General Criteria for Installation of Gas Appliances and Gas Piping," issued by Public Service and available on request.

7.3. **Gas Equipment and Appliances:** All gas equipment and appliances shall be certified to applicable U.S. standards by a nationally recognized testing laboratory, and marked with the appropriate certification approval. The manner of installation of all gas equipment and appliances shall be in accordance with all local construction codes, the most current edition of the standards of the fuel gas subcode of the "Uniform Construction Code", and the regulations set forth in "General Criteria for Installation of Gas Appliances and Gas Piping," issued by Public Service and available on request.

7.4. **Back Pressure and Suction:** When the nature of customer's gas fired equipment, gas compressors or gas piping configuration is such that it may cause back pressure or suction in the piping system, meters or other associated equipment of Public Service, suitable protective devices as defined by the standards of the fuel gas subcode of the "Uniform Construction Code", fittings, valves or check valves shall be furnished, installed and maintained by the customer, subject to the inspection and approval by Public Service.

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7.5. Maintenance of Customer's Installation: Customer's entire installation shall be maintained in the condition required by the municipal or other public authorities having jurisdiction and by Public Service.

7.6. Appliance Adjustments: Public Service will make, without additional charge, safety related adjustments to gas burners and certain associated equipment as determined by the Board to be necessary to the functioning of gas appliances in use on customer's premises. Other adjustments or repairs to such appliances may be made, or other services connected with the rendering of gas service may be performed, by Public Service at the customer's expense. Service procedures are detailed in "Servicing Equipment and Facilities on Customers' Premises," issued by Public Service and available on request.

7.7. Adequacy and Safety of Installation: Public Service shall not be required to supply gas service until the customer's installation shall have been approved by the authorities having jurisdiction. Public Service may withhold or discontinue its service whenever such installation or part thereof is deemed by Public Service to be unsafe, inadequate, or unsuitable for receiving service, or to interfere with or impair the continuity or quality of service to the customer or to others.

Public Service will assume no responsibility for the condition of customer's gas installation or for accidents, fires, or failures which may occur as the result of the condition of such gas installation.

Neither by inspection or nonrejection, nor in any other way, does Public Service give any warranty, expressed or implied, as to the adequacy, safety, or other characteristics of any structure, equipment, wires, pipes, appliances, or devices used by the customer.

7.8. Liability for Customer's Installation: Public Service will not be liable for damages or for injuries sustained by customers or others or by the equipment of customers or others by reason of the condition or character of customers' facilities or the equipment of others on customers' premises or by reason of the characteristics of the service that are in accord with Section 4.1 of these Standard Terms and Conditions. Public Service will not be liable for the use, care or handling of the gas service delivered to the customer after same passes beyond the point at which the service facilities of Public Service connect to the customers' facilities.

8. METER READING AND BILLING

8.1. Measurement of Gas Used: Public Service will select the type and make of metering equipment and may, from time to time, change or alter such equipment; its sole obligation is to supply meters that will accurately and adequately furnish records for billing purposes.

Where service through more than one meter is permitted by Public Service as outlined under Section 6.1 of these Standard Terms and Conditions, the cubic-foot use registered by the individual meters will be combined for billing purposes. In all other instances, each meter shall be billed separately.

Bills will be based upon registration of Public Service meters except as otherwise provided for in this Tariff.

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8.2. Correction for Pressure: In any case where, pursuant to Section 4.3, Public Service measures the gas delivered to a customer under pressure greater than that exerted by a column of water seven inches in height, the cubic feet of gas registered by the meter or meters of Public Service shall be subject to correction for billing purposes by the application of a proper correction factor.

8.3. Metering on Customer's Premises:

8.3.1. General: The service and supply of gas by Public Service for the use of owners, landlords, tenants, or occupants of newly constructed or renovated residential units will be furnished to them as customers of Public Service through Public Service individual meters, except as noted below in Section 8.3.2.

The service and supply of gas by Public Service to owners, landlords, tenants, or occupants of industrial or commercial buildings or residential premises as noted below in section 8.3.2 may be further distributed to other users within such structures and such use and resultant charges, including reasonable administrative costs, apportioned to such users. However, such charges shall not exceed the amount that Public Service would charge if the tenant were served and billed directly by Public Service on the most appropriate rate schedule. In no event will a customer buying gas service from Public Service be permitted to resell it for a profit.

Where customer installs, or has installed a gas-fired pool heating device, service to such device must be limited to a separate line with a shutoff valve or a separate meter.

8.3.2. Sub-metering: The practice where a primary customer of Public Service or customer of record, through the use of direct metering devices, installed, operated and maintained at such customer's expense, monitors, evaluates, or measures their own gas consumption or the consumption of a tenant for accounting or conservations purposes.

Gas sub-meters are devices that measure the volume of gas being delivered to particular locations in a system after measurement by a Public Service owned meter. Gas sub-meters provide the customer-of-record the means to apportion among the end users the cost of gas service being supplied through the Public Service owned meter.

Sub-metering will be permitted in new or existing buildings or premises where the basic characteristic of use is industrial or commercial. Sub-metering will not be permitted in new or existing buildings or premises where the basic characteristic of use is residential, except where such buildings or premises are publicly financed or government owned; or are condominiums or cooperative housing; or are eleemosynary in nature. In the case of dwelling units, all gas consuming devices must be metered through a single sub-meter.

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Sub-metering for the aforementioned purposes and applications shall not adversely affect the ability of Public Service to render service to any customer within the affected building or premises or any other customer. The customer shall contact Public Service prior to the installation of any sub-metering device to ascertain that it will not cause operating problems. The ownership of all sub-metering devices is that of the customer, along with all incidents in connection with said ownership, including accuracy of the equipment, meter reading and billing, liability arising from the presence of the equipment and the maintenance and repair of the equipment. Any additional costs which may result from and are attributable to the installation of sub-metering devices shall be borne by the customer.

The customer shall be responsible for the accuracy of sub-metering equipment. In the event of a dispute involving such accuracy, the Public Service meter will be presumed correct, subject to test results.

8.4. **Testing of Meters:** At such times as Public Service may deem proper, or as the Board of Public Utilities may require, Public Service will test its meters in accordance with the standards and bases prescribed by the Board of Public Utilities.

Public Service shall, without charge, make a test of the accuracy of a meter(s) upon request of the customer, provided such customer does not make a request for test more frequently than once in 12 months. A report giving results of such tests shall be made to the customer, and a complete record of such tests shall be kept on file at the office of Public Service in conformance with the New Jersey Administrative Code.

8.5. **Metering Options:** The following optional metering services are available to customers and are subject to the following charges as indicated in the following subsections:

8.5.1. **Gas Data Pulses and Remotes:** Public Service will install and maintain the necessary equipment to supply data pulses for the customer's use, and remote metering equipment at the customer's request. Customers requesting these services are subject to a minimum term of one year:

Description	**Set-Up Charge – Data Pulses**		**Monthly Charge**
	Charges	Charges including SUT	
Residential Meter	$100.00	$ 106.63	$1.00
Large Diaphragm – Retrofit	$ 40.00	$ 42.65	$1.00
Large Diaphragm – Change			
Model 53 lt	$100.00	$ 106.63	$2.00
Model 10 lt	$130.00	$ 138.61	$2.00
Model 20 lt	$130.00	$ 138.61	$2.00
Model 30 lt	$340.00	$ 362.53	$3.00
Model 60 lt	$650.00	$ 693.06	$3.00
Rotary without Instrument	$450.00	$ 479.81	$2.00
Rotary with Instrument	$100.00	$ 106.63	$2.00
Turbine	$100.00	$ 106.63	$2.00

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8.5.2. **Customer Usage Information:** Where Public Service has an interval meter installed, twelve months of interval usage, where available, will be provided upon request of the customer. The historical interval data will be provided based upon the measurement interval of the installed meter, and will be sent to the customer in an electronic format. The cost per meter, per request is $40.00.

Where Public Service has an interval meter installed, Public Service will provide Internet access to customer historical usage data on a next-day basis for those customers who request such service. The charges for this service shall include a set up charge of $107.00 per meter, and a monthly charge of $17.00 per meter per month. Customer will be required to sign an Agreement for this service.

8.6. **Billing Adjustments:** Whenever a meter is found to be registering fast by 2% or more, an adjustment of charges shall be made. When a meter is found to be registering slow by more than 2%, an adjustment of charges may be made in the case of meter tampering, non-register meters, or in circumstances in which a customer, other than RSG, should reasonably have known that the bill did not accurately reflect the usage. Billing adjustments shall be made in accordance with N.J.A.C. 14:3-4.6.

8.7. **Meter Reading and Billing Period**: All charges are stated on a monthly basis. The term “month” for billing purposes shall mean the period between any two consecutive regularly scheduled meter readings. Meter reading schedules provide for reading meters, in accordance with their geographic location, as nearly as may be practicable every thirty days. Schedules are prepared in advance by Public Service and are available for inspection.

8.8. **Proration of Monthly Charges**: For all billings for service, including initial bills, final bills, and bills for periods other than twenty-five to thirty-six days inclusive, except for temporary service accounts and Rate Schedules CIG, TSG-F, TSG-NF, and CSG, the monthly charges will be prorated based on the number of days in the billing month. For temporary service accounts the minimum period for billing purposes shall be one month.

8.9. **Averaged Bills:** Where Public Service is unable to read the meter, Public Service may estimate the amount of gas supplied and submit an averaged bill, so marked, for customer’s acceptance. Adjustments for averaged bills shall be made in Accordance with N.J.A.C. 14:3-7.2. Adjustment of such customer’s averaged use to actual use will be made after an actual meter reading is obtained.

Public Service reserves the right to discontinue gas service when a meter reading is not obtained for eight (8) consecutive billing periods (monthly accounts), and after written notice is sent to a customer on the fifth and seventh months explaining that a meter reading must be obtained. Public Service will take all reasonable means to obtain a meter reading during normal working hours, evening hours or Saturdays before discontinuing service. After all reasonable means to obtain a meter reading have been exhausted, Public Service may discontinue service provided at least eight months have passed since the last meter reading was obtained, the Board of Public Utilities has been so notified and the customer has been properly notified by prior mailing.

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8.10. Budget Plan (Equal Payment Plan): Customers billed under Rate Schedules RSG and GSG (where GSG gas service is used for residential purposes in buildings of four or fewer units), shall have the option of paying for their Public Service charges in equal, estimated monthly installments. Budget plans for residential accounts shall be made in accordance with N.J.A.C. 14:3-7.5. The total Public Service charges for a twelve month period will be averaged over twelve months and may be paid in twelve equal monthly installments. Adjustments will be made in the twelfth month if actual charges are more or less than the budget amounts billed. A review between the actual cost of service and the monthly budget amount will be made at least once in the budget plan year. A final bill for a budget plan year shall be issued at the end of the budget plan year and shall contain that month’s monthly budget amount plus any adjustments will be made if actual charges are more or less than the budget amount billed.

8.11. Billing of Charges in Tariff: Unless otherwise ordered by the Board of Public Utilities, the charges and the classification of service set forth in this Tariff or in amendments hereof shall apply to the first month’s billing of service in the regular course on and after the effective date set forth in such Tariff covering the use of gas service subsequent to the scheduled meter reading date for the immediately preceding month.

8.12. Payment of Bills: At least 15 days’ time for payment shall be allowed after sending a bill. Bills are payable at any Customer Service Center of Public Service, or by mail, or to any collector or collection agency duly authorized by Public Service. Whenever a residential customer advises Public Service that the customer wishes to discuss a deferred payment agreement because the customer is presently unable to pay a total outstanding bill and/or deposit, Public Service will make a good-faith effort to allow the customer the opportunity to enter into a fair and reasonable deferred payment agreement, which takes into consideration the customer’s financial situation. A residential electric or gas customer is not required to pay, as a down payment, more than 25% of the total outstanding bill due at the time of the agreement. Such agreements which extend more than 2 months must be in writing and shall provide that a customer who is presently unable to pay an outstanding debt for Public Service services may make reasonable periodic payments until the debt is liquidated, while continuing payment of current bills. While a deferred payment agreement for each separate service need not be entered into more than once a year, Public Service may offer more than one such agreement in a year. If the customer defaults on any of the terms of the agreement, Public Service may discontinue service after providing the customer with a notice of discontinuance. If a customer’s service has been terminated for non-payment of bills, and has met all requirements for restoration of service, Public Service may require a deposit, but not prior to service restoration. Instead, Public Service will bill payment of the deposit, or make other reasonable arrangements. The amount of the deposit required for restoration of service will be determined in accordance with N.J.A.C. 14:3-3.4.

In the case of a residential customer who receives more than one utility service from Public Service and has entered into a separate agreement for each separate service, default on one such agreement shall constitute grounds for discontinuance of only that service.

8.13. Late Payment Charge: A late payment charge at the rate of 1.416% per monthly billing period shall be applied to the accounts of customers taking service under all rate schedules contained herein except for Rate Schedule RSG. Service to a body politic will not be subject to a late payment charge. The charge will be applied to all amounts billed including accounts payable and unpaid finance charges applied to previous bills,

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and will not be applied sooner than 25 days after a bill is rendered, in accordance with N.J.A.C. 14:3-7.1(e). The amount of the finance charge to be added to the unpaid balance shall be calculated by multiplying the unpaid balance by the late payment charge rate. When payment is received by Public Service from a customer who has an unpaid balance which includes charges for late payment, the payment shall be applied first to such charges and then to the remainder of the unpaid balance.

8.14. Returned Check Charge: A $15.00 charge shall be applied to the accounts of customers who have checks to Public Service returned unhonored by the bank.

8.15. Field Collection Charge: A charge may be applied to the accounts of customers when it becomes necessary for Public Service to make a collection visit to the customer or premises. A charge of $30.00 may be applied to commercial and industrial accounts which include Rate Schedules: GSG, LVG, SLG, CIG, TSG-F, TSG-NF and CSG.

8.16. Customer's Responsibility to Cooperate with the Company: The charge provisions for extensions are predicated upon cooperation by the Customer in an effort to keep the Company's cost as low as possible. Additional costs resulting from the Customer's failure to cooperate, such as the paving of roads, parking areas or driveways prior to the installation of Company's facilities, shall be borne by the Customer.

9. LEAKAGE

Customer shall immediately give notice to Public Service at its office of any escape of gas in or about the customer's premises. If a leakage is suspected, immediately exit the building and move at least 350 feet away. Once the customer is at a safe distance, call PSE&G Emergency Service Line at 1-800-880-PSEG (7734) or 911 to report a potential gas leak. Customer will not be charged for reporting a potential gas leak.

10. ACCESS TO CUSTOMER'S PREMISES

Public Service shall have the right of reasonable and safe access to customer's premises, and to all property furnished by Public Service, at all reasonable times for the purpose of inspection of customer's premises incident to the rendering of service, reading meters or inspecting, testing, or repairing its facilities used in connection with supplying the service, or for the removal of its property. The customer shall obtain, or cause to be obtained, all permits needed by Public Service for access to its facilities. Access to facilities of Public Service shall not be given except to authorized employees of Public Service or duly authorized governmental officials.

10.1. Drivable Surfaces: When a vehicle is needed to drive on customer's property to access Public Service facilities, the customer shall ensure that the path has a drivable surface that will prevent the vehicle from becoming disabled.

11. DISCONTINUANCE OF SERVICE

11.1. By Public Service: Public Service, upon notice, when it can be reasonably given, may suspend or curtail or discontinue service for the following reasons: (1) for the purpose of making permanent or temporary repairs, changes or improvements in any part of its system; (2) for compliance in good faith with any governmental order or directive notwithstanding such order or directive subsequently may be held to be invalid; (3) for any of the following acts or omissions on the part of the customer: (a) nonpayment of a valid bill due for service furnished at a present or previous location, however, nonpayment for business service shall not be a reason for discontinuance of residential service except in cases of diversion of service pursuant to N.J.A.C. 14:3-7.8; (b) tampering with any facility of Public Service; (c) fraudulent representation in relation to the use of service; (d) customer moving from the premises, unless the customer requests that service be continued; (e) providing service to others without approval of Public Service except as permitted under Section 8.3 Metering on Customer's Premises of these Standard Terms and Conditions; (f) failure to make or increase an advance payment or deposit as provided for in these Standard Terms and Conditions; (g) refusal to contract for service where such contract is required; (h) connecting and operating equipment in such manner as to produce disturbing effects on the service of Public Service or other customers; (i) failure of the customer to comply with any of these Standard Terms and Conditions; (j) where the condition of the customer's installation presents a hazard to life or property; or (k) failure of customer to repair any faulty facility of the customer; (4) for refusal of reasonable and safe access to customer's premises for necessary purposes in connection with rendering of service, including meter installation, reading or testing, or the maintenance or removal of the property of Public Service.

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STANDARD TERMS AND CONDITIONS
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Public Service shall apply the regulations set forth in N.J.A.C. 14:3.3A.2(a), and only discontinue service for nonpayment of bills if one or both of the following criteria are met: 1) the customer's arrearage is more than $200.00; and/or 2) the customer's account is more than 3 months in arrears.

Public Service may not discontinue service for nonpayment of bills unless it gives the customer at least 10 days written notice of its intentions to discontinue service, 15 days if a landlord-tenant relationship is known to exist. The notice of discontinuance shall not be served until the expiration of the 15-day period indicated in Section 8.12 Payment of Bills of these Standard Terms and Conditions. No additional notice will be required when, in a response to a notice of discontinuance, payment by check is subsequently dishonored. However, in case of fraud, illegal use, or when it is clearly indicated that the customer is preparing to leave, immediate payment of accounts may be required.

Public Service may not discontinue service because of nonpayment of bills in cases where a charge is in dispute, provided that the undisputed charges are paid and a request is made to the Board for investigation of the disputed charge. In such cases, Public Service shall notify the customer that unless steps are taken to invoke formal or informal Board action within 5 days, service will be discontinued for nonpayment.

Public Service may not discontinue residential service involuntarily except between the hours of 8:00 A.M. and 4:00 P.M. Monday through Thursday, unless there is a safety related emergency. There shall be no involuntary termination of service on Friday, Saturday, and Sunday or on the day before a holiday or on a holiday, absent such emergency.

Subject to the conditions set forth below, discontinuance of residential service for non-payment is prohibited if a medical emergency exists within the premises which would be aggravated by discontinuance of service. Discontinuance shall be prohibited for a period of 90 days initially when a customer submits a licensed medical professional's statement in writing to Public Service as to the existence of the emergency, its nature and probable duration, and that termination of service will aggravate the medical emergency. Public Service may also require the customer to give reasonable proof of inability to pay. However, at the end of such period of emergency, the customer shall still remain liable for payment of service(s) rendered, subject to the provision of N.J.A.C. 14:3-7.7.

1. The Board may extend the 90-day period for good cause upon the receipt of a written request from the customer. The written request shall be in accordance with the preceding terms. Pending the Board's consideration and decision regarding the request for extension, service shall not be discontinued.

2. Public Service may in its discretion, delay discontinuance of residential service for nonpayment prior to submission of the licensed medical professional's statement required by this subsection when a medical emergency is known to exist.

If Public Service disconnects service to an unknown account and is notified that a medical emergency exists in the residential premises, Public Service shall: (1) restore service immediately; (2) allow 14 days to apply for service; and (3) allow 7 additional days following the service activation date or 21 days following the date it is notified of a medical emergency, whichever date is later, to submit a medical certification to Public Service written by a licensed medical professional in accordance with the preceding terms.

If a residential customer offers payment of the full amount or a reasonable portion of the amount due at the time of discontinuance, a Public Service representative shall accept payment without discontinuance of service. Whenever such payment is made, the representative shall provide the customer with a receipt showing the date, account number, customer's name and address and amount received.

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Public Service shall make every reasonable effort to determine when a landlord-tenant relationship exists at residential premises being served. If such a relationship is known to exist, and if the tenants are not the customers of record but are end-users, service will not be discontinued unless Public Service has given a 15-day written notice to the owner of the premises or to the customer of record to whom the last preceding bill was rendered. Public Service will use its best efforts to provide discontinuance notices to all tenants, including providing tenants with a 15-day written notice, which will be hand-delivered, mailed or posted in a conspicuous area of the premises and in the common areas of multiple family premises.

In addition, if posting is the method of notification used, Public Service will use its best efforts to place a copy of the notice on each tenant's car windshield or under the door of each tenant's dwelling. In the case of tenants of single and two-family dwellings, each tenant will be provided with a 15-day individual notice.

When a landlord-tenant relationship is known to exist, at the landlord's request, Public Service will provide the landlord with notice and/or have the service placed in the landlord's name if the tenant's service is being discontinued.

If Public Service disconnects service to a master metered premises in which the landlord is the actual customer of record and Public Service has been notified that a medical emergency exists by a tenant, Public Service shall restore service for a period of 7 days to allow the customer of record to resolve the nonpayment issue and to provide the tenant with time to make alternative arrangements.

Public Service shall not discontinue service during the period from November 15 through March 15, in accordance with N.J.A.C. 14:3-3A.5(a), unless otherwise ordered by the Board of Public Utilities, to those residential customers who demonstrate at the time of the intended termination that they are: (1) recipients of benefits under the Lifeline Credit Program; (2) recipients of benefits under the Federal Home Energy Assistance Program (HEAP), or certified as eligible therefor under standards set by the New Jersey Department of Human Services; (3) recipients of Temporary Assistance to Needy Families (TANF); (4) recipients of Federal Supplemental Security Income (SSI); (5) recipients of Pharmaceutical Assistance to the Aged and Disabled (PAAD); (6) recipients of General Assistance (GA) benefits; (7) recipients of the Universal Service Fund (USF); or (8) persons unable to pay their utility bills because of circumstances beyond their control.

Public Service shall not discontinue service to any residential customer, for reasons of nonpayment, failure to pay a cash security deposit or guarantee, or failure to comply with the terms of a deferred payment plan, whenever the high temperature is forecast to be 32 degrees Fahrenheit or below during the next 24 hours, in accordance with N.J.A.C. 14:3-3A.2(e)1.

Public Service shall not discontinue service to any residential customer eligible for the Winter Termination Program, for reasons of nonpayment, failure to pay a cash security deposit or guarantee, or failure to comply with a deferred payment agreement, whenever the high temperature is forecast to be 90 degrees Fahrenheit or more at any time during the following 48 hours, in accordance with N.J.A.C. 14:3-3A.2(e)3.

11.2. **At Customer's Request:** A customer wishing to discontinue service must give notice as provided in the applicable rate schedule. Within 48 hours of said notice, Public Service will discontinue service or obtain a meter reading for the purpose of calculating a final bill. Where such notice is not received by Public Service, customer shall be liable for service until final reading of the meter is taken. Notice to discontinue service will not relieve a customer from any minimum or guaranteed payment under any contract or rate schedule.

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12. RECONNECTION CHARGE

A reconnection charge of $45.00 will be made for restoration of service when service has been suspended or discontinued for non-payment of any bill due.

13. SERVICE LIMITATIONS

13.1. Continuity of Service: Public Service will use reasonable diligence to provide a regular and uninterrupted supply of service; but, should the supply be suspended, curtailed, or discontinued by Public Service for any of the reasons set forth in Section 11 of these Standard Terms and Conditions, or should the supply of service be interrupted, curtailed, deficient, defective, or fail, by reason of any act of God, accident, strike, legal process, governmental interference, or by reason of compliance in good faith with any governmental order or directive, notwithstanding such order or directive subsequently may be held to be invalid, Public Service shall not be liable for any loss or damage, direct or consequential, resulting from any such suspension, discontinuance, interruption, curtailment, deficiency, defect, or failure.

13.2. Emergencies: Public Service may curtail or interrupt service to any customer or customers in the event of an emergency threatening the integrity of its system or the systems to which it is directly or indirectly connected if, in its sole judgment, such action will prevent or alleviate the emergency condition.

13.3. Unusual Conditions: Public Service may place limitations on the amount and character of gas service it will supply or transport and may refuse such service to new customers, to existing customers for additional load, or to customers whose service agreements have expired if Public Service is or will be unable to obtain or does not have assured the necessary production raw materials, equipment and facilities to supply such gas or transportation service. In the case of transportation service, if Public Service, at its sole discretion, determines that such service would not be consistent with the best interest of its customers served under all rate schedules contained herein such service may be denied to applicants for such service.

14. THIRD PARTY SUPPLIER SERVICE PROVISIONS

14.1. Third Party Supplier Gas Supply: Customers served on Rate Schedules RSG, GSG, LVG, SLG, TSG-NF, and CSG may choose to receive gas supply from either a Third Party Supplier (TPS) or from Public Service through its Basic Gas Supply Service. Customers on these rate schedules who are not enrolled with a TPS will receive their gas supply from Public Service. Customers served on Rate Schedule TSG-F may only receive gas supply from a TPS. The customer’s supply of gas is limited to one TPS for the account(s) at a particular customer facility or complex.

A TPS is either a retail energy provider that has been licensed by the Board or is a customer served under Rate Schedules TSG-NF and CSG that has elected to self supply and act as a TPS on their own behalf. All TPSs must execute an Application for Service, be accepted by Public Service, and conform with the Third Party Supplier Requirements section of this Tariff.

14.2. Enrollment: Customers may request an enrollment package from Public Service which in addition to providing general information regarding gas supply describes the process necessary for a customer to obtain a TPS for gas supply. This enrollment package will be provided to the customer at no charge and may be obtained by calling or writing Public Service or visiting a Customer Service Center. Once the customer has chosen a TPS, the customer must provide appropriate authorization as required by their designated supplier.

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14.3. Selection or Change of Third Party Supplier: In order to be eligible to receive gas supply from a TPS, the customer must contract with a TPS to obtain gas supply for delivery to the customer by Public Service. The customer's designated TPS is required to notify Public Service of its selection as the customer's provider of gas supply on or before the 10th calendar day of the month to become effective on the first scheduled meter reading date beginning with the first calendar day of the following month for Rate Schedules RSG, GSG, LVG, and SLG. Notification for customers on Rate Schedules TSG-F, TSG-NF, and CSG is required prior to the last business day of the month. Such selection shall remain in effect for the entire billing period.

For customers on Rate Schedule RSG, GSG, LVG, SLG, TSG-F, TSG-NF and CSG, once Public Service has received the TPS notification for the initial, or subsequent, enrollment with a TPS, Public Service will confirm the customer's selection of its designated TPS by sending a letter of confirmation to the customer, which will be sent within one business day. In the event of a dispute, assignment of a customer will not occur unless and until the dispute is resolved. This confirmation letter will include notification of the RSG customer's right to rescind their contract with their designated TPS which must be exercised within seven (7) days of mailing of the letter of confirmation. Once assignment has occurred, the TPS will be required to supply all of the gas supply on the Public Service customer's account.

14.4. Return to Public Service Basic Gas Supply Service Default Service: Customers may return to Public Service Basic Gas Supply Service default service for commodity supply under the conditions and procedures as outlined below.

14.4.1. Customers on Rate Schedules RSG, GSG, LVG and SLG: Customers that subsequently choose to return to Basic Gas Supply Service default service must notify Public Service on or before the 10th calendar day of the month to become effective on the first scheduled meter reading date beginning with the first calendar day of the following month. Public Service will confirm the customer's selection of Basic Gas Supply Service default service gas supply by sending a letter of confirmation to the customer, which will be sent within one business day. This confirmation letter will include notification of the customer's right to rescind their selection which must be exercised within seven (7) days of mailing of the letter of confirmation. GSG, LVG, and SLG customers not exercising their right of rescission within the seven (7) day period may be subject to renewable one-year terms on Basic Gas Supply Service default service.

If a customer's TPS notifies Public Service on or before the 10th calendar day of the month that it has terminated its supply relationship with the customer, such termination will become effective on the first scheduled meter reading date beginning with the first calendar day of the following month. The customer will be advised by Public Service in writing of this change in supplier. The customer will be placed on the applicable Public Service Basic Gas Supply Service default service unless the customer has selected another TPS in accordance with Section 14.3. GSG, LVG, and SLG customers provided Basic Gas Supply Service default service for two or more consecutive months may be subject to renewable one-year terms on Basic Gas Supply Service default service.

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14.4.2. Customers on Rate Schedules TSG-NF and CSG (with maximum requirement of less than 2,000 therms per hour): For customers that subsequently choose to return to Basic Gas Supply Service default service, the return will become effective on the first of the month following the customer's written notification to Public Service, provided that such notice was given prior to the last business day of the preceding month. Public Service will confirm the customer's selection of Basic Gas Supply Service default service gas supply by sending a letter of confirmation to the customer, which will be sent within one business day.

If a customer's TPS notifies Public Service that it has terminated its supply relationship with the customer, such termination will become effective on the first of the month after such notification, provided such notification was received no later than the next to last business day of the month. In the event that notification is received after the next to last business day of the month, such termination shall become effective the first of the second month following such notification. The customer will be advised by Public Service in writing of this change in supplier. The customer will be placed on the applicable Public Service Basic Gas Supply Service default service unless the customer has selected another TPS in accordance with Section 14.3.

14.4.3. Customers on Rate Schedule TSG-F: Basic Gas Supply Service default service is not available for customers on Rate Schedule TSG-F.

14.5. Emergency Sales Service: Under certain conditions as specified below, Public Service may supply gas commodity on the Emergency Sales Service provision. Emergency Sales Service will be offered at the sole discretion of Public Service, after taking into consideration its other firm supply obligations. Public Service reserves the right to curtail service to any customer if deliveries from customer's TPS pursuant to Third Party Supplier Requirements are curtailed.

14.5.1. Customers on Rate Schedules RSG, GSG, LVG and SLG: During any month where Public Service cannot confirm that the customer has an eligible TPS, or if the TPS no longer satisfies the Third Party Supply Requirements section of this tariff, Public Service may supply gas commodity service to such customer as Emergency Sales Service unless and until customer selects another TPS in accordance with Section 14.3. The customer will be advised by Public Service in writing that, until the customer's next meter reading date the customer will be billed, in addition to all applicable delivery charges, the Emergency Sales Service Charge for all of its applicable Daily Contract Quantity (DCQ) therms. Thereafter, the customer will be placed on the applicable Public Service Basic Gas Supply Service default service. GSG, LVG, and SLG customers provided Basic Gas Supply Service default service for two or more consecutive months may be subject to renewable one-year terms on Basic Gas Supply Service default service.

14.5.2. Customers on Rate Schedules TSG-NF and CSG (with maximum requirement of less than 2,000 therms per hour): During any month where Public Service cannot confirm that the customer has an eligible TPS, or if the TPS no longer satisfies the Third Party Supply Requirements section of this tariff, Public Service may supply gas commodity service to such customer as Emergency Sales Service unless and until customer selects another TPS in accordance with Section 14.3. The customer will be advised by Public Service in writing that, for the balance of the current month the customer will be billed, in addition to all applicable delivery charges, the Emergency Sales Service Charge for all of its therm usage. Commencing on the first of the following month the customer will be placed on the applicable Public Service Basic Gas Supply Service default service.

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14.5.3. Customers on Rate Schedule TSG-F: During any month where Public Service cannot confirm that the customer has an eligible TPS, or if the TPS no longer satisfies the Third Party Supply Requirements section of this tariff, Public Service may supply gas commodity service to such customer as Emergency Sales Service unless and until customer selects another TPS in accordance with Section 14.3. The customer will be advised by Public Service in writing that the customer will be billed, in addition to all applicable delivery charges the Emergency Sales Service Charge for all of its therm usage.

14.6. Customer Billing Process: For TPS retail customers served under Rate Schedule RSG, GSG, LVG and SLG, Public Service will provide one combined bill containing both Public Service charges and TPS gas supply charges, providing the TPS executes and satisfies the terms of the Third Party Supplier Customer Account Services Master Service Agreement, and the retail customer(s) maintain a satisfactory bill payment history. Customer(s) may elect to receive a separate bill directly from its TPS for third party supplied services. If a customer requests and is permitted to receive a combined bill, but the customer's account subsequently becomes 120 days in arrears at any point in the future, such customer will thereafter be required to receive a separate bill directly from its TPS (including any subsequent TPS) for third party supplied services and will not be permitted to receive a combined bill from Public Service until such time the customer's arrearage is reduced to 60 days or less. Only Public Service owned, installed, and read meters will be used to determine customer usage for the purpose of calculating Public Service charges.

14.6.1. Payment of Bills: Where Public Service provides billing service, the payment of bills, including TPS's charges for gas supply if billed by Public Service, will be made to Public Service and will be in accordance with Section 8, Meter Reading and Billing, of these Standard Terms and Conditions. Any customer overpayment will be held in the customer's Public Service account to be applied against future customer bills or will be refunded to the customer at the customer's request.

14.6.2. Late Payment Charges: A late payment charge in accordance with Section 8.13, Late Payment Charge, of these Standard Terms and Conditions is to be applicable to Public Service customer charges and TPS's charges for gas supply if billed by Public Service. Customer shut-offs in cases where there is non-payment to Public Service for its customer charges and TPS's charges for gas supply if billed by Public Service, are only performed in accordance with Section 11, Discontinuance of Service, of these Standard Terms and Conditions.

14.6.3. Billing Disputes: In the event of a billing dispute between the customer and the TPS, Public Service's sole duty is to verify its customer charges and billing determinants. Customer continues to remain responsible for the timely payment of all Public Service charges and all undisputed TPS charges for gas supply if such charges are billed by Public Service in accordance with Section 8, Meter Reading and Billing, and Section 14.6.1, Payment of Bills, of these Standard Terms and Conditions. All questions regarding TPS's charges or other terms of the customer's agreement with a TPS are to be resolved between the customer and its TPS. Public Service will not be responsible for the enforcement, intervention, mediation, or arbitration of agreements entered into between TPS customer and TPS. Billing disputes that may arise regarding Public Service's charges shall be subject to Section 11, Discontinuance of Service, of these Standard Terms and Conditions.

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14.7. Third Party Supplier's Termination of Customer's Gas Supply: A TPS will not be permitted to physically connect or disconnect gas supply service to a customer.

14.8. Continuity of Service: Public Service shall have the right: (i) to require a TPS's gas supply sources to be disconnected from Public Service's gas system; (ii) to otherwise curtail, interrupt, or reduce a TPS's gas supply; or (iii) to disconnect a TPS's customer(s) in accordance with Section 11, Discontinuance of Service, and Section 13, Service Limitations, of these Standard Terms and Conditions.

14.9. Regulatory Requirements: Public Service will not be responsible for: making any arrangements necessary; obtaining from appropriate regulatory bodies any approvals necessary; any costs, charges and expenses including but not limited to the payment to appropriate governmental entities for any tax or assessment relative to the acquisition, transportation or use of customer's gas supply.

14.10. Delivery Liability: Public Service will not be liable in any way for any failure in whole or in part, temporary or permanent, to deliver gas under this Tariff for Gas Service to the extent such failure is due to customer's TPS's failure to deliver gas supplies to Public Service in accordance with the TPS Requirements. Public Service will not be liable in any way for errors in the calculation of the customer's DCQ and/or delivery requirement.

14.11. Delivery Control and Possession: After customer delivers gas or causes gas to be delivered to Public Service at Public Service's point of interconnection with the applicable interstate pipeline, Public Service will be deemed to be in control and possession of the gas until an equivalent amount of gas, less losses, is delivered to customer at customer's Public Service meter.

15. NEW JERSEY AUTHORIZED TAXES

The following taxes are authorized by the State of New Jersey and are applied in accordance with P.L. 1997, c. 162 (the "Energy Tax Reform Statute"), as amended by P.L. 2006, c. 44, as amended by P.L. 2009, c. 240 and P.L. 2016, c. 57, and are included in the appropriate charges contained within this Tariff for Gas Service.

15.1. New Jersey Sales and Use Tax: In accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c. 57, provision for the New Jersey Sales and Use Tax (SUT) has been included in all applicable charges by multiplying the charges that would apply before application of the SUT by the factor 1.06625.

15.1.1. Exemptions due to the Energy Tax Reform Statute: The Energy Tax Reform Statute exempts the following customers from the SUT provision, and when billed to such customers, the charges otherwise applicable shall be reduced by the provision for the SUT included therein:

a) Franchised providers of utility services (gas, electricity, water, wastewater and telecommunications services provided by local exchange carriers) within the State of New Jersey.

b-1) Cogenerators in operation, or which had filed an application for an operating permit or a construction permit and a certificate of operation in order to comply with air quality standards under P.L. 1954, c. 212 (C.26:2C-1 *et seq.*) with the New Jersey Department of Environmental Protection, on or before March 10, 1997.

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b-2) Cogeneration facilities that are constructed after January 1, 2010.

c) Special contract customers for which a customer-specific tax classification was approved by a written Order of the New Jersey Board of Public Utilities prior to January 1, 1998.

d) Agencies or instrumentalities of the federal government.

e) International organizations of which the United States of America is a member.

f) Additional customers as authorized by the State of New Jersey Department of Treasury in accordance with the provisions of P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c. 57.

15.1.2. Exemptions due to the Business Retention and Relocation Assistance Act: The Business Retention and Relocation Assistance Act (P.L. 2004, c. 65) and subsequent amendment (P.L. 2005, c. 374) exempts the following customers from the SUT provision, and when billed to such customers, the charges otherwise applicable shall be reduced by the provision for the SUT included therein:

a) A qualified business that employs at least 250 people within an enterprise zone, at least 50% of whom are directly employed in a manufacturing process, for the exclusive use or consumption of such business within an enterprise zone, and

b) A group of two or more persons:

(b-1) Each of which is a qualified business that are all located within a single redevelopment area adopted pursuant to the “Local Redevelopment and Housing Law,” P.L.1992, c.79 (C.40A:12A-1 *et seq.*);
(b-2) That collectively employ at least 250 people within an enterprise zone, at least 50% of whom are directly employed in a manufacturing process;
(b-3) Are each engaged in a vertically integrated business, evidenced by the manufacture and distribution of a product or family of products that, when taken together, are primarily used, packaged and sold as a single product; and
(b-4) Collectively use the energy and utility service for the exclusive use or consumption of each of the persons that comprise a group within an enterprise zone.

c) A business facility located within a county that is designated for the 50% tax exemption under section 1 of P.L. 1993, c. 373 (C.54:32B-8.45) provided that the business certifies that it employs at least 50 people at that facility, at least 50% of whom are directly employed in a manufacturing process, and provided that the energy and utility services are consumed exclusively at that facility.

A business that meets the requirements in (a), (b) or (c) above shall not be provided the exemption described in this section until it has complied with such requirements for obtaining the exemption as may be provided pursuant to P.L.1983, c. 303 (C.52:27H-60 *et seq.*) and P.L.1966, c. 30 (C.54:32B-1 *et seq.*) and Public Service has received a sales tax exemption letter issued by the New Jersey Department of Treasury, Division of Taxation.

15.2. New Jersey Corporation Business Tax: In accordance with P.L. 1997, c. 162, provision for the New Jersey Corporation Business Tax (CBT) has been included in the Service Charge, Distribution Charge, and the Demand Charge.

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15.2.1. Exemptions due to the Energy Tax Reform Statute: The Energy Tax Reform Statute exempts the following customers from the CBT provision, and when billed to such customers, the above tariff charges otherwise applicable shall be reduced by the provision for the CBT (and related SUT) included therein.

a) Franchised providers of utility services (gas, electricity, water, wastewater and telecommunications services provided by local exchange carriers) within the State of New Jersey.
b) Cogenerators in operation, or which had filed an application for an operating permit or a construction permit and a certificate of operation in order to comply with air quality standards under P.L. 1954, c. 212 (C.26:2C-1 *et seq.*) with the New Jersey Department of Environmental Protection, on or before March 10, 1997.
c) Special contract customers for which a customer-specific tax classification was approved by a written Order of the New Jersey Board of Public Utilities prior to January 1, 1998.
d) Additional customers as authorized by the State of New Jersey Department of Treasury in accordance with the provisions of P.L. 1997, c. 162.

16. NEW JERSEY AUTHORIZED EXEMPTIONS

The following exemptions are authorized by the State of New Jersey and are applied in accordance with P.L. 2011, c.9 (the “Long Term Capacity Agreement Pilot Program”, “LCAPP Legislation”). The exemptions take effect January 28, 2011.

16.1. Exemptions due to LCAPP Legislation: Electric generators who use natural gas to generate electricity that is sold for resale will be exempt from a societal benefits charge pursuant to N.J.S.A. 48:3-60.1 or any other charge designed to recover the costs for social, energy efficiency, conservation, environmental or renewable energy on natural gas delivery service or commodity that is used to generate electricity that is sold for resale. This exemption includes the Societal Benefits Charge (SBC) and the Green Programs Recovery Charge (GPRC). Each customer’s exemption will be effective upon completion of an Annual Certification form.

a) The Annual Certification form shall be a prerequisite for the exemption and shall be furnished to customers of record in December and returned to Public Service by the customer no later than January 15th of each year. The Annual Certification form shall certify the percentage of gas used at their New Jersey generation facilities during the immediately preceding calendar year to generate electricity that was sold for resale. This Certification will serve as the percentage of the customers’ throughput that will be exempt from the SBC and the GPRC. This Certification will then be used for the succeeding annual period commencing in February. If the customer fails to return the form, then the SBC and the GPRC will be assessed on all of the customer’s usage until a completed Annual Certification form is received to be effective after the next subsequent meter reading. If the customer returns a completed Annual Certification Form on or before January 15, then adjustments to customer’s bills to reflect changes in the percentage of gas used to generate electricity for resale will be made on a prospective basis beginning in February.

b) In those cases where prior calendar year usage is not available, the customer will submit an Annual Certification form with an estimated percentage of gas that will be used at their New Jersey generation facilities for the current calendar year to generate electricity to be sold for resale. Once agreement has been reached with PSE&G regarding the estimated percentage, the completed Certification will serve as the percentage of the customers’ throughput that will be exempt from the SBC and the GPRC effective after the next subsequent meter reading on a prospective basis for the remainder of the current calendar year.

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17. TERMINATION, CHANGE OR MODIFICATION OF PROVISIONS OF TARIFF

This tariff is subject to the lawful orders of the Board of Public Utilities of the State of New Jersey.

Public Service may at any time and in any manner permitted by law, and the applicable rules and regulations of the Board of Public Utilities of the State of New Jersey, terminate, or change or modify by revision, amendment, supplement, or otherwise, this Tariff or any part thereof, or any revision or amendment hereof or supplement hereto.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS

Original Sheet No. 37
Original Sheet No. 38
Original Sheet No. 39
Original Sheet No. 40

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 41**

SOCIETAL BENEFITS CHARGE

CHARGE APPLICABLE TO
RATE SCHEDULES RSG, GSG, LVG, SLG,
TSG-F, TSG-NF, CIG, CSG
(Per Therm)

Social Programs	$ 0.000000
Energy Efficiency and Renewables Programs	0.019520
Manufactured Gas Plant Remediation	0.008753
Universal Service Fund - Permanent	0.010800
Universal Service Fund - Lifeline	0.005800
Societal Benefits Charge	$ 0.044873
Societal Benefits Charge including New Jersey Sales and Use Tax (SUT)	$ 0.047846

Societal Benefits Charge

This mechanism is designed to insure recovery of costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Actual costs incurred by the Company for each of these cost components will be subject to deferred accounting. Interest at the two-year constant maturity treasury rate plus 60 basis points will be accrued monthly on any under-over recovered balances for all components other than Manufactured Gas Plant Remediation. Interest at the seven-year constant maturity treasury rate plus 60 basis points will be accrued monthly on any under- or over-recovered balances for the Manufactured Gas Plant Remediation. The interest rates for all components other than USF and Lifeline shall change each August 1. The interest rates for the USF and Lifeline components shall be reset each month.

See Section 16 of the Standard Terms and Conditions for exemptions from this charge.

(Charges are for illustrative purposes only and are based on the Ninth Revised Sheet No. 41 filed with the BPU on October 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 42**

SOCIETAL BENEFITS CHARGE
(Continued)

SOCIAL PROGRAMS

This factor shall recover costs associated with existing social programs.

ENERGY EFFICIENCY AND RENEWABLES (EE&R) PROGRAMS

This factor is a recovery mechanism which will operate in accordance with the Demand Side Management (DSM) conservation incentive regulations and successor regulations. The factor has been used to recover past Core and Performance Program Costs and Performance Program Payments, payments for Large-Scale Conservation Investments, and all recoverable costs associated with the Board’s Comprehensive Resource Analysis Orders, including but not limited to the low income Comfort Partners Program.

MANUFACTURED GAS PLANT REMEDIATION

This factor shall recovery costs associated with addressing and resolving claims by and or requirements of governmental entities and private parties related to activities necessary to perform investigations and the remediation of environmental media.

UNIVERSAL SERVICE FUND

These factors shall recover costs associated with new or expanded social programs.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 43**

MARGIN ADJUSTMENT CHARGE

CHARGE APPLICABLE TO
RATE SCHEDULES RSG, GSG, LVG, SLG, TSG-F
(Per Therm)

Margin Adjustment Charge .... ($0.005821)

Margin Adjustment Charge including New Jersey Sales and Use Tax (SUT)..................... ($0.006207)

Margin Adjustment Charge

This mechanism is designed to insure return of certain net revenues to the customer classes denoted above. Actual net revenues will be subject to deferred accounting. Interest at the seven-year constant maturity treasury rate plus 60 basis points will be accrued monthly on any under- or over-recovered balances.

(Charges are for illustrative purposes only and are based on the Fifth Revised Sheet No. 43 filed with the BPU on October 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 44**

GREEN PROGRAMS RECOVERY CHARGE

CHARGE APPLICABLE TO
RATE SCHEDULES RSG, GSG, LVG, SLG,
TSG-F, TSG-NF, CIG, CSG
(Per Therm)

Component:

Carbon Abatement Program	($0.000470)
Energy Efficiency Economic Stimulus Program	0.000167
Energy Efficiency Economic Extension Program	0.000329
Energy Efficiency Economic Extension Program II	0.000472
Energy Efficiency 2017 Program	0.003000
Clean Energy Future – Energy Efficiency Program	0.005528
Green Programs Recovery Charge	$0.009026
Green Programs Recovery Charge including New Jersey Sales and Use Tax SUT	$0.009624

Green Programs Recovery Charge

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs. The charge will be reset nominally on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under- or over- recovered balances. The interest rate shall be reset each month.

See Section 16 of the Standard Terms and Conditions for exemptions from this charge.

(Charges are for illustrative purposes only and are based on the Eighth Revised Sheet No. 44 filed with the BPU on October 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 48**

CONSERVATION INCENTIVE PROGRAM

**CHARGE APPLICABLE TO
RATE SCHEDULES RSG, GSG, LVG
(Per Therm)**

	Conservation Incentive Program	Conservation Incentive Program including SUT
RSG	$0.060736	$0.064760
GSG	$0.044451	$0.047396
LVG	$0.004748	$0.005063

Conservation Incentive Program

This charge shall be applicable to the rate schedules listed above. The Conservation Incentive Program shall be based on the differences between actual and allowed usage per customer during the preceding annual period. The Conservation Incentive Mechanism shall be determined as follows:

I. DEFINITION OF TERMS AS USED HEREIN

1. Actual Number of Customers
– the Actual Number of Customers ("ANC") shall be determined on a monthly basis for each of the Customer Class Groups to which the Conservation Incentive Program ("CIP") Clause applies. The ANC shall equal the aggregate actual monthly Service Charge revenue for each class of customers subject to the CIP as recorded on the Company's books, divided by the service charge rate applicable to such class of customers in each Customer Class Group.

2. Actual Usage Per Customer
– the Actual Usage per Customer ("AUC") shall be determined in therms on a monthly basis for each of the Customer Class Groups to which the CIP applies. The AUC shall equal the aggregate actual booked sales for the month as recorded on the Company's books divided by the ANC for the corresponding month.

3. Adjustment Period
– shall be the year beginning immediately following the conclusion of the Annual Period.

4. Annual Period
– shall be the twelve consecutive months from October 1 of one calendar year through September 30 of the following calendar year.

5. Average 13 Month Common Equity Balance
– shall be the average of the beginning and ending common equity balances based on the latest publically available financials available before the end of the Annual Period. The Company shall provide the most recently available actual months plus forecasted data at the time of each Initial Filing. The forecasted data will be updated with actuals once the financial statements for the months have been disclosed.

6. Baseline Usage per Customer
– the Baseline Usage per Customer ("BUC") shall be stated in therms on a monthly basis for each of the Customer Class Groups to which the CIP applies. The BUC shall be rounded to the nearest one tenth of one therm.

The BUC shall be reset each time new base rates are placed into effect through a base rate case.

**(Charges are for illustrative purposes only and are based on the
Third Revised Sheet No. 48 filed with the BPU on October 1, 2023)**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 48A**

CONSERVATION INCENTIVE PROGRAM
(Continued)

7. Customer Class Group
– for purposes of determining and applying the CIP, customers shall be aggregated into three separate recovery class groups. The Customer Class Groups shall be as follows:

Group I:	RSG
Group II:	GSG
Group III:	LVG

8. Forecast Annual Usage
– the Forecast Annual Usage ("FAU") shall be the projected total annual throughput for all customers within the applicable Customer Class Group. The FAU shall be estimated based on normal weather.

9. Margin Revenue Factor
– the Margin Revenue Factor ("MRF") shall be the weighted-average margin rate as quoted in the individual service classes to which the CIP applies. The MRFs by Customer Class Group are as follows:

Group I	(RSG):	$0.437483
Group II	(GSG):	$0.328242
Group III	(LVG):	$0.046383

The MRF shall be reset each time new base rates are placed into effect, including Infrastructure Investment Program ("IIP") or all other future base rate changes.

10. Degree Days (DD)
– the difference between 65°F and the mean daily temperature for the day. The mean daily temperature is the simple average of the 24 hourly temperature observations for a day.

11. Actual Calendar Month Degree Days
– the accumulation of the actual Degree Days for each day of a calendar month.

12. Normal Calendar Month Degree Days
– the level of calendar month degree days to which the weather portion of the CIP applies.

The normal calendar month Degree Days will be the twenty-year average of the National Oceanic and Atmospheric Administration (NOAA) First Order Weather Observation Station at the Newark airport and will be updated annually. The base level of normal HDD for the defined winter period months for the 2023-2024 Winter Period are set forth in the table below:

Month	Normal Heating Degree Days
October 2023	225.14
November 2023	515.50
December 2023	810.29
January 2024	1,005.68
February 2024	868.22
March 2024	682.63
April 2024	355.17
May 2024	123.16

13. Winter Period
– shall be the eight consecutive calendar months from October of one calendar year through May of the following calendar year.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 48B**

CONSERVATION INCENTIVE PROGRAM
(Continued)

14. Degree Day Consumption Factors
– the use per degree day component of the gas sales equations by month used in forecasting firm gas sales for the applicable rate schedules. Degree day Consumption Factors for the 2023-2024 Winter Period are set forth below and presented as therms per degree day:

	RSG-Residential		Commercial			Industrial		
Month			GSG		LVG	GSG		LVG
	Heating	Non- Heating	Heating	Non- Heating		Heating	Non- Heating	
Oct.-23	183,348	-	-	-	88,624	633	-	7,326
Nov.-23	269,657	2,352	34,861	2,625	88,624	1,220	139	7,321
Dec.-23	269,443	3,088	51,188	3,709	88,624	2,154	259	7,315
Jan.-24	303,067	3,111	52,644	3,907	90,462	2,463	234	7,452
Feb.-24	291,037	2,723	54,216	4,014	90,462	1,934	138	7,445
Mar.-24	293,337	3,012	55,149	4,047	90,462	2,215	243	7,437
Apr.-24	285,355	3,138	57,596	4,118	90,462	1,748	229	7,428
May-24	209,054	3,458	29,705	3,863	90,462	1,160	163	7,418

II. BASELINE USE PER CUSTOMER

The BUC for each Customer Class Group by month are as follows:

Month	RSG	GSG	LVG
Oct.	38.7	110.8	2,350.0
Nov.	87.6	172.0	3,486.2
Dec.	144.9	320.4	5,220.9
Jan.	180.6	421.1	6,506.4
Feb.	153.5	351.6	5,940.9
Mar.	124.5	275.8	5,478.7
Apr.	70.4	170.7	3,703.5
May	37.0	80.1	2,037.8
Jun.	21.0	49.2	1,477.0
Jul.	18.0	58.5	1,374.6
Aug.	18.0	50.5	1,379.9
Sep.	19.5	52.6	1,322.8
Total Annual	**913.7**	**2,113.3**	**40,278.7**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 48C**

CONSERVATION INCENTIVE PROGRAM
(Continued)

III. DETERMINATION OF THE CONSERVATION INCENTIVE PROGRAM

1. At the end of the Annual Period, a calculation shall be made that determines for each Customer Class Group the deficiency or excess to be surcharged or credited to customers pursuant to the CIP mechanism. The deficiency or excess shall be calculated each month by multiplying the result obtained from subtracting the Baseline Usage per Customer from the Actual Usage per Customer by the Actual Number of Customers and then multiplying the resulting therms by the Margin Revenue Factor.

2. The weather related change in customer usage shall be calculated as the difference between actual degree days and the above normal degree days multiplied by the consumption factors, and multiplying the result by the margin revenue factors as defined in Section I.9. of this rate schedule to determine the weather-related deficiency or excess. The weather-related amount will be subtracted from the total deficiency or excess to determine the non-weather related deficiency or excess.

3. Recovery of margin deficiency associated with non-weather related deficiency in customer usage will be subject to a BGSS savings test and a Variable Margin Revenue recovery limitation (“recovery tests”). Recovery of non-weather related margin deficiency will be limited to the smaller of (1) the level of BGSS savings achieved when such savings are less than 75 percent of the non-weather related margin deficiency, i.e. BGSS savings test, and (2) 4.0 percent of variable margins for the CIP Annual Period, i.e., Margin Revenue recovery limitation. Any amount that exceeds the above limitations may be deferred for future recovery and is subject to either or both of the recovery tests in a future year consistent with the amount by which either or both of the non-weather related margin deficiency exceeded the recovery tests. For the purposes of this calculation, the value of the weather related portion shall be calculated as set forth in Section III.2. of this rate schedule.

4. In addition, if the calculated ROE exceeds the allowed ROE from the utility's last base rate case by 50 basis points or more, recovery of lost revenues through the CIP shall not be allowed for the applicable filing period. For purposes of this section, the Company's rate of return on common equity shall be calculated by dividing the Company's net income for the applicable period as defined in the Average 13 Month Common Equity Balance by the Company's average common equity balance for the same period, all as reflected in the Company's monthly reports to the Board of Public Utilities. The Company's net income shall be calculated by subtracting from total operating income, any clause related Net Income, such as the Green Program’s Recovery Charge and interest expenses. The Company's Average 13 Month Common Equity Balance shall be the ratio of Gas Net Plant (including the Gas allocation of Common Plant) to total PSE&G Net Plant for the Average 13 Month Common Equity Balance period multiplied by the Company's total common equity for the same period.

5. The amount to be surcharged or credited shall equal the eligible aggregate deficiency or excess for all months during the Annual Period determined in accordance with the provisions herein, divided by the Forecast Annual Usage for the Customer Class Group.

IV. TRACKING THE OPERATION OF THE CONSERVATION INCENTIVE PROGRAM

The revenues billed, or credits applied, net of taxes and assessments, through the application of the Conservation Incentive Program Rate shall be accumulated for each month of the Adjustment Period and applied against the CIP excess or deficiency from the Annual Period and any cumulative balances remaining from prior periods.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 49**
Original Sheet No. 50

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 51**

TAX ADJUSTMENT CREDIT

Rate Schedule	Charge per Therm	Charge per Therm Including SUT
RSG	($0.064753)	($0.069043)
GSG	($0.054983)	($0.058626)
LVG	($0.025916)	($0.027633)
SLG	($0.094749)	($0.101026)
TSG-F	($0.022261)	($0.023736)
TSG-NF	($0.011569)	($0.012335)
CIG	($0.017044)	($0.018173)
CSG	($0.001181)	($0.001259)

Tax Adjustment Credit

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month.

(Charges are for illustrative purposes only and are based on the Sixth Revised Sheet No. 51 filed with the BPU on October 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 52**

DISTRIBUTION ADJUSTMENT CHARGE

CHARGE APPLICABLE TO
RATE SCHEDULES RSG, GSG, LVG, SLG,
TSG-F, TSG-NF, CIG, CSG
(Per Therm)

Component:

Storm Recovery Charge	$0.XXXXXX
COVID-19 Cost Recovery	0.XXXXXX
Distribution Adjustment Charge	$0.XXXXXX
Distribution Adjustment Charge including New Jersey Sales and Use Tax SUT	$0.XXXXXX

Distribution Adjustment Charge

This charge is designed to recover Board-approved costs. The charge will be reset nominally on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under- or over- recovered balances. The interest rates shall be reset each month.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 53**

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 54**

BGSS-RSG
BASIC GAS SUPPLY SERVICE-RSG
COMMODITY CHARGES APPLICABLE TO RATE SCHEDULE RSG
(Per Therm)

Estimated Non-Gulf Coast Cost of Gas	$0.074813
Estimated Gulf Coast Cost of Gas	0.339920
Adjustment to Gulf Coast Cost of Gas	0.000000
Prior period (over) or under recovery	(0.049390)
Adjusted Cost of Gas	0.365343
Commodity Charge after application of losses: (Loss Factor = 2.0%)	$0.372799
Commodity Charge including New Jersey Sales and Use Tax (SUT)	$0.397497

The above Commodity Charge will be established on a level annualized basis immediately prior to the winter season of each year for the succeeding twelve-month period. The estimated average Non-Gulf and Gulf Coast Cost of Gas will be adjusted for any under- or over-recovery together with applicable interest thereon which may have occurred during the operation of the Company's previously approved Commodity Charge filing. Further, the Company will be permitted a limited self-implementing increase to the Commodity Charge on December 1 and February 1 of each year. These limited self-implementing increases, if applied, are to be in accordance with a Board of Public Utilities approved methodology. Commodity Charge decreases would be permitted at any time if applicable.

The difference between actual costs and Public Service's recovery of these costs shall be determined monthly. If actual costs exceed the recovery of these costs, an underrecovery or a negative balance will result. If the recovery of these costs exceeds actual costs, an overrecovery or a positive balance will result. Interest shall be applied monthly to the average monthly cumulative deferred balance, positive or negative, from the beginning to the end of the annual period. Monthly interest on negative deferred balances (underrecoveries) shall be netted against monthly interest on positive deferred balances (overrecoveries) for the annual period. A cumulative net positive interest balance at the end of the annual period is owed to customers and shall be returned to customers in the next annual period. A cumulative net negative interest balance shall be zeroed out at the end of the annual period. The sum of the calculated monthly interests shall be added to the overrecovery balance or subtracted from the underrecovery balance at the end of the annual period. The positive interest balance shall be rolled into the beginning under- or over-recovery balance of the subsequent annual period.

Pursuant to the Board's January 6, 2003 Order approving the BGSS price structure under Docket No. GX01050304 and the BGSS Pricing Proposal appended as Attachment A to and approved in that Order, Public Service Electric and Gas Company may issue a bill credit for its BGSS-RSG customers as detailed below.

Effective	BGSS-RSG Credit (per therm)	BGSS-RSG Credit including SUT (per therm)
February 1, 2020 through March 31, 2020	($0.070340)	($0.075000)
April 1, 2020	$0.000000	$0.000000

(Charges are for illustrative purposes only and are based on the Twenty-Third Revised Sheet No. 54 filed with the BPU on October 1, 2023)

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Issued by SCOTT S. JENNINGS, SVP – Finance, Planning & Strategy – PSE&G
80 Park Plaza, Newark, New Jersey 07102
Filed pursuant to Order of Board of Public Utilities dated
in Docket No.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 55**

BGSS-F
BASIC GAS SUPPLY SERVICE-FIRM
COMMODITY CHARGES APPLICABLE TO RATE SCHEDULES GSG, LVG, SLG, CSG
(Per Therm)

COMMODITY CHARGE:	Commodity Charge	$ 0.499741
	Commodity Charge including New Jersey Sales and Use Tax (SUT)	$ 0.532849
FLOOR PRICE:	Non-Gulf Coast Cost of Gas component	$ 0.173461
	Variable Cost of Commodity and Fuel	0.000000
	Cost of Gas Acquired to serve BGSS-F for the month	0.198685
	Total Cost of Gas	$ 0.372146
	Floor Price after application of losses (Loss Factor = 2.0%)	$ 0.379741
CEILING PRICE:	Commodity Charge	$ 0.505582

A market based charge including all applicable taxes to be posted by Public Service on a monthly basis. The foregoing Commodity Charge will be subject to a floor price equal to the sum of the Non-Gulf Coast Cost of Gas component and the Cost of Gas Acquired for these customers. Additionally, this Commodity Charge will not exceed a Ceiling Price equal to the applicable charge for Emergency Sales Service.

The Cost of Gas Acquired will be established prior to the beginning of each month based on the NYMEX closing price for the following month plus other fixed adjustments of a negative $0.050515 per therm.

This service is only available for customers with a maximum requirement of 2,000 therms per hour.

(Charges are for illustrative purposes only and are based on the Fifty-Eighth Revised Sheet No. 55 filed with the BPU on July 28, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 56**

BGSS-I
BASIC GAS SUPPLY SERVICE-INTERRUPTIBLE
COMMODITY CHARGE APPLICABLE TO RATE SCHEDULES TSG-NF, CSG
(Per Therm)

COMMODITY CHARGE:	Commodity Charge	$ 0.462786
	Commodity Charge including New Jersey Sales and Use Tax (SUT)	$ 0.493446
FLOOR PRICE:	50% of the Non-Gulf Coast Cost of Gas component	$ 0.086730
	Variable Cost of Commodity and Fuel	0.000000
	Cost of Gas Acquired to serve BGSS-I for the month	0.249200
	Total Cost of Gas	$ 0.335930
	Floor Price after application of losses (Loss Factor = 2.0%)	$ 0.342786
CEILING PRICE:	Floor Price plus $0.18	$ 0.522786

A market based charge including all applicable taxes to be posted by Public Service on a monthly basis. The foregoing Commodity Charge will be subject to a floor price equal to the sum of 50% of the Non-Gulf Coast Cost of Gas component and the Cost of Gas Acquired for these customers. Additionally, this Commodity Charge will not exceed a Ceiling Price equal to the Floor Price plus 18 cents per therm.

The Cost of Gas Acquired will be established prior to the beginning of each month based on the NYMEX closing price for the following month.

This service is only available for customers with a maximum requirement of 2,000 therms per hour.

(Charges are for illustrative purposes only and are based on the Fifty-Eighth Revised Sheet No. 56 filed with the BPU on July 28, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 57**

BGSS-CIG
BASIC GAS SUPPLY SERVICE – COGENERATION INTERRUPTIBLE
COMMODITY CHARGES APPLICABLE TO RATE SCHEDULE CIG
(Per Therm)

COMMODITY CHARGE:

Estimated Average Commodity Cost for the month	$ 0.249200
Variable Cost of Commodity and Fuel	0.000000
50% Weighted Average Pipeline Demand Costs	0.022352
Total Commodity Cost of Gas for the month	$ 0.271552
Total Commodity Cost of Gas after application of losses (Loss Factor = 2.0%)	$ 0.277094
Cogeneration Facilities in Service on or before March 10, 1997.	$ 0.277094
Cogeneration Facilities in Service after March 10, 1997 (Charges include New Jersey Sales and Use Tax)	$ 0.295451

Combined Commodity and Distribution Charge – Information Only:

Cogeneration Facilities in Service on or before March 10, 1997

Sum of a Distribution Charge of $0.088960 per therm for the first 600,000 therms used in each month plus the above Commodity Charge......................................	$ 0.366054
Sum of a Distribution Charge of $0.078960 per therm in excess of 600,000 therms used in each month plus the above Commodity Charge......................................	$ 0.356054

Cogeneration Facilities in Service after March 10, 1997
(Charges include New Jersey Sales and Use Tax)

Sum of a Distribution Charge of $0.094854 per therm for the first 600,000 therms used in each month plus the above Commodity Charge......................................	$ 0.390305
Sum of a Distribution Charge of $0.084191 per therm in excess of 600,000 therms used in each month plus the above Commodity Charge......................................	$ 0.379642

The monthly Distribution Charges for Rate Schedule CIG are shown on Sheet No. 107.

(Charges are for illustrative purposes only and are based on the Fifty-Eighth Revised Sheet No. 57 filed with the BPU on July 28, 2023)

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Issued by SCOTT S. JENNINGS, SVP – Finance, Planning & Strategy – PSE&G
80 Park Plaza, Newark, New Jersey 07102
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PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 58**

EMERGENCY SALES SERVICE
CHARGE APPLICABLE TO RATE SCHEDULES RSG, GSG, LVG,
SLG, TSG-F, TSG-NF, CSG
(Per Therm)

Public Service's BGSS supplier(s)'s weighted average pipeline transportation cost including fuel, calculated at 100% load factor (WATC)........	$ 0.044850
Public Service's BGSS supplier(s)'s highest cost of gas purchased or used by Public Service during the month	0.269620
A charge of $0.181........	0.181000
Total	$ 0.495470
Emergency Sales Service Charge after application of losses (Loss Factor = 2.0%)........	$ 0.505582
Emergency Sales Service Charge including New Jersey Sales and Use Tax (SUT)......	$ 0.539077

The charge for Emergency Sales Service will equal the sum of: (1) Public Service's BGSS supplier(s)'s weighted average pipeline transportation cost including fuel, calculated at 100% load factor (WATC); (2) Public Service's BGSS supplier(s)'s highest cost of gas purchased or used during that month, (including associated storage costs, if any); (3) a charge of 18.1 cents per therm; (4) application of losses; and (5) all other applicable taxes and surcharges.

This service is only available for customers with a maximum requirement of 2,000 therms per hour.

(Charges are for illustrative purposes only and are based on the Fifty-Seventh Revised Sheet No. 58 filed with the BPU on July 28, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 59**

BGSS-RSGOP
BASIC GAS SUPPLY SERVICE-RSG OFF-PEAK

COMMODITY CHARGE APPLICABLE TO
RATE SCHEDULE RSG OFF-PEAK USE
(Per Therm)

Cost of Off-Peak RSG Gas Acquired..	$ 0.263220
20% of the Non-Gulf Coast Cost of Gas seasonal component...	0.010280
Total Cost of Gas	$ 0.273500
Commodity Charge after application of losses: (Loss Factor = 2.0%)..............................	$ 0.279082
Commodity Charge including New Jersey Sales and Use Tax (SUT)..............................	$ 0.297571

The Commodity Charge will be established on a level basis for the billing months of May to October immediately prior to the Off-Peak season of each year. The Commodity Charge will equal the Cost of Off-Peak RSG Gas Acquired (plus the variable pipeline transportation cost including fuel) and 20% of the Non-Gulf Coast Cost of Gas seasonal component. The Commodity Charge will be adjusted for losses.

The Cost of Off-Peak RSG Gas Acquired will be established prior to the beginning of the Off-Peak period based on the average NYMEX closing price for the first 15 days of April for natural gas to be supplied in the months of May through October.

(Charges are for illustrative purposes only and are based on the Fifth Revised Sheet No. 59 filed with the BPU on October 1, 2023)

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80 Park Plaza, Newark, New Jersey 07102
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PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 60**

INFRASTRUCTURE IMPROVEMENT PROGRAM CHARGES

Rate Schedule		Base Distribution Charges Including SUT*	Energy Strong II Charges	Energy Strong II Charges Including SUT	Total Charges Including SUT
RSG					
Service Charge	per Month	$8.62	$0.00	$0.00	$8.62
Distribution Charges	per therm	0.046399	0.002603	0.002775	0.466475
Balancing Charge	per Balancing therm	0.097914	0.000000	0.000000	0.097914
Off-Peak Use	per therm	0.231851	0.001301	0.001388	0.233238
GSG					
Service Charge	per Month	20.09	0.13	0.14	20.23
Distribution Charge - Pre July 14, 1997	per therm	0.348581	0.001341	0.001430	0.350010
Distribution Charge - All Others	per therm	0.348581	0.001341	0.001430	0.350010
Balancing Charge	per Balancing therm	0.097914	0.000000	0.000000	0.097914
Off-Peak Use Dist Charge - Pre July 14, 1997	per therm	0.174290	0.000670	0.000715	0.175005
Off-Peak Use Dist Charge - All Others	per therm	0.174290	0.000670	0.000715	0.175005
LVG					
Service Charge	per Month	178.38	1.20	1.28	179.66
Demand Charge	per Demand therm	4.6464	0.0177	0.0188	4.6653
Distribution Charge 0-1,000 pre July 14, 1997	per therm	0.035914	(0.000629)	(0.000671)	0.035244
Distribution Charge over 1,000 pre July 14, 1997	per therm	0.052989	0.000404	0.000431	0.053420
Distribution Charge 0-1,000 post July 14, 1997	per therm	0.035914	(0.000629)	(0.000671)	0.035244
Distribution Charge over 1,000 post July 14, 1997	per therm	0.052989	0.000404	0.000431	0.053420
Balancing Charge	per Balancing therm	0.097914	0.000000	0.000000	0.097914
SLG					
Single-Mantle Lamp	per Unit per Month	14.1119	0.0000	0.0000	14.1119
Double-Mantle Lamp, inverted	per Unit per Month	14.1119	0.0000	0.0000	14.1119
Double Mantle Lamp, upright	per Unit per Month	14.1119	0.0000	0.0000	14.1119
Triple-Mantle Lamp, prior to January 1, 1993	per Unit per Month	14.1119	0.0000	0.0000	14.1119
Triple-Mantle Lamp, on and after January 1, 1993	per Unit per Month	71.9465	0.0000	0.0000	71.9465
Distribution Therm Charge	per therm	0.056854	0.000210	0.000224	0.057077

*Base Distribution Charges include GSMPII changes pursuant to Docket Nos. GR21121256, GR22060409 & GR22120749.

(Charges are for illustrative purposes only and are based on the Sixth Revised Sheet No. 60 filed with the BPU on October 1, 2023)

Date of Issue: Effective:
Issued by SCOTT S. JENNINGS, SVP – Finance, Planning & Strategy – PSE&G
80 Park Plaza, Newark, New Jersey 07102
Filed pursuant to Order of Board of Public Utilities dated
in Docket No.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 61**

INFRASTRUCTURE IMPROVEMENT PROGRAM CHARGES (Continued)

Rate Schedule		Base Distribution Charges Including SUT*	Energy Strong II Charges	Energy Strong II Charges Including SUT	Total Charges Including SUT
TSG-F					
Service Charge	per Month	$955.37	$6.41	$6.84	$962.21
Demand Charge	per Demand therm	2.3306	0.0038	0.0040	2.3347
Distribution Charges	per therm	0.089084	0.000147	0.000157	0.089241
TSG-NF					
Service Charge	per Month	955.37	6.41	6.84	962.21
Distribution Charge 0-50,000	per therm	0.104741	0.000447	0.000476	0.105218
Distribution Charge over 50,000	per therm	0.104741	0.000447	0.000476	0.105218
CIG					
Service Charge	per Month	211.29	0.95	1.01	212.30
Distribution Charge 0-600,000	per therm	0.094412	0.000414	0.000441	0.094854
Distribution Charge over 600,000	per therm	0.083750	0.000414	0.000442	0.084191
CSG					
Service Charge	per Month	955.37	6.41	6.84	962.21
Distribution Charge - Non-Firm	per therm	0.104741	0.000447	0.000476	0.105218

*Base Distribution Charges include GSMPII changes pursuant to Docket Nos. GR21121256, GR22060409 & GR22120749.

INFRASTRUCTURE IMPROVEMENT PROGRAM CHARGE

These charges are designed to recover the revenue requirements associated with the Company's Infrastructure Improvement Programs (IIPs) in accordance with the New Jersey Board of Public Utilities' rules on IIPs, N.J.A.C. 14:3-2A.

For detail concerning individual rate class base distribution charges, see individual rate class tariff sheets.

(Charges are for illustrative purposes only and are based on the Seventh Revised Sheet No. 61 filed with the BPU on October 1, 2023)

Date of Issue: Effective:
Issued by SCOTT S. JENNINGS, SVP – Finance, Planning & Strategy – PSE&G
80 Park Plaza, Newark, New Jersey 07102
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PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 62**
Original Sheet No. 63
Original Sheet No. 64

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 65**

RATE SCHEDULE RSG
RESIDENTIAL SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Firm delivery service for residential purposes. Customers may either purchase gas supply from a Third Party Supplier (TPS) or from Public Service's Basic Gas Supply Service default service as detailed in this rate schedule.

DELIVERY CHARGES:

Service Charge:

$8.08 in each month [$8.62 including New Jersey Sales and Use Tax (SUT)].

Distribution Charges:

Charge	Charge Including SUT	
$0.437491	$0.466475	per therm

Balancing Charge:

Charge	Charge Including SUT	
$0.091830	$0.097914	per Balancing Use Therm

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 60 for details of these charges.

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Societal Benefits include: 1) Social Programs, 2) Demand Side Management Programs, 3) Manufactured Gas Plant Remediation, 4) Consumer Education, and 5) Universal Service Fund. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Margin Adjustment Charge:

This charge shall credit net revenue associated with Rate Schedule Non-Firm Transportation Gas Service (TSG-NF) to customers on Rate Schedules RSG, GSG, LVG, SLG and TSG-F. Refer to the Margin Adjustment Charge sheet of this Tariff for the current charge.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs as approved by the Board. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

(Charges are for illustrative purposes only and are based on the Nineteenth Revised Sheet No. 65 filed with the BPU on October 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 66**

RATE SCHEDULE RSG
RESIDENTIAL SERVICE
(Continued)

Tax Adjustment Credit:

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current charge.

Conservation Incentive Program Charge:

This mechanism removes the Company's disincentive for promoting conservation by truing up actual usage to a baseline per customer established in its last approved rate case. Refer to the Conservation Incentive Program sheet of this Tariff for the current charge.

Distribution Adjustment Charge:

This charge is designed to recover Board-approved costs. Refer to the Distribution Adjustment Charge sheet of this Tariff for the current charge.

The Societal Benefits Charge, the Margin Adjustment Charge, the Green Programs Recovery Charge, the Tax Adjustment Credit, the Conservation Incentive Program Charge, and the Distribution Adjustment Charge will be combined with the Distribution Charge for billing.

COMMODITY CHARGES:

A customer may choose to receive gas supply from either:

a) A TPS who has agreed to the terms and conditions of the Third Party Supplier Requirements portion of this Tariff, or
b) Public Service through its Basic Gas Supply Service default service. Public Service may also supply Emergency Sales Service in certain instances where a customer selected TPS does not deliver sufficient quantities of gas.

Third Party Supply:

A customer that receives gas supply from a TPS will be charged for gas supply according to any agreement between the customer and the TPS. The customer will not be charged for commodity by Public Service, except as provided for in Emergency Sales Service below.

Emergency Sales Service:

In the event that, during any month, a customer's chosen TPS does not deliver the quantities of gas required, or if Public Service cannot confirm that the customer has an eligible TPS, Public Service may supply the deficiencies as Emergency Sales Service.

Emergency Sales Service will be offered at the sole discretion of Public Service, after taking into consideration its other firm supply obligations. Public Service reserves the right to curtail service to any customer if deliveries from customer's TPS pursuant to Third Party Supplier Requirements are curtailed.

If a customer is receiving Emergency Sales Service and does not wish to designate a TPS for future deliveries or customer, for any reason, no longer desires to receive gas supply from a TPS, the customer may receive gas supply pursuant to Public Service's Basic Gas Supply Service-RSG.

The conditions under which Emergency Sales Service will apply are detailed in Section 14 - Third Party Supplier Service Provisions of the Standard Terms and Conditions of this Tariff, and the charges for this service are defined on the Emergency Sales Service sheet of this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 67**

RATE SCHEDULE RSG
RESIDENTIAL SERVICE
(Continued)

Basic Gas Supply Service:
Customers that do not receive gas supply from a TPS will be supplied under the Basic Gas Supply Service-RSG (BGSS-RSG) default service.

The BGSS-RSG Commodity Charge will be applied to all therms billed each month, except customers that receive Delivery Service under Special Provision (c) of this Rate Schedule where the therms used for all purposes in excess of 50 therms in any month during the Off-Peak Period shall be charged at the BGSS-RSGOP Commodity Charge.

Refer to the Basic Gas Supply Service – RSG sheets of this Tariff for the current charge for the BGSS-RSG commodity charge and the BGSS-RSGOP commodity charge.

OTHER CHARGES:

See Special Provisions (c) and (g) below.

BILLING DETERMINANTS:

Therms:
The number of therms used shall be determined by multiplying the number of hundred cubic feet used by the conversion factors which appear on every bill.

Balancing Use Therms:
During each of the billing months of October through May, if the average daily usage of gas in any month exceeds the average daily usage during the preceding billing months of June through September, the therms used in such month in excess of the product of the average daily usage in the preceding months of June through September times the number of days in the billing month shall be the Balancing Use Therms and subject to the Balancing Charge. For new customers and for customers who install additional gas burning equipment, the average daily usage in the preceding June through September time period to be used in the above calculation shall be estimated by Public Service.

Daily Contract Quantity:
The Customer’s Daily Contract Quantity (DCQ) for each month shall be calculated by Public Service for twelve (12) months by dividing customer’s weather-normalized usage, adjusted for losses, for each of the most recent twelve (12) billing months by the total number of days in each billing month. Public Service may adjust customer’s DCQ during the year, due to changes in customer’s gas equipment or pattern of usage, or projected usage. For new customers, customer’s initial DCQ will be estimated by Public Service, based upon the rating of the customer’s gas equipment and expected utilization of the equipment. At the end of each billing period Public Service will calculate the difference between customer’s actual usage, adjusted for losses, and actual TPS supply for the billing period, taking into consideration any adjustments from prior months, and will adjust the DCQ for the second succeeding month by that difference divided by the total number of days in the month, provided that such adjustment will not decrease that month’s adjusted DCQ to a level less than zero. Any such adjustment that would result in a particular month’s DCQ being less than zero will be carried to a future month.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 68**

RATE SCHEDULE RSG
RESIDENTIAL SERVICE
(Continued)

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill.

TERM:

Customer may discontinue delivery service upon notice.

SPECIAL PROVISIONS APPLICABLE TO ALL CUSTOMERS:

(a) This rate schedule is available where all service is for residential purposes:

(a-1) In individual residences and appurtenant outbuildings;

(a-2) In residential premises where customer's use of gas service for purposes other than residential is incidental to the customer's residential use;

(a-3) For rooming or boarding houses where the number of rented rooms does not exceed twice the number of bedrooms occupied by the customer;

(a-4) In separately metered individual flats or apartments in multiple-family buildings;

(a-5) In multiple-family buildings of two or more individual flats or apartments where gas service is measured by one meter and is furnished to the tenants or occupants of the flats or apartments by the owner. Where Special Provision (c) is applicable, the applicable therms shall be multiplied by the number of individual flats or apartments, whether occupied or not;

(a-6) In multiple-family buildings of two to four individual flats or apartments where gas fired equipment serves multiple flats or apartments. Where Special Provision (c) is applicable, the applicable therms shall be multiplied by the number of individual flats or apartments, whether occupied or not.

(b) Service under this rate schedule is not available for resale.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 69**

RATE SCHEDULE RSG
RESIDENTIAL SERVICE
(Continued)

(c) **Off-Peak Use**: Limited to customers with gas central air-conditioning equipment having a rated capacity of not less than two tons of refrigeration. For all eligible customers the Distribution Charge for the therms used for all purposes in excess of 50 therms in any month during the Off-Peak period shall be set equal to one-half (1/2) the above Distribution Charge.

The Off-Peak period shall commence and end with the regularly scheduled meter readings in the months of April and October, respectively.

SPECIAL PROVISIONS APPLICABLE TO CUSTOMERS SELECTING THIRD PARTY SUPPLIERS FOR COMMODITY SERVICE:

(d) Customers who desire to purchase their gas supply from a TPS may request an enrollment package from Public Service that describes the process necessary for the customer to obtain a TPS for gas supply. This package will be provided to the customer at no charge by Public Service.

(e) The customer must contract with a TPS to arrange for deliveries to Public Service of the DCQ, and such TPS agrees to abide by the provisions of the Third Party Supplier Requirements. A customer is limited to one (1) TPS for gas for each account for which the customer receives delivery service.

(f) The customer's TPS is required to notify Public Service of the customer's selection on or before the 10th calendar day of the month to become effective on the first scheduled meter reading date beginning with the first calendar day of the following month, and such selection shall remain in effect for the billing period, subject to the conditions of Emergency Sales Service.

(g) Upon customer return to BGSS, change in TPS or the cessation of delivery service, Public Service shall review the status of customer's imbalance between actual usage and actual TPS's deliveries to the customer, less losses, and shall include such imbalances in that TPS's future delivery requirement.

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 15 of the Standard Terms and Conditions for additional details and/or exceptions.

THIRD PARTY SUPPLIER REQUIREMENTS:

TPSs are subject to the Third Party Supplier Requirements of this Tariff.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 70**
Original Sheet No. 71

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 72**

RATE SCHEDULE GSG
GENERAL SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Firm delivery service for general purposes where: 1) customer does not qualify for RSG and 2) customer's usage does not exceed 3,000 therms in any month. Customers may either purchase gas supply from a Third Party Supplier (TPS) or from Public Service's Basic Gas Supply Service default service as detailed in this rate schedule.

DELIVERY CHARGES:

Service Charge:

$18.97 in each month [$20.23 including New Jersey Sales and Use Tax (SUT)].

Distribution Charges:

Pre-July 14, 1997 *		All Others		
Charge	Charge Including SUT	Charge	Charge Including SUT	
$0.328263	$0.350010	$0.328263	$0.350010	per therm

* Applicable to customers who have taken TPS supplied commodity service continuously since July 14, 1997.

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 60 for details of these charges.

Balancing Charge:

Charge	Charge Including SUT	
$0.091830	$0.097914	per Balancing Use Therm

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Societal Benefits include: 1) Social Programs, 2) Demand Side Management Programs, 3) Manufactured Gas Plant Remediation, 4) Consumer Education, and 5) Universal Service Fund. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Margin Adjustment Charge:

This charge shall credit net revenue associated with Rate Schedule Non-Firm Transportation Gas Service (TSG-NF) to customers on Rate Schedules RSG, GSG, LVG, SLG and TSG-F. Refer to the Margin Adjustment Charge sheet of this Tariff for the current charge.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs as approved by the Board. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

(Charges are for illustrative purposes only and are based on the Eighteenth Revised Sheet No. 72 filed with the BPU on October 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 73**

RATE SCHEDULE GSG
GENERAL SERVICE
(Continued)

Tax Adjustment Credit:

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current charge.

Conservation Incentive Program Charge:
This mechanism removes the Company's disincentive for promoting conservation by truing up actual usage to a baseline per customer established in its last approved rate case. Refer to the Conservation Incentive Program sheet of this Tariff for the current charge.

Distribution Adjustment Charge:
This charge is designed to recover Board-approved costs. Refer to the Distribution Adjustment Charge sheet of this Tariff for the current charge.

The Tax Adjustment Credit, the Conservation Incentive Program Charge, and the Distribution Adjustment Charge will be combined with the distribution charge for billing.

The Societal Benefits Charge, the Margin Adjustment Charge, and the Green Programs Recovery Charge will be combined for billing.

COMMODITY CHARGES:

A customer may choose to receive gas supply from either:

a) A TPS who has agreed to the terms and conditions of the Third Party Supplier Requirements portion of this Tariff, or
b) Public Service through its Basic Gas Supply Service default service. Public Service may also supply Emergency Sales Service in certain instances where a customer selected TPS does not deliver sufficient quantities of gas.

Third Party Supply:
A customer that receives gas supply from a TPS will be charged for gas supply according to any agreement between the customer and the TPS. The customer will not be charged for commodity by Public Service, except as provided for in Emergency Sales Service below.

Emergency Sales Service:
In the event that, during any month, a customer's chosen TPS does not deliver the quantities of gas required, or if Public Service cannot confirm that the customer has an eligible TPS, Public Service may supply the deficiencies as Emergency Sales Service.

Emergency Sales Service will be offered at the sole discretion of Public Service, after taking into consideration its other firm supply obligations. Public Service reserves the right to curtail service to any customer if deliveries from customer's TPS pursuant to Third Party Supplier Requirements are curtailed.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 74**

RATE SCHEDULE GSG
GENERAL SERVICE
(Continued)

If a customer is receiving Emergency Sales Service and does not wish to designate a TPS for future deliveries or customer, for any reason, no longer desires to receive gas supply from a TPS, the customer may receive gas supply pursuant to Public Service's Basic Gas Supply Service-Firm.

The conditions under which Emergency Sales Service will apply are detailed in Section 14 - Third Party Supply Service Provisions of the Standard Terms and Conditions of this Tariff, and the charges for this service are defined on the Emergency Sales Service sheet of this Tariff.

Basic Gas Supply Service:
Customers that do not receive gas supply from a TPS will be supplied under the Basic Gas Supply Service Firm (BGSS-F) default service, which will be applied to all therms billed each month. Refer to the Basic Gas Supply Service – Firm sheet of this Tariff for the current charge for BGSS-F commodity charge.

OTHER CHARGES:

See Special Provisions (b), (e) and (i) below.

BILLING DETERMINANTS:

Therms:
The number of therms used shall be determined by multiplying the number of hundred cubic feet used by the conversion factors which appear on every bill.

Balancing Use Therms:
During each of the billing months of October through May, if the average daily usage of gas in any month exceeds the average daily usage during the preceding billing months of June through September, the therms used in such month in excess of the product of the average daily usage in the preceding months of June through September times the number of days in the billing month shall be the Balancing Use Therms and subject to the Balancing Charge. For new customers and for customers who install additional gas burning equipment, the average daily usage in the preceding June through September time period to be used in the above calculation shall be estimated by Public Service.

Daily Contract Quantity:
The Customer's Daily Contract Quantity (DCQ) for each month shall be calculated by Public Service for twelve (12) months by dividing customer's weather-normalized usage, adjusted for losses, for each of the most recent twelve (12) billing months by the total number of days in each billing month. Public Service may adjust customer's DCQ during the year, due to changes in customer's gas equipment or pattern of usage, or projected usage. For new customers, customer's initial DCQ will be estimated by Public Service, based upon the rating of the customer's gas equipment and expected utilization of the equipment. At the end of each billing period, Public Service will calculate the difference between customer's actual usage, adjusted for losses, and actual TPS supply for the billing period, taking into consideration any adjustments from prior months, and will adjust the DCQ for the second succeeding month by that difference divided by the total number of days in the month, provided that such adjustment will not decrease that month's adjusted DCQ to a level less than zero. Any such adjustment that would result in a particular month's DCQ being less than zero will be carried to a future month.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 75**

RATE SCHEDULE GSG
GENERAL SERVICE
(Continued)

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill and subject to a late payment charge at the rate of 1.416% per monthly billing period in accordance with Section 8.13 of the Standard Terms and Conditions. Service to a body politic will not be subject to a late payment charge.

TERM:

One year and thereafter until terminated by five days' notice.

Customers who transfer from third party supply to Basic Gas Supply Service may be subject to renewable one year terms. Refer to Section 14 of the Standard Terms and Conditions of this Tariff for additional limitations regarding the term of Basic Gas Supply Service.

SPECIAL PROVISIONS APPLICABLE TO ALL CUSTOMERS:

(a) Service under this rate schedule is not available for resale, except where service is for motor vehicle fuel supplied through compression equipment.

(b) **Off-Peak Use:** This separately metered gas service is applicable for cooling or dehumidification when supplied through a separate meter. For all eligible customers the Distribution Charge for the therms used during the Off-Peak period shall be set equal to one-half (1/2) the above Distribution Charge.

The Off-Peak period shall commence and end with the regularly scheduled meter readings in the months of April and October, respectively.

(c) Service supplied under this rate schedule shall be separately metered and shall not be combined with use under any other rate schedule for billing purposes. Customer shall not be eligible to receive service under this rate schedule and any other rate schedule for the same equipment or for equipment supplying a common steam header.

(d) **Cogeneration Use:** Applicable to separately metered service for the sequential production of electrical energy and useful thermal energy from the same fuel source by a Qualifying Facility, as defined in Section 201 of the Public Utilities Regulatory Policies Act of 1978 whose cogeneration equipment meets the efficiency standards set forth in Chapter 18 of the Code of Federal Regulations, Sections 292.205 (a) and (b). Customer must document that qualifying status has been granted by the Federal Energy Regulatory Commission.

Service to a qualifying cogeneration facility as set forth above may be exempt from taxes as set forth in Section 15 of the Standard Terms and Conditions.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 76**

RATE SCHEDULE GSG
GENERAL SERVICE
(Continued)

(e) **Unmetered Service:** Unmetered service will be furnished, at the discretion of Public Service, for customer owned and installed gas lamps or other continuous burning devices. No other gas using devices shall be connected to this service. The customer shall provide, at the customer's expense, all necessary equipment and piping after the gas Service Connection. Further, the customer may be required to furnish and install, at the customer's own expense, a load-limiting device approved by Public Service, which shall be maintained by Public Service at customer's expense. Customer shall notify Public Service in writing as to changes in conditions or operation that may affect the gas consumption of the connected device(s). Public Service reserves the right to meter any and all such installations where customer does not comply with the requirements of this Special Provision.

(f) **Veterans' Organization Service:** Pursuant to N.J.S.A. 48:2-21.41, when natural gas service is delivered to a customer that is a Veterans' Organization, serving the needs of veterans of the armed forces, the customer may apply and be eligible for billing under this Special Provision.

(f-1) Each customer shall be eligible for billing under this Special Provision upon submitting an Application for Veterans' Organization Service under this rate schedule and by qualifying as a Veterans' Organization as defined by N.J.S.A. 48:2-21.41 as "an organization dedicated to serving the needs of veterans of the armed forces that: is chartered under federal law, qualifies as a tax exempt organization under paragraph (19) of subsection (c) of section 501 of the federal Internal Revenue Code of 1986, 26 U.S.C. s.501 (c)(19), or that is organized as a corporation under the 'New Jersey Nonprofit Corporation Act,' N.J.S.A. 15:1-1 et seq." Under N.J.S.A. 48: 2-21.41, a qualified Veterans' Organization shall be charged the residential rate for service delivered to the property where the Veterans' Organization primarily operates, if the residential rate is lower than the commercial rate for service at that property.

The customer shall furnish satisfactory proof of eligibility of service under this Special Provision to the Company. Once proof of eligibility is determined by the Company, service under this Special Provision shall begin with the next billing cycle following receipt of the Application.

(f-2) The customer will continue to be billed on this rate schedule. At least once annually, the Company shall review eligible customers' delivery charges under this Special Provision for all relevant periods. If the comparable delivery charges under the Residential Service (RSG) rate schedule are lower than the delivery charges under its current rate schedule, a credit in the amount of the difference will be applied to the customer's next bill.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 77**

RATE SCHEDULE GSG
GENERAL SERVICE
(Continued)

SPECIAL PROVISIONS APPLICABLE TO CUSTOMERS SELECTING THIRD PARTY SUPPLIERS FOR COMMODITY SERVICE:

(g) Customers who desire to purchase their gas supply from a TPS may request an enrollment package from Public Service that describes the process necessary for the customer to obtain a TPS for gas supply. This package will be provided to the customer at no charge by Public Service.

(h) The customer must contract with a TPS to arrange for deliveries to Public Service of the DCQ, and such TPS agrees to abide by the provisions of the Third Party Supplier Requirements. A customer is limited to one (1) TPS for gas for each account for which the customer receives delivery service.

(i) The customer's TPS is required to notify Public Service of the customer's selection on or before the 10th calendar day of the month to become effective on the first scheduled meter reading date beginning with the first calendar day of the following month, and such selection shall remain in effect for the billing period, subject to the conditions of Emergency Sales Service.

(j) Upon customer return to BGSS, change in TPS or the cessation of delivery service, Public Service shall review the status of customer's imbalance between actual usage and actual TPS deliveries to the customer, less losses, and shall include such imbalances in that TPS's future delivery requirement.

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 15 of the Standard Terms and Conditions for additional details and/or exceptions.

THIRD PARTY SUPPLIER REQUIREMENTS:

TPSs are subject to the Third Party Supplier Requirements of this Tariff.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 78**

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 79**

RATE SCHEDULE LVG
LARGE VOLUME SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Firm delivery service for general purposes. Customers may either purchase gas supply from a Third Party Supplier (TPS) or from Public Service's Basic Gas Supply Service default service as detailed in this rate schedule.

DELIVERY CHARGES:

Service Charge:

$168.50 in each month [$179.66 including New Jersey Sales and Use Tax (SUT)].

Demand Charge (Applicable in the months of November through March):

Charge	Charge Including SUT	
$4.3754	$4.6653	per Demand Therm

Distribution Charges:

Per therm for the first 1,000 therms used in each month		Per therm in excess of 1,000 therms used in each month	
Charges	Charges Including SUT	Charges	Charges Including SUT
$0.033054	$0.035244	$0.050101	$0.053420

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 60 for details of these charges.

Balancing Charge:

Charge	Charge Including SUT	
$0.091830	$0.097914	per Balancing Use Therm

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Societal Benefits include: 1) Social Programs, 2) Demand Side Management Programs, 3) Manufactured Gas Plant Remediation, 4) Consumer Education, and 5) Universal Service Fund. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

(Charges are for illustrative purposes only and are based on the Eighteenth Revised Sheet No. 79 filed with the BPU on October 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 80**

RATE SCHEDULE LVG
LARGE VOLUME SERVICE
(Continued)

Margin Adjustment Charge:
This charge shall credit net revenue associated with Rate Schedule Non-Firm Transportation Gas Service (TSG-NF) to customers on Rate Schedules RSG, GSG, LVG, SLG and TSG-F. Refer to the Margin Adjustment Charge sheet of this Tariff for the current charge.

Green Programs Recovery Charge:
This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs as approved by the Board. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

Tax Adjustment Credit:
This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current charge.

Conservation Incentive Program Charge:
This mechanism removes the Company's disincentive for promoting conservation by truing up actual usage to a baseline per customer established in its last approved rate case. Refer to the Conservation Incentive Program sheet of this Tariff for the current charge.

Distribution Adjustment Charge:
This charge is designed to recover Board-approved costs. Refer to the Distribution Adjustment Charge sheet of this Tariff for the current charge.

The Tax Adjustment Credit, the Conservation Incentive Program Charge, and the Distribution Adjustment Charge will be combined with the distribution charge for billing.

The Societal Benefits Charge, the Margin Adjustment Charge, and the Green Programs Recovery Charge will be combined for billing.

COMMODITY CHARGES:

A customer may choose to receive gas supply from either:

a) A TPS who has agreed to the terms and conditions of the Third Party Supplier Requirements portion of this Tariff, or
b) Public Service through its Basic Gas Supply Service default service. Public Service may also supply Emergency Sales Service in certain instances where a customer selected TPS does not deliver sufficient quantities of gas.

Third Party Supply:
A customer that receives gas supply from a TPS will be charged for gas supply according to any agreement between the customer and the TPS. The customer will not be charged for commodity by Public Service, except as provided for in Emergency Sales Service below.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 81**

RATE SCHEDULE LVG
LARGE VOLUME SERVICE
(Continued)

Emergency Sales Service:
In the event that, during any month, a customer's chosen TPS does not deliver the quantities of gas required, or if Public Service cannot confirm that the customer has an eligible TPS, Public Service may supply the deficiencies as Emergency Sales Service.

Emergency Sales Service will be offered at the sole discretion of Public Service, after taking into consideration its other firm supply obligations. Public Service reserves the right to curtail service to any customer if deliveries from customer's TPS pursuant to Third Party Supplier Requirements are curtailed.

If a customer is receiving Emergency Sales Service and does not wish to designate a TPS for future deliveries or customer, for any reason, no longer desires to receive gas supply from a TPS, the customer may receive gas supply pursuant to Public Service's Basic Gas Supply Service-Firm.

The conditions under which Emergency Sales Service will apply are detailed in Section 14 - Third Party Supply Service Provisions of the Standard Terms and Conditions of this Tariff, and the charges for this service are defined on the Emergency Sales Service sheet of this Tariff.

Basic Gas Supply Service:
Customers that do not receive gas supply from a TPS will be supplied under the Basic Gas Supply Service Firm (BGSS-F) default service, which will be applied to all therms billed each month. Refer to the Basic Gas Supply Service – Firm sheet of this Tariff for the current charge for BGSS-F commodity charge.

OTHER CHARGES:

See Special Provisions (f) and (i) below.

BILLING DETERMINANTS:

Therms:
The number of therms used shall be determined by multiplying the number of hundred cubic feet used by the conversion factors which appear on every bill.

Demand Therms:
The Demand Therms shall be the highest winter month (November through March) average daily usage calculated for the current month and all winter months occurring during the preceding 11 months. The customer's winter month average daily usage shall be determined for each billing month during that period of November through March by dividing billed therms, used by the customer, by the actual number of days in the billing period.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 82**

RATE SCHEDULE LVG
LARGE VOLUME SERVICE
(Continued)

Balancing Use Therms:
During each of the billing months of October through May, if the average daily usage of gas in any month exceeds the average daily usage during the preceding billing months of June through September, the therms used in such month in excess of the product of the average daily usage in the preceding months of June through September times the number of days in the billing month shall be the Balancing Use Therms and subject to the Balancing Charge. For new customers and for customers who install additional gas burning equipment, the average daily usage in the preceding June through September time period to be used in the above calculation shall be estimated by Public Service.

Daily Contract Quantity:
The Customer's Daily Contract Quantity (DCQ) for each month shall be calculated by Public Service for twelve (12) months by dividing customer's weather-normalized usage, adjusted for losses, for each of the most recent twelve (12) billing months by the total number of days in each billing month. Public Service may adjust customer's DCQ during the year, due to changes in customer's gas equipment or pattern of usage, or projected usage. For new customers, customer's initial DCQ will be estimated by Public Service, based upon the rating of the customer's gas equipment and expected utilization of the equipment. At the end of each billing period, Public Service will calculate the difference between customer's actual usage, adjusted for losses, and actual TPS supply for the billing period, taking into consideration any adjustments from prior months, and will adjust the DCQ for the second succeeding month by that difference divided by the total number of days in the month, provided that such adjustment will not decrease that month's adjusted DCQ to a level less than zero. Any such adjustment that would result in a particular month's DCQ being less than zero will be carried to a future month.

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill and subject to a late payment charge at the rate of 1.416% per monthly billing period in accordance with Section 8.13 of the Standard Terms and Conditions. Service to a body politic will not be subject to a late payment charge.

TERM:

One year and thereafter until terminated by five days' notice.

Customers who transfer from third party supply to Basic Gas Supply Service may be subject to renewable one year terms. Refer to Section 14 of the Standard Terms and Conditions of this Tariff for additional limitations regarding the term of Basic Gas Supply Service.

SPECIAL PROVISIONS APPLICABLE TO ALL CUSTOMERS:

(a) Service under this rate schedule is not available for resale, except where service is for motor vehicle fuel supplied through compression equipment.

(b) Service supplied under this rate schedule shall be separately metered and shall not be combined with use under any other rate schedule for billing purposes. Customer shall not be eligible to receive service under this rate schedule and any other rate schedule for the same equipment or for equipment supplying a common steam header during the term of the Service Agreement.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 83**

RATE SCHEDULE LVG
LARGE VOLUME SERVICE
(Continued)

(c) Where Public Service is unable to read the meter on a regular basis, Public Service may require the installation of a remote meter reading device at the customer's expense.

(d) **Cogeneration Use:** Applicable to separately metered service for the sequential production of electrical energy and useful thermal energy from the same fuel source by a Qualifying Facility, as defined in Section 201 of the Public Utilities Regulatory Policies Act of 1978 whose cogeneration equipment meets the efficiency standards set forth in Chapter 18 of the Code of Federal Regulations, Sections 292.205 (a) and (b). Customer must document that qualifying status has been granted by the Federal Energy Regulatory Commission.

Service to a qualifying cogeneration facility as set forth above may be exempt from taxes as set forth in Section 15 of the Standard Terms and Conditions.

(e) **Veterans' Organization Service:** Pursuant to N.J.S.A. 48:2-21.41, when natural gas service is delivered to a customer that is a Veterans' Organization, serving the needs of veterans of the armed forces, the customer may apply and be eligible for billing under this Special Provision.

(e-1) Each customer shall be eligible for billing under this Special Provision upon submitting an Application for Veterans' Organization Service under this rate schedule and by qualifying as a Veterans' Organization as defined by N.J.S.A. 48:2-21.41 as "an organization dedicated to serving the needs of veterans of the armed forces that: is chartered under federal law, qualifies as a tax exempt organization under paragraph (19) of subsection (c) of section 501 of the federal Internal Revenue Code of 1986, 26 U.S.C. s.501 (c)(19), or that is organized as a corporation under the 'New Jersey Nonprofit Corporation Act,' N.J.S.A. 15:1-1 et seq." Under N.J.S.A. 48: 2-21.41, a qualified Veterans' Organization shall be charged the residential rate for service delivered to the property where the Veterans' Organization primarily operates, if the residential rate is lower than the commercial rate for service at that property.

The customer shall furnish satisfactory proof of eligibility of service under this Special Provision to the Company. Once proof of eligibility is determined by the Company, service under this Special Provision shall begin with the next billing cycle following receipt of the Application.

(e-2) The customer will continue to be billed on this rate schedule. At least once annually, the Company shall review eligible customers' delivery charges under this Special Provision for all relevant periods. If the comparable delivery charges under the Residential Service (RSG) rate schedule are lower than the delivery charges under its current rate schedule, a credit in the amount of the difference will be applied to the customer's next bill.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 84**

RATE SCHEDULE LVG
LARGE VOLUME SERVICE
(Continued)

SPECIAL PROVISIONS APPLICABLE TO CUSTOMERS SELECTING THIRD PARTY SUPPLIERS FOR COMMODITY SERVICE:

(f) Customers who desire to purchase their gas supply from a TPS may request an enrollment package from Public Service that describes the process necessary for the customer to obtain a TPS for gas supply. This package will be provided to the customer at no charge by Public Service.

(g) The customer must contract with a TPS to arrange for deliveries to Public Service of the DCQ, and such TPS agrees to abide by the provisions of the Third Party Supplier Requirements. A customer is limited to one (1) TPS for gas for each account for which the customer receives delivery service.

(h) The customer's TPS is required to notify Public Service of the customer's selection on or before the 10th calendar day of the month to become effective on the first scheduled meter reading date beginning with the first calendar day of the following month, and such selection shall remain in effect for the billing period, subject to the conditions of Emergency Sales Service.

(i) Upon customer return to BGSS, change in TPS or the cessation of delivery service, Public Service shall review the status of customer's imbalance between actual usage and actual TPS deliveries to the customer, less losses, and shall include such imbalances in that TPS's future delivery requirement.

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 15 of the Standard Terms and Conditions for additional details and/or exceptions.

THIRD PARTY SUPPLIER REQUIREMENTS:

TPSs are subject to the Third Party Supplier Requirements of this Tariff.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 85**
Original Sheet No. 86

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 87**

RATE SCHEDULE SLG
STREET LIGHTING SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Lamps, posts, maintenance, and firm delivery service for street lighting purposes. Customers may either purchase gas supply from a Third Party Supplier (TPS) or from Public Service's Basic Gas Supply Service default service as detailed in this rate schedule.

DELIVERY CHARGES:

Monthly Charge Per Unit (Includes lamp, post, maintenance and firm delivery service):

Lamps Installed Prior to January 1, 1993:

	Charges	Charges Including SUT
Single–mantle lamp	$ 13.2351	$ 14.1119
Double–mantle lamp, inverted	13.2351	14.1119
Double-mantle lamp, upright	13.2351	14.1119
Triple–mantle lamp	13.2351	14.1119

Lamps Installed on or after January 1, 1993:

	Charges	Charges Including SUT
Triple–mantle lamp	$ 67.4762	$ 71.9465

Allowance for Lamp Outages:

The Monthly Charge per unit reflects an outage allowance based upon normal operating conditions. No further allowance will be made.

Distribution Charge per Therm:

Charge	Charge Including SUT
$0.053531	$0.057077

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 60 for details of these charges.

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Societal Benefits include: 1) Social Programs, 2) Demand Side Management Programs, 3) Manufactured Gas Plant Remediation, 4) Consumer Education, and 5) Universal Service Fund. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Margin Adjustment Charge:

This charge shall credit net revenue associated with Rate Schedule Non-Firm Transportation Gas Service (TSG-NF) to customers on Rate Schedules RSG, GSG, LVG, SLG and TSG-F. Refer to the Margin Adjustment Charge sheet of this Tariff for the current charge.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs as approved by the Board. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

(Charges are for illustrative purposes only and are based on the Eleventh Revised Sheet No. 87 filed with the BPU on June 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 88**

RATE SCHEDULE SLG
STREET LIGHTING SERVICE
(Continued)

Tax Adjustment Credit:

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current charge.

Distribution Adjustment Charge:
This charge is designed to recover Board-approved costs. Refer to the Distribution Adjustment Charge sheet of this Tariff for the current charge.

The Tax Adjustment Credit and the Distribution Adjustment Charge will be combined with the distribution charge for billing.

The Societal Benefits Charge, the Margin Adjustment Charge, and the Green Programs Recovery Charge will be combined for billing.

COMMODITY CHARGES:

A customer may choose to receive gas supply from either:

a) A TPS who has agreed to the terms and conditions of the Third Party Supplier Requirements portion of this Tariff, or
b) Public Service through its Basic Gas Supply Service default service. Public Service may also supply Emergency Sales Service in certain instances where a customer selected TPS does not deliver sufficient quantities of gas.

Third Party Supply:
A customer that receives gas supply from a TPS will be charged for gas supply according to any agreement between the customer and the TPS. The customer will not be charged for commodity by Public Service, except as provided for in Emergency Sales Service below.

Emergency Sales Service:
In the event that, during any month, a customer's chosen TPS does not deliver the quantities of gas required, or if Public Service cannot confirm that the customer has an eligible TPS, Public Service may supply the deficiencies as Emergency Sales Service.

Emergency Sales Service will be offered at the sole discretion of Public Service, after taking into consideration its other firm supply obligations. Public Service reserves the right to curtail service to any customer if deliveries from customer's TPS pursuant to Third Party Supplier Requirements are curtailed.

If a customer is receiving Emergency Sales Service and does not wish to designate a TPS for future deliveries or customer, for any reason, no longer desires to receive gas supply from a TPS, the customer may receive gas supply pursuant to Public Service's Basic Gas Supply Service-Firm.

The conditions under which Emergency Sales Service will apply are detailed in Section 14 - Third Party Supplier Service Provisions of the Standard Terms and Conditions of this Tariff, and the charges for this service are defined on the Emergency Sales Service sheet of this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 89**

RATE SCHEDULE SLG
STREET LIGHTING SERVICE
(Continued)

Basic Gas Supply Service:
Customers that do not receive gas supply from a TPS will be supplied under the Basic Gas Supply Service-Firm (BGSS-F) default service, which will be applied to all therms billed each month. Refer to the Basic Gas Supply Service – Firm sheet of this Tariff for the current charge for the BGSS-F commodity charge.

OTHER CHARGES:

See Special Provision (e) below.

BILLING DETERMINANTS:

Therms:
The number of therms used are shown below for each lamps type.

Single-mantle .... 0.69 therms per day
Double-mantle, inverted .... 0.77 therms per day
Double-mantle, upright .... 1.37 therms per day
Triple-mantle .... 0.77 therms per day

Daily Contract Quantity:
The Customer's Daily Contract Quantity (DCQ) for each month shall be calculated by Public Service for twelve (12) months by multiplying the number of days in the billing month by the above listed daily usage values in therms, adjusted for losses, for each lamp type times the number of customer lamps. If the customer has multiple lamp types then the DCQ would be the sum from all lamp types calculated in the preceding manner. Public Service may adjust customer's DCQ during the year, due to changes in the number and types of customer's lamps.

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill and subject to a late payment charge at the rate of 1.416% per monthly billing period in accordance with Section 8.13 of the Standard Terms and Conditions. Service to a body politic will not be subject to a late payment charge.

TERM:

Five years; written contract required.

Customers who transfer from third party supply to Basic Gas Supply Service may be subject to renewable one year terms. Refer to Section 14 of the Standard Terms and Conditions of this Tariff for additional limitations regarding the term of Basic Gas Supply Service.

SPECIAL PROVISIONS APPLICABLE TO ALL CUSTOMERS:

(a) Service under this rate schedule is not available for resale.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 90**

RATE SCHEDULE SLG
STREET LIGHTING SERVICE
(Continued)

SPECIAL PROVISIONS APPLICABLE TO CUSTOMERS SELECTING THIRD PARTY SUPPLIERS FOR COMMODITY SERVICE:

(b) Customers who desire to purchase their gas supply from a TPS may request an enrollment package from Public Service that describes the process necessary for the customer to obtain a TPS for gas supply. This package will be provided to the customer at no charge by Public Service.

(c) The customer must contract with a TPS to arrange for deliveries to Public Service of the DCQ, and such TPS agrees to abide by the provisions of the Third Party Supplier Requirements. A customer is limited to one (1) TPS for gas for each account for which the customer receives delivery service.

(d) The customer's TPS is required to notify Public Service of the customer's selection on or before the 10th calendar day of the month to become effective on the first scheduled meter reading date beginning with the first calendar day of the following month, and such selection shall remain in effect for the billing period, subject to the conditions of Emergency Sales Service.

(e) Upon customer return to BGSS, change in TPS or the cessation of delivery service, Public Service shall review the status of customer's imbalance between actual usage and actual TPS deliveries to the customer, less losses, and shall include such imbalances in that TPS's future delivery requirement.

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 15 of the Standard Terms and Conditions for additional details and/or exceptions.

THIRD PARTY SUPPLIER REQUIREMENTS:

TPSs are subject to the Third Party Supplier Requirements of this Tariff.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 91**
Original Sheet No. 92

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 93**

RATE SCHEDULE TSG-F
FIRM TRANSPORTATION GAS SERVICE

This rate schedule is limited to customers continuously taking service under this rate schedule since December 1, 1994, with the exception of any new customers for whom commitments by Public Service had been made prior to December 1, 1994.

APPLICABLE TO USE OF SERVICE FOR:

Firm delivery, subject to Public Service's available capacity to provide such service, where the maximum requirement for firm gas is not less than 150 therms per hour and where the customer's Third Party Supplier (TPS) and/or its agent has arranged for the delivery of gas supplies to interconnection points with Public Service's distribution system, from which Public Service may receive and physically transport and deliver the customer's purchased gas supply.

DELIVERY CHARGES:

Service Charge:

$902.42 in each month [$962.21 including New Jersey Sales and Use Tax (SUT)].

Demand Charge (Applicable in the months of November through March):

Charge	Charge Including SUT	
$2.1896	$2.3347	per Demand Therm

Distribution Charges:

Charge	Charge Including SUT	
$0.083696	$0.089241	per therm

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 61 for details of these charges.

Public Service may reduce the Distribution Charge at the beginning of the month and/or during the month to reflect market conditions.

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Societal Benefits include: 1) Social Programs, 2) Demand Side Management Programs, 3) Manufactured Gas Plant Remediation, 4) Consumer Education, and 5) Universal Service Fund. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Margin Adjustment Charge:

This charge shall credit net revenue associated with Rate Schedule Non-Firm Transportation Gas Service (TSG-NF) to customers on Rate Schedules RSG, GSG, LVG, SLG and TSG-F. Refer to the Margin Adjustment Charge sheet of this Tariff for the current charge.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs as approved by the Board. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

(Charges are for illustrative purposes only and are based on the Eleventh Revised Sheet No. 93 filed with the BPU on June 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 94**

RATE SCHEDULE TSG-F
FIRM TRANSPORTATION GAS SERVICE
(Continued)

Tax Adjustment Credit:

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current charge.

Distribution Adjustment Charge:

This charge is designed to recover Board-approved costs. Refer to the Distribution Adjustment Charge sheet of this Tariff for the current charge.

The Tax Adjustment Credit and the Distribution Adjustment Charge will be combined with the distribution charge for billing.

The Societal Benefits Charge, the Margin Adjustment Charge and the Green Programs Recovery Charge will be combined for billing.

COMMODITY CHARGES:

A customer must choose to receive gas supply from a TPS who has agreed to the terms and conditions of the Third Party Supplier Requirements portion of this Tariff.

Third Party Supply:

A customer that receives gas supply from a TPS will be charged for gas supply according to any agreement between the customer and the TPS. The customer will not be charged for commodity by Public Service, except as provided for in Emergency Sales Service below.

Emergency Sales Service:

In the event that, during any month, Public Service cannot confirm that the customer has an eligible TPS, or if the TPS no longer satisfies the requirement of the Third Party Supplier Requirement portion of this Tariff, Public Service may supply the deficiencies as Emergency Sales Service. Public Service may supply gas commodity service to such customer as Emergency Sales Service unless and until customer selects another TPS.

Emergency Sales Service will be offered at the sole discretion of Public Service, after taking into consideration its other firm sales obligations. Public Service reserves the right to curtail service to any customer if deliveries from customer's TPS pursuant to Third Party Supplier Requirements are curtailed.

The conditions under which Emergency Sales Service will apply are detailed in Section 14 - Third Party Supply Service Provisions of the Standard Terms and Conditions of this Tariff, and the charges for this service are defined on the Emergency Sales Service sheet of this Tariff.

BILLING DETERMINANTS:

Therms:

The number of therms used shall be determined by multiplying the number of hundred cubic feet used by the conversion factors which appear on every bill. The conversion factor used for the "therm multiplier" shall be on the basis of the actual heating value of the gas used.

Demand Therms:

The Demand Therms shall be the highest winter month (November through March) average daily usage calculated for the current month and all winter months occurring during the preceding 11 months. The customer's winter month average daily usage shall be determined for each billing month during that period of November through March by dividing billed therms, used by the customer, by the actual number of days in the billing period.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 95**

RATE SCHEDULE TSG-F
FIRM TRANSPORTATION GAS SERVICE
(Continued)

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill and subject to a late payment charge at the rate of 1.416% per monthly billing period in accordance with Section 8.13 of the Standard Terms and Conditions. Service to a body politic will not be subject to a late payment charge.

TERM:

One year and thereafter until terminated by five days' notice.

SPECIAL PROVISIONS APPLICABLE TO ALL CUSTOMERS:

(a) Customer will be restricted to the maximum annual, daily and hourly requirements, and the location and equipment specified in the service agreement. Upon request by customer, Public Service may deliver available volumes of gas supply, adjusted for losses, in excess of the maximum requirements, for limited periods. Such deliveries shall not be deemed to constitute a change in the requirements specified in the service agreement.

(b) The customer must contract with a TPS to arrange for deliveries to Public Service of its daily usage, adjusted for losses, and such TPS agrees to abide by the provisions of the Third Party Supplier Requirements. A customer is limited to one (1) TPS for gas for each account for which the customer receives delivery service.

The customer's TPS is required to notify Public Service of the customer's selection prior to the last business day of the month for deliveries to commence on the first (1st) of the next month, and such selection shall remain in effect for the entire month, subject to the conditions of Emergency Sales Service. Customer can change TPSs effective only on the first day of the month.

Details for third party supply can be obtained by referring to Section 14 – Third Party Supplier Service Provisions of the Standard Terms and Conditions of this Tariff.

(c) Metering shall include a recording device, furnished by Public Service. Customer shall furnish an electrical supply for the operation of the recording device.

(d) Service supplied under this rate schedule shall be separately metered and shall not be combined with use under any other rate schedule for billing purposes. Customer shall not be eligible to receive service under this rate schedule and any other rate schedule for the same equipment or for equipment supplying a common steam header.

(e) Service under this rate schedule is not available for resale.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 96**

RATE SCHEDULE TSG-F
FIRM TRANSPORTATION GAS SERVICE
(Continued)

(f) Cogeneration Use: Applicable to separately metered service for the sequential production of electrical energy and useful thermal energy from the same fuel source by a Qualifying Facility, as defined in Section 201 of the Public Utilities Regulatory Policies Act of 1978 whose cogeneration equipment meets the efficiency standards set forth in Chapter 18 of the Code of Federal Regulations, Sections 292.205(a) and (b). Customer must document that qualifying status has been granted by the Federal Energy Regulatory Commission.

Service to qualifying cogeneration facility as set forth above may be exempt from taxes as set forth in Section 15 of the Standard Terms and Conditions.

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 15 of the Standard Terms and Conditions for additional details and/or exceptions.

THIRD PARTY SUPPLIER REQUIREMENTS:

TPSs are subject to the Third Party Supplier Requirements of this Tariff.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff except Section 7.6, Appliance Adjustments.

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 99**

RATE SCHEDULE TSG-NF
NON-FIRM TRANSPORTATION GAS SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Interruptible delivery for general purposes where the maximum requirement for interruptible gas is not less than 150 therms per hour and where the customer has the installed capability to utilize an alternate type of fuel, except as provided for in Special Provision (a). Customers may either purchase gas supply from a Third Party Supplier (TPS) or from Public Service's Basic Gas Supply Service default service as detailed in this rate schedule.

DELIVERY CHARGES:

Service Charge:

$902.42 in each month [$962.21 including New Jersey Sales and Use Tax (SUT)].

Distribution Charges:

Charge	Charge including SUT	
$0.098680	$0.105218	per therm

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 61 for details of these charges.

Public Service may reduce the Distribution Charge at the beginning of the month and/or during the month to reflect market conditions.

This charge does not apply to gas sold to customer by Public Service pursuant to Special Provision (d).

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Societal Benefits include: 1) Social Programs, 2) Demand Side Management Programs, 3) Manufactured Gas Plant Remediation, 4) Consumer Education, and 5) Universal Service Fund. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs as approved by the Board. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

Tax Adjustment Credit:

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current charge.

Distribution Adjustment Charge:

This charge is designed to recover Board-approved costs. Refer to the Distribution Adjustment Charge sheet of this Tariff for the current charge.

The Tax Adjustment Credit and the Distribution Adjustment Charge will be combined with the distribution charge for billing.

The Societal Benefits Charge and the Green Programs Recovery Charge will be combined for billing.

COMMODITY CHARGES:

A customer may choose to receive gas supply from either:

a) A TPS who has agreed to the terms and conditions of the Third Party Supplier Requirements portion of this Tariff, or

(Charges are for illustrative purposes only and are based on the Eleventh Revised Sheet No. 99 filed with the BPU on June 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 100**

RATE SCHEDULE TSG-NF
NON-FIRM TRANSPORTATION GAS SERVICE
(Continued)

b) Public Service through its Basic Gas Supply Service default service. Public Service may also supply Emergency Sales Service in certain instances as indicated below.

Third Party Supply:
A customer that receives gas supply from a TPS will be charged for gas supply according to any agreement between the customer and the TPS. The customer will not be charged for commodity by Public Service, except as provided for in Emergency Sales Service below.

Emergency Sales Service:
In the event that, during any month, if Public Service cannot confirm that the customer has an eligible TPS, or if the TPS no longer satisfies the Third Party Supplier Requirements of this tariff, Public Service may supply the deficiencies as Emergency Sales Service.

Emergency Sales Service will be offered at the sole discretion of Public Service, after taking into consideration its other firm supply obligations. Public Service reserves the right to curtail service to any customer if deliveries from customer's TPS pursuant to Third Party Supplier Requirements are curtailed.

If a customer is receiving Emergency Sales Service and does not wish to designate a TPS for future deliveries or customer, for any reason, no longer desires to receive gas supply from a TPS, the customer may receive gas supply pursuant to Public Service's Basic Gas Supply Service.

The conditions under which Emergency Sales Service will apply are detailed in Section 14 - Third Party Supplier Service Provisions of the Standard Terms and Conditions of this Tariff, and the charges for this service are defined on the Emergency Sales Service sheet of this Tariff.

Basic Gas Supply Service:
Customers with a maximum requirement of less than 2,000 therms per hour and who do not receive gas supply from a TPS will be supplied under the Basic Gas Supply Service-Interruptible (BGSS-I) default service, which will be applied to all therms billed each month. Refer to the Basic Gas Supply Service – Interruptible sheet of this Tariff for the current charge for BGSS-I commodity charge.

OTHER CHARGES:

See Special Provisions (d) and (e).

BILLING DETERMINANTS:

Therms:
The number of therms used shall be determined by multiplying the number of hundred cubic feet used by the conversion factors which appears on every bill. The conversion factor used for the "therm multiplier" shall be on the basis of the actual heating value of the gas used.

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill and subject to a late payment charge at the rate of 1.416% per monthly billing period in accordance with Section 8.13 of the Standard Terms and Conditions. Service to a body politic will not be subject to a late payment charge.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 101**

RATE SCHEDULE TSG-NF
NON-FIRM TRANSPORTATION GAS SERVICE
(Continued)

TERM:

Unless otherwise agreed upon by customer and Public Service, one year from the commencement date specified in the service agreement required by Special Provision (a) and successive one-year periods thereafter. Service may be terminated by either customer or Public Service by providing no less than one month's notice prior to the expiration of the term.

SPECIAL PROVISIONS APPLICABLE TO ALL CUSTOMERS:

(a) Customer will be required to sign a service agreement and service will be restricted to the maximum annual, daily, and hourly requirements, and the location and equipment specified. Upon request by customer, Public Service may deliver available volumes of gas supply, adjusted for losses, in excess of the maximum requirements, for limited periods. Such deliveries shall not be deemed to constitute a change in the requirements specified in the service agreement. Attached to the service agreement will be a signed affidavit, certifying the specific grade of fuel oil (or oils), or other alternate fuel, that can physically and legally be utilized by the installation being served. This affidavit shall be a prerequisite for receiving service under this rate schedule and shall be furnished by the customer each fall no later than November 1st. The affidavit shall include the percentage of operation which can physically and legally be served by each alternate fuel. The customer will submit, within 30 days of change in operations, a new affidavit to Public Service when such change affects its alternate fuel capability. Additionally, the Affidavit shall require customers using No. 2 Fuel Oil, No. 4 Fuel Oil, jet fuel, or kerosene to provide certification that they have, and will maintain, either seven days of alternate fuel available through on-site storage capacity or additional firm contractual supply to make-up for any storage deficiencies so as to be equal to a seven day supply. Customers providing certification that they will suspend operations during an interruption are exempt from the alternate fuel requirement. Public Service reserves the right to inspect the customer's operation as to alternate fuel capability. Customers that fail to provide an affidavit by November 1st of each year shall continue to be subject to all of the terms of this rate schedule and in addition be subject to the Demand Charge as provided for in Rate Schedule LVG.

(b) Customers who were taking service under former Rate Schedule ISG Special Provision (b) on January 8, 2002 will be provided service under this rate schedule and are exempt from the minimum connected load requirement of 150 therms per hour.

(c) Upon advance notice of eight hours or more, from any hour of any day given to customer by Public Service, customer shall discontinue the use of gas until further notice; customer shall designate personnel who will accept such notification at any hour of any day.

(d) If customer does not discontinue the use of gas after notification pursuant to Special Provision (c) customer shall be charged $1.89 ($2.02 including SUT) per therm for an amount not to exceed one hour's maximum requirement per day of interruption.

The charge for all additional gas used shall be ten times the highest price of the "Absolute" daily ranges for delivery in Transco Zone 6, New York, or Texas Eastern Zone M-3 which are published in *Gas Daily* on the table "Final Daily Price Survey" for each therm of gas used by the customer. This rate shall not be lower than the maximum penalty charge for unauthorized daily overruns as provided for in the FERC-approved gas tariffs of the interstate pipelines which deliver gas into New Jersey.

(Charges are for illustrative purposes only and are based on the Original Sheet No. 101 filed with the BPU on November 1, 2018)

Date of Issue: Effective:
Issued by SCOTT S. JENNINGS, SVP – Finance, Planning & Strategy – PSE&G
80 Park Plaza, Newark, New Jersey 07102
Filed pursuant to Order of Board of Public Utilities dated
in Docket No.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 102**

RATE SCHEDULE TSG-NF
NON-FIRM TRANSPORTATION GAS SERVICE
(Continued)

If a customer persistently does not discontinue the use of gas after notification pursuant to Special Provision (c), in addition to the aforementioned penalty charge, the customer will be notified that it no longer qualifies for service under an interruptible rate schedule. Applicable firm service will be available on a prospective basis subject to the availability of supply and delivery capacity.

Except for pilots, however, Public Service has no obligation to deliver gas at any time following notice pursuant to Special Provision (c) and may discontinue completely all other deliveries of gas to customer during the period of interruption.

(e) If a customer requests a change from this delivery rate schedule to firm service firm service will be available on a prospective basis subject to the availability of supply and delivery capacity, If a customer switches to firm service, they must remain on firm service for at least one year. If necessary, the customer will also be charged for system reinforcement, in accordance with Section 3, Charges for Service of the Standard Terms and Conditions of this Tariff.

(f) Customer may be required to make a deposit toward the total cost of facilities which Public Service installed to provide service if gas equipment or applications were, in the prior five-year period, previously served under Rate Schedules RSG, GSG, LVG or TSG-F for the same customer. Such deposit will be determined as if such gas equipment or applications had been served under Rate Schedule TSG-NF for the entire period served under the above firm rates, utilizing the deposit calculations in existence at the time the customer began service.

(g) Metering shall include a recording device, furnished by Public Service. Customer shall furnish an electrical supply for the operation of the recording device.

(h) Service supplied under this rate schedule shall be separately metered and shall not be combined with use under any other rate schedule for billing purposes. Customer shall not be eligible to receive service under this rate schedule and any other rate schedule for the same equipment or for equipment supplying a common steam header.

(i) Except as provided in Special Provision (a) customer has installed and maintains complete and adequate standby equipment and fuel supply for operation with another fuel when the gas supply is interrupted.

(j) Customers with a maximum requirement of 7,500 therms per hour or greater shall designate personnel physically located at the customer's facility having operational control of the gas usage at that facility who can be directly contacted by telephone or other electronic means at any hour of any day by Public Service. If the customer obtains gas supply from a TPS, these personnel shall be responsible for coordinating the balancing of customer's gas consumption and deliveries by the customer's TPS and shall be the only party that Public Service contacts for all operational coordination requirements including those during periods of suspension or limitation and critical periods as detailed in Sections 6.3.2 and 6.3.3 of the Third Party Supplier Requirements of this tariff. If the customer obtains gas supply from Public Service under BGSS-I default service, Public Service may establish similar operational coordination requirements.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 103**

RATE SCHEDULE TSG-NF
NON-FIRM TRANSPORTATION GAS SERVICE
(Continued)

(k) Service under this rate schedule is not available for resale.

(l) Cogeneration Use: Applicable to separately metered service for the sequential production of electrical energy and useful thermal energy from the same fuel source by a Qualifying Facility, as defined in Section 201 of the Public Utilities Regulatory Policies Act of 1978 whose cogeneration equipment meets the efficiency standards set forth in Chapter 18 of the Code of Federal Regulations, Sections 292.205 (a) and (b). Customer must document that qualifying status has been granted by the Federal Energy Regulatory Commission.

Service to a qualifying cogeneration facility as set forth above may be exempt from taxes as set forth in Section 15 of the Standard Terms and Conditions.

(m) Military Service: United States Department of Defense Military bases may apply for service under this special provision. Under this special provision: 1) a customer must choose to receive gas supply from a TPS who has agreed to the terms and conditions of the Third Party Supplier Requirements of this Tariff; 2) delivery service will not be interrupted with respect to the customer's gas that is delivered to Public Service by the customer's TPS on any day; 3) all service for each service location must be through a single meter; 4) the requirements for an alternate fuel shall not apply; and 5) in lieu of the annual alternate fuel certification required by each November 1st as described in Special Provision (a) above, the customer is required to submit a certification by each November 1st that it has a contract with a TPS to supply its gas requirements each day through the end of the following March.

SPECIAL PROVISIONS APPLICABLE TO CUSTOMERS SELECTING THIRD PARTY SUPPLIERS FOR COMMODITY SERVICE:

(n) The customer must contract with a TPS to arrange for deliveries to Public Service of their daily usage, adjusted for losses, and such TPS agrees to abide by the provisions of the Third Party Supplier Requirements. A customer is limited to one (1) TPS for gas for each account for which the customer receives delivery service.

(o) The customer's TPS is required to notify Public Service of the customer's selection prior to the last business day of the month for deliveries to commence on the first (1st) of the next month, and such selection shall remain in effect for the entire month, subject to the conditions of Emergency Sales Service. Customer can change TPSs effective only on the first day of the month.

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 15 of the Standard Terms and Conditions for additional details and/or exceptions.

THIRD PARTY SUPPLIER REQUIREMENTS:

TPSs are subject to the Third Party Supplier Requirements of this Tariff.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff except Section 7.6, Appliance Adjustments.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS

Original Sheet No. 104
Original Sheet No. 105
Original Sheet No. 106

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 107**

RATE SCHEDULE CIG
COGENERATION INTERRUPTIBLE SERVICE

This rate schedule is limited to customers continuously taking service under this rate schedule or former Rate Schedule CEG since January 8, 2002, with the exception of any new customers for whom commitments by Public Service had been made prior to January 9, 2002.

APPLICABLE TO USE OF SERVICE FOR:

Interruptible gas delivery and supply service for the sequential production of electrical energy and useful thermal energy from the same fuel source by a Qualifying Facility, as defined in Section 201 of the Public Utility Regulatory Policies Act of 1978, and regularly meeting the efficiency standards set forth in Chapter 18 of the Code of Federal Regulations, Sections 292.205 (a) and (b) and where the combined nameplate-rated capacity of the generation equipment is not less than 1.5 megawatts and not greater than 20 megawatts. This size limitation shall not apply to customer's Qualifying Facilities receiving service under this rate schedule prior to January 1, 1993.

DELIVERY CHARGES:

Service Charge:

$199.11 in each month [$212.30 including New Jersey Sales and Use Tax (SUT)].

Distribution Charges:

Charge	Charge including SUT	
$0.088960	$0.094854	per therm for the first 600,000 therms used in each month.
$0.078960	$0.084191	per therm in excess of 600,000 therms used in each month.

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 61 for details of these charges.

This charge does not apply to gas sold to customers by Public Service pursuant to Special Provision (c).

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Societal Benefits include: 1) Social Programs, 2) Demand Side Management Programs, 3) Manufactured Gas Plant Remediation, 4) Consumer Education, and 5) Universal Service Fund. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs as approved by the Board. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

Tax Adjustment Credit:

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current charge.

Distribution Adjustment Charge:
This charge is designed to recover Board-approved costs. Refer to the Distribution Adjustment Charge sheet of this Tariff for the current charge.

The Tax Adjustment Credit and the Distribution Adjustment Charge will be combined with the distribution charge for billing.

The Societal Benefits Charge and the Green Programs Recovery Charge will be combined for billing.

(Charges are for illustrative purposes only and are based on the

Eleventh Revised Sheet No. 107 filed with the BPU on June 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 108**

RATE SCHEDULE CIG
COGENERATION INTERRUPTIBLE SERVICE
(Continued)

COMMODITY CHARGES:

Customers taking service under this rate schedule are required to receive their commodity service from Public Service. Refer to the BGSS-CIG Commodity Charge sheet of this Tariff for the current charge.

Other Charges:
See Special Provisions (c) and (n).

BILLING DETERMINANTS:

Therms:
The number of therms used shall be determined by multiplying the number of hundred cubic feet used by the conversion factors which appear on every bill. The conversion factor used for the "therm multiplier" shall be on the basis of the actual heating value of the gas used.

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill and subject to a late payment charge at the rate of 1.416% per monthly billing period in accordance with Section 8.13 of the Standard Terms and Conditions. Service to a body politic will not be subject to a late payment charge.

TERM:

One year and thereafter until terminated by five days' notice.

SPECIAL PROVISIONS APPLICABLE TO ALL CUSTOMERS:

(a) Customer must certify that qualifying status has been granted by the Federal Energy Regulatory Commission and will be required to sign a service agreement. Service will be restricted to the maximum annual and hourly requirements, and the location and equipment specified in that service agreement. Upon request by customer, Public Service may deliver available volumes of gas in excess of the maximum hourly requirement for limited periods. Such deliveries shall not be deemed to constitute a change in the requirements specified in that service agreement.

(b) Upon advance notice of eight hours or more, from any hour of any day given to customer by Public Service, customer shall discontinue the use of gas until further notice; customer shall designate personnel who will accept such notification at any hour of any day.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 109**

RATE SCHEDULE CIG
COGENERATION INTERRUPTIBLE SERVICE
(Continued)

(c) If customer does not discontinue the use of gas after notification pursuant to Special Provision (b), the Commodity Charge shall be $1.89 ($2.02 including SUT) per therm for an amount not to exceed one hour's maximum requirement per day of interruption. Use of this amount shall be limited to a per therm quantity not to exceed one hour's maximum requirement per day of interruption.

The charge for all additional gas used shall be ten times the highest price of the "Absolute" daily ranges for delivery in Transco Zone 6, New York, or Texas Eastern Zone M-3 which are published in *Gas Daily* on the table "Final Daily Price Survey." This rate shall not be lower than the maximum penalty charge for unauthorized daily overruns as provided for in the FERC-approved gas tariffs of the interstate pipelines which deliver gas into New Jersey.

If a customer persistently does not discontinue the use of gas after notification pursuant to Special Provision (b), in addition to the aforementioned penalty charge, the customer will be notified that it no longer qualifies for service under an interruptible rate schedule. Applicable firm service will be available on a prospective basis, subject to the availability of supply and delivery capacity.

Except for pilots, however, Public Service has no obligation to supply gas at any time following notice pursuant to Special Provision (b) and may discontinue completely all other deliveries of gas to customer during the period of interruption.

If a customer requests a change from this delivery rate schedule to firm service, firm service will be available on a prospective basis subject to the availability of supply and delivery capacity. If a customer switches to firm service, they must remain on firm service for at least one year,

(d) Metering shall include a recording device, furnished by Public Service. Customer shall furnish an electrical supply for the operation of the recording device.

(e) Service supplied under this rate schedule shall be separately metered and shall not be combined with use under any other rate schedule for billing purposes.

(f) Service will not be supplied under this rate schedule and any other gas rate schedule for the same process or operation at the same location except as specified under Special Provision (i).

(g) Public Service agrees that service under this rate schedule will not be interrupted unless service to the TSG-NF customers receiving BGSS-I default service has already been interrupted.

(h) Gas supplied under this rate schedule is limited to a quantity equal to the lesser of either 0.150 therms for each net kilowatt-hour of cogenerated electric generation fueled by gas or the quantity of gas actually consumed by the cogeneration facility when operated in a cogeneration mode as determined by Public Service. Net cogenerated electric generation is defined as generation output less energy used to run the cogeneration facility's auxiliary equipment. Auxiliary equipment includes, but it is not limited to, forced and induced draft fans, boiler feed pumps and lubricating oil systems.

(Charges are for illustrative purposes only and are based on the Original Sheet No. 109 filed with the BPU on November 1, 2018)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 110**

RATE SCHEDULE CIG
COGENERATION INTERRUPTIBLE SERVICE
(Continued)

(i) Gas supplied in excess of the quantity described in Special Provision (h) will be billed under an applicable rate schedule as determined by Public Service except as specified under Special Provision (c).

(j) Net cogenerated electric generation fueled by natural gas will be determined each month as follows:

(j-1) For facilities which burn two or more fuels simultaneously for cogeneration, net cogenerated electric generation will be allocated between such fuels on the Btu input of each fuel.

(j-2) For facilities which change fuel usage between gas and an alternate fuel for cogeneration, net cogenerated electrical generation fueled by gas will be based on meter readings taken by the customer at the time the fuel change occurs or the portion of the allocated amount determined in Special Provision (h) prorated by the number of hours or days that the customer used gas.

(k) Public Service, at its sole discretion, may utilize readings from customer or Company-owned meters to determine the quantity of gas to which this rate schedule is applicable in lieu of the allocation specified in Special Provision (j-1). The customer shall make available, and Public Service shall have the right to read, inspect and/or test such customer-owned meters during normal working hours. Additional gas, electric and/or useful thermal output meters required to determine the amount of gas to which this rate schedule is applicable will be installed, owned and operated by Public Service. However, Public Service may, at its sole option, use calculated or estimated data to determine such gas usage.

(l) Customer is required to file a monthly report to Public Service containing the total amount of kilowatt-hours produced by the cogeneration facility.

(m) Service under this rate schedule is not available for resale.

(n) **Extended Gas Service:** Gas service under this Special Provision is limited to customers having an executed service agreement for this Special Provision. Customer's executed service agreement must be received by Public Service no later than November 15th for service to be provided for the upcoming winter season. Approval of the customer's request will be provided on a case by case basis so as not to adversely impact Public Service's distribution system. When service under this Rate Schedule is interrupted, service under this Special Provision will be supplied at Public Service's option. When Extended Gas Service is offered by Public Service, the following provisions shall apply:

(n-1) In lieu of the Therm Charge hereinbefore set forth, the following charges shall apply: 1) a Special Delivery Charge which, based upon the marketability of this gas, would fall between a floor price of $0.100 ($0.107 including SUT) per therm and a ceiling price of $0.180 ($0.192 including SUT) per therm for each therm of Extended Gas Service supplied to the customer; and 2) a Commodity Charge which shall be the maximum of the "Common" range value stated in the Final Daily Price Survey section of Platt's Gas Daily for Transco Zone 6 New York for the day(s) when service under this Special Provision is offered.

(Charges are for illustrative purposes only and are based on the Original Sheet No. 110 filed with the BPU on November 1, 2018)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 111**

RATE SCHEDULE CIG
COGENERATION INTERRUPTIBLE SERVICE
(Continued)

(n-2) A service agreement for this Extended Gas Service shall be executed for each winter season and shall include the customer's maximum daily requirements under this Special Provision and a prepayment equal to four days of the Special Delivery Charge at a rate of $0.150 ($0.160 including SUT) per therm at the customer's maximum daily requirement. Use of gas above the maximum daily requirement, on any day for which Public Service has offered and the customer has requested Extended Gas Service, will be subject to the penalty as stated in Special Provision (c). Such prepayment shall be non-refundable unless and to the extent that Public Service does not offer customer such Extended Gas Service for at least 96 hours, during the winter season. If Public Service, offers such service for less than 96 hours, the refund shall be made on a prorated basis. In addition to such prepayment, a non-refundable application charge of $800.00 ($853.00 including SUT) shall be paid by each customer.

(n-3) Customer will be notified electronically or by phone of the Extended Gas Therm Charge at least eight hours prior to the availability of this service, or prior to a change in the Extended Gas Therm Charge. Following receipt of Public Service's notice, the customer will have two hours within which to electronically notify Public Service the customer's acceptance of the Extended Gas Therm Charge for the service. If customer does not accept this service, customer must discontinue the use of gas at the time designated by Public Service, which time shall not be less than eight hours after Public Service's notice to Customer of the availability and the Therm Charge of the Extended Gas Service. Any gas usage by customer following the time designated by Public Service shall be subject to the penalty as stated in Special Provision (c).

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c.57, and is included in the appropriate charges in this rate schedule. See Section 15 of the Standard Terms and Conditions for additional details and/or exceptions.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff except section 7.6, Appliance Adjustments.

(Charges are for illustrative purposes only and are based on the Original Sheet No. 111 filed with the BPU on November 1, 2018)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 112**

RATE SCHEDULE CSG
CONTRACT SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Firm or interruptible delivery service for general purposes where the customer is requesting a discount rate from a Public Service Rate Schedule for delivery service based on an (a) Economically Viable Bypass alternative or (b) Other Considerations.

Public Service will review all applications to verify for completeness within 45 days of receipt. If any data is missing, Public Service will notify customer of the information needed to complete the application. Public Service reserves the right to request additional information as needed on a case by case basis. Once a request is deemed complete, Public Service will have 45 days to complete its analysis and respond to the customer. Once agreement has been reached, Public Service will forward the application to the Board of Public Utilities for review and approval. Once approved by the Board of Public Utilities, the customer agrees that the discounted rate set forth under this rate schedule will not be confidential.

Customers may purchase gas supply from a Third Party Supplier (TPS) or, for customers with a maximum requirement of less than 2,000 therms per hour, from Public Service's Basic Gas Supply Service default service as detailed in this rate schedule.

ECONOMICALLY VIABLE BYPASS

For all customers requesting this tariff service based on an economically viable bypass alternative, the customer must submit to Public Service the following minimum information but not limited to:

1. A bypass feasibility report issued by the interstate pipeline or an independent engineering consultant setting forth:
   i. Maps showing the route of the potential bypass;
   ii. Flow diagrams showing the major components of the bypass from the interstate pipeline interconnection to the customer;
   iii. Engineering studies related to the proposed cost to bypass including estimated costs for: right-of-way; regulatory approvals; material; equipment; structures; construction; overheads; contingencies and tax gross-up applicable to pipeline company facilities;
   iv. The location class, design pressure, size, length, pipe specification, yield strength and wall thickness of the bypass pipeline;
   v. Schedule of all permits from State or Federal agencies and railroads necessary for the bypass;
   vi. Project schedule;
   vii. The cost estimate classification level following AACE International Recommended Practice No.18R-97;
   viii. Statement from the interstate pipeline that the proposed interconnection is operationally viable and that the pipeline can effectuate service as requested.
2. Creditworthiness of customer.
3. Estimated annual therm usage along with all supporting assumptions and calculations.

OTHER CONSIDERATIONS

Service under this rate schedule where the customer is requesting this tariff service based on considerations other than an economically viable bypass alternative will be offered by the Company in circumstances in which it determines in its sole reasonable judgment that such rates are necessary to prevent (i) economic bypass of the Company's distribution system, or (ii) the loss of load that could otherwise be served at rates that exceed marginal costs.

Customer seeking negotiated rates under this provision must provide the Company: (i) such information as the customer deems relevant to its request; (ii) such information as the Company may require given the particular circumstances.

In determining whether to offer individually negotiated rates, terms or conditions under this provision to a particular customer, the Company will consider all relevant information provided by the customer and make a judgment as to whether or not the negotiated rates are necessary to prevent an economic bypass or the loss of load that could otherwise be served at rates that exceed marginal costs.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 112A**

RATE SCHEDULE CSG
CONTRACT SERVICE
(Continued)

ECONOMICALLY VIABLE BYPASS
DELIVERY CHARGES:

Service Charge:

$902.42 in each month [$962.21 including New Jersey Sales and Use Tax (SUT)]

Distribution Charge:

Net Alternative Delivery Cost multiplied by the applicable Net Alternative Delivery Cost Factor divided by the Contracted Monthly Therms rounded to the nearest $0.000000 per therm.

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 61 for details of these charges.

Maintenance Charges:

Equals the Alternative Delivery Cost multiplied by the applicable Alternative Delivery Cost Factor divided by the Contract Monthly Therms rounded to the nearest $0.000000 per therm.

Plus any customer site-specific ongoing or continuing cost not directly related to the operation, maintenance or inspection of the customer's planned by-pass pipeline. This shall include, but not be limited to, periodic payments for rights-of-way, easements, pipeline cost differentials, permits or other such costs. These charges shall be expressed on a monthly levelized basis over the term of service.

Public Service will also take into consideration any operational or deliverability differences that would be reasonably expected between the pipeline and/or service over Public Service's distribution system in determining Delivery Charges. In no event shall the Delivery Charges be lower than an amount sufficient to generate a return on the capital investments made by Public Service and recovery of marginal and embedded costs, including depreciation, to provide service to the customer over the term of each CSG agreement.

Balancing Charge:

Applicable only if the customer is provided Public Service's Basic Gas Supply Service – Firm (BGSS-F) default service.

Charge	Charge Including SUT	
$0.091830	$0.097914	per Balancing Use Therm

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by government. In appropriate circumstances, the Board of Public Utilities may approve a discount from the Societal Benefits Charge. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge and applicable exemptions.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs as approved by the Board. In appropriate circumstances, the Board of Public Utilities may approve a discount from the Green Programs Recovery Charge. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge and applicable exceptions.

(Charges are for illustrative purposes only and are based on the Eighteenth Revised Sheet No. 112A filed with the BPU on October 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 112B**

RATE SCHEDULE CSG
CONTRACT SERVICE
(Continued)

Tax Adjustment Credit:
This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current charge.

Distribution Adjustment Charge:
This charge is designed to recover Board-approved costs. Refer to the Distribution Adjustment Charge sheet of this Tariff for the current charge.

The Tax Adjustment Credit and the Distribution Adjustment Charge will be combined with the distribution charge for billing.

The Societal Benefits Charge and the Green Programs Recovery Charge will be combined for billing.

OTHER CONSIDERATIONS
DELIVERY CHARGES:
The Delivery Charges shall be set to be sufficient to recover revenues in excess of marginal costs for Public Service to provide service to the customer under this rate schedule. Delivery Charges will be based on agreement reached with Public Service and approved by the Board of Public Utilities.

COMMODITY CHARGES:
A customer may choose to receive gas supply from either:
a) A TPS who has agreed to the terms and conditions of the Third Party Supplier Requirements portion of this Tariff, or
b) For customers with a maximum requirement of less than 2,000 therms per hour, Public Service through its Basic Gas Supply Service default service. Such supply service may be either firm or interruptible. Public Service may also supply Emergency Sales Service in certain instances as indicated below.

Third Party Supply:
A customer that receives gas supply from a TPS will be charged for gas supply according to any agreement between the customer and the TPS. The customer will not be charged for commodity by Public Service, except as provided for in Emergency Sales Service below.

Emergency Sales Service:
Emergency Sales Service is only available for customers with a maximum requirement of less than 2,000 therms per hour.

In the event that, during any month, if Public Service cannot confirm that the customer has an eligible TPS, or if the TPS no longer satisfies the Third Party Supplier Requirements of this tariff, Public Service may supply the deficiencies as Emergency Sales Service.

Emergency Sales Service will be offered at the sole discretion of Public Service, after taking into consideration its other firm supply obligations. Public Service reserves the right to curtail service to any customer if deliveries from customer's TPS pursuant to Third Party Supplier Requirements are curtailed.

If a customer is receiving Emergency Sales Service and does not wish to designate a TPS for future deliveries or customer, for any reason, no longer desires to receive gas supply from a TPS, the customer may receive gas supply pursuant to Public Service's Basic Gas Supply Service.

The conditions under which Emergency Sales Service will apply are detailed in Section 14 - Third Party Supplier Service Provisions of the Standard Terms and Conditions of this Tariff, and the charges for this service are defined on the Emergency Sales Service sheet of this Tariff.

Basic Gas Supply Service:
A customer with a Maximum Requirement of less than 2,000 therms per hour that does not receive gas supply from a TPS will be supplied, at the customer's option, under either the Basic Gas Supply Service – Firm (BGSS-F) default service or the Basic Gas Supply Service-Interruptible (BGSS-I) default service as applicable based on whether Customer is being provided firm or interruptible service pursuant to this Rate Schedule. Refer to the Basic Gas Supply Service – Firm sheet of this Tariff for the current charge for BGSS-F commodity charge or to the Basic Gas Supply Service – Interruptible sheet of this Tariff for the current charge for BGSS-I commodity charge.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 112C**

RATE SCHEDULE CSG
CONTRACT SERVICE
(Continued)

OTHER CHARGES:
See Special Provision (f).

MINIMUM ANNUAL DISTRIBUTION CHARGE:
If customer's annual usage is less than 50% of the customer's Contract Monthly Therms multiplied by 12, then the customer will be billed for the difference between the actual annual therms and 50% of the customer's Contract Monthly Therms multiplied by 12 and then multiplied by the Distribution Charge. The Minimum Annual Distribution Charge, if applicable, will be billed at the end of the customer's annualized period. This charge applies to both Economically Viable Bypass customers and Other Consideration customers.

BILLING DETERMINANTS:

Therms:
The number of therms used shall be determined by multiplying the number of hundred cubic feet used by the conversion factor which appears on every bill. The conversion factor used for the "therm multiplier" shall be on the basis of the actual heating value of the gas used.

Balancing Use Therms:
Applicable only if the customer is provided Public Service's Basic Gas Supply Service – Firm (BGSS-F) default service.

During each of the billing months of October through May, if the average daily usage of gas in any month exceeds the average daily usage during the preceding billing months of June through September, the therms used in such month in excess of the product of the average daily usage in the preceding months of June through September times the number of days in the billing month shall be the Balancing Use Therms and subject to the Balancing Charge. For new customers and for customers who install additional gas burning equipment, the average daily usage in the preceding June through September time period to be used in the above calculation shall be estimated by Public Service.

Contract Monthly Therms:
Estimated annual therm usage (see Item 3, Tariff Sheet No. 112) determined as reasonable by Public Service divided by 12 and rounded to the nearest therm.

Alternative Delivery Cost:
a) For Firm Delivery Service: The estimated total up-front cost of the customer's bypass plan, based on a detailed cost estimate provided by the applicable interstate pipeline.
b) For Interruptible Delivery Service: The sum of 90% of the estimated total up-front cost of the customer's bypass plan, based on a detailed cost estimate provided by the applicable interstate pipeline, plus 10% of the incremental installed cost for Public Service to provide interruptible delivery service as estimated by Public Service.

Net Alternative Delivery Cost:
The Net Alternative Delivery Cost is equal to the Alternative Delivery Cost net of any customer contribution made to Public Service to provide service under this Rate Schedule without Public Service tax gross-up effects.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 112D**

RATE SCHEDULE CSG
CONTRACT SERVICE
(Continued)

Distribution Charge Factor: per $ of Net Alternative Delivery Cost

Term	Monthly Factor	Monthly Factor Including SUT
5 Years	$0.025583	$0.027278
10 Years	0.015773	0.016818
20 Years	0.010716	0.011426

Maintenance Charge Factor: per $ of Alternative Delivery Cost

Term	Monthly Charge	Monthly Charge Including SUT
5 Years	$0.000262	$0.000279
10 Years	0.000276	0.000294
20 Years	0.000300	0.000320

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill and subject to a late payment charge at the rate of 1.416% per monthly billing period in accordance with Section 8.13 of the Standard Terms and Conditions. Service to a body politic will not be subject to a late payment charge.

TERM:

Up to twenty years from the commencement date specified in the service agreement required by Special Provision (a), which length to be determined by agreement of the parties or, in the case of an economically viable physical bypass, based on the length of financing offered by the interstate pipeline company. The Distribution Charge and the Maintenance Charges as of the commencement date will remain unchanged for the term of the service agreement. The customer may terminate service by providing no less than one month's notice. Customers shall be required to make a termination payment for all such service terminated prior to the end of the Term equal to 50% of the sum of the Distribution Charge multiplied by the Contract Monthly Therms multiplied by the number of months remaining for the term of the service agreement. The termination payment shall be due to Public Service upon the date the termination becomes effective pursuant to the customer's notice.

SPECIAL PROVISIONS APPLICABLE TO ALL CUSTOMERS:

(a) Customer will be required to sign a service agreement and service will be restricted to the maximum daily capacity of the alternative delivery option used to determine the Monthly Distribution Charge. Deliveries in excess of the maximum specified in such service agreement will require the establishment of an additional new service agreement and related monthly charges, where such charges for such excess capacity shall be based upon the then current costs for such alternative delivery option and the then current pricing factor.

(b) Upon advanced written notice to Public Service, such service agreement shall be transferable to a new customer or owner of the facility at the location specified in the service agreement.

(c) Requests for a change between interruptible delivery service under this rate schedule to or from firm delivery service under this rate schedule will require the establishment of a new service agreement and new term of service based on the then current costs and pricing factor. There shall be no termination payment required related to a change from interruptible delivery service to firm delivery service under this rate schedule. A change from firm delivery service to interruptible delivery service will require a termination payment as detailed above.

(Charges are for illustrative purposes only and are based on the Original Sheet No. 112D filed with the BPU on November 1, 2018)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 112E**

RATE SCHEDULE CSG
CONTRACT SERVICE
(Continued)

(d) For customers with a maximum requirement of 2,000 therms per hour or greater, Public Service reserves the right to discontinue delivery service at any time the total imbalance cash-out amounts unpaid, including amounts billed and amounts not yet billed, by the customer's TPS are greater than 90% of the current credit Security amount held by Public Service for the customer's TPS in accordance with Section 5 of the Third Party Supplier Requirements of this tariff.

(e) Customers with a maximum requirement of 7,500 therms per hour or greater shall designate personnel physically located at the customer's facility having operational control of the gas usage at that facility who can be directly contacted by telephone or other electronic means at any hour of any day by Public Service. These personnel shall be responsible for coordinating the balancing of customer's gas consumption and deliveries by the customer's TPS and shall be the only party that Public Service contacts for all operational coordination requirements including those during periods of suspension or limitation and critical periods as detailed in Sections 6.3.2 and 6.3.3 of the Third Party Supplier Requirements of this tariff.

(f) Where the customer has selected BGSS-I as their gas supply option or is supplied interruptible delivery service under this rate schedule, the following shall apply:

(f-1) The customer shall provide a signed affidavit, certifying the specific grade of fuel oil (or oils), or other alternate fuel, that can physically and legally be utilized by the installation being served. This affidavit shall be a prerequisite for receiving service under this rate schedule and shall be furnished by the customer each fall no later than November 1st. The affidavit shall include the percentage of operation which can physically and legally be served by each alternate fuel. The customer will submit, within 30 days of change in operations, a new affidavit to Public Service when such change affects its alternate fuel capability. Additionally, the Affidavit shall require customers using No. 2 Fuel Oil, No. 4 Fuel Oil, jet fuel, or kerosene to provide certification that they have, and will maintain, either seven days of alternate fuel available through on-site storage capacity or additional firm contractual supply to make-up for any storage deficiencies so as to be equal to a seven day supply. Customers providing certification that they will suspend operations during an interruption are exempt from the alternate fuel requirement. Public Service reserves the right to inspect the customer's operation as to alternate fuel capability. Customers that fail to provide an affidavit by November 1st of each year shall continue to be subject to all of the terms of this rate schedule and in addition be subject to the Demand Charge as provided for in Rate Schedule LVG.

(f-2) Upon advance notice of eight hours or more, from any hour of any day given to customer by Public Service by telephone, or other electronic means, customer shall discontinue the use of gas until further notice; customer shall designate personnel who will accept such notification at any hour of any day.

(f-3) If customer does not discontinue the use of gas after notification pursuant to Special Provision (f-2) customer shall be charged $1.89 ($2.02 including SUT) per therm for an amount not to exceed one hour's maximum requirement per day of interruption. Use of this amount shall be limited to a use rate per hour not greater than 5% of customer's maximum hourly requirement.

The charge for all additional gas used shall be ten times the highest price of the daily ranges for delivery in Transco Zone 6, New York, or Texas Eastern Zone M-3 which are published in *Gas Daily* on the table "Daily Price Survey" for each therm of gas used by the customer. This rate shall not be lower than the maximum penalty charge for unauthorized daily overruns as provided for in the FERC-approved gas tariffs of the interstate pipelines which deliver gas into New Jersey.

(Charges are for illustrative purposes only and are based on the Original Sheet No. 112E filed with the BPU on November 1, 2018)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 112F**

RATE SCHEDULE CSG
CONTRACT SERVICE
(Continued)

If a customer supplied under Rate Schedule BGSS-I persistently does not discontinue the use of gas after notification pursuant to Special Provision (f-2), in addition to the aforementioned penalty charge, the customer will be notified that it no longer qualifies for service under interruptible supply service Rate Schedule BGSS-I. Applicable firm supply service will be available on a prospective basis under Rate Schedule BGSS-F subject to the availability of supply and delivery capacity.

Except for pilots, however, Public Service has no obligation to deliver gas at any time following notice pursuant to Special Provision (f-2) and may discontinue completely all other deliveries of gas to customer during the period of interruption.

(g) Unless otherwise agreed to by Public Service, metering shall include a recording device, furnished by Public Service. Customer shall furnish an electrical supply for the operation of the recording device.

(h) Service supplied under this rate schedule shall be separately metered and shall not be combined with use under any other rate schedule for billing purposes. Customer shall not be eligible to receive service under this rate schedule and any other rate schedule for the same equipment or for equipment supplying a common steam header.

(i) Service under this rate schedule is not available for resale.

SPECIAL PROVISIONS APPLICABLE TO CUSTOMERS SERVED BY THIRD PARTY SUPPLIERS FOR COMMODITY SERVICE:

(j) The customer must contract with a TPS to arrange for deliveries to Public Service of their daily usage, adjusted for losses, and such TPS agrees to abide by the provisions of the Third Party Supplier Requirements. A customer is limited to one (1) TPS for gas for each account for which the customer receives delivery service.

(k) The customer's TPS is required to notify Public Service of the customer's selection prior to the last business day of the month for deliveries to commence on the first (1st) of the next month, and such selection shall remain in effect for the entire month, subject to the conditions of Emergency Sales Service. Customers eligible to receive Emergency Sales Service can change TPSs effective only on the first day of the month. Customers not eligible to receive Emergency Sales Service can change TPSs at any time in the event that their TPS fails to deliver supply.

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 15 of the Standard Terms and Conditions for additional details and/or exceptions.

THIRD PARTY SUPPLIER REQUIREMENTS:

TPSs are subject to the Third Party Supplier Requirements of this Tariff.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff except Section 7.6, Appliance Adjustments.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 113**

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 114**

THIRD PARTY SUPPLIER REQUIREMENTS

1. GENERAL

A Third Party Supplier (TPS) of natural gas is an entity that has contracted with customers of Public Service to deliver supplies of natural gas to interconnection points with Public Service's distribution system, or is a customer who is self-supplying and acting as a TPS on their own behalf in purchasing and transporting natural gas to interconnection points with Public Service's distribution system, from which Public Service may receive and physically transport and deliver on a firm basis these gas supplies to the customer pursuant to Rate Schedules RSG, SLG, GSG, LVG, TSG-F, or CSG and on an interruptible basis to customers pursuant to Rate Schedules TSG-NF or CSG. In order for an entity to qualify as a TPS it must execute an Application for Service and satisfy Public Service's credit requirements as noted herein. In order for a customer to qualify to self-supply, the Public Service customer of record for gas delivery service must be served on Rate Schedule TSG-NF or CSG and must be the same corporate entity that is purchasing and transporting the natural gas to interconnection points with Public Service's distribution system. A self-suppling customer must meet all of the TPS requirements herein, except the requirement for licensure by the Board of Public Utilities. TPSs, other than qualifying self-supplying customers, must be licensed by the Board of Public Utilities (Board).

A TPS must successfully complete all Electronic Data Interchange testing in order to enroll new customers that receive service under Rate Schedules RSG, GSG, LVG, SLG, TSG-F, TSG-NF, and CSG.

TPSs agree to abide by the Board's regulations and with <u>N.J.A.C.</u> 14:4 *et seq*., *Energy Competition,* including but not limited to Subchapter 7 *Retail Choice Consumer Protection.* Public Service is not responsible for the administration or the enforcement of either of the aforementioned regulations or Code.

2. CUSTOMER CONFIRMATION

By the twenty-second (22nd) of each month, for service to RSG, SLG, GSG, or LVG which is to commence on the first (1st) of the next calendar month, Public Service will provide to each TPS by electronic or other means, as specified by Public Service, a list which includes: (1) those customers who have requested to be served by that particular TPS and have represented that they have a contractual relationship with that TPS, including their required Daily Contract Quantity (DCQ), expressed in therms; (2) former customers' applicable imbalances, expressed in therms; and (3) the TPS's Aggregate Daily Contract Quantity (ADCQ), adjusted for losses, expressed in dekatherms, equal to the sum of the DCQ's of each of the customers of that TPS. TPS will be required to notify Public Service by electronic or other means, as specified by Public Service, by the twenty-second (22nd) of the month as to any corrections or changes to their list of customers, otherwise the list will be assumed to be accurate. Public Service will only amend the list of customers and their respective DCQ's in accordance with the above procedures prior to the next month if a good faith dispute arises concerning the respective TPS's list.

Public Service will provide to each TPS by electronic or other means, as specified by Public Service, a list which includes those TSG-F, TSG-NF, and CSG customers who have requested to be served by that particular TPS and have represented that they have a contractual relationship with that TPS.

3. DELIVERY

3.1 **General:** Subject to the Force Majeure provisions in Section 7, TPS must deliver to Public Service on each day of the month at points specified on Public Service's distribution system, which points are operationally acceptable to Public Service in its sole discretion, the ADCQ for its RSG, SLG, GSG, and LVG customers and the daily or, under certain circumstances, the hourly usage of its TSG-F, TSG-NF, and CSG customers, adjusted for losses (hereinafter collectively referred to as "usage"). Failure to comply with this provision shall subject TPS to the cash-out pursuant to Sections 6.1, 6.2, and/or 6.3.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 115**

THIRD PARTY SUPPLIER REQUIREMENTS
(Continued)

3.2. **Warranty of Title:** TPS warrants that, at the time of delivery of gas to Public Service, it will have good title to deliver all gas volumes made available.

3.3. **Delivery Control and Possession:** After TPS delivers gas or causes gas to be delivered to Public Service at Public Service's point of interconnection with the applicable interstate pipeline, Public Service will be deemed to be in control and possession of the gas until an equivalent amount of gas, less losses, is delivered to customer at customer's Public Service meter.

3.4. **Delivery Liability:** Public Service shall in no way be liable for any errors in the calculation of the DCQ or ADCQ, nor be responsible for any additional gas costs incurred by TPS due to any error in the calculation of the DCQ or ADCQ.

3.5. **Delivery Allocation:** On each day deliveries of gas by TPS to Public Service shall be first allocated to TPS's ADCQ on such day and any remaining volume shall be allocated to TPS's TSG-F, TSG-NF, and CSG customers.

4. NOMINATION PROCEDURES

4.1. **General:** Unless otherwise provided for under section 4.3, Public Service will provide TPS(s) notice by July 1 of each year of the allocation of receipt capacity by pipeline that it expects to have available for all deliveries by TPS(s) at its city gate interconnections, based on existing contractual commitments, for the twelve (12) month period beginning the following November 1. Each TPS(s) will be allocated the receipt capacity based on the total expected firm and interruptible load versus the amount of available receipt capacity.

TPS will be credited for deliveries to Public Service on each day in accordance with the final daily volume confirmations of the interstate pipelines designated by TPS pursuant to this Sub-section.

4.2. **TPS Nomination Requirements:** TPS will be required to nominate to Public Service by electronic or other means, as specified by Public Service, the total volume it intends to deliver to Public Service for subsequent delivery, along with the interstate pipelines it intends to utilize for this delivery and any additional information required by Public Service to fully identify such deliveries. TPS shall nominate to Public Service by 2:30 p.m. Eastern Time prior to the day gas is scheduled to flow (ie. the "Gas Day", defined as the 24 hour period commencing at 10:00 AM Eastern Time). TPS will be permitted to submit requests to modify nominations after the 2:30 pm deadline for supplies for the Gas Day, which may include modifications to both pipeline contracts and volumes. Such modifications will be consistent with the prevailing NAESB protocols, of 7:00 PM Eastern Time on the day prior to the Gas Day, and 11:00 AM Eastern Time ("Intra-day 1"), 3:30 PM Eastern Time ("Intra-day 2"), and 8:00 PM Eastern Time ("Intra-day 3") during the Gas Day. Any such requests for modifications to nominations for a Gas Day must be submitted in writing and received by Public Service up until 8:00 PM Eastern Time during the applicable Gas Day. Public Service will not be obligated to accept gas which has not been nominated in accordance with this Section. In any event, Public Service may refuse any revision in the nomination made during the day of delivery for operating reasons, and if, in its sole opinion, such revision is not related to the customer balancing its supplies and usage for the day.

Public Service will accept deliveries of gas for customers on the interstate pipelines of Transco or Texas Eastern. However, due to delivery limitations, Public Service reserves the right to require a reasonable apportionment of deliveries between Transco and Texas Eastern.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 116**

THIRD PARTY SUPPLIER REQUIREMENTS
(Continued)

5. CREDIT REQUIREMENTS

5.1. **General:** Public Service's acceptance of a request for service under these Third Party Supplier Requirements is contingent upon TPS providing Security in an amount determined by Public Service.

A TPS may provide one of the following additional credit assurances to meet its Security obligation: (1) an advance cash deposit; or (2) a standby irrevocable letter of credit.

5.2. **Credit Amount:** The total Security at all times must be of an amount not less than the product of the TPS's Daily Requirements, expressed in dekatherms, and $70.00, plus the amount of balancing cash-out obligations outstanding to Public Service, whether billed or not billed, such total amount rounded down to the next lower multiple of $15,000. Daily Requirements is defined as the sum of the TPS's maximum month ADCQs for RSG, SLG, GSG and LVG customers and the total of the maximum month average daily usage for TSG-F, TSG-NF, and CSG customers, as stated in their respective service agreements. At any time, the maximum month's value shall be the greatest total ADCQ or average daily usage, as applicable, in the prior 12 month period (otherwise known as a rolling 12 month period).

If, at any point in time, the TPS's Daily Requirements decreases, TPS has the option to reduce the level of the Security to the product of the new Daily Requirements and $70.00, after all the outstanding obligations payable to Public Service are satisfied.

In all cases, any required increase in the level of Security must be satisfied within two (2) business days after receipt of the Public Service notice for additional Security requirements to continue service. If such Security is not posted in accordance with the foregoing, then Public Service is not required to continue service.

5.3. **Interest:** Interest, on cash deposited with Public Service as Security, will be the lower of the average Federal Funds Effective Rate (as published daily on the Federal Reserve website) for the period of time the funds are on deposit or six (6) percent. Cash deposits shall cease to bear interest upon discontinuance of service by the TPS or, if earlier, when Public Service closes the account. When the executed service agreement is terminated or when a portion of the cash deposit is returned to the TPS, such cash deposits will be returned with accrued interest upon payment or deduction of all charges and other debts that the TPS might owe Public Service.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 117**

THIRD PARTY SUPPLIER REQUIREMENTS
(Continued)

5.4. Failure to Deliver for Customers on Rate Schedules RSG, SLG, GSG, and LVG: In the event that, for a particular TPS, at any time, the sum of the cumulative imbalances, for non Force Majeure reasons, which Public Service has not yet received payment are underdeliveries that exceed three (3) times the ADCQ, Public Service will immediately notify the TPS via telephone, electronic, or similar means. If such underdeliveries reach five (5) times the ADCQ, the following will occur: (1) the TPS is no longer eligible for these Third Party Supplier Requirements unless and until the conditions below are satisfied, but not before the first (1st) day of the following month; and (2) for the balance of the current month, the affected TPS's customers will be supplied natural gas by Public Service and will be billed for Emergency Sales Service pursuant to their rate schedules for their DCQ times the number of days remaining in the current month. Such customers will continue to be charged the Emergency Sales Service rate until TPS service commences from an eligible TPS pursuant to Section 14.3 of the Standard Terms and Conditions or from BGSS default service pursuant to Section 14.5 of the Standard Terms and Conditions.

In order to be reinstated as an eligible TPS following an occurrence of an under-delivery event as described above, the former TPS, in addition to meeting all other applicable tariff requirements must post and maintain for a one (1) year period Security in an amount equal to two (2) times that otherwise required pursuant to Section 5.2 of these Third Party Supplier Requirements. At the conclusion of that year and assuming no additional occurrence of an under-delivery event as described above, TPS's requirement regarding maintenance of the Security will be returned to that described in Section 5.2. If an additional under-delivery event as described above occurs during that year period, the TPS will be ineligible for these Third Party Supplier Requirements for an additional one (1) year period.

5.5. Failure to Deliver for Customers on Rate Schedules TSG-F, TSG-NF, and CSG: In the event that, for a particular TPS, at any time, the amount of obligations outstanding to Public Service, whether billed or not billed, exceed 70% of the current level of Security, Public Service will immediately notify the TPS via telephone, electronic, or similar means.

At this time the TPS will be given the option to increase the total amount of Security held by Public Service to the required amount as described in Section 5.2 of these TPS Requirements within two (2) business days or to provide immediate payment on outstanding amounts, whether billed or not billed, due to Public Service.

At such time the amount of obligations outstanding to Public Service, whether billed or not billed, exceed 100% of the current level of Security, the TPS is no longer eligible under these Third Party Supplier Requirements unless and until the conditions below are satisfied, but not before the first (1st) day of the following month. The affected TPS's customers eligible for Emergency Sales Service will be supplied natural gas by Public Service for their usage for the remainder of the month. Such customers will continue to be charged the Emergency Sales Service rate until TPS service commences from an eligible TPS or from BGSS default service. Delivery service to customers not eligible for Emergency Sales Service will be ceased until such customers arrange for gas supplies from an eligible TPS.

In order to be reinstated as an eligible TPS following an occurrence of event as described above, the former TPS, in addition to meeting all other applicable tariff requirements must post and maintain for a one (1) year period Security in an amount equal to two (2) times that otherwise required pursuant to Section 5.2 of these Third Party Supplier Requirements. At the conclusion of that year and assuming no additional occurrence of an event in which outstanding obligations, whether billed or not billed, exceed Security as described above, TPS's requirement regarding maintenance of the Security will be returned to that described in Section 5.2.

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THIRD PARTY SUPPLIER REQUIREMENTS
(Continued)

If an additional event in which outstanding obligations, whether billed or not billed, exceed Security as described above occurs during that year period, the TPS will be ineligible under these Third Party Supplier Requirements for an additional one (1) year period.

6. IMBALANCE CASH-OUT PROCEDURES

6.1. TPS Imbalance Cash-out for Customers on Rate Schedules RSG, SLG, GSG, and LVG: On any day that TPS delivers a volume other than the aggregate of the ADCQs, of its RSG, SLG, GSG and LVG customers, the TPS will be subject to a daily cash-out as follows:

6.1.1. Over deliveries: On any day that TPS delivers a volume greater than the aggregate of the ADCQs, of its RSG, SLG, GSG and LVG customers, the TPS will be subject to a daily cash-out as follows:

The TPS will be cashed out each day for over delivered quantity of gas (in dekatherms) at cost based on an index. The index shall be the weighted average of the minimum of the "Common" range values stated in the Final Daily Price Survey section of Platt's Gas Daily for Texas Eastern M-3 and Transco Zone 6 New York for that day. The weights in the calculation shall be the required percentages of deliveries at the Texas Eastern M-3 and Transco Zone 6 New York delivery points.

For over deliveries of the ADCQ of less than 5% the PSE&G will cash out the TPS for the excess gas at 90% the index. For over deliveries of the ADCQ greater than or equal to 5% but less than 15% PSE&G will cash out the TPS for the excess gas at 75% of the index. For over deliveries of the ADCQ greater than or equal to 15% but less than 25%, PSE&G will cash out the TPS for the excess gas at 50% of the index. For over deliveries of the ADCQ greater than or equal to 25%, PSE&G will cash out the TPS for the excess gas at 40% of the index.

6.1.2. Under deliveries: The TPS will be cashed out each day for under delivered quantity of gas (in dekatherms) at cost based on an index. The index shall be the weighted average of the maximum of the "Common" range values stated in the Final Daily Price Survey section of Platt's Gas Daily for Texas Eastern M-3 and Transco Zone 6 New York for that day. The weights in the calculation shall be the required percentages of deliveries at the Texas Eastern M-3 and Transco Zone 6 New York delivery points.

For under deliveries of the ADCQ of less than 5% PSE&G will cash out the TPS for the deficiency at 110 % of the index cost times the under delivered quantity. For under deliveries of greater than or equal to 5%, PSE&G will cash out the TPS for the deficiency at 200% of the index.

6.1.3. Balancing during Critical Periods: Upon no less than eight (8) hours' notice, Public Service may on any days that it determines that its gas supply condition is critical, declare such days to be a "Critical Period." For any under deliveries by a TPS greater than two (2) percent of the ADCQ during a Critical Period, the TPS will pay a charge per dekatherm at a rate equal to ten times the daily price index calculated in paragraph 6.1.1. The resulting price index shall not be lower than the maximum penalty charge for unauthorized daily overruns as provided for in the FERC- approved gas tariffs of the interstate pipelines which deliver gas into New Jersey. In addition, Public Service has the right to recover proportionately from undelivered TPSs any penalties or other charges or damages assessed on Public Service as a result of any under deliveries by eligible TPSs. For all over deliveries by an eligible TPS greater than two (2) percent of the ADCQ during a Critical Period, the TPS will be cashed out at the minimum of the "Common" range values stated in the Final Daily Price Survey section of Platt's Gas Daily for Transco Leidy Line Receipts for that day.

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THIRD PARTY SUPPLIER REQUIREMENTS
(Continued)

6.2. TPS Imbalance Cash-out for Customers with a Maximum Requirement of Less Than 7,500 Therms Per Hour on Rate Schedules TSG-F, TSG-NF, and CSG: TPS is responsible to deliver gas to Public Service for their applicable customers at the same daily rate that the aggregate of their applicable customers are utilizing gas. The Daily Cash-out Price for over- or under deliveries by a TPS for any day will be the weighted average of the higher of lower of the “Common” range values stated in the Final Daily Price Survey section of Platt’s *Gas Daily* for Texas Eastern M-3 and Transco Zone 6 New York for that day. The weights for the weighted average shall be the required percentages of natural gas delivered on the Texas Eastern and Transco pipelines. Under any circumstance, Public Service has the right to recover proportionately from undelivered TPSs any penalties or other charges or damages assessed on Public Service as a result of any underdeliveries by eligible TPSs.

Public Service, in its sole discretion, may refuse to accept any deliveries of gas which it determines to be excess to a TPS’s customers’ daily usage.

6.2.1. Normal Daily Balancing for Under-deliveries: The TPS will be cashed out each day for the under delivered quantity of gas (in dekatherms) at cost based on an index. The index shall be the weighted average of the maximum of the “Common” range values stated in the Final Daily Price Survey section of Platt’s Gas Daily for Texas Eastern M-3 and Transco Zone 6 New York for that day. The weights in the calculation shall be the required percentages of deliveries at the Texas Eastern M-3 and Transco Zone 6 New York delivery points.

PSE&G will cash out the TPS for under deliveries based upon the level of under delivery. For any imbalance level, the total cost will be the sum of costs for all prior levels of under-delivery.

Imbalance Level	Cost to TPS
0% to < 5%	Under delivered volume (dth) < 5% * 1.0 * index
≥ 5% to < 15%	5% ≤ under delivered volume < 15% * 1.25 * index
≥ 15 % to < 25%	15% ≤ under delivered volume < 25% * 1.5 * index
≥ 25%	25% ≤ under delivered volume * 2.0 * index

6.2.2. Normal Daily Balancing for Over-deliveries. The TPS will be cashed out each day for the over delivered quantity of gas (in dekatherms) at cost based on an index. The index shall be the weighted average of the minimum of the “Common” range values stated in the Final Daily Price Survey section of Platt’s Gas Daily for Texas Eastern M-3 and Transco Zone 6 New York for that day. The weights in the calculation shall be the required percentages of deliveries at the Texas Eastern M-3 and Transco Zone 6 New York delivery points.

PSE&G will cash out the TPS for under deliveries based upon the level of over delivery. For any imbalance level, the purchase credit will be the sum of credits for all prior levels of over-delivery.

.Imbalance Level	Credit to TPS
0% to < 5%	Over delivered volume (dth) < 5% * 1.0 * index
≥ 5% to < 15%	5% ≤ over delivered volume < 15% * 0.75 * index
≥ 15 % to < 25%	15% ≤ over delivered volume < 25% * 0.5 * index
≥ 25%	25% ≤ over delivered volume * 0.4 * index

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THIRD PARTY SUPPLIER REQUIREMENTS
(Continued)

6.2.3. Balancing During Critical Periods: Upon no less than eight (8) hours' notice to the TPS, Public Service may on any day that it determines that its gas supply condition is critical, declare such days to be a "Critical Period". During such a Critical Period all under deliveries by the TPS greater than two (2) percent will be cashed out at ten times the Daily Cash-out Price. The price for under deliveries shall not be lower than the maximum penalty charge for unauthorized daily overruns as provided for in the FERC-approved gas tariffs of the interstate pipelines which deliver gas into New Jersey. All over deliveries of greater than two (2) percent will be cashed out at the minimum of the "Common" range values stated in the Final Daily Price Survey section of Platt's Gas Daily for Transco Leidy Line Receipts for that day.

6.3. TPS Imbalance Cash-out for Customers with a Maximum Requirement of 7,500 Therms Per Hour and Greater on Rate Schedules TSG-F, TSG-NF, and CSG: TPS is responsible to deliver gas to Public Service for each of their applicable customers at the same daily rate each customer is utilizing gas. Except as provided for in Section 6.3.5 below, or as specified in the applicable TSG-NF or CSG agreement, all balancing and cash-out calculations shall be performed separately for each applicable customer. The basis for the Daily Cash-out Price for over- or under deliveries by a TPS will be the weighted average of the higher or lower of the "Common" range value(s) for Texas Eastern M-3 and/or Transco Zone 6 New York, as applicable. The weights for the weighted average shall be based upon the required delivery on the interstate pipeline(s) by the TPS, as published in Platt's *Gas Daily* on the table "Final Daily Price Survey". Under any circumstance, Public Service has the right to recover proportionately from undelivered TPSs any penalties or other charges or damages assessed on Public Service as a result of any under deliveries by eligible TPSs.

If at any time customer's TPS fails to deliver, or arrange for delivery of a quantity of gas, which is consistent with the quantity of gas being consumed by customer, Public Service, in its sole discretion, may suspend deliveries of gas to customer until such time as the delivery of gas to Public Service is equal to the quantity of gas being consumed by customer commences. Public Service, in its sole discretion, may refuse to accept any deliveries of gas which it determines to be excess to a TPS's customers' daily usage.

6.3.1. Normal Daily Balancing for Under-deliveries: The TPS will be cashed out each day for the under delivered quantity of gas (in dekatherms) at cost based on an index. The index shall be the weighted average of the maximum of the "Common" range values stated in the Final Daily Price Survey section of Platt's Gas Daily for Texas Eastern M-3 and Transco Zone 6 New York for that day. The weights in the calculation shall be the required percentages of deliveries at the Texas Eastern M-3 and Transco Zone 6 New York delivery points.

PSE&G will cash out the TPS for under deliveries based upon the level of under delivery. For any imbalance level, the total cost will be the sum of costs for all prior levels of under-delivery.

Imbalance Level	Cost to TPS
0% to < 5%	Under delivered volume (dth) < 5% * 1.0 * index
≥ 5% to < 15%	5% ≤ under delivered volume < 15% * 1.25 * index
≥ 15 % to < 25%	15% ≤ under delivered volume < 25% * 1.5 * index
≥ 25%	25% ≤ under delivered volume * 2.0 * index

THIRD PARTY SUPPLIER REQUIREMENTS
(Continued)

6.3.2. Normal Daily Balancing for Over-deliveries: The TPS will be cashed out each day for the over delivered quantity of gas (in dekatherms) at cost based on an index. The index shall be the weighted average of the minimum of the "Common" range values stated in the Final Daily Price Survey section of Platt's Gas Daily for Texas Eastern M-3 and Transco Zone 6 New York for that day. The weights in the calculation shall be the required percentages of deliveries at the Texas Eastern M-3 and Transco Zone 6 New York delivery points.

PSE&G will cash out the TPS for under deliveries based upon the level of over delivery. For any imbalance level, the purchase credit will be the sum of credits for all prior levels of over-delivery

. Imbalance Level	Credit to TPS
0% to < 5%	Over delivered volume (dth) < 5% * 1.0 * index
≥ 5% to < 15%	5% ≤ over delivered volume < 15% * 0.75 * index
≥ 15 % to < 25%	15% ≤ over delivered volume < 25% * 0.5 * index
≥ 25%	25% ≤ over delivered volume * 0.4 * index

6.3.3. Balancing During Periods of Suspension or Limitation: If at any time any customer is consuming gas at a rate other than a uniform hourly rate or consuming gas at a rate that doesn't correspond with the customer's TPS' deliveries, and Public Service determines that in its sole judgment that the integrity of all or a portion of its gas distribution system is being jeopardized because of such action, or the interstate pipeline upon which such gas is being delivered to Public Service enforces uniform hourly take restrictions, Public Service may limit the total amount of gas delivered to a TPS's customer to the same hourly rate at which the TPS is delivering gas to the Public Service gas system.

Public Service will provide the TPS two hours' notice that it intends to suspend or limit deliveries of gas to one or more customers, except in the case of an emergency on the Public Service gas distribution system or when the interstate pipeline enforces uniform hourly take provisions, in which case the TPS shall be notified as soon as practicable. Such notice from Public Service shall indicate the action Public Service intends to take with respect to suspending or limiting deliveries to a customer, the estimated time period of such suspension or limitation, and the time when such suspension or limitation shall go into effect.

If, during such a period of suspension or limitation of service, the TPS delivers a quantity of gas that is inconsistent with such suspension or limitation, then all under deliveries by the TPS greater than two (2) percent will be cashed out at five times the Daily Cash-out Price. All over deliveries of greater than two (2) percent will be cashed out at the minimum of the "Common" range values stated in the Final Daily Price Survey section of Platt's Gas Daily for Transco Leidy Line Receipts for that day.

6.3.4. Balancing During Critical Periods: Upon no less than eight (8) hours' notice to the TPS, Public Service may on any day that it determines that its gas supply condition is critical, declare such days to be a "Critical Period". During such a Critical Period all under deliveries by the TPS greater than two (2) percent will be cashed out at ten times the Daily Cash-out Price. The price for under deliveries shall not be lower than the maximum penalty charge for unauthorized daily overruns as provided for in the FERC-approved gas tariffs of the interstate pipelines which deliver gas into New Jersey. All over deliveries of greater than two (2) percent will be cashed out at the minimum of the "Common" range values stated in the Final Daily Price Survey section of Platt's Gas Daily for Transco Leidy Line Receipts for that day.

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THIRD PARTY SUPPLIER REQUIREMENTS
(Continued)

6.3.5. Designated Personnel: The customer's designated personnel having operational control of the gas usage at that facility shall be responsible for coordinating the balancing of customer's gas consumption and deliveries by the customer's TPS. Such personnel shall be the only party that Public Service contacts for all operational coordination requirements, including those during periods of Suspension or Limitation and Critical Periods as detailed in Sections 6.3.2 and 6.3.3.

6.4. Cash-out Billing and Payment: Public Service will invoice the TPS any cash-out costs and these charges are due within ten (10) days of the date of Public Service's invoice. Such bills will be subject to a late payment charge at the rate of 1.416% per monthly billing period in accordance with Section 8.13 of the Standard Terms and Conditions. Public Service has the right to call on Security in an amount equal to all unpaid cash out costs within 30 days of issuance of the cash-out invoice unless Public Service has agreed in writing to extend the period for repayment. Public Service will notify the TPS of the amount of the Security used and the amount of additional security that the TPS shall be required to post. The TPS is required to replenish this Security withing two (2) business days as described in Section 5.2 of these Third Party Supplier requirements.

It is the obligation of the TPS to provide Public Service with contact information for cash-out billing annually, and timely notification of any subsequent change to those billing contacts.

Notwithstanding the above, Public Service maintains the right to suspend transportation deliveries to any customer under Rate Schedules RSG, SLG, GSG, LVG, TSG-F, TSG-NF, and CSG from a particular TPS, and return such customers to BGSS, if in Public Service's sole opinion that TPS is not satisfying the TPS requirements as specified herein. Such TPS may also be disqualified from enrolling new customers.

7. FORCE MAJEURE

If an interstate pipeline that deliveries gas to PSE&G's system has declared a Force Majeure event, pursuant to the terms of that pipeline's FERC approved tariff, that substantially affects the ability of a TPS to deliver the required ADCQ on any given day, Public Service may

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

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THIRD PARTY SUPPLIER REQUIREMENTS
(Continued)

excuse a TPS from performing pursuant to Sections 6.1, 6.2 and 6.3 of these Third Party Supplier Requirements to the extent of such curtailment, and may cash-out the TPS for related under-deliveries at the higher of the (i) weighted average of the maximum of the “Common” range values stated in the Final Daily Price Survey section of Platt’s Gas Daily for Texas Eastern M-3 and Transco Zone 6 New York for that day (the weights in the calculation shall be the required percentages of deliveries at the Texas Eastern M-3 and Transco Zone 6 New York delivery points), or (ii) the Company’s average cost of supply for the period in question (inclusive of any pipeline penalties assessed on the Company). The TPS is responsible for supplying complete information and verifiable proof of all the particulars requested by Public Service related to any such Force Majeure exclusion. The TPS must have a firm, non-interruptible service with the affected pipeline that is covered by the Force Majeure event and must be willing to present such agreements to Public Service.

8. STANDARD TERMS AND CONDITIONS

These Third Party Supplier Requirements are subject to the Standard Terms and Conditions of this Tariff, as applicable.

Item	Sheet No.		Description
Table of Contents	Original Sheet No. 2		Updated page numbers and inserted line for proposed new Distribution Adjustment Charge
Standard Terms & Conditions	Original Sheet No. 9		Updated the address for Board of Public Utilities.
			Updated methods for application of service
	Original Sheet No. 14		§ 3.7.1. a) Correction to holding deposits without interest
	Original Sheet No. 19		§ 6.3. – Added language to ensure Company access to meters
	Original Sheet No. 22		§ 8.3.1. – Specifying circumstances in which individual metering will be required
	Original Sheet No. 26		§ 8.16. – Added Customer's Responsibility to Cooperate with the Company
			§ 9. – Added instructions and contact number for gas leaks
			§ 10.1. – Added requirement for customer to furnish drivable surfaces for Company equipment to access sites
	Original Sheet Nos. 26 to 28		Updated Discontinuance of Service language to reflect N.J.A.C. 14:3-3A
Clauses			
Weather Normalization Charge	Original Sheet Nos. 45 to 47		Removed Charge as it is replaced by Conservation Incentive Program
Distribution Adjustment Charge	Original Sheet No. 52		Added the Distribution Adjustment Charge
Supply			
BGSS-F	Original Sheet No. 55		Removed language "For Rate Schedule CSG"
BGSS-I	Original Sheet No. 56		Removed language "For Rate Schedule CSG"
Emergency Sales Service	Original Sheet No. 58		Removed language "For Rate Schedule CSG"
Infrastructure Improvement Program Charges (Continued)	Original Sheet No. 61		Made formatting consistent among rate schedules
			Removed BGSS-RSG as it is impacted by multiple other factors
Delivery			
Rate Schedule RSG	Original Sheet No. 66		Added the Distribution Adjustment Charge to applicable clauses
			Corrected language regarding bundling of CIP rate for billing
Rate Schedule GSG	Original Sheet No. 73		Added inclusion of the Distribution Adjustment Charge to applicable clauses
			Corrected language regarding bundling of CIP rate for billing
	Original Sheet No. 76		Corrected reference to New Jersey Statutes Annotated
Rate Schedule LVG	Original Sheet No. 80		Added the Distribution Adjustment Charge to applicable clauses
			Corrected language regarding bundling of CIP rate for billing
	Original Sheet No. 83		Corrected reference to New Jersey Statutes Annotated

Item	Sheet No.		Description
Rate Schedule SLG	Original Sheet No. 88		Added the Distribution Adjustment Charge to applicable clauses
Rate Schedule TSG-F	Original Sheet No. 94		Added the Distribution Adjustment Charge to applicable clauses
Rate Schedule TSG-NF	Original Sheet No. 99		Added the Distribution Adjustment Charge to applicable clauses
	Original Sheet No. 100		Added language limiting customers taking Basic Gas Supply Service to a maximum of 2,000 therms per hour
	Original Sheet No. 102		Added requirement for customers switching to firm service to remain on firm service for one year
Rate Schedule CIG	Original Sheet No. 107		Added the Distribution Adjustment Charge to applicable clauses
	Original Sheet No. 109		Added requirement for customers switching to firm service to remain on firm service for one year
	Original Sheet No. 110		Defined Commodity Charge when gas is supplied under Extended Gas Service
	Original Sheet No. 111		Removed “facsimile machine” as it is no longer used and clarified that communications would be conducted electronically
Rate Schedule CSG	Original Sheet No. 112B		Added the Distribution Adjustment Charge to applicable clauses
	Original Sheet No. 112C		Added language to clarify that the Minimum Annual Distribution Charge applies to both Economically Viable Bypass customers and Other Consideration customers
	Original Sheet No. 112E		Removed “telegram” as it is no longer used and clarified that communications would be conducted electronically
	Original Sheet No. 112F		Removed Rate Schedule CSG Periodic Update
Third Party Supplier Requirements			
Nomination Procedures	Original Sheet No. 115		§ 4.2. Added definition of a “Gas Day” and additional language to TPS Nomination Requirements
	Original Sheet Nos. 115 to 116		Removed § 4.3. TPS Nomination Requirements for Customers with a Maximum Requirement of 7,500 Therms Per Hour and Greater
Credit Requirements	Original Sheet No. 116		Added Security obligations for Third Party Suppliers
	Original Sheet No. 117		Changed “facsimile” to “electronic”
Imbalance Cash-Out Procedures	Original Sheet No. 118		§ 6.1.3. Changed “Under deliveries” to “Balancing” and specified the price reference during critical periods
	Original Sheet No. 120		Specified price reference during critical periods
	Original Sheet No. 121		§ 6.3.3. Added language addressing imbalance; § 6.3.4. Specified price reference during critical periods
	Original Sheet No. 122		§ 6.3.6. Deleted Pooling language as it is not commonly used now
			§ 6.4. Added language to Cash-out Billing and Payment
Force Majeure	Original Sheet Nos. 122 to 123		Revised language describing applicable scenarios

TARIFF

FOR

GAS SERVICE

Applicable in

Territory served as shown on

Sheet Nos. 3 through 6 of this Tariff

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

GENERAL OFFICES

80 PARK PLAZA

NEWARK, NEW JERSEY 07102

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 2**

TABLE OF CONTENTS

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Filed pursuant to Order of Board of Public Utilities dated
in Docket No.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 3**

TERRITORY SERVED

BERGEN COUNTY

Allendale, Borough of
Alpine, Borough of
Bergenfield, Borough of
Bogota, Borough of
Carlstadt, Borough of
Cliffside Park, Borough of
Closter, Borough of
Cresskill, Borough of
Demarest, Borough of
Dumont, Borough of
East Rutherford, Borough of
Edgewater, Borough of
Elmwood Park, Borough of
Emerson, Borough of
Englewood, City of
Englewood Cliffs, Borough of
Fair Lawn, Borough of
Fairview, Borough of
Fort Lee, Borough of
Franklin Lakes, Borough of
Garfield, City of
Glen Rock, Borough of
Hackensack, City of
Harrington Park, Borough of
Hasbrouck Heights, Borough of
Haworth, Borough of
Hillsdale, Borough of
Ho-Ho-Kus, Borough of
Leonia, Borough of
Little Ferry, Borough of
Lodi, Borough of
Lyndhurst, Township of
Mahwah, Township of
Maywood, Borough of
Midland Park, Borough of
Montvale, Borough of
Moonachie, Borough of
New Milford, Borough of
North Arlington, Borough of
Northvale, Borough of
Norwood, Borough of
Oakland, Borough of
Old Tappan, Borough of
Oradell, Borough of
Palisades Park, Borough of
Paramus, Borough of
Park Ridge, Borough of
Ramsey, Borough of
Ridgefield, Borough of
Ridgefield Park, Village of
Ridgewood, Village of
River Edge, Borough of
River Vale, Township of
Rochelle Park, Township of
Rockleigh, Borough of
Rutherford, Borough of
Saddle Brook, Township of
Saddle River, Borough of
South Hackensack, Township of
Teaneck, Township of
Tenafly, Borough of
Teterboro, Borough of
Upper Saddle River, Borough of
Waldwick, Borough of
Wallington, Borough of
Washington, Township of
Westwood, Borough of
Woodcliff Lake, Borough of
Wood-Ridge, Borough of
Wyckoff, Township of

BURLINGTON COUNTY

Beverly, City of
Bordentown, City of
Bordentown, Township of
Burlington, City of
Burlington, Township of

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 4**

TERRITORY SERVED
(Continued)

BURLINGTON COUNTY (continued)

Chesterfield, Township of
Cinnaminson, Township of
Delanco, Township of
Delran, Township of
Eastampton, Township of
Edgewater Park, Township of
Evesham, Township of
Fieldsboro, Borough of
Florence, Township of
Hainesport, Township of
Lumberton, Township of
Mansfield, Township of
Maple Shade, Township of
Medford, Township of
Moorestown, Township of
Mount Holly, Township of
Mount Laurel, Township of
New Hanover, Township of
North Hanover, Township of
Palmyra, Borough of
Pemberton, Borough of
Pemberton, Township of
Riverside, Township of
Riverton, Borough of
Southampton, Township of
Springfield, Township of
Westampton, Township of
Willingboro, Township of
Woodland, Township of
Wrightstown, Borough of

CAMDEN COUNTY

Audubon, Borough of
Audubon Park, Borough of
Barrington, Borough of
Bellmawr, Borough of
Brooklawn Borough of
Camden, City of
Cherry Hill, Township of
Collingswood, Borough of
Gloucester, City of
Haddon, Township of
Haddonfield, Borough of
Haddon Heights, Borough of
Lawnside, Borough of
Merchantville, Borough of
Mount Ephraim, Borough of
Oaklyn, Borough of
Pennsauken, Township of
Tavistock, Borough of
Woodlynne, Borough of

ESSEX COUNTY

Belleville, Town of
Bloomfield, Township of
Caldwell, Borough of
Cedar Grove, Township of
East Orange, City of
Essex Fells, Borough of
Fairfield, Township of
Glen Ridge, Borough of
Irvington, Township of
Livingston, Township of
Maplewood, Township of
Millburn, Township of
Montclair, Township of
Newark, City of
North Caldwell, Borough of
Nutley, Township of
Orange, City of
Roseland, Borough of
South Orange Village, Township of
Verona, Township of
West Caldwell, Township of
West Orange, Township of

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 5**

TERRITORY SERVED
(Continued)

GLOUCESTER COUNTY

Deptford, Township of
National Park, Borough of
West Deptford, Township of
Westville, Borough of
Woodbury, City of

HUDSON COUNTY

Bayonne, City of
East Newark, Borough of
Guttenberg, Town of
Harrison, Town of
Hoboken, City of
Jersey City, City of
Kearny, Town of
North Bergen, Township of
Secaucus, Town of
Union City, City of
Weehawken, Township of
West New York, Town of

HUNTERDON COUNTY

East Amwell, Township of
Readington, Township of
Tewksbury, Township of

MERCER COUNTY

East Windsor, Township of
Ewing, Township of
Hamilton, Township of
Hightstown, Borough of
Lawrence, Township of
Princeton, Borough of
Princeton, Township of
Robbinsville, Township of
Trenton, City of
West Windsor, Township of

MIDDLESEX COUNTY

Cranbury, Township of
Dunellen, Borough of
East Brunswick, Township of
Edison, Township of
Helmetta, Borough of
Highland Park, Borough of
Jamesburg, Borough of
Middlesex, Borough of
Milltown, Borough of
Monroe, Township of
New Brunswick, City of
North Brunswick, Township of
Old Bridge, Township of
Piscataway, Township of
Plainsboro, Township of
Sayreville, Borough of
South Amboy, City of
South Brunswick, Township of
South Plainfield, Borough of
South River, Borough of
Spotswood, Borough of

MONMOUTH COUNTY

Allentown, Borough of
Millstone, Township of
Roosevelt, Borough of
Upper Freehold, Township of

MORRIS COUNTY

Butler, Borough of
Chatham, Borough of
Chatham, Township of
Chester, Borough of
Chester, Township of
Denville, Township of
East Hanover, Township of
Florham Park, Borough of

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 6**

TERRITORY SERVED
(Continued)

MORRIS COUNTY (continued)

Hanover, Township of
Harding, Township of
Jefferson, Township of
Kinnelon, Borough of
Long Hill, Township of
Madison, Borough of
Mendham, Borough of
Mendham, Township of
Morris, Township of
Morris Plains, Borough of
Morristown, Town of
Parsippany-Troy Hills, Township of
Pequannock, Township of
Randolph, Township of
Riverdale, Borough of

OCEAN COUNTY

Plumsted, Township of

PASSAIC COUNTY

Bloomingdale, Borough of
Clifton, City of
Haledon, Borough of
Hawthorne, Borough of
Little Falls, Township of
North Haledon, Borough of
Passaic, City of
Paterson, City of
Pompton Lakes, Borough of
Prospect Park, Borough of
Ringwood, Borough of
Totowa, Borough of
Wanaque, Borough of
Wayne, Township of
West Milford, Township of
Woodland Park, Borough of

SOMERSET COUNTY

Bedminster, Township of
Bernards, Township of
Bernardsville, Borough of
Bound Brook, Borough of
Branchburg, Township of
Bridgewater, Township of
Far Hills, Borough of
Franklin, Township of
Green Brook, Township of
Hillsborough, Township of
Manville, Borough of
Millstone, Borough of
Montgomery, Township of
North Plainfield, Borough of
Peapack-Gladstone, Borough of
Raritan, Borough of
Rocky Hill, Borough of
Somerville, Borough of
South Bound Brook, Borough of
Warren, Township of
Watchung, Borough of

UNION COUNTY

Berkeley Heights, Township of
New Providence, Borough of
Plainfield, City of
Springfield, Township of
Summit, City of

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 7**

STANDARD TERMS AND CONDITIONS - INDEX

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 8**

STANDARD TERMS AND CONDITIONS – INDEX
(Continued)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 9**

STANDARD TERMS AND CONDITIONS

1. GENERAL

These Standard Terms and Conditions, filed as part of the Gas Tariff of Public Service Electric and Gas Company, hereinafter referred to as "Public Service", set forth the terms and conditions under which gas service will be supplied and govern all classes of service to the extent applicable, and are made a part of all agreements for the supply of gas service unless specifically modified in a particular rate schedule.

No representative of Public Service has authority to modify any provision contained in this Tariff or to bind Public Service by any promise or representation contrary thereto.

Public Service will construct, own, and maintain distribution mains and services located on land, streets, highways, rights of way acquired by Public Service, and on private property, used or usable as part of the distribution system of Public Service. Payment of monthly charges, or a deposit or a contribution shall not give the customer, Applicant or depositor any interest in the facilities, the ownership being vested exclusively in Public Service.

Publications set forth by title in sections of these Standard Terms and Conditions are incorporated in this Tariff by reference.

This tariff is subject to the lawful orders of the Board of Public Utilities of the State of New Jersey. Complaints may be directed to: Board of Public Utilities, Division of Customer Assistance, 44 South Clinton Avenue, ~~Third Floor, Suite 314,~~ P.O. Box 350, Trenton, New Jersey, 08625-0350 or 1-800-624-0241; www.nj.gov/bpu.

2. OBTAINING SERVICE

2.1. Application: An application for service may be made at any of the Customer Service Centers of Public Service in person, ~~by mail,~~or by telephone, by the Company's website at www.pseg.com, ~~or by facsimile transmission~~ or electronic mail, where available. Forms for application for service, when required, together with terms and conditions and rate schedules, will be furnished upon request. All customers shall be given a copy of the Customer Bill of Rights, effective at the time of service initiation. Customer shall state, at the time of making application for service, the conditions under which service will be required and customer may be required to sign an agreement or other form then in use by Public Service covering special circumstances for the supply of gas service. Data requested from customers may include proof of identification as well as copies of leases, deeds and corporate charters in accordance with N.J.A.C. 14:3-3.2 (e) and (f). Such information shall be considered confidential.

Public Service may reject applications for service where such service is not available or where such service might affect the supply of gas to other customers, or for failure of customer to agree to comply with any of these Standard Terms and Conditions.

See also Section 13 Service Limitations, of these Standard Terms and Conditions.

2.2. Initial Selection of Rate Schedule: Public Service will assist in the selection of the available rate schedule which is most favorable from the standpoint of the customer. Any advice given by Public Service will necessarily be based on customer's written statements detailing the customer's proposed operating conditions.

Customers may, upon written notice to Public Service within three months after service has begun, elect to change and to receive service under any other available rate schedule. Public Service will furnish service to and bill the customer under the rate schedule so selected from the date of last scheduled meter reading, but no further change will be allowed during the next twelve months.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

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STANDARD TERMS AND CONDITIONS
(Continued)

2.2.1. **Change of Rate Schedule**: Subsequent to initial selection of a rate schedule, customer shall notify Public Service in writing of any change in the customer's use of service which might affect the selection of a rate schedule or provision within a rate schedule. Any change in schedule or provision shall be applicable, if permitted, to the next regular billing subsequent to such notification.

2.3. **Deposit and Guarantee**: Public Service may require a reasonable deposit as a condition of supplying service, in accordance with the provisions as set forth in Board of Public Utility regulations.

A deposit may be required from a customer equal to the average monthly charge for a twelve-month period and one month's average bill. A customer taking service for a period of less than thirty days may be required to deposit an amount equal to the estimated bill for such temporary period.

Upon closing any account, the balance of any deposit remaining after the closing bill for service has been settled, shall be returned promptly to the customer with any interest due. The customer has the option of having the deposit refund applied to the account in the form of a credit or of having the deposit refunded by separate check in a period not to exceed one full billing cycle.

Public Service shall review a residential customer's account at least once every year and a non-residential customer's account at least once every 2 years. If such review indicates that the customer has established credit satisfactory to Public Service, then the outstanding deposit shall be refunded to the customer. The customer has the option of having the deposit refund applied to the account in the form of a credit or of having the deposit refunded by separate check in a period not to exceed one billing cycle.

In accordance with N.J.A.C. 14:3-3.5(d), simple interest at a rate equal to the average yields on new six-month Treasury Bills for the twelve month period ending each September 30 shall be paid by Public Service on all deposits held by it after notification by the BPU of the new effective rate. Said rate shall be determined by the Board of Public Utilities ("Board"), and shall become effective on January 1 of the following year.

For residential customers, interest payments shall be made at least once during each 12-month period in which a deposit is held. Residential customers shall have the option of a credit to the customer's account or a separate check.

A deposit is not a payment or part payment of any bill for service, except that on discontinuance of service Public Service may apply said deposit against unpaid bills for service, and only the remaining balance of the deposit will be refunded. Public Service shall promptly read the meters and ascertain that the obligations of the customer have been fully performed before being required to return any deposit. To have service resumed, a deposit may be required, but the deposit shall not be required prior to restoration of service. Public Service shall bill the customer for the deposit and allow at least 15 days after the billing for payment of deposit, or make other reasonable arrangements.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 11**

STANDARD TERMS AND CONDITIONS
(Continued)

2.4. **Permits**: Public Service, where necessary, will make application for any street opening permits for installing its gas facilities necessary to provide new or upgraded service to a customer and shall not be required to furnish service until after such permits are granted. The Applicant may be required to pay the municipal charge, if any, for permission to open the street. The Applicant shall obtain and present to Public Service, for recording or for registration, all instruments providing for easements or rights of way, and all permits (except street opening permits), consents, and certificates necessary for the introduction of service.

2.5. **Service Connections:** The customer may be required to make a contribution toward the cost of installing a service connection as set forth in Section 5 of these Standard Terms and Conditions.

2.6. **Temporary Service:** Where service is to be used at an installation for a limited period and such installation is not permanent in nature, the use of service shall be classified as temporary. In such cases, the customer may be required to pay to Public Service the cost of the facilities required to furnish service. The minimum period of temporary service for billing purposes shall be one month.

After two years of service a temporary service installation shall be eligible for refunds. Excluding the first two annual service periods, refunds equal to 10% of the revenue from Service Charges, Distribution Charges and Demand Charges received by Public Service during an annual service period shall be made at the end of such period. In no case shall the total amount refunded be in excess of the installation cost paid by the customer, nor shall refunds be made for more than eight consecutive annual service periods.

3. CHARGES FOR SERVICE

3.1. **General:** Charges for gas usage are set forth in the rate schedules included elsewhere in this Tariff. In addition to the charges for gas usage, Public Service may require additional monthly charges, up-front contributions or deposits (including the gross-up for income tax effects) from an Applicant for providing Temporary Services, for certain Standard and Atypical Conditions, or for an Extension.

3.2. **Definitions:** The following are defined terms as used in this Tariff:

a) Applicant is the individual or entity, who may or may not be the ultimate customer, requesting new, additional, temporary, or upgraded gas service from Public Service.

b) Applicant For An Extension is an Applicant where Public Service has determined that an Extension is necessary to provide service.

c) N.J.A.C. is the New Jersey Administrative Code.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

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STANDARD TERMS AND CONDITIONS
(Continued)

d) Distribution Revenue as used in this Section 3 means the total revenue, plus related New Jersey Sales and Use Tax (SUT), charged a customer by Public Service, minus Basic Gas Supply Service charges including SUT, assessed in accordance with this Tariff for Gas Service. For Rate CIG the Basic Gas Supply Service Charges is the Estimated Average Commodity Cost plus Losses and applicable SUT.

e) Temporary Service is where service is provided through an installation for a limited period and such installation is not permanent in nature.

f) An Extension means the construction or installation of plant and/or facilities by Public Service used to convey service from existing or new plant and/or facilities to one or more new customers, and also means the plant and/or facilities themselves. An Extension includes all Public Service plant and/or facilities used for gas transmission (non-FERC jurisdictional) and/or distribution, whether located on a public street or right of way, or on private property or private right of way, and includes the pipe, rights of way, land, valves, site restoration, regulators and metering equipment and other means of conveying service from existing plant and/or facilities to each unit or structure to be served. An Extension does not include equipment solely used for administrative purposes, such as office equipment used for administering a billing system.

An Extension begins at the existing Public Service infrastructure and ends at the meter and includes the meter. The new plant and/or facilities installed constituting an Extension must be nominally physically continuous from the beginning to the end of the Extension.

Plant and/or facilities installed to supply the increased load of existing non-residential customers are also considered an Extension where existing Public Service facilities are upgraded or replaced due to an Applicant's new or additional gas load being greater than 50% of the total design capacity of the pre-existing facilities.

g) Cost means, with respect to the cost of construction of an Extension, actual and/or site-specific unitized expenses incurred by Public Service for materials and labor, including both internal and external labor, employed in the actual design, purchase, construction, and/or installation of the Extension, including overhead directly attributable to the work, as well as overrides or loading factors such as those for mapping and design. This term does not include expenses for clerical, dispatching, supervision, or general office functions. Costs shall be determined by the Company and shall include all costs inclusive of upgrades to existing infrastructure as well as tax gross ups, inclusive of the applicable bonus depreciation credits. Costs related to plant and/or facilities installed to serve increased load from an existing customer are determined on a similar basis.

3.3. **Removal of Public Service Facilities:** There is normally no charge for the permanent removal of above ground Public Service facilities or the abandonment in place of underground Public Service facilities where an easement for such facilities does not exist. Where an easement exists, and when approved by Public Service, and unless preempted by statute, the requesting party shall be responsible for all costs related to the removal or abandonment of requested facilities and if necessary, the installation of all new facilities necessary to provide the same level of service to all other customers.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

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STANDARD TERMS AND CONDITIONS
(Continued)

3.4. **Temporary Service**: Where Public Service provides Temporary Service, the customer will be required to pay to Public Service the cost of the installation and removal of facilities required to furnish service. The minimum period of temporary service for billing purposes shall be one month.

After two years of service, a Temporary Service installation shall be eligible for refunds. Excluding the first two annual service periods, refunds equal to 10% of the Distribution Revenue received by Public Service during each annual service period shall be made at the end of such period. In no case shall the total amount refunded be in excess of the installation and removal cost paid by the customer, nor shall refunds be made for more than eight consecutive annual service periods.

Temporary service will not be supplied under Rate Schedule SLG.

3.5. **Provision of Service:** Gas service shall be supplied in accordance with these Standard Terms and Conditions and the applicable rate schedule and shall be based upon customer's anticipated load and upon plant facilities that are sufficient for safe, proper, and adequate service based upon Public Service's design standards and reliability criteria. Both the Applicant's anticipated load and sufficient plant facilities will be as determined by Public Service.

3.5.1. **Standard Conditions:** Underground construction is the standard for all gas mains and services. Metering and regulating facilities are normally located above ground outside of buildings, unless required by Public Service operating conditions in which case they will be located inside.

3.5.2. **Atypical Conditions:** When special facilities are required due to conditions beyond the control of Public Service, or are requested by the Applicant and approved by Public Service, or are required due to local ordinance, the added cost of such special facilities, grossed up for income tax effects, shall be paid by the Applicant as a non-refundable contribution.

Public Service may require agreements for a longer term than specified in the rate schedule, may require contributions toward the investment, and may establish such Minimum Charges and Facilities Charges as may be equitable under the circumstances involved where: (1) large or special investment is necessary for the supply of service; (2) capacity required to serve Rate Schedules GSG or LVG customer's weather-sensitive or dual-fueled equipment is out of proportion to the use of gas service for occasional, intermittent, or low load factor purposes, or is for short durations. The assessment of any Minimum Charges will be based upon a minimum use requirement of 850 therms per year for each therm of applicable connected load. To the extent that total annual therm usage is less than 850 therms per therm of connected load, any deficiency will be assessed a Minimum Charge of $0.25 ($0.27 including SUT) per therm.

Unless there is a material change in the provision of service, once charges are established for a premises pursuant to this Section 3.5.2, they shall be used for all subsequent customers at that premises requesting such similar service, regardless of any lapse in the provision of such similar service characteristics to that premises.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

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STANDARD TERMS AND CONDITIONS
(Continued)

3.6. Extensions – General Provisions: Where it is necessary for Public Service to construct an Extension to serve the requirements of an Applicant, Public Service may require a deposit or contribution from the customer to cover all or part of the cost of the Extension, which is required to be paid to Public Service prior to any work being performed. The costs will be estimated based upon normal conditions, and may be increased if severe conditions, such as excessive rock or other unknown conditions, are found during excavation.

3.7. Charges for Extensions: Applicants requesting service may be charged a deposit for service. Such deposit will be determined by Public Service by comparing the estimated Distribution Revenue to the applicable costs of the Extension. The detailed calculations of such deposits, if any, are contained in the remainder of Section 3.7 of these Standard Terms and Conditions.

3.7.1. Individual Residential Customer: Where application for service is made by an Applicant for individual residential use, and the service requested is not for a limited period of less than ten (10) years, the following shall apply:

a) Excess cost is defined as the total cost of the Extension less any contribution required for Atypical Conditions less ten times the estimated average annual Distribution Revenue, such result grossed up for income tax effects. The excess cost shall not be less than zero in any case.

Any excess cost shall be deposited and remain with Public Service without interest. Public Service will waive the deposit requirement where the excess cost is $3,000.00 or less.

b) In each annual period from the date of connection, if the actual Distribution Revenue from the customer exceeds the greater of either: (1) the estimated annual Distribution Revenue used as the basis for the initial deposit computation, or (2) the highest actual Distribution Revenue from any prior year, there shall be returned to the Applicant an additional amount, equal to ten times such excess multiplied by the tax gross up factor used when the deposit was taken.

c) As additional customers not originally anticipated are supplied from this Extension and Public Service still holds at least some part of the deposit from the original Applicant, a reduction may be made to such remaining deposit. The cost of the Extension or cost for Increased Load for any such additional customer will be first compared to the estimated additional Distribution Revenue as detailed in the appropriate paragraph of this Section 3. Once any deposit requirement has been satisfied, any remaining Distribution Revenue credit will be applied toward the original customer's remaining deposit in an amount equal to ten times such excess Distribution Revenue multiplied by the tax gross up factor used when the deposit was taken.

d) In no event shall more than the original deposit be returned to the Applicant nor shall any part of the deposit remaining after ten years from the date of the original deposit be returned.

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(Continued)

3.7.2. Multi-unit Developments: Where application for service is made for gas service to a multi-unit residential or multi-unit non-residential development, the following shall apply:

a) Excess cost for an Applicant is defined as the total cost of the Extension less any contribution required for Atypical Conditions, such result grossed up for income tax effects.

Any excess cost shall be deposited and remain with Public Service with interest. Public Service will waive the deposit, requirement where the excess cost is $3,000.00 or less, or where ten times the estimated annual Distribution Revenue is greater than the excess costs and the excess cost is less than $20,000.00.

b) As each unit is connected, as determined by the setting and activation of the Public Service gas meter, there shall be returned to the Applicant an amount equal to ten times the estimated annual Distribution Revenue from that unit multiplied by the tax gross up factor used when the deposit was taken.

c) In each annual period from the date of deposit, if for all customers receiving service for the entire prior one year period the actual annual Distribution Revenue exceeds the greater of either: (1) the estimated annual Distribution Revenue, or (2) the highest actual Distribution Revenue from any prior year, there shall be returned to the Applicant an additional amount equal to ten times such excess multiplied by the tax gross up factor used when the deposit was taken.

d) As additional customers not originally anticipated are supplied from this Extension and Public Service still holds at least some part of the deposit from the original Applicant, a reduction may be made to such remaining deposit. The cost of the Extension or cost for Increased Load for any such additional customer will be first compared to the estimated additional Distribution Revenue as detailed in the appropriate paragraph of this Section 3. Once any deposit requirement has been satisfied, any remaining Distribution Revenue credit will be applied toward the original customer’s remaining deposit in an amount equal to ten times such excess Distribution Revenue multiplied by the tax gross up factor used when the deposit was taken.

e) In no event shall more than the original deposit be returned to the Applicant nor shall any part of the deposit remaining after ten years from the date of the original deposit be returned.

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STANDARD TERMS AND CONDITIONS
(Continued)

3.7.3. Individual Commercial and Industrial Customers: Where application for service is made for individual non-residential use, and the service requested is not for a limited period of less than ten (10) years, the following shall apply:

a) Excess cost for an Applicant is defined as the total cost of the Extension less any contribution required for Atypical Conditions less ten times the estimated average annual Distribution Revenue, such result grossed up for income tax effects. The excess cost shall not be less than zero in any case.

Any excess cost shall be deposited and remain with Public Service with interest. Public Service will waive the deposit requirement where the excess cost is $3,000.00 or less, or where ten times the estimated annual Distribution Revenue is greater than the excess costs and the excess cost is less than $20,000.00.

b) As the Public Service gas meter is set, there shall be returned to the Applicant an amount equal to ten (10) times the estimated average annual Distribution revenue multiplied by the tax gross up factor used when the deposit was taken.

c) In each annual period from the date of deposit, if the actual Distribution Revenue from the customer exceeds the greater of: (1) the estimated annual Distribution Revenue used as the basis for the initial deposit, or (2) the highest actual Distribution Revenue from any prior year; there shall be returned to the Applicant an additional amount, equal to ten times such excess multiplied by the tax gross up factor used when the deposit was taken.

d) As additional customers not originally anticipated are supplied from this Extension and Public Service still holds at least some part of the deposit from the original Applicant, a reduction may be made to such remaining deposit. The cost of the Extension or cost for Increased Load for any such additional customer will be first compared to the estimated additional Distribution Revenue as detailed in the appropriate paragraph of this Section 3. Once any deposit requirement has been satisfied, any remaining Distribution Revenue credit will be applied toward the original customer’s remaining deposit in an amount equal to ten times such excess Distribution Revenue multiplied by the tax gross up factor used when the deposit was taken.

e) In no event shall more than the original deposit be returned to the Applicant nor shall any part of the original deposit remaining after ten years from the date of the original deposit be returned.

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STANDARD TERMS AND CONDITIONS
(Continued)

3.8. **Charges for Increased Load:** When it is necessary for Public Service to construct, upgrade, or install facilities necessary to service the additional requirements of existing customers and these facilities do not meet the definition of an Extension as defined in Section 3.2 (f) of these Standard Terms and Conditions, the following shall apply:

a) Public Service may require a deposit from the customer to cover all or part of the investment necessary to supply service. Any such deposit will be calculated by comparing the estimated annual increase in Distribution Revenue as determined by Public Service to the total cost of the applicable work to determine if excess costs exist.

b) Excess cost is defined as the total cost of the applicable work less any contribution required for Atypical Conditions less the ten times the estimated average annual increase in Distribution Revenue, such result grossed up for income tax effects. The excess cost shall not be less than zero in any case.

c) Any excess cost shall be deposited and remain with Public Service without interest. Public Service will waive the deposit requirement where the excess cost is $3,000.00 or less.

d) In each annual period from the date of connection of such additional load, if the actual increase in Distribution Revenue from the customer exceeds the greater of either: (1) the estimated annual increase in Distribution Revenue used as the basis for the initial deposit, or (2) the highest increase in actual Distribution Revenue from any prior year, there shall be returned to the Applicant an additional amount, equal to ten times such excess multiplied by the tax gross up factor used when the deposit was taken.

e) In no event shall more than the original deposit be returned to the Applicant nor shall any part of the deposit remaining after ten years from the date of the original deposit be returned.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

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STANDARD TERMS AND CONDITIONS
(Continued)

4. CHARACTERISTICS OF SERVICE

4.1. Standard Service Supply: Public Service may commingle gas supplies from several sources. All gas delivered to any customer may be a mixture of gas manufactured or derived from natural sources, altered to remove impurities and to add desirable constituents. The heat content of delivered gas may vary between 950 and 1,150 Btu per cubic foot. The character of the gas will be of a nature which will allow an atmospheric burner to operate without repeated adjustment.

4.2. Heat Measurement and Billing Units: For billing purposes, the customer's gas use in cubic feet will be converted to therms, using the actual weighted average heating value, on a dry basis, of the gas distributed in the second preceding calendar month, where a therm is a unit of heat energy equivalent to 100,000 British thermal units (Btu). Metered usage in cubic feet at standard pressure will be corrected to atmospheric pressure by application of a 1.012 multiplier. Metered usage at higher than standard pressure will be corrected to atmospheric pressure by application of appropriate multipliers.

4.3. Standard Pressure: The standard pressure supplied at the meter outlet will be within the range of 4 to 7 inches water column pressure.

5. SERVICE CONNECTIONS

5.1. General: The Applicant shall consult Public Service as to the exact point at which the meter set will be located and connection to customer piping will be made before installing interior gas piping or starting any other work dependent upon the location of the service pipe.

Public Service will determine the location of the service pipe depending upon existing facilities in the street and other practical considerations.

Gas service will be supplied to each building or premises through a single service pipe except where, in the judgment of Public Service, its economic considerations; conditions on its distribution system; improvement of service conditions; or volume of the customer's requirements, make it desirable to install more than one service pipe.

5.2. Change in Location of Existing Service Pipe: Any change requested by the customer in the location of the existing service pipe, if approved by Public Service, will be made at the expense of the customer. A request to install facilities for the same building within 12 months of the removal of similar facilities may be considered a relocation of the existing facilities if the load served is similar or lower and the building served is essentially the same.

6. METERS AND ASSOCIATED EQUIPMENT

6.1. General: A single meter will be furnished and installed by Public Service for each separately billed rate schedule under which a customer receives service. Public Service shall be consulted regarding meter locations. Meter installations shall be in conformance

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STANDARD TERMS AND CONDITIONS
(Continued)

with the standards of the fuel gas subcode of the "Uniform Construction Code" and the "General Criteria for Installation of Gas Appliances and Gas Piping," issued by Public Service and available on request. Where permitted, the meter shall be located outside. If the meter is not located outside solely due to the request of the customer, Public Service reserves the right to install remote metering equipment at the customer's expense. See Section 8.5 of these Standard Terms and Conditions. The installation of meters and connections shall be in accordance with N.J.A.C. 14:3-4.2.

When requested by a customer, remote meter reading equipment may be installed, if feasible, at the expense of the customer. The payment shall not give the customer any interest in the equipment thus installed, the ownership being vested exclusively in Public Service.

Additional meters will be installed only where, in the judgment of Public Service, its economic considerations; conditions on its distribution system; improvement of service conditions; or the volume of the customer's requirements, make it desirable to install such additional meters.

6.2. **Seals:** Public Service may seal or lock any meters or enclosures containing meters and associated metering equipment. No person except a duly authorized employee of Public Service shall break or remove a Public Service seal or lock.

6.3. **Protection of Meter and Service Equipment:** Customer shall furnish and maintain a suitable space for the meter and associated equipment. Such space shall be as near as practicable to the point of entrance of the gas service pipe, adequately ventilated, dry (inside installation only) and free from corrosive vapors, not subject to extreme temperatures, readily accessible to duly authorized employees or agents of Public Service and shall otherwise conform to the standards of the fuel gas subcode of the "Uniform Construction Code" and to the "General Criteria for Installation of Gas Appliances and Gas Piping," issued by Public Service and available on request. The gas meter cannot be located behind fences or gates unless no other practical location can be identified. Customer shall not tamper with or remove meters or other equipment, nor permit access thereto except by duly authorized employees or agents of Public Service. In case of loss or damage to the property of Public Service from the act or negligence of the customer or the customer's agents or servants, or of failure to return equipment supplied by Public Service, customer shall pay to Public Service the amount of such loss or damage to the property. All equipment furnished at the expense of Public Service shall remain its property and may be replaced whenever deemed necessary and may be removed by it at any reasonable time after the discontinuance of service. In the case of defective service, the customer shall not interfere or tamper with the apparatus belonging to Public Service but shall immediately notify Public Service to have the defects remedied.

6.4. **Public Service to Turn on Gas:** No person other than a duly authorized employee or agent of Public Service shall turn gas into any new system of piping or into any old system of piping from which the use of gas had been discontinued.

6.5. **Change in Location of Meters and Associated Equipment:** Any change requested by the customer in the existing location of meters and associated equipment, if approved by Public Service, will be made at the expense of the customer.

6.6. **Tampering:** In the event it is established that Public Service meters or other equipment on the customer's premises have been tampered with, and, such tampering results in incorrect measurement of the service supplied, the charges for such gas service under the applicable rate schedule including Basic Gas Supply Service default service, based

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upon the Public Service estimate from available data and not registered by Public Service meters shall be paid by the beneficiary of such service. In the case of a residential customer, such unpaid service shall be limited to not more than one year prior to the date of correcting the tampered account and for no more than the unpaid service alleged to be used by such customer. The beneficiary shall be the customer or other party who benefits from such tampering. The actual cost of investigation, inspection, and determination of such tampering, and other costs, such as but not limited to, the installation of protective equipment, legal fees, and other costs related to the administrative, civil or criminal proceedings, shall be billed to the responsible party. The responsible party shall be the party who either tampered with or caused the tampering with a meter or other equipment or knowingly received the benefit of tampering by or caused by another. In the event a residential customer unknowingly received the benefit of meter or equipment tampering, Public Service shall only seek from the benefiting customer the cost of the service provided under the applicable rate schedule including Basic Gas Supply Service default service but not the cost of investigation.

These provisions are subject to the customer's right to pursue a bill dispute proceeding pursuant to N.J.A.C. 14:3-7.6.

Tampering with Public Service facilities may be punishable by fine and/or imprisonment under the New Jersey Code of Criminal Justice.

7. CUSTOMER'S INSTALLATION

7.1. **General:** No material change in the total input rating, or method of operation of customer's equipment shall be made without previous written notice to Public Service. For the purpose of this paragraph a material change in total input rating is defined as a change of 50,000 Btu per hour input or 10%, whichever is larger. A material change in method of operation is defined as a 50% change in the customer's total annual gas consumption.

7.2. **Piping:** Gas piping installed on the customer's premises must conform to all requirements of municipal or other properly constituted public authorities, the most current edition of the standards of the fuel gas subcode of the "Uniform Construction Code", and to the regulations set forth in "General Criteria for Installation of Gas Appliances and Gas Piping," issued by Public Service and available on request.

7.3. **Gas Equipment and Appliances:** All gas equipment and appliances shall be certified to applicable U.S. standards by a nationally recognized testing laboratory, and marked with the appropriate certification approval. The manner of installation of all gas equipment and appliances shall be in accordance with all local construction codes, the most current edition of the standards of the fuel gas subcode of the "Uniform Construction Code", and the regulations set forth in "General Criteria for Installation of Gas Appliances and Gas Piping," issued by Public Service and available on request.

7.4. **Back Pressure and Suction:** When the nature of customer's gas fired equipment, gas compressors or gas piping configuration is such that it may cause back pressure or suction in the piping system, meters or other associated equipment of Public Service, suitable protective devices as defined by the standards of the fuel gas subcode of the "Uniform Construction Code", fittings, valves or check valves shall be furnished, installed and maintained by the customer, subject to the inspection and approval by Public Service.

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7.5. **Maintenance of Customer's Installation:** Customer's entire installation shall be maintained in the condition required by the municipal or other public authorities having jurisdiction and by Public Service.

7.6. **Appliance Adjustments:** Public Service will make, without additional charge, safety related adjustments to gas burners and certain associated equipment as determined by the Board to be necessary to the functioning of gas appliances in use on customer's premises. Other adjustments or repairs to such appliances may be made, or other services connected with the rendering of gas service may be performed, by Public Service at the customer's expense. Service procedures are detailed in "Servicing Equipment and Facilities on Customers' Premises," issued by Public Service and available on request.

7.7. **Adequacy and Safety of Installation:** Public Service shall not be required to supply gas service until the customer's installation shall have been approved by the authorities having jurisdiction. Public Service may withhold or discontinue its service whenever such installation or part thereof is deemed by Public Service to be unsafe, inadequate, or unsuitable for receiving service, or to interfere with or impair the continuity or quality of service to the customer or to others.

Public Service will assume no responsibility for the condition of customer's gas installation or for accidents, fires, or failures which may occur as the result of the condition of such gas installation.

Neither by inspection or nonrejection, nor in any other way, does Public Service give any warranty, expressed or implied, as to the adequacy, safety, or other characteristics of any structure, equipment, wires, pipes, appliances, or devices used by the customer.

7.8. **Liability for Customer's Installation:** Public Service will not be liable for damages or for injuries sustained by customers or others or by the equipment of customers or others by reason of the condition or character of customers' facilities or the equipment of others on customers' premises or by reason of the characteristics of the service that are in accord with Section 4.1 of these Standard Terms and Conditions. Public Service will not be liable for the use, care or handling of the gas service delivered to the customer after same passes beyond the point at which the service facilities of Public Service connect to the customers' facilities.

8. METER READING AND BILLING

8.1. **Measurement of Gas Used:** Public Service will select the type and make of metering equipment and may, from time to time, change or alter such equipment; its sole obligation is to supply meters that will accurately and adequately furnish records for billing purposes.

Where service through more than one meter is permitted by Public Service as outlined under Section 6.1 of these Standard Terms and Conditions, the cubic-foot use registered by the individual meters will be combined for billing purposes. In all other instances, each meter shall be billed separately.

Bills will be based upon registration of Public Service meters except as otherwise provided for in this Tariff.

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8.2. Correction for Pressure: In any case where, pursuant to Section 4.3, Public Service measures the gas delivered to a customer under pressure greater than that exerted by a column of water seven inches in height, the cubic feet of gas registered by the meter or meters of Public Service shall be subject to correction for billing purposes by the application of a proper correction factor.

8.3. Metering on Customer's Premises:

8.3.1. General: The service and supply of gas by Public Service for the use of owners, landlords, tenants, or occupants of newly constructed or renovated residential units~~buildings or premises~~ will be furnished to them as customers of Public Service through Public Service individual meters, except as noted below in Section 8.3.2.

The service and supply of gas by Public Service to owners, landlords, tenants, or occupants of industrial or commercial buildings or residential premises as noted below in section 8.3.2 may be further distributed to other users within such structures and such use and resultant charges, including reasonable administrative costs, apportioned to such users. However, such charges shall not exceed the amount that Public Service would charge if the tenant were served and billed directly by Public Service on the most appropriate rate schedule. In no event will a customer buying gas service from Public Service be permitted to resell it for a profit.

Where customer installs, or has installed a gas-fired pool heating device, service to such device must be limited to a separate line with a shutoff valve or a separate meter.

8.3.2. Sub-metering: The practice where a primary customer of Public Service or customer of record, through the use of direct metering devices, installed, operated and maintained at such customer's expense, monitors, evaluates, or measures their own gas consumption or the consumption of a tenant for accounting or conservations purposes.

Gas sub-meters are devices that measure the volume of gas being delivered to particular locations in a system after measurement by a Public Service owned meter. Gas sub-meters provide the customer-of-record the means to apportion among the end users the cost of gas service being supplied through the Public Service owned meter.

Sub-metering will be permitted in new or existing buildings or premises where the basic characteristic of use is industrial or commercial. Sub-metering will not be permitted in new or existing buildings or premises where the basic characteristic of use is residential, except where such buildings or premises are publicly financed or government owned; or are condominiums or cooperative housing; or are eleemosynary in nature. In the case of dwelling units, all gas consuming devices must be metered through a single sub-meter.

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Sub-metering for the aforementioned purposes and applications shall not adversely affect the ability of Public Service to render service to any customer within the affected building or premises or any other customer. The customer shall contact Public Service prior to the installation of any sub-metering device to ascertain that it will not cause operating problems. The ownership of all sub-metering devices is that of the customer, along with all incidents in connection with said ownership, including accuracy of the equipment, meter reading and billing, liability arising from the presence of the equipment and the maintenance and repair of the equipment. Any additional costs which may result from and are attributable to the installation of sub-metering devices shall be borne by the customer.

The customer shall be responsible for the accuracy of sub-metering equipment. In the event of a dispute involving such accuracy, the Public Service meter will be presumed correct, subject to test results.

8.4. **Testing of Meters:** At such times as Public Service may deem proper, or as the Board of Public Utilities may require, Public Service will test its meters in accordance with the standards and bases prescribed by the Board of Public Utilities.

Public Service shall, without charge, make a test of the accuracy of a meter(s) upon request of the customer, provided such customer does not make a request for test more frequently than once in 12 months. A report giving results of such tests shall be made to the customer, and a complete record of such tests shall be kept on file at the office of Public Service in conformance with the New Jersey Administrative Code.

8.5. **Metering Options:** The following optional metering services are available to customers and are subject to the following charges as indicated in the following subsections:

8.5.1. **Gas Data Pulses and Remotes:** Public Service will install and maintain the necessary equipment to supply data pulses for the customer's use, and remote metering equipment at the customer's request. Customers requesting these services are subject to a minimum term of one year:

Description	**Set-Up Charge – Data Pulses**		**Monthly Charge**
	Charges	Charges including SUT	
Residential Meter	$100.00	$ 106.63	$1.00
Large Diaphragm – Retrofit	$ 40.00	$ 42.65	$1.00
Large Diaphragm – Change			
Model 53 lt	$100.00	$ 106.63	$2.00
Model 10 lt	$130.00	$ 138.61	$2.00
Model 20 lt	$130.00	$ 138.61	$2.00
Model 30 lt	$340.00	$ 362.53	$3.00
Model 60 lt	$650.00	$ 693.06	$3.00
Rotary without Instrument	$450.00	$ 479.81	$2.00
Rotary with Instrument	$100.00	$ 106.63	$2.00
Turbine	$100.00	$ 106.63	$2.00

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8.5.2. **Customer Usage Information:** Where Public Service has an interval meter installed, twelve months of interval usage, where available, will be provided upon request of the customer. The historical interval data will be provided based upon the measurement interval of the installed meter, and will be sent to the customer in an electronic format. The cost per meter, per request is $40.00.

Where Public Service has an interval meter installed, Public Service will provide Internet access to customer historical usage data on a next-day basis for those customers who request such service. The charges for this service shall include a set up charge of $107.00 per meter, and a monthly charge of $17.00 per meter per month. Customer will be required to sign an Agreement for this service.

8.6. **Billing Adjustments:** Whenever a meter is found to be registering fast by 2% or more, an adjustment of charges shall be made. When a meter is found to be registering slow by more than 2%, an adjustment of charges may be made in the case of meter tampering, non-register meters, or in circumstances in which a customer, other than RSG, should reasonably have known that the bill did not accurately reflect the usage. Billing adjustments shall be made in accordance with N.J.A.C. 14:3-4.6.

8.7. **Meter Reading and Billing Period**: All charges are stated on a monthly basis. The term “month” for billing purposes shall mean the period between any two consecutive regularly scheduled meter readings. Meter reading schedules provide for reading meters, in accordance with their geographic location, as nearly as may be practicable every thirty days. Schedules are prepared in advance by Public Service and are available for inspection.

8.8. **Proration of Monthly Charges**: For all billings for service, including initial bills, final bills, and bills for periods other than twenty-five to thirty-six days inclusive, except for temporary service accounts and Rate Schedules CIG, TSG-F, TSG-NF, and CSG, the monthly charges will be prorated based on the number of days in the billing month. For temporary service accounts the minimum period for billing purposes shall be one month.

8.9. **Averaged Bills:** Where Public Service is unable to read the meter, Public Service may estimate the amount of gas supplied and submit an averaged bill, so marked, for customer’s acceptance. Adjustments for averaged bills shall be made in Accordance with N.J.A.C. 14:3-7.2. Adjustment of such customer’s averaged use to actual use will be made after an actual meter reading is obtained.

Public Service reserves the right to discontinue gas service when a meter reading is not obtained for eight (8) consecutive billing periods (monthly accounts), and after written notice is sent to a customer on the fifth and seventh months explaining that a meter reading must be obtained. Public Service will take all reasonable means to obtain a meter reading during normal working hours, evening hours or Saturdays before discontinuing service. After all reasonable means to obtain a meter reading have been exhausted, Public Service may discontinue service provided at least eight months have passed since the last meter reading was obtained, the Board of Public Utilities has been so notified and the customer has been properly notified by prior mailing.

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8.10. Budget Plan (Equal Payment Plan): Customers billed under Rate Schedules RSG and GSG (where GSG gas service is used for residential purposes in buildings of four or fewer units), shall have the option of paying for their Public Service charges in equal, estimated monthly installments. Budget plans for residential accounts shall be made in accordance with N.J.A.C. 14:3-7.5. The total Public Service charges for a twelve month period will be averaged over twelve months and may be paid in twelve equal monthly installments. Adjustments will be made in the twelfth month if actual charges are more or less than the budget amounts billed. A review between the actual cost of service and the monthly budget amount will be made at least once in the budget plan year. A final bill for a budget plan year shall be issued at the end of the budget plan year and shall contain that month's monthly budget amount plus any adjustments will be made if actual charges are more or less than the budget amount billed.

8.11. Billing of Charges in Tariff: Unless otherwise ordered by the Board of Public Utilities, the charges and the classification of service set forth in this Tariff or in amendments hereof shall apply to the first month's billing of service in the regular course on and after the effective date set forth in such Tariff covering the use of gas service subsequent to the scheduled meter reading date for the immediately preceding month.

8.12. Payment of Bills: At least 15 days' time for payment shall be allowed after sending a bill. Bills are payable at any Customer Service Center of Public Service, or by mail, or to any collector or collection agency duly authorized by Public Service. Whenever a residential customer advises Public Service that the customer wishes to discuss a deferred payment agreement because the customer is presently unable to pay a total outstanding bill and/or deposit, Public Service will make a good-faith effort to allow the customer the opportunity to enter into a fair and reasonable deferred payment agreement, which takes into consideration the customer's financial situation. A residential electric or gas customer is not required to pay, as a down payment, more than 25% of the total outstanding bill due at the time of the agreement. Such agreements which extend more than 2 months must be in writing and shall provide that a customer who is presently unable to pay an outstanding debt for Public Service services may make reasonable periodic payments until the debt is liquidated, while continuing payment of current bills. While a deferred payment agreement for each separate service need not be entered into more than once a year, Public Service may offer more than one such agreement in a year. If the customer defaults on any of the terms of the agreement, Public Service may discontinue service after providing the customer with a notice of discontinuance. If a customer's service has been terminated for non-payment of bills, and has met all requirements for restoration of service, Public Service may require a deposit, but not prior to service restoration. Instead, Public Service will bill payment of the deposit, or make other reasonable arrangements. The amount of the deposit required for restoration of service will be determined in accordance with N.J.A.C. 14:3-3.4.

In the case of a residential customer who receives more than one utility service from Public Service and has entered into a separate agreement for each separate service, default on one such agreement shall constitute grounds for discontinuance of only that service.

8.13. Late Payment Charge: A late payment charge at the rate of 1.416% per monthly billing period shall be applied to the accounts of customers taking service under all rate schedules contained herein except for Rate Schedule RSG. Service to a body politic will not be subject to a late payment charge. The charge will be applied to all amounts billed including accounts payable and unpaid finance charges applied to previous bills,

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and will not be applied sooner than 25 days after a bill is rendered, in accordance with N.J.A.C. 14:3-7.1(e). The amount of the finance charge to be added to the unpaid balance shall be calculated by multiplying the unpaid balance by the late payment charge rate. When payment is received by Public Service from a customer who has an unpaid balance which includes charges for late payment, the payment shall be applied first to such charges and then to the remainder of the unpaid balance.

8.14. Returned Check Charge: A $15.00 charge shall be applied to the accounts of customers who have checks to Public Service returned unhonored by the bank.

8.15. Field Collection Charge: A charge may be applied to the accounts of customers when it becomes necessary for Public Service to make a collection visit to the customer or premises. A charge of $30.00 may be applied to commercial and industrial accounts which include Rate Schedules: GSG, LVG, SLG, CIG, TSG-F, TSG-NF and CSG.

8.16. Customer's Responsibility to Cooperate with the Company: The charge provisions for extensions are predicated upon cooperation by the Customer in an effort to keep the Company's cost as low as possible. Additional costs resulting from the Customer's failure to cooperate, such as the paving of roads, parking areas or driveways prior to the installation of Company's facilities, shall be borne by the Customer.

9. LEAKAGE

Customer shall immediately give notice to Public Service at its office of any escape of gas in or about the customer's premises. If a leakage is suspected, immediately exit the building and move at least 350 feet away. Once the customer is at a safe distance, call PSE&G Emergency Service Line at 1-800-880-PSEG (7734) or 911 to report a potential gas leak. Customer will not be charged for reporting a potential gas leak.

10. ACCESS TO CUSTOMER'S PREMISES

Public Service shall have the right of reasonable and safe access to customer's premises, and to all property furnished by Public Service, at all reasonable times for the purpose of inspection of customer's premises incident to the rendering of service, reading meters or inspecting, testing, or repairing its facilities used in connection with supplying the service, or for the removal of its property. The customer shall obtain, or cause to be obtained, all permits needed by Public Service for access to its facilities. Access to facilities of Public Service shall not be given except to authorized employees of Public Service or duly authorized governmental officials.

10.1. Drivable Surfaces: When a vehicle is needed to drive on customer's property to access Public Service facilities, the customer shall ensure that the path has a drivable surface that will prevent the vehicle from becoming disabled.

11. DISCONTINUANCE OF SERVICE

11.1. By Public Service: Public Service, upon ~~reasonable~~ notice, when it can be reasonably given, may suspend or curtail or discontinue service for the following reasons: (1) for the purpose of making permanent or temporary repairs, changes or improvements in any part of its system; (2) for compliance in good faith with any governmental order or directive notwithstanding such order or directive subsequently may be held to be invalid; (3) for any of the following acts or omissions on the part of the customer: (a) non~~-~~payment of a valid bill due for service furnished at a present or previous location~~. H~~, however, non~~-~~payment for business service shall not be a reason for discontinuance of ~~residence~~ residential service except in cases of diversion of service pursuant to N.J.A.C. 14:3-7.8; (b) tampering with any facility of Public Service; (c) fraudulent representation in relation to the use of service; (d) customer moving from the premises, unless the customer requests that service be continued; (e) providing service to others without approval of Public Service except as permitted under Section 8.3 Metering on Customer's Premises of these Standard Terms and Conditions; (f) failure to make or increase an advance payment or deposit as provided for in these Standard Terms and Conditions; (g) refusal to contract for service where such contract is required; (h) connecting and operating equipment in such manner as to produce disturbing effects on the service of Public Service or other customers; (i) failure of the customer to comply with any of these Standard Terms and Conditions; (j) where the condition of the customer's installation presents a hazard to life or property; or (k) failure of customer to repair any faulty facility of the customer; (4) for refusal of reasonable and safe access to customer's premises for necessary purposes in connection with rendering of service, including meter installation, reading or testing, or the maintenance or removal of the property of Public Service.

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Public Service ~~The Company~~ shall apply the regulations set forth in N.J.A.C. 14:3.3A.2(a), and only discontinue service for non-payment of bills if one or both of the following criteria are met: 1) the customer's arrearage is more than $~~100~~200.00; and/or 2) the customer's account is more than 3 months in arrears.

Public Service may not discontinue service for non-payment of bills unless it gives the customer at least 10 days written notice of its intentions to discontinue service, 15 days if a landlord-tenant relationship is known to exist. The notice of discontinuance shall not be served until the expiration of the 15-day period indicated in Section 8.12 Payment of Bills of these Standard Terms and Conditions. No additional notice will be required when, in a response to a notice of discontinuance, payment by check is subsequently dishonored. However, in case of fraud, illegal use, or when it is clearly indicated that the customer is preparing to leave, immediate payment of accounts may be required.

Public Service may not discontinue service because of non-payment of bills in cases where a charge is in dispute, provided that the undisputed charges are paid and a request is made to the Board for investigation of the disputed charge. In such cases, Public Service shall notify the customer that unless steps are taken to invoke formal or informal Board action within 5 days, service will be discontinued for non-payment.

Public Service may not discontinue residential service involuntarily except between the hours of 8:00 A.M. ~~to~~ and 4:00 P.M. Monday through Thursday, unless there is a safety related emergency. There shall be no involuntary termination of service on Friday, Saturday, and Sunday or on the day before a holiday or on a holiday, absent such emergency.

Subject to the conditions set forth below, d~~D~~iscontinuance of residential service for non-payment is prohibited if a medical emergency exists within the premises which would be aggravated by discontinuance of service. ~~and the customer gives reasonable proof of inability to pay.~~ Discontinuance shall be prohibited for a period of ~~up to 2 months~~90 days initially when a customer submits a ~~physician's statement~~licensed medical professional's statement in writing to Public Service as to the existence of the emergency, its nature and probable duration, and that termination of service will aggravate the medical emergency. Public Service may also require the customer to give reasonable proof of inability to pay. ~~Recertification by the physician as to continuance of the medical emergency shall be submitted to Public Service after 30 days.~~ However, at the end of such period of emergency, the customer shall still remain liable for payment of service(s) rendered, subject to the provision of N.J.A.C. 14:3-7.7.

1. The Board may extend the ~~6~~90-day period for good cause upon the receipt of a written request from the customer. ~~That~~The written request shall be in accordance with the preceding terms. Pending the Board's consideration and decision regarding the request for extension, service shall not be discontinued.

2. Public Service may in its discretion, delay discontinuance of residential service for nonpayment prior to submission of the licensed medical professional's~~physician's~~ statement required by this subsection when a medical emergency is known to exist.

If Public Service disconnects service to an unknown account and is notified that a medical emergency exists in the residential premises, Public Service shall: (1) restore service immediately; (2) allow 14 days to apply for service; and (3) allow 7 additional days following the service activation date or 21 days following the date it is notified of a medical emergency, whichever date is later, to submit a medical certification to Public Service written by a licensed medical professional in accordance with the preceding terms.

If a residential customer offers payment of the full amount or a reasonable portion of the amount due at the time of discontinuance, a Public Service representative shall accept payment without discontinuance of service. Whenever such payment is made, the representative shall provide the customer with a receipt showing the date, account number, customer's name and address and amount received.

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Public Service shall make every reasonable effort to determine when a landlord-tenant relationship exists at residential premises being served. If such a relationship is known to exist, and if the tenants are not the customers of record but are ~~end~~ end-users, service will not be ~~shut off~~discontinued unless Public Service has given a 15-day written notice to the owner of the premises or to the customer of record to whom the last preceding bill was rendered. Public Service will use its best efforts to provide discontinuance notices to all tenants, including providing tenants with a 15-day written notice, which will be ~~hand~~ hand-delivered, mailed or posted in a conspicuous area of the premises and in the common areas of multiple family premises.

In addition, if posting is the method of notification used, Public Service will use its best efforts to place a copy of the notice on each tenant's car windshield or under the door of each tenant's dwelling. In the case of tenants of single and two-family dwellings, each tenant will be provided with a 15-day individual notice.

When a landlord-tenant relationship is known to exist, at the landlord's request, Public Service will provide the landlord with notice and/or have the service placed in the landlord's name if the tenant's service is being discontinued.

If Public Service disconnects service to a master metered premises in which the landlord is the actual customer of record and Public Service has been notified that a medical emergency exists by a tenant, Public Service shall restore service for a period of 7 days to allow the customer of record to resolve the nonpayment issue and to provide the tenant with time to make alternative arrangements.

Public Service shall not discontinue service during the period from November 15 through March 15, in accordance with N.J.A.C. 14:3-3A.5(a), unless otherwise ordered by the Board of Public Utilities, to those residential customers who demonstrate at the time of the intended termination that they are: (1) recipients of benefits ~~of: (1)~~under the Lifeline Credit Program; (2) recipients of benefits under the Federal Home Energy Assistance Program (HEAP)~~; (3)~~, or certified as eligible therefor under standards set by the New Jersey Department of Human Services; (3) recipients of Temporary Assistance to Needy Families (TANF); (4) recipients of Federal Supplemental Security Income (SSI); (5) recipients of Pharmaceutical Assistance to the Aged and Disabled (PAAD); (6) recipients of General Assistance (GA) benefits; (7) recipients of the Universal Service Fund (USF); or (8) ~~Persons~~ persons unable to pay their utility bills because of circumstances beyond their control.

Public Service shall not discontinue service to any residential customer, for reasons of nonpayment, failure to pay a cash security deposit or guarantee, or failure to comply with the terms of a deferred payment plan, whenever the high temperature is forecast to be 32 degrees Fahrenheit or below during the next 24 hours, in accordance with N.J.A.C. 14:3-3A.2(e)1.

Public Service shall not discontinue service to any residential customer eligible for the Winter Termination Program, for reasons of nonpayment, failure to pay a cash security deposit or guarantee, or failure to comply with a deferred payment agreement, whenever the high temperature is forecast to be ~~95~~ 90 degrees Fahrenheit or more at any time during the following 48 hours, in accordance with N.J.A.C. 14:3-3A.2(e)3.

11.2. **At Customer's Request:** A customer wishing to discontinue service must give notice as provided in the applicable rate schedule. Within 48 hours of said notice, Public Service will discontinue service or obtain a meter reading for the purpose of calculating a final bill. Where such notice is not received by Public Service, customer shall be liable for service until final reading of the meter is taken. Notice to discontinue service will not relieve a customer from any minimum or guaranteed payment under any contract or rate schedule.

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12. RECONNECTION CHARGE

A reconnection charge of $45.00 will be made for restoration of service when service has been suspended or discontinued for non-payment of any bill due.

13. SERVICE LIMITATIONS

13.1. **Continuity of Service:** Public Service will use reasonable diligence to provide a regular and uninterrupted supply of service; but, should the supply be suspended, curtailed, or discontinued by Public Service for any of the reasons set forth in Section 11 of these Standard Terms and Conditions, or should the supply of service be interrupted, curtailed, deficient, defective, or fail, by reason of any act of God, accident, strike, legal process, governmental interference, or by reason of compliance in good faith with any governmental order or directive, notwithstanding such order or directive subsequently may be held to be invalid, Public Service shall not be liable for any loss or damage, direct or consequential, resulting from any such suspension, discontinuance, interruption, curtailment, deficiency, defect, or failure.

13.2. **Emergencies:** Public Service may curtail or interrupt service to any customer or customers in the event of an emergency threatening the integrity of its system or the systems to which it is directly or indirectly connected if, in its sole judgment, such action will prevent or alleviate the emergency condition.

13.3. **Unusual Conditions:** Public Service may place limitations on the amount and character of gas service it will supply or transport and may refuse such service to new customers, to existing customers for additional load, or to customers whose service agreements have expired if Public Service is or will be unable to obtain or does not have assured the necessary production raw materials, equipment and facilities to supply such gas or transportation service. In the case of transportation service, if Public Service, at its sole discretion, determines that such service would not be consistent with the best interest of its customers served under all rate schedules contained herein such service may be denied to applicants for such service.

14. THIRD PARTY SUPPLIER SERVICE PROVISIONS

14.1. **Third Party Supplier Gas Supply:** Customers served on Rate Schedules RSG, GSG, LVG, SLG, TSG-NF, and CSG may choose to receive gas supply from either a Third Party Supplier (TPS) or from Public Service through its Basic Gas Supply Service. Customers on these rate schedules who are not enrolled with a TPS will receive their gas supply from Public Service. Customers served on Rate Schedule TSG-F may only receive gas supply from a TPS. The customer's supply of gas is limited to one TPS for the account(s) at a particular customer facility or complex.

A TPS is either a retail energy provider that has been licensed by the Board or is a customer served under Rate Schedules TSG-NF and CSG that has elected to self supply and act as a TPS on their own behalf. All TPSs must execute an Application for Service, be accepted by Public Service, and conform with the Third Party Supplier Requirements section of this Tariff.

14.2. **Enrollment:** Customers may request an enrollment package from Public Service which in addition to providing general information regarding gas supply describes the process necessary for a customer to obtain a TPS for gas supply. This enrollment package will be provided to the customer at no charge and may be obtained by calling or writing Public Service or visiting a Customer Service Center. Once the customer has chosen a TPS, the customer must provide appropriate authorization as required by their designated supplier.

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STANDARD TERMS AND CONDITIONS
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14.3. Selection or Change of Third Party Supplier: In order to be eligible to receive gas supply from a TPS, the customer must contract with a TPS to obtain gas supply for delivery to the customer by Public Service. The customer's designated TPS is required to notify Public Service of its selection as the customer's provider of gas supply on or before the 10th calendar day of the month to become effective on the first scheduled meter reading date beginning with the first calendar day of the following month for Rate Schedules RSG, GSG, LVG, and SLG. Notification for customers on Rate Schedules TSG-F, TSG-NF, and CSG is required prior to the last business day of the month. Such selection shall remain in effect for the entire billing period.

For customers on Rate Schedule RSG, GSG, LVG, SLG, TSG-F, TSG-NF and CSG, once Public Service has received the TPS notification for the initial, or subsequent, enrollment with a TPS, Public Service will confirm the customer's selection of its designated TPS by sending a letter of confirmation to the customer, which will be sent within one business day. In the event of a dispute, assignment of a customer will not occur unless and until the dispute is resolved. This confirmation letter will include notification of the RSG customer's right to rescind their contract with their designated TPS which must be exercised within seven (7) days of mailing of the letter of confirmation. Once assignment has occurred, the TPS will be required to supply all of the gas supply on the Public Service customer's account.

14.4. Return to Public Service Basic Gas Supply Service Default Service: Customers may return to Public Service Basic Gas Supply Service default service for commodity supply under the conditions and procedures as outlined below.

14.4.1. Customers on Rate Schedules RSG, GSG, LVG and SLG: Customers that subsequently choose to return to Basic Gas Supply Service default service must notify Public Service on or before the 10th calendar day of the month to become effective on the first scheduled meter reading date beginning with the first calendar day of the following month. Public Service will confirm the customer's selection of Basic Gas Supply Service default service gas supply by sending a letter of confirmation to the customer, which will be sent within one business day. This confirmation letter will include notification of the customer's right to rescind their selection which must be exercised within seven (7) days of mailing of the letter of confirmation. GSG, LVG, and SLG customers not exercising their right of rescission within the seven (7) day period may be subject to renewable one-year terms on Basic Gas Supply Service default service.

If a customer's TPS notifies Public Service on or before the 10th calendar day of the month that it has terminated its supply relationship with the customer, such termination will become effective on the first scheduled meter reading date beginning with the first calendar day of the following month. The customer will be advised by Public Service in writing of this change in supplier. The customer will be placed on the applicable Public Service Basic Gas Supply Service default service unless the customer has selected another TPS in accordance with Section 14.3. GSG, LVG, and SLG customers provided Basic Gas Supply Service default service for two or more consecutive months may be subject to renewable one-year terms on Basic Gas Supply Service default service.

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14.4.2. Customers on Rate Schedules TSG-NF and CSG (with maximum requirement of less than 2,000 therms per hour): For customers that subsequently choose to return to Basic Gas Supply Service default service, the return will become effective on the first of the month following the customer's written notification to Public Service, provided that such notice was given prior to the last business day of the preceding month. Public Service will confirm the customer's selection of Basic Gas Supply Service default service gas supply by sending a letter of confirmation to the customer, which will be sent within one business day.

If a customer's TPS notifies Public Service that it has terminated its supply relationship with the customer, such termination will become effective on the first of the month after such notification, provided such notification was received no later than the next to last business day of the month. In the event that notification is received after the next to last business day of the month, such termination shall become effective the first of the second month following such notification. The customer will be advised by Public Service in writing of this change in supplier. The customer will be placed on the applicable Public Service Basic Gas Supply Service default service unless the customer has selected another TPS in accordance with Section 14.3.

14.4.3. Customers on Rate Schedule TSG-F: Basic Gas Supply Service default service is not available for customers on Rate Schedule TSG-F.

14.5. Emergency Sales Service: Under certain conditions as specified below, Public Service may supply gas commodity on the Emergency Sales Service provision. Emergency Sales Service will be offered at the sole discretion of Public Service, after taking into consideration its other firm supply obligations. Public Service reserves the right to curtail service to any customer if deliveries from customer's TPS pursuant to Third Party Supplier Requirements are curtailed.

14.5.1. Customers on Rate Schedules RSG, GSG, LVG and SLG: During any month where Public Service cannot confirm that the customer has an eligible TPS, or if the TPS no longer satisfies the Third Party Supply Requirements section of this tariff, Public Service may supply gas commodity service to such customer as Emergency Sales Service unless and until customer selects another TPS in accordance with Section 14.3. The customer will be advised by Public Service in writing that, until the customer's next meter reading date the customer will be billed, in addition to all applicable delivery charges, the Emergency Sales Service Charge for all of its applicable Daily Contract Quantity (DCQ) therms. Thereafter, the customer will be placed on the applicable Public Service Basic Gas Supply Service default service. GSG, LVG, and SLG customers provided Basic Gas Supply Service default service for two or more consecutive months may be subject to renewable one-year terms on Basic Gas Supply Service default service.

14.5.2. Customers on Rate Schedules TSG-NF and CSG (with maximum requirement of less than 2,000 therms per hour): During any month where Public Service cannot confirm that the customer has an eligible TPS, or if the TPS no longer satisfies the Third Party Supply Requirements section of this tariff, Public Service may supply gas commodity service to such customer as Emergency Sales Service unless and until customer selects another TPS in accordance with Section 14.3. The customer will be advised by Public Service in writing that, for the balance of the current month the customer will be billed, in addition to all applicable delivery charges, the Emergency Sales Service Charge for all of its therm usage. Commencing on the first of the following month the customer will be placed on the applicable Public Service Basic Gas Supply Service default service.

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14.5.3. Customers on Rate Schedule TSG-F: During any month where Public Service cannot confirm that the customer has an eligible TPS, or if the TPS no longer satisfies the Third Party Supply Requirements section of this tariff, Public Service may supply gas commodity service to such customer as Emergency Sales Service unless and until customer selects another TPS in accordance with Section 14.3. The customer will be advised by Public Service in writing that the customer will be billed, in addition to all applicable delivery charges the Emergency Sales Service Charge for all of its therm usage.

14.6. Customer Billing Process: For TPS retail customers served under Rate Schedule RSG, GSG, LVG and SLG, Public Service will provide one combined bill containing both Public Service charges and TPS gas supply charges, providing the TPS executes and satisfies the terms of the Third Party Supplier Customer Account Services Master Service Agreement, and the retail customer(s) maintain a satisfactory bill payment history. Customer(s) may elect to receive a separate bill directly from its TPS for third party supplied services. If a customer requests and is permitted to receive a combined bill, but the customer's account subsequently becomes 120 days in arrears at any point in the future, such customer will thereafter be required to receive a separate bill directly from its TPS (including any subsequent TPS) for third party supplied services and will not be permitted to receive a combined bill from Public Service until such time the customer's arrearage is reduced to 60 days or less. Only Public Service owned, installed, and read meters will be used to determine customer usage for the purpose of calculating Public Service charges.

14.6.1. Payment of Bills: Where Public Service provides billing service, the payment of bills, including TPS's charges for gas supply if billed by Public Service, will be made to Public Service and will be in accordance with Section 8, Meter Reading and Billing, of these Standard Terms and Conditions. Any customer overpayment will be held in the customer's Public Service account to be applied against future customer bills or will be refunded to the customer at the customer's request.

14.6.2. Late Payment Charges: A late payment charge in accordance with Section 8.13, Late Payment Charge, of these Standard Terms and Conditions is to be applicable to Public Service customer charges and TPS's charges for gas supply if billed by Public Service. Customer shut-offs in cases where there is non-payment to Public Service for its customer charges and TPS's charges for gas supply if billed by Public Service, are only performed in accordance with Section 11, Discontinuance of Service, of these Standard Terms and Conditions.

14.6.3. Billing Disputes: In the event of a billing dispute between the customer and the TPS, Public Service's sole duty is to verify its customer charges and billing determinants. Customer continues to remain responsible for the timely payment of all Public Service charges and all undisputed TPS charges for gas supply if such charges are billed by Public Service in accordance with Section 8, Meter Reading and Billing, and Section 14.6.1, Payment of Bills, of these Standard Terms and Conditions. All questions regarding TPS's charges or other terms of the customer's agreement with a TPS are to be resolved between the customer and its TPS. Public Service will not be responsible for the enforcement, intervention, mediation, or arbitration of agreements entered into between TPS customer and TPS. Billing disputes that may arise regarding Public Service's charges shall be subject to Section 11, Discontinuance of Service, of these Standard Terms and Conditions.

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(Continued)

14.7. Third Party Supplier's Termination of Customer's Gas Supply: A TPS will not be permitted to physically connect or disconnect gas supply service to a customer.

14.8. Continuity of Service: Public Service shall have the right: (i) to require a TPS's gas supply sources to be disconnected from Public Service's gas system; (ii) to otherwise curtail, interrupt, or reduce a TPS's gas supply; or (iii) to disconnect a TPS's customer(s) in accordance with Section 11, Discontinuance of Service, and Section 13, Service Limitations, of these Standard Terms and Conditions.

14.9. Regulatory Requirements: Public Service will not be responsible for: making any arrangements necessary; obtaining from appropriate regulatory bodies any approvals necessary; any costs, charges and expenses including but not limited to the payment to appropriate governmental entities for any tax or assessment relative to the acquisition, transportation or use of customer's gas supply.

14.10. Delivery Liability: Public Service will not be liable in any way for any failure in whole or in part, temporary or permanent, to deliver gas under this Tariff for Gas Service to the extent such failure is due to customer's TPS's failure to deliver gas supplies to Public Service in accordance with the TPS Requirements. Public Service will not be liable in any way for errors in the calculation of the customer's DCQ and/or delivery requirement.

14.11. Delivery Control and Possession: After customer delivers gas or causes gas to be delivered to Public Service at Public Service's point of interconnection with the applicable interstate pipeline, Public Service will be deemed to be in control and possession of the gas until an equivalent amount of gas, less losses, is delivered to customer at customer's Public Service meter.

15. NEW JERSEY AUTHORIZED TAXES

The following taxes are authorized by the State of New Jersey and are applied in accordance with P.L. 1997, c. 162 (the "Energy Tax Reform Statute"), as amended by P.L. 2006, c. 44, as amended by P.L. 2009, c. 240 and P.L. 2016, c. 57, and are included in the appropriate charges contained within this Tariff for Gas Service.

15.1. New Jersey Sales and Use Tax: In accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c. 57, provision for the New Jersey Sales and Use Tax (SUT) has been included in all applicable charges by multiplying the charges that would apply before application of the SUT by the factor 1.06625.

15.1.1. Exemptions due to the Energy Tax Reform Statute: The Energy Tax Reform Statute exempts the following customers from the SUT provision, and when billed to such customers, the charges otherwise applicable shall be reduced by the provision for the SUT included therein:

a) Franchised providers of utility services (gas, electricity, water, wastewater and telecommunications services provided by local exchange carriers) within the State of New Jersey.

b-1) Cogenerators in operation, or which had filed an application for an operating permit or a construction permit and a certificate of operation in order to comply with air quality standards under P.L. 1954, c. 212 (C.26:2C-1 *et seq.*) with the New Jersey Department of Environmental Protection, on or before March 10, 1997.

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STANDARD TERMS AND CONDITIONS
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b-2) Cogeneration facilities that are constructed after January 1, 2010.

c) Special contract customers for which a customer-specific tax classification was approved by a written Order of the New Jersey Board of Public Utilities prior to January 1, 1998.

d) Agencies or instrumentalities of the federal government.

e) International organizations of which the United States of America is a member.

f) Additional customers as authorized by the State of New Jersey Department of Treasury in accordance with the provisions of P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c. 57.

15.1.2. Exemptions due to the Business Retention and Relocation Assistance Act: The Business Retention and Relocation Assistance Act (P.L. 2004, c. 65) and subsequent amendment (P.L. 2005, c. 374) exempts the following customers from the SUT provision, and when billed to such customers, the charges otherwise applicable shall be reduced by the provision for the SUT included therein:

a) A qualified business that employs at least 250 people within an enterprise zone, at least 50% of whom are directly employed in a manufacturing process, for the exclusive use or consumption of such business within an enterprise zone, and

b) A group of two or more persons:

(b-1) Each of which is a qualified business that are all located within a single redevelopment area adopted pursuant to the “Local Redevelopment and Housing Law,” P.L.1992, c.79 (C.40A:12A-1 *et seq.*);
(b-2) That collectively employ at least 250 people within an enterprise zone, at least 50% of whom are directly employed in a manufacturing process;
(b-3) Are each engaged in a vertically integrated business, evidenced by the manufacture and distribution of a product or family of products that, when taken together, are primarily used, packaged and sold as a single product; and
(b-4) Collectively use the energy and utility service for the exclusive use or consumption of each of the persons that comprise a group within an enterprise zone.

c) A business facility located within a county that is designated for the 50% tax exemption under section 1 of P.L. 1993, c. 373 (C.54:32B-8.45) provided that the business certifies that it employs at least 50 people at that facility, at least 50% of whom are directly employed in a manufacturing process, and provided that the energy and utility services are consumed exclusively at that facility.

A business that meets the requirements in (a), (b) or (c) above shall not be provided the exemption described in this section until it has complied with such requirements for obtaining the exemption as may be provided pursuant to P.L.1983, c. 303 (C.52:27H-60 *et seq.*) and P.L.1966, c. 30 (C.54:32B-1 *et seq.*) and Public Service has received a sales tax exemption letter issued by the New Jersey Department of Treasury, Division of Taxation.

15.2. New Jersey Corporation Business Tax: In accordance with P.L. 1997, c. 162, provision for the New Jersey Corporation Business Tax (CBT) has been included in the Service Charge, Distribution Charge, and the Demand Charge.

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15.2.1. Exemptions due to the Energy Tax Reform Statute: The Energy Tax Reform Statute exempts the following customers from the CBT provision, and when billed to such customers, the above tariff charges otherwise applicable shall be reduced by the provision for the CBT (and related SUT) included therein.

a) Franchised providers of utility services (gas, electricity, water, wastewater and telecommunications services provided by local exchange carriers) within the State of New Jersey.

b) Cogenerators in operation, or which had filed an application for an operating permit or a construction permit and a certificate of operation in order to comply with air quality standards under P.L. 1954, c. 212 (C.26:2C-1 *et seq.*) with the New Jersey Department of Environmental Protection, on or before March 10, 1997.

c) Special contract customers for which a customer-specific tax classification was approved by a written Order of the New Jersey Board of Public Utilities prior to January 1, 1998.

d) Additional customers as authorized by the State of New Jersey Department of Treasury in accordance with the provisions of P.L. 1997, c. 162.

16. NEW JERSEY AUTHORIZED EXEMPTIONS

The following exemptions are authorized by the State of New Jersey and are applied in accordance with P.L. 2011, c.9 (the “Long Term Capacity Agreement Pilot Program”, “LCAPP Legislation”). The exemptions take effect January 28, 2011.

16.1. Exemptions due to LCAPP Legislation: Electric generators who use natural gas to generate electricity that is sold for resale will be exempt from a societal benefits charge pursuant to N.J.S.A. 48:3-60.1 or any other charge designed to recover the costs for social, energy efficiency, conservation, environmental or renewable energy on natural gas delivery service or commodity that is used to generate electricity that is sold for resale. This exemption includes the Societal Benefits Charge (SBC) and the Green Programs Recovery Charge (GPRC). Each customer’s exemption will be effective upon completion of an Annual Certification form.

a) The Annual Certification form shall be a prerequisite for the exemption and shall be furnished to customers of record in December and returned to Public Service by the customer no later than January 15th of each year. The Annual Certification form shall certify the percentage of gas used at their New Jersey generation facilities during the immediately preceding calendar year to generate electricity that was sold for resale. This Certification will serve as the percentage of the customers’ throughput that will be exempt from the SBC and the GPRC. This Certification will then be used for the succeeding annual period commencing in February. If the customer fails to return the form, then the SBC and the GPRC will be assessed on all of the customer’s usage until a completed Annual Certification form is received to be effective after the next subsequent meter reading. If the customer returns a completed Annual Certification Form on or before January 15, then adjustments to customer’s bills to reflect changes in the percentage of gas used to generate electricity for resale will be made on a prospective basis beginning in February.

b) In those cases where prior calendar year usage is not available, the customer will submit an Annual Certification form with an estimated percentage of gas that will be used at their New Jersey generation facilities for the current calendar year to generate electricity to be sold for resale. Once agreement has been reached with PSE&G regarding the estimated percentage, the completed Certification will serve as the percentage of the customers’ throughput that will be exempt from the SBC and the GPRC effective after the next subsequent meter reading on a prospective basis for the remainder of the current calendar year.

STANDARD TERMS AND CONDITIONS
(Continued)

17. TERMINATION, CHANGE OR MODIFICATION OF PROVISIONS OF TARIFF

This tariff is subject to the lawful orders of the Board of Public Utilities of the State of New Jersey.

Public Service may at any time and in any manner permitted by law, and the applicable rules and regulations of the Board of Public Utilities of the State of New Jersey, terminate, or change or modify by revision, amendment, supplement, or otherwise, this Tariff or any part thereof, or any revision or amendment hereof or supplement hereto.

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RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 41**

SOCIETAL BENEFITS CHARGE

**CHARGE APPLICABLE TO
RATE SCHEDULES RSG, GSG, LVG, SLG,
TSG-F, TSG-NF, CIG, CSG
(Per Therm)**

Social Programs	$ 0.000000
Energy Efficiency and Renewables Programs	0.019520
Manufactured Gas Plant Remediation	0.008753
Universal Service Fund - Permanent	0.010800
Universal Service Fund - Lifeline	0.005800
Societal Benefits Charge	$ 0.044873
Societal Benefits Charge including New Jersey Sales and Use Tax (SUT)	$ 0.047846

Societal Benefits Charge

This mechanism is designed to insure recovery of costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Actual costs incurred by the Company for each of these cost components will be subject to deferred accounting. Interest at the two-year constant maturity treasury rate plus 60 basis points will be accrued monthly on any under-over recovered balances for all components other than Manufactured Gas Plant Remediation. Interest at the seven-year constant maturity treasury rate plus 60 basis points will be accrued monthly on any under- or over-recovered balances for the Manufactured Gas Plant Remediation. The interest rates for all components other than USF and Lifeline shall change each August 1. The interest rates for the USF and Lifeline components shall be reset each month.

See Section 16 of the Standard Terms and Conditions for exemptions from this charge.

**(Charges are for illustrative purposes only and are based on the
Ninth Revised Sheet No. 41 filed with the BPU on October 1, 2023)**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 42**

SOCIETAL BENEFITS CHARGE
(Continued)

SOCIAL PROGRAMS

This factor shall recover costs associated with existing social programs.

ENERGY EFFICIENCY AND RENEWABLES (EE&R) PROGRAMS

This factor is a recovery mechanism which will operate in accordance with the Demand Side Management (DSM) conservation incentive regulations and successor regulations. The factor has been used to recover past Core and Performance Program Costs and Performance Program Payments, payments for Large-Scale Conservation Investments, and all recoverable costs associated with the Board's Comprehensive Resource Analysis Orders, including but not limited to the low income Comfort Partners Program.

MANUFACTURED GAS PLANT REMEDIATION

This factor shall recovery costs associated with addressing and resolving claims by and or requirements of governmental entities and private parties related to activities necessary to perform investigations and the remediation of environmental media.

UNIVERSAL SERVICE FUND

These factors shall recover costs associated with new or expanded social programs.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 43**

MARGIN ADJUSTMENT CHARGE

**CHARGE APPLICABLE TO
RATE SCHEDULES RSG, GSG, LVG, SLG, TSG-F
(Per Therm)**

Margin Adjustment Charge .... ($0.005821)

Margin Adjustment Charge including New Jersey Sales and Use Tax (SUT)...................... ($0.006207)

Margin Adjustment Charge

This mechanism is designed to insure return of certain net revenues to the customer classes denoted above. Actual net revenues will be subject to deferred accounting. Interest at the seven-year constant maturity treasury rate plus 60 basis points will be accrued monthly on any under- or over-recovered balances.

(Charges are for illustrative purposes only and are based on the Fifth Revised Sheet No. 43 filed with the BPU on October 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 44**

GREEN PROGRAMS RECOVERY CHARGE

CHARGE APPLICABLE TO
RATE SCHEDULES RSG, GSG, LVG, SLG,
TSG-F, TSG-NF, CIG, CSG
(Per Therm)

Component:

Carbon Abatement Program	($0.000470)
Energy Efficiency Economic Stimulus Program	0.000167
Energy Efficiency Economic Extension Program	0.000329
Energy Efficiency Economic Extension Program II	0.000472
Energy Efficiency 2017 Program	0.003000
Clean Energy Future – Energy Efficiency Program	0.005528
Green Programs Recovery Charge	$0.009026
Green Programs Recovery Charge including New Jersey Sales and Use Tax SUT	$0.009624

Green Programs Recovery Charge

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs. The charge will be reset nominally on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under- or over- recovered balances. The interest rate shall be reset each month.

See Section 16 of the Standard Terms and Conditions for exemptions from this charge.

(Charges are for illustrative purposes only and are based on the Eighth Revised Sheet No. 44 filed with the BPU on October 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 48**

CONSERVATION INCENTIVE PROGRAM

CHARGE APPLICABLE TO
RATE SCHEDULES RSG, GSG, LVG
(Per Therm)

	Conservation Incentive Program	Conservation Incentive Program including SUT
RSG	$0.060736	$0.064760
GSG	$0.044451	$0.047396
LVG	$0.004748	$0.005063

Conservation Incentive Program

This charge shall be applicable to the rate schedules listed above. The Conservation Incentive Program shall be based on the differences between actual and allowed usage per customer during the preceding annual period. The Conservation Incentive Mechanism shall be determined as follows:

I. DEFINITION OF TERMS AS USED HEREIN

1. Actual Number of Customers
– the Actual Number of Customers (“ANC”) shall be determined on a monthly basis for each of the Customer Class Groups to which the Conservation Incentive Program (“CIP”) Clause applies. The ANC shall equal the aggregate actual monthly Service Charge revenue for each class of customers subject to the CIP as recorded on the Company’s books, divided by the service charge rate applicable to such class of customers in each Customer Class Group.

2. Actual Usage Per Customer
– the Actual Usage per Customer (“AUC”) shall be determined in therms on a monthly basis for each of the Customer Class Groups to which the CIP applies. The AUC shall equal the aggregate actual booked sales for the month as recorded on the Company’s books divided by the ANC for the corresponding month.

3. Adjustment Period
– shall be the year beginning immediately following the conclusion of the Annual Period.

4. Annual Period
– shall be the twelve consecutive months from October 1 of one calendar year through September 30 of the following calendar year.

5. Average 13 Month Common Equity Balance
– shall be the average of the beginning and ending common equity balances based on the latest publically available financials available before the end of the Annual Period. The Company shall provide the most recently available actual months plus forecasted data at the time of each Initial Filing. The forecasted data will be updated with actuals once the financial statements for the months have been disclosed.

6. Baseline Usage per Customer
– the Baseline Usage per Customer (“BUC”) shall be stated in therms on a monthly basis for each of the Customer Class Groups to which the CIP applies. The BUC shall be rounded to the nearest one tenth of one therm.

The BUC shall be reset each time new base rates are placed into effect through a base rate case.

(Charges are for illustrative purposes only and are based on the Third Revised Sheet No. 48 filed with the BPU on October 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 48A**

CONSERVATION INCENTIVE PROGRAM
(Continued)

7. Customer Class Group
– for purposes of determining and applying the CIP, customers shall be aggregated into three separate recovery class groups. The Customer Class Groups shall be as follows:

Group I:	RSG
Group II:	GSG
Group III:	LVG

8. Forecast Annual Usage
– the Forecast Annual Usage ("FAU") shall be the projected total annual throughput for all customers within the applicable Customer Class Group. The FAU shall be estimated based on normal weather.

9. Margin Revenue Factor
– the Margin Revenue Factor ("MRF") shall be the weighted-average margin rate as quoted in the individual service classes to which the CIP applies. The MRFs by Customer Class Group are as follows:

Group I	(RSG):	$0.437483
Group II	(GSG):	$0.328242
Group III	(LVG):	$0.046383

The MRF shall be reset each time new base rates are placed into effect, including Infrastructure Investment Program ("IIP") or all other future base rate changes.

10. Degree Days (DD)
– the difference between 65ºF and the mean daily temperature for the day. The mean daily temperature is the simple average of the 24 hourly temperature observations for a day.

11. Actual Calendar Month Degree Days
– the accumulation of the actual Degree Days for each day of a calendar month.

12. Normal Calendar Month Degree Days
– the level of calendar month degree days to which the weather portion of the CIP applies.

The normal calendar month Degree Days will be the twenty-year average of the National Oceanic and Atmospheric Administration (NOAA) First Order Weather Observation Station at the Newark airport and will be updated annually. The base level of normal HDD for the defined winter period months for the 2023-2024 Winter Period are set forth in the table below:

Month	Normal Heating Degree Days
October 2023	225.14
November 2023	515.50
December 2023	810.29
January 2024	1,005.68
February 2024	868.22
March 2024	682.63
April 2024	355.17
May 2024	123.16

13. Winter Period
– shall be the eight consecutive calendar months from October of one calendar year through May of the following calendar year.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 48B**

CONSERVATION INCENTIVE PROGRAM
(Continued)

14. Degree Day Consumption Factors
– the use per degree day component of the gas sales equations by month used in forecasting firm gas sales for the applicable rate schedules. Degree day Consumption Factors for the 2023-2024 Winter Period are set forth below and presented as therms per degree day:

	RSG-Residential		Commercial			Industrial		
Month			GSG		LVG	GSG		LVG
	Heating	Non- Heating	Heating	Non- Heating		Heating	Non- Heating	
Oct.-23	183,348	-	-	-	88,624	633	-	7,326
Nov.-23	269,657	2,352	34,861	2,625	88,624	1,220	139	7,321
Dec.-23	269,443	3,088	51,188	3,709	88,624	2,154	259	7,315
Jan.-24	303,067	3,111	52,644	3,907	90,462	2,463	234	7,452
Feb.-24	291,037	2,723	54,216	4,014	90,462	1,934	138	7,445
Mar.-24	293,337	3,012	55,149	4,047	90,462	2,215	243	7,437
Apr.-24	285,355	3,138	57,596	4,118	90,462	1,748	229	7,428
May-24	209,054	3,458	29,705	3,863	90,462	1,160	163	7,418

II. BASELINE USE PER CUSTOMER

The BUC for each Customer Class Group by month are as follows:

Month	RSG	GSG	LVG
Oct.	38.7	110.8	2,350.0
Nov.	87.6	172.0	3,486.2
Dec.	144.9	320.4	5,220.9
Jan.	180.6	421.1	6,506.4
Feb.	153.5	351.6	5,940.9
Mar.	124.5	275.8	5,478.7
Apr.	70.4	170.7	3,703.5
May	37.0	80.1	2,037.8
Jun.	21.0	49.2	1,477.0
Jul.	18.0	58.5	1,374.6
Aug.	18.0	50.5	1,379.9
Sep.	19.5	52.6	1,322.8
Total Annual	**913.7**	**2,113.3**	**40,278.7**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 48C**

CONSERVATION INCENTIVE PROGRAM
(Continued)

III. DETERMINATION OF THE CONSERVATION INCENTIVE PROGRAM

1. At the end of the Annual Period, a calculation shall be made that determines for each Customer Class Group the deficiency or excess to be surcharged or credited to customers pursuant to the CIP mechanism. The deficiency or excess shall be calculated each month by multiplying the result obtained from subtracting the Baseline Usage per Customer from the Actual Usage per Customer by the Actual Number of Customers and then multiplying the resulting therms by the Margin Revenue Factor.

2. The weather related change in customer usage shall be calculated as the difference between actual degree days and the above normal degree days multiplied by the consumption factors, and multiplying the result by the margin revenue factors as defined in Section I.9. of this rate schedule to determine the weather-related deficiency or excess. The weather-related amount will be subtracted from the total deficiency or excess to determine the non-weather related deficiency or excess.

3. Recovery of margin deficiency associated with non-weather related deficiency in customer usage will be subject to a BGSS savings test and a Variable Margin Revenue recovery limitation (“recovery tests”). Recovery of non-weather related margin deficiency will be limited to the smaller of (1) the level of BGSS savings achieved when such savings are less than 75 percent of the non-weather related margin deficiency, i.e. BGSS savings test, and (2) 4.0 percent of variable margins for the CIP Annual Period, i.e., Margin Revenue recovery limitation. Any amount that exceeds the above limitations may be deferred for future recovery and is subject to either or both of the recovery tests in a future year consistent with the amount by which either or both of the non-weather related margin deficiency exceeded the recovery tests. For the purposes of this calculation, the value of the weather related portion shall be calculated as set forth in Section III.2. of this rate schedule.

4. In addition, if the calculated ROE exceeds the allowed ROE from the utility's last base rate case by 50 basis points or more, recovery of lost revenues through the CIP shall not be allowed for the applicable filing period. For purposes of this section, the Company's rate of return on common equity shall be calculated by dividing the Company's net income for the applicable period as defined in the Average 13 Month Common Equity Balance by the Company's average common equity balance for the same period, all as reflected in the Company's monthly reports to the Board of Public Utilities. The Company's net income shall be calculated by subtracting from total operating income, any clause related Net Income, such as the Green Program’s Recovery Charge and interest expenses. The Company's Average 13 Month Common Equity Balance shall be the ratio of Gas Net Plant (including the Gas allocation of Common Plant) to total PSE&G Net Plant for the Average 13 Month Common Equity Balance period multiplied by the Company's total common equity for the same period.

5. The amount to be surcharged or credited shall equal the eligible aggregate deficiency or excess for all months during the Annual Period determined in accordance with the provisions herein, divided by the Forecast Annual Usage for the Customer Class Group.

IV. TRACKING THE OPERATION OF THE CONSERVATION INCENTIVE PROGRAM

The revenues billed, or credits applied, net of taxes and assessments, through the application of the Conservation Incentive Program Rate shall be accumulated for each month of the Adjustment Period and applied against the CIP excess or deficiency from the Annual Period and any cumulative balances remaining from prior periods.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 49**
Original Sheet No. 50

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 51**

TAX ADJUSTMENT CREDIT

Rate Schedule	Charge per Therm	Charge per Therm Including SUT
RSG	($0.064753)	($0.069043)
GSG	($0.054983)	($0.058626)
LVG	($0.025916)	($0.027633)
SLG	($0.094749)	($0.101026)
TSG-F	($0.022261)	($0.023736)
TSG-NF	($0.011569)	($0.012335)
CIG	($0.017044)	($0.018173)
CSG	($0.001181)	($0.001259)

Tax Adjustment Credit

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month.

(Charges are for illustrative purposes only and are based on the Sixth Revised Sheet No. 51 filed with the BPU on October 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 52**

DISTRIBUTION ADJUSTMENT CHARGE

CHARGE APPLICABLE TO
RATE SCHEDULES RSG, GSG, LVG, SLG,
TSG-F, TSG-NF, CIG, CSG
(Per Therm)

Component:

Storm Recovery Charge.. $0.XXXXXX
COVID-19 Cost Recovery 0.XXXXXX
Distribution Adjustment Charge $0.XXXXXX

Distribution Adjustment Charge including New Jersey Sales and Use Tax SUT $0.XXXXXX

Distribution Adjustment Charge

This charge is designed to recover Board-approved costs. The charge will be reset nominally on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under- or over- recovered balances. The interest rates shall be reset each month.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS ~~**Original Sheet No. 52**~~
Original Sheet No. 53

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 54**

BGSS-RSG
BASIC GAS SUPPLY SERVICE-RSG
COMMODITY CHARGES APPLICABLE TO RATE SCHEDULE RSG
(Per Therm)

Estimated Non-Gulf Coast Cost of Gas	$0.074813
Estimated Gulf Coast Cost of Gas	0.339920
Adjustment to Gulf Coast Cost of Gas	0.000000
Prior period (over) or under recovery	(0.049390)
Adjusted Cost of Gas	0.365343
Commodity Charge after application of losses: (Loss Factor = 2.0%)........	$0.372799
Commodity Charge including New Jersey Sales and Use Tax (SUT)	$0.397497

The above Commodity Charge will be established on a level annualized basis immediately prior to the winter season of each year for the succeeding twelve-month period. The estimated average Non-Gulf and Gulf Coast Cost of Gas will be adjusted for any under- or over-recovery together with applicable interest thereon which may have occurred during the operation of the Company's previously approved Commodity Charge filing. Further, the Company will be permitted a limited self-implementing increase to the Commodity Charge on December 1 and February 1 of each year. These limited self-implementing increases, if applied, are to be in accordance with a Board of Public Utilities approved methodology. Commodity Charge decreases would be permitted at any time if applicable.

The difference between actual costs and Public Service's recovery of these costs shall be determined monthly. If actual costs exceed the recovery of these costs, an underrecovery or a negative balance will result. If the recovery of these costs exceeds actual costs, an overrecovery or a positive balance will result. Interest shall be applied monthly to the average monthly cumulative deferred balance, positive or negative, from the beginning to the end of the annual period. Monthly interest on negative deferred balances (underrecoveries) shall be netted against monthly interest on positive deferred balances (overrecoveries) for the annual period. A cumulative net positive interest balance at the end of the annual period is owed to customers and shall be returned to customers in the next annual period. A cumulative net negative interest balance shall be zeroed out at the end of the annual period. The sum of the calculated monthly interests shall be added to the overrecovery balance or subtracted from the underrecovery balance at the end of the annual period. The positive interest balance shall be rolled into the beginning under- or over-recovery balance of the subsequent annual period.

Pursuant to the Board's January 6, 2003 Order approving the BGSS price structure under Docket No. GX01050304 and the BGSS Pricing Proposal appended as Attachment A to and approved in that Order, Public Service Electric and Gas Company may issue a bill credit for its BGSS-RSG customers as detailed below.

Effective	BGSS-RSG Credit (per therm)	BGSS-RSG Credit including SUT (per therm)
February 1, 2020 through March 31, 2020	($0.070340)	($0.075000)
April 1, 2020	$0.000000	$0.000000

(Charges are for illustrative purposes only and are based on the Twenty-Third Revised Sheet No. 54 filed with the BPU on October 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 55**

BGSS-F
BASIC GAS SUPPLY SERVICE-FIRM
COMMODITY CHARGES APPLICABLE TO RATE SCHEDULES GSG, LVG, SLG, CSG
(Per Therm)

COMMODITY CHARGE:	Commodity Charge	$ 0.499741
	Commodity Charge including New Jersey Sales and Use Tax (SUT)	$ 0.532849
FLOOR PRICE:	Non-Gulf Coast Cost of Gas component	$ 0.173461
	Variable Cost of Commodity and Fuel	0.000000
	Cost of Gas Acquired to serve BGSS-F for the month	0.198685
	Total Cost of Gas	$ 0.372146
	Floor Price after application of losses (Loss Factor = 2.0%)	$ 0.379741
CEILING PRICE:	Commodity Charge	$ 0.505582

A market based charge including all applicable taxes to be posted by Public Service on a monthly basis. The foregoing Commodity Charge will be subject to a floor price equal to the sum of the Non-Gulf Coast Cost of Gas component and the Cost of Gas Acquired for these customers. Additionally, this Commodity Charge will not exceed a Ceiling Price equal to the applicable charge for Emergency Sales Service.

The Cost of Gas Acquired will be established prior to the beginning of each month based on the NYMEX closing price for the following month plus other fixed adjustments of a negative $0.050515 per therm.

~~For Rate Schedule CSG, t~~This service is only available for customers with a maximum requirement of 2,000 therms per hour.

(Charges are for illustrative purposes only and are based on the Fifty-Eighth Revised Sheet No. 55 filed with the BPU on July 28, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 56**

BGSS-I
BASIC GAS SUPPLY SERVICE-INTERRUPTIBLE
COMMODITY CHARGE APPLICABLE TO RATE SCHEDULES TSG-NF, CSG
(Per Therm)

COMMODITY CHARGE:	Commodity Charge	$ 0.462786
	Commodity Charge including New Jersey Sales and Use Tax (SUT)	$ 0.493446
FLOOR PRICE:	50% of the Non-Gulf Coast Cost of Gas component	$ 0.086730
	Variable Cost of Commodity and Fuel	0.000000
	Cost of Gas Acquired to serve BGSS-I for the month	0.249200
	Total Cost of Gas	$ 0.335930
	Floor Price after application of losses (Loss Factor = 2.0%)	$ 0.342786
CEILING PRICE:	Floor Price plus $0.18	$ 0.522786

A market based charge including all applicable taxes to be posted by Public Service on a monthly basis. The foregoing Commodity Charge will be subject to a floor price equal to the sum of 50% of the Non-Gulf Coast Cost of Gas component and the Cost of Gas Acquired for these customers. Additionally, this Commodity Charge will not exceed a Ceiling Price equal to the Floor Price plus 18 cents per therm.

The Cost of Gas Acquired will be established prior to the beginning of each month based on the NYMEX closing price for the following month.

~~For Rate Schedule CSG, t~~This service is only available for customers with a maximum requirement of 2,000 therms per hour.

(Charges are for illustrative purposes only and are based on the Fifty-Eighth Revised Sheet No. 56 filed with the BPU on July 28, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 57**

BGSS-CIG
BASIC GAS SUPPLY SERVICE – COGENERATION INTERRUPTIBLE
COMMODITY CHARGES APPLICABLE TO RATE SCHEDULE CIG
(Per Therm)

COMMODITY CHARGE:

Estimated Average Commodity Cost for the month	$ 0.249200
Variable Cost of Commodity and Fuel	0.000000
50% Weighted Average Pipeline Demand Costs	0.022352
Total Commodity Cost of Gas for the month	$ 0.271552
Total Commodity Cost of Gas after application of losses (Loss Factor = 2.0%)	$ 0.277094
Cogeneration Facilities in Service on or before March 10, 1997.	$ 0.277094
Cogeneration Facilities in Service after March 10, 1997 (Charges include New Jersey Sales and Use Tax)	$ 0.295451

<u>Combined Commodity and Distribution Charge – Information Only:</u>

Cogeneration Facilities in Service on or before March 10, 1997

Sum of a Distribution Charge of $0.088960 per therm for the first 600,000 therms used in each month plus the above Commodity Charge......................................	$ 0.366054
Sum of a Distribution Charge of $0.078960 per therm in excess of 600,000 therms used in each month plus the above Commodity Charge......................................	$ 0.356054

Cogeneration Facilities in Service after March 10, 1997
(Charges include New Jersey Sales and Use Tax)

Sum of a Distribution Charge of $0.094854 per therm for the first 600,000 therms used in each month plus the above Commodity Charge......................................	$ 0.390305
Sum of a Distribution Charge of $0.084191 per therm in excess of 600,000 therms used in each month plus the above Commodity Charge......................................	$ 0.379642

The monthly Distribution Charges for Rate Schedule CIG are shown on Sheet No. 107.

(Charges are for illustrative purposes only and are based on the Fifty-Eighth Revised Sheet No. 57 filed with the BPU on July 28, 2023)

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80 Park Plaza, Newark, New Jersey 07102
Filed pursuant to Order of Board of Public Utilities dated
in Docket No.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 58**

EMERGENCY SALES SERVICE
CHARGE APPLICABLE TO RATE SCHEDULES RSG, GSG, LVG, SLG, TSG-F, TSG-NF, CSG
(Per Therm)

Public Service's BGSS supplier(s)'s weighted average pipeline transportation cost including fuel, calculated at 100% load factor (WATC)...	$ 0.044850
Public Service's BGSS supplier(s)'s highest cost of gas purchased or used by Public Service during the month	0.269620
A charge of $0.181	0.181000
Total	$ 0.495470
Emergency Sales Service Charge after application of losses (Loss Factor = 2.0%)...	$ 0.505582
Emergency Sales Service Charge including New Jersey Sales and Use Tax (SUT)......	$ 0.539077

The charge for Emergency Sales Service will equal the sum of: (1) Public Service's BGSS supplier(s)'s weighted average pipeline transportation cost including fuel, calculated at 100% load factor (WATC); (2) Public Service's BGSS supplier(s)'s highest cost of gas purchased or used during that month, (including associated storage costs, if any); (3) a charge of 18.1 cents per therm; (4) application of losses; and (5) all other applicable taxes and surcharges.

~~For Rate Schedule CSG, t~~This service is only available for customers with a maximum requirement of 2,000 therms per hour.

(Charges are for illustrative purposes only and are based on the Fifty-Seventh Revised Sheet No. 58 filed with the BPU on July 28, 2023)

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 59**

BGSS-RSGOP
BASIC GAS SUPPLY SERVICE-RSG OFF-PEAK

COMMODITY CHARGE APPLICABLE TO
RATE SCHEDULE RSG OFF-PEAK USE
(Per Therm)

Cost of Off-Peak RSG Gas Acquired	$ 0.263220
20% of the Non-Gulf Coast Cost of Gas seasonal component	0.010280
Total Cost of Gas	$ 0.273500
Commodity Charge after application of losses: (Loss Factor = 2.0%)	$ 0.279082
Commodity Charge including New Jersey Sales and Use Tax (SUT)	$ 0.297571

The Commodity Charge will be established on a level basis for the billing months of May to October immediately prior to the Off-Peak season of each year. The Commodity Charge will equal the Cost of Off-Peak RSG Gas Acquired (plus the variable pipeline transportation cost including fuel) and 20% of the Non-Gulf Coast Cost of Gas seasonal component. The Commodity Charge will be adjusted for losses.

The Cost of Off-Peak RSG Gas Acquired will be established prior to the beginning of the Off-Peak period based on the average NYMEX closing price for the first 15 days of April for natural gas to be supplied in the months of May through October.

(Charges are for illustrative purposes only and are based on the Fifth Revised Sheet No. 59 filed with the BPU on October 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 60**

INFRASTRUCTURE IMPROVEMENT PROGRAM CHARGES

Rate Schedule		Base Distribution Charges Including SUT*	Energy Strong II Charges	Energy Strong II Charges Including SUT	Total Charges Including SUT
RSG					
Service Charge	per Month	$8.62	$0.00	$0.00	$8.62
Distribution Charges	per therm	0.046399	0.002603	0.002775	0.466475
Balancing Charge	per Balancing therm	0.097914	0.000000	0.000000	0.097914
Off-Peak Use	per therm	0.231851	0.001301	0.001388	0.233238
GSG					
Service Charge	per Month	20.09	0.13	0.14	20.23
Distribution Charge - Pre July 14, 1997	per therm	0.348581	0.001341	0.001430	0.350010
Distribution Charge - All Others	per therm	0.348581	0.001341	0.001430	0.350010
Balancing Charge	per Balancing therm	0.097914	0.000000	0.000000	0.097914
Off-Peak Use Dist Charge - Pre July 14, 1997	per therm	0.174290	0.000670	0.000715	0.175005
Off-Peak Use Dist Charge - All Others	per therm	0.174290	0.000670	0.000715	0.175005
LVG					
Service Charge	per Month	178.38	1.20	1.28	179.66
Demand Charge	per Demand therm	4.6464	0.0177	0.0188	4.6653
Distribution Charge 0-1,000 pre July 14, 1997	per therm	0.035914	(0.000629)	(0.000671)	0.035244
Distribution Charge over 1,000 pre July 14, 1997	per therm	0.052989	0.000404	0.000431	0.053420
Distribution Charge 0-1,000 post July 14, 1997	per therm	0.035914	(0.000629)	(0.000671)	0.035244
Distribution Charge over 1,000 post July 14, 1997	per therm	0.052989	0.000404	0.000431	0.053420
Balancing Charge	per Balancing therm	0.097914	0.000000	0.000000	0.097914
SLG					
Single-Mantle Lamp	per Unit per Month	14.1119	0.0000	0.0000	14.1119
Double-Mantle Lamp, inverted	per Unit per Month	14.1119	0.0000	0.0000	14.1119
Double Mantle Lamp, upright	per Unit per Month	14.1119	0.0000	0.0000	14.1119
Triple-Mantle Lamp, prior to January 1, 1993	per Unit per Month	14.1119	0.0000	0.0000	14.1119
Triple-Mantle Lamp, on and after January 1, 1993	per Unit per Month	71.9465	0.0000	0.0000	71.9465
Distribution Therm Charge	per therm	0.056854	0.000210	0.000224	0.057077

*Base Distribution Charges include GSMPII changes pursuant to Docket Nos. GR21121256, GR22060409 & GR22120749.

(Charges are for illustrative purposes only and are based on the Sixth Revised Sheet No. 60 filed with the BPU on October 1, 2023)

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 61**

INFRASTRUCTURE IMPROVEMENT PROGRAM CHARGES
(Continued)

Rate Schedule		Base Distribution Charges Including SUT*	Energy Strong II Charges	Energy Strong II Charges Including SUT	Total Charges Including SUT
TSG-F					
Service Charge	per Month	$955.37	$6.41	$6.84	$962.21
Demand Charge	per Demand therm	2.3306	0.0038	0.0040	2.3347
Distribution Charges	per therm	0.089084	0.000147	0.000157	0.089241
TSG-NF					
Service Charge	per Month	955.37	6.41	6.84	962.21
Distribution Charge 0-50,000	per therm	0.104741	0.000447	0.000476	0.105218
Distribution Charge over 50,000	per therm	0.104741	0.000447	0.000476	0.105218
CIG					
Service Charge	per Month	211.29	0.95	1.01	212.30
Distribution Charge 0-600,000	per therm	0.094412	0.000414	0.000441	0.094854
Distribution Charge over 600,000	per therm	0.083750	0.000414	0.000442	0.084191
~~**BGSS-RSG**~~					
~~Commodity Charge including Losses~~	~~per therm~~	~~0.397512~~	~~(0.000015)~~	~~(0.000015)~~	~~0.397497~~
CSG					
Service Charge	per Month	955.37	6.41	6.84	962.21
Distribution Charge - Non-Firm	per therm	0.104741	0.000447	0.000476	0.105218

*Base Distribution Charges include GSMPII changes pursuant to Docket Nos. GR21121256, GR22060409 & GR22120749.

INFRASTRUCTURE IMPROVEMENT PROGRAM CHARGE

These charges are designed to recover the revenue requirements associated with the Company's Infrastructure Improvement Programs (IIPs) in accordance with the New Jersey Board of Public Utilities' rules on IIPs, N.J.A.C. 14:3-2A.

For detail concerning individual rate class base distribution charges, see individual rate class tariff sheets.

(Charges are for illustrative purposes only and are based on the Seventh Revised Sheet No. 61 filed with the BPU on October 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS

Original Sheet No. 62
Original Sheet No. 63
Original Sheet No. 64

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 65**

RATE SCHEDULE RSG
RESIDENTIAL SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Firm delivery service for residential purposes. Customers may either purchase gas supply from a Third Party Supplier (TPS) or from Public Service's Basic Gas Supply Service default service as detailed in this rate schedule.

DELIVERY CHARGES:

Service Charge:

$8.08 in each month [$8.62 including New Jersey Sales and Use Tax (SUT)].

Distribution Charges:

Charge	Charge Including SUT	
$0.437491	$0.466475	per therm

Balancing Charge:

Charge	Charge Including SUT	
$0.091830	$0.097914	per Balancing Use Therm

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 60 for details of these charges.

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Societal Benefits include: 1) Social Programs, 2) Demand Side Management Programs, 3) Manufactured Gas Plant Remediation, 4) Consumer Education, and 5) Universal Service Fund. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Margin Adjustment Charge:

This charge shall credit net revenue associated with Rate Schedule Non-Firm Transportation Gas Service (TSG-NF) to customers on Rate Schedules RSG, GSG, LVG, SLG and TSG-F. Refer to the Margin Adjustment Charge sheet of this Tariff for the current charge.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs as approved by the Board. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

(Charges are for illustrative purposes only and are based on the Nineteenth Revised Sheet No. 65 filed with the BPU on October 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 66**

RATE SCHEDULE RSG
RESIDENTIAL SERVICE
(Continued)

Tax Adjustment Credit:

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current charge.

Conservation Incentive Program Charge:

This mechanism removes the Company's disincentive for promoting conservation by truing up actual usage to a baseline per customer established in its last approved rate case. Refer to the Conservation Incentive Program sheet of this Tariff for the current charge.

Distribution Adjustment Charge:

This charge is designed to recover Board-approved costs. Refer to the Distribution Adjustment Charge sheet of this Tariff for the current charge.

The Societal Benefits Charge, the Margin Adjustment Charge, the Green Programs Recovery Charge, the Tax Adjustment Credit, ~~and~~ the Conservation Incentive Program Charge, and the Distribution Adjustment Charge will be combined with the Distribution Charge for billing.

COMMODITY CHARGES:

A customer may choose to receive gas supply from either:

a) A TPS who has agreed to the terms and conditions of the Third Party Supplier Requirements portion of this Tariff, or
b) Public Service through its Basic Gas Supply Service default service. Public Service may also supply Emergency Sales Service in certain instances where a customer selected TPS does not deliver sufficient quantities of gas.

Third Party Supply:

A customer that receives gas supply from a TPS will be charged for gas supply according to any agreement between the customer and the TPS. The customer will not be charged for commodity by Public Service, except as provided for in Emergency Sales Service below.

Emergency Sales Service:

In the event that, during any month, a customer's chosen TPS does not deliver the quantities of gas required, or if Public Service cannot confirm that the customer has an eligible TPS, Public Service may supply the deficiencies as Emergency Sales Service.

Emergency Sales Service will be offered at the sole discretion of Public Service, after taking into consideration its other firm supply obligations. Public Service reserves the right to curtail service to any customer if deliveries from customer's TPS pursuant to Third Party Supplier Requirements are curtailed.

If a customer is receiving Emergency Sales Service and does not wish to designate a TPS for future deliveries or customer, for any reason, no longer desires to receive gas supply from a TPS, the customer may receive gas supply pursuant to Public Service's Basic Gas Supply Service-RSG.

The conditions under which Emergency Sales Service will apply are detailed in Section 14 - Third Party Supplier Service Provisions of the Standard Terms and Conditions of this Tariff, and the charges for this service are defined on the Emergency Sales Service sheet of this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 67**

RATE SCHEDULE RSG
RESIDENTIAL SERVICE
(Continued)

Basic Gas Supply Service:
Customers that do not receive gas supply from a TPS will be supplied under the Basic Gas Supply Service-RSG (BGSS-RSG) default service.

The BGSS-RSG Commodity Charge will be applied to all therms billed each month, except customers that receive Delivery Service under Special Provision (c) of this Rate Schedule where the therms used for all purposes in excess of 50 therms in any month during the Off-Peak Period shall be charged at the BGSS-RSGOP Commodity Charge.

Refer to the Basic Gas Supply Service – RSG sheets of this Tariff for the current charge for the BGSS-RSG commodity charge and the BGSS-RSGOP commodity charge.

OTHER CHARGES:

See Special Provisions (c) and (g) below.

BILLING DETERMINANTS:

Therms:
The number of therms used shall be determined by multiplying the number of hundred cubic feet used by the conversion factors which appear on every bill.

Balancing Use Therms:
During each of the billing months of October through May, if the average daily usage of gas in any month exceeds the average daily usage during the preceding billing months of June through September, the therms used in such month in excess of the product of the average daily usage in the preceding months of June through September times the number of days in the billing month shall be the Balancing Use Therms and subject to the Balancing Charge. For new customers and for customers who install additional gas burning equipment, the average daily usage in the preceding June through September time period to be used in the above calculation shall be estimated by Public Service.

Daily Contract Quantity:
The Customer's Daily Contract Quantity (DCQ) for each month shall be calculated by Public Service for twelve (12) months by dividing customer's weather-normalized usage, adjusted for losses, for each of the most recent twelve (12) billing months by the total number of days in each billing month. Public Service may adjust customer's DCQ during the year, due to changes in customer's gas equipment or pattern of usage, or projected usage. For new customers, customer's initial DCQ will be estimated by Public Service, based upon the rating of the customer's gas equipment and expected utilization of the equipment. At the end of each billing period Public Service will calculate the difference between customer's actual usage, adjusted for losses, and actual TPS supply for the billing period, taking into consideration any adjustments from prior months, and will adjust the DCQ for the second succeeding month by that difference divided by the total number of days in the month, provided that such adjustment will not decrease that month's adjusted DCQ to a level less than zero. Any such adjustment that would result in a particular month's DCQ being less than zero will be carried to a future month.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 68**

RATE SCHEDULE RSG
RESIDENTIAL SERVICE
(Continued)

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill.

TERM:

Customer may discontinue delivery service upon notice.

SPECIAL PROVISIONS APPLICABLE TO ALL CUSTOMERS:

(a) This rate schedule is available where all service is for residential purposes:

(a-1) In individual residences and appurtenant outbuildings;

(a-2) In residential premises where customer's use of gas service for purposes other than residential is incidental to the customer's residential use;

(a-3) For rooming or boarding houses where the number of rented rooms does not exceed twice the number of bedrooms occupied by the customer;

(a-4) In separately metered individual flats or apartments in multiple-family buildings;

(a-5) In multiple-family buildings of two or more individual flats or apartments where gas service is measured by one meter and is furnished to the tenants or occupants of the flats or apartments by the owner. Where Special Provision (c) is applicable, the applicable therms shall be multiplied by the number of individual flats or apartments, whether occupied or not;

(a-6) In multiple-family buildings of two to four individual flats or apartments where gas fired equipment serves multiple flats or apartments. Where Special Provision (c) is applicable, the applicable therms shall be multiplied by the number of individual flats or apartments, whether occupied or not.

(b) Service under this rate schedule is not available for resale.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 69**

RATE SCHEDULE RSG
RESIDENTIAL SERVICE
(Continued)

(c) **Off-Peak Use**: Limited to customers with gas central air-conditioning equipment having a rated capacity of not less than two tons of refrigeration. For all eligible customers the Distribution Charge for the therms used for all purposes in excess of 50 therms in any month during the Off-Peak period shall be set equal to one-half (1/2) the above Distribution Charge.

The Off-Peak period shall commence and end with the regularly scheduled meter readings in the months of April and October, respectively.

SPECIAL PROVISIONS APPLICABLE TO CUSTOMERS SELECTING THIRD PARTY SUPPLIERS FOR COMMODITY SERVICE:

(d) Customers who desire to purchase their gas supply from a TPS may request an enrollment package from Public Service that describes the process necessary for the customer to obtain a TPS for gas supply. This package will be provided to the customer at no charge by Public Service.

(e) The customer must contract with a TPS to arrange for deliveries to Public Service of the DCQ, and such TPS agrees to abide by the provisions of the Third Party Supplier Requirements. A customer is limited to one (1) TPS for gas for each account for which the customer receives delivery service.

(f) The customer's TPS is required to notify Public Service of the customer's selection on or before the 10th calendar day of the month to become effective on the first scheduled meter reading date beginning with the first calendar day of the following month, and such selection shall remain in effect for the billing period, subject to the conditions of Emergency Sales Service.

(g) Upon customer return to BGSS, change in TPS or the cessation of delivery service, Public Service shall review the status of customer's imbalance between actual usage and actual TPS's deliveries to the customer, less losses, and shall include such imbalances in that TPS's future delivery requirement.

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 15 of the Standard Terms and Conditions for additional details and/or exceptions.

THIRD PARTY SUPPLIER REQUIREMENTS:

TPSs are subject to the Third Party Supplier Requirements of this Tariff.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff.

Date of Issue: Effective:
Issued by SCOTT S. JENNINGS, SVP – Finance, Planning & Strategy – PSE&G
80 Park Plaza, Newark, New Jersey 07102
Filed pursuant to Order of Board of Public Utilities dated
in Docket No.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 70**
Original Sheet No. 71

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 72**

RATE SCHEDULE GSG
GENERAL SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Firm delivery service for general purposes where: 1) customer does not qualify for RSG and 2) customer's usage does not exceed 3,000 therms in any month. Customers may either purchase gas supply from a Third Party Supplier (TPS) or from Public Service's Basic Gas Supply Service default service as detailed in this rate schedule.

DELIVERY CHARGES:

Service Charge:

$18.97 in each month [$20.23 including New Jersey Sales and Use Tax (SUT)].

Distribution Charges:

Pre-July 14, 1997 *		All Others		
Charge	Charge Including SUT	Charge	Charge Including SUT	
$0.328263	$0.350010	$0.328263	$0.350010	per therm

* Applicable to customers who have taken TPS supplied commodity service continuously since July 14, 1997.

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 60 for details of these charges.

Balancing Charge:

Charge	Charge Including SUT	
$0.091830	$0.097914	per Balancing Use Therm

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Societal Benefits include: 1) Social Programs, 2) Demand Side Management Programs, 3) Manufactured Gas Plant Remediation, 4) Consumer Education, and 5) Universal Service Fund. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Margin Adjustment Charge:

This charge shall credit net revenue associated with Rate Schedule Non-Firm Transportation Gas Service (TSG-NF) to customers on Rate Schedules RSG, GSG, LVG, SLG and TSG-F. Refer to the Margin Adjustment Charge sheet of this Tariff for the current charge.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs as approved by the Board. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

(Charges are for illustrative purposes only and are based on the Eighteenth Revised Sheet No. 72 filed with the BPU on October 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 73**

RATE SCHEDULE GSG
GENERAL SERVICE
(Continued)

Tax Adjustment Credit:

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current charge.

~~The Tax Adjustment Credit will be combined with the distribution charge for billing.~~

Conservation Incentive Program Charge:
This mechanism removes the Company's disincentive for promoting conservation by truing up actual usage to a baseline per customer established in its last approved rate case. Refer to the Conservation Incentive Program sheet of this Tariff for the current charge.

Distribution Adjustment Charge:
This charge is designed to recover Board-approved costs. Refer to the Distribution Adjustment Charge sheet of this Tariff for the current charge.

The Tax Adjustment Credit, the Conservation Incentive Program Charge, and the Distribution Adjustment Charge will be combined with the distribution charge for billing.

The Societal Benefits Charge, the Margin Adjustment Charge, and the Green Programs Recovery Charge ~~and the Conservation Incentive Program Charge~~ will be combined for billing.

COMMODITY CHARGES:

A customer may choose to receive gas supply from either:
a) A TPS who has agreed to the terms and conditions of the Third Party Supplier Requirements portion of this Tariff, or
b) Public Service through its Basic Gas Supply Service default service. Public Service may also supply Emergency Sales Service in certain instances where a customer selected TPS does not deliver sufficient quantities of gas.

Third Party Supply:
A customer that receives gas supply from a TPS will be charged for gas supply according to any agreement between the customer and the TPS. The customer will not be charged for commodity by Public Service, except as provided for in Emergency Sales Service below.

Emergency Sales Service:
In the event that, during any month, a customer's chosen TPS does not deliver the quantities of gas required, or if Public Service cannot confirm that the customer has an eligible TPS, Public Service may supply the deficiencies as Emergency Sales Service.

Emergency Sales Service will be offered at the sole discretion of Public Service, after taking into consideration its other firm supply obligations. Public Service reserves the right to curtail service to any customer if deliveries from customer's TPS pursuant to Third Party Supplier Requirements are curtailed.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 74**

RATE SCHEDULE GSG
GENERAL SERVICE
(Continued)

If a customer is receiving Emergency Sales Service and does not wish to designate a TPS for future deliveries or customer, for any reason, no longer desires to receive gas supply from a TPS, the customer may receive gas supply pursuant to Public Service's Basic Gas Supply Service-Firm.

The conditions under which Emergency Sales Service will apply are detailed in Section 14 - Third Party Supply Service Provisions of the Standard Terms and Conditions of this Tariff, and the charges for this service are defined on the Emergency Sales Service sheet of this Tariff.

Basic Gas Supply Service:
Customers that do not receive gas supply from a TPS will be supplied under the Basic Gas Supply Service Firm (BGSS-F) default service, which will be applied to all therms billed each month. Refer to the Basic Gas Supply Service – Firm sheet of this Tariff for the current charge for BGSS-F commodity charge.

OTHER CHARGES:

See Special Provisions (b), (e) and (i) below.

BILLING DETERMINANTS:

Therms:
The number of therms used shall be determined by multiplying the number of hundred cubic feet used by the conversion factors which appear on every bill.

Balancing Use Therms:
During each of the billing months of October through May, if the average daily usage of gas in any month exceeds the average daily usage during the preceding billing months of June through September, the therms used in such month in excess of the product of the average daily usage in the preceding months of June through September times the number of days in the billing month shall be the Balancing Use Therms and subject to the Balancing Charge. For new customers and for customers who install additional gas burning equipment, the average daily usage in the preceding June through September time period to be used in the above calculation shall be estimated by Public Service.

Daily Contract Quantity:
The Customer's Daily Contract Quantity (DCQ) for each month shall be calculated by Public Service for twelve (12) months by dividing customer's weather-normalized usage, adjusted for losses, for each of the most recent twelve (12) billing months by the total number of days in each billing month. Public Service may adjust customer's DCQ during the year, due to changes in customer's gas equipment or pattern of usage, or projected usage. For new customers, customer's initial DCQ will be estimated by Public Service, based upon the rating of the customer's gas equipment and expected utilization of the equipment. At the end of each billing period, Public Service will calculate the difference between customer's actual usage, adjusted for losses, and actual TPS supply for the billing period, taking into consideration any adjustments from prior months, and will adjust the DCQ for the second succeeding month by that difference divided by the total number of days in the month, provided that such adjustment will not decrease that month's adjusted DCQ to a level less than zero. Any such adjustment that would result in a particular month's DCQ being less than zero will be carried to a future month.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 75**

RATE SCHEDULE GSG
GENERAL SERVICE
(Continued)

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill and subject to a late payment charge at the rate of 1.416% per monthly billing period in accordance with Section 8.13 of the Standard Terms and Conditions. Service to a body politic will not be subject to a late payment charge.

TERM:

One year and thereafter until terminated by five days' notice.

Customers who transfer from third party supply to Basic Gas Supply Service may be subject to renewable one year terms. Refer to Section 14 of the Standard Terms and Conditions of this Tariff for additional limitations regarding the term of Basic Gas Supply Service.

SPECIAL PROVISIONS APPLICABLE TO ALL CUSTOMERS:

(a) Service under this rate schedule is not available for resale, except where service is for motor vehicle fuel supplied through compression equipment.

(b) **Off-Peak Use:** This separately metered gas service is applicable for cooling or dehumidification when supplied through a separate meter. For all eligible customers the Distribution Charge for the therms used during the Off-Peak period shall be set equal to one-half (1/2) the above Distribution Charge.

The Off-Peak period shall commence and end with the regularly scheduled meter readings in the months of April and October, respectively.

(c) Service supplied under this rate schedule shall be separately metered and shall not be combined with use under any other rate schedule for billing purposes. Customer shall not be eligible to receive service under this rate schedule and any other rate schedule for the same equipment or for equipment supplying a common steam header.

(d) **Cogeneration Use:** Applicable to separately metered service for the sequential production of electrical energy and useful thermal energy from the same fuel source by a Qualifying Facility, as defined in Section 201 of the Public Utilities Regulatory Policies Act of 1978 whose cogeneration equipment meets the efficiency standards set forth in Chapter 18 of the Code of Federal Regulations, Sections 292.205 (a) and (b). Customer must document that qualifying status has been granted by the Federal Energy Regulatory Commission.

Service to a qualifying cogeneration facility as set forth above may be exempt from taxes as set forth in Section 15 of the Standard Terms and Conditions.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 76**

RATE SCHEDULE GSG
GENERAL SERVICE
(Continued)

(e) **Unmetered Service:** Unmetered service will be furnished, at the discretion of Public Service, for customer owned and installed gas lamps or other continuous burning devices. No other gas using devices shall be connected to this service. The customer shall provide, at the customer's expense, all necessary equipment and piping after the gas Service Connection. Further, the customer may be required to furnish and install, at the customer's own expense, a load-limiting device approved by Public Service, which shall be maintained by Public Service at customer's expense. Customer shall notify Public Service in writing as to changes in conditions or operation that may affect the gas consumption of the connected device(s). Public Service reserves the right to meter any and all such installations where customer does not comply with the requirements of this Special Provision.

(f) **Veterans' Organization Service:** Pursuant to N.J.S.A. 48:2-21.41, when natural gas service is delivered to a customer that is a Veterans' Organization, serving the needs of veterans of the armed forces, the customer may apply and be eligible for billing under this Special Provision.

(f-1) Each customer shall be eligible for billing under this Special Provision upon submitting an Application for Veterans' Organization Service under this rate schedule and by qualifying as a Veterans' Organization as defined by N.J.S.A. 48:2-21.41 as "an organization dedicated to serving the needs of veterans of the armed forces that: is chartered under federal law, qualifies as a tax exempt organization under paragraph (19) of subsection (c) of section 501 of the federal Internal Revenue Code of 1986, 26 U.S.C. s.501 (c)(19), or that is organized as a corporation under the 'New Jersey Nonprofit Corporation Act,' N.J.S.~~15~~A. 15:1-1 et seq." Under N.J.S.A. 48: 2-21.41, a qualified Veterans' Organization shall be charged the residential rate for service delivered to the property where the Veterans' Organization primarily operates, if the residential rate is lower than the commercial rate for service at that property.

The customer shall furnish satisfactory proof of eligibility of service under this Special Provision to the Company. Once proof of eligibility is determined by the Company, service under this Special Provision shall begin with the next billing cycle following receipt of the Application.

(f-2) The customer will continue to be billed on this rate schedule. At least once annually, the Company shall review eligible customers' delivery charges under this Special Provision for all relevant periods. If the comparable delivery charges under the Residential Service (RSG) rate schedule are lower than the delivery charges under its current rate schedule, a credit in the amount of the difference will be applied to the customer's next bill.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 77**

RATE SCHEDULE GSG
GENERAL SERVICE
(Continued)

SPECIAL PROVISIONS APPLICABLE TO CUSTOMERS SELECTING THIRD PARTY SUPPLIERS FOR COMMODITY SERVICE:

(g) Customers who desire to purchase their gas supply from a TPS may request an enrollment package from Public Service that describes the process necessary for the customer to obtain a TPS for gas supply. This package will be provided to the customer at no charge by Public Service.

(h) The customer must contract with a TPS to arrange for deliveries to Public Service of the DCQ, and such TPS agrees to abide by the provisions of the Third Party Supplier Requirements. A customer is limited to one (1) TPS for gas for each account for which the customer receives delivery service.

(i) The customer's TPS is required to notify Public Service of the customer's selection on or before the 10th calendar day of the month to become effective on the first scheduled meter reading date beginning with the first calendar day of the following month, and such selection shall remain in effect for the billing period, subject to the conditions of Emergency Sales Service.

(j) Upon customer return to BGSS, change in TPS or the cessation of delivery service, Public Service shall review the status of customer's imbalance between actual usage and actual TPS deliveries to the customer, less losses, and shall include such imbalances in that TPS's future delivery requirement.

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 15 of the Standard Terms and Conditions for additional details and/or exceptions.

THIRD PARTY SUPPLIER REQUIREMENTS:

TPSs are subject to the Third Party Supplier Requirements of this Tariff.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 78**

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 79**

RATE SCHEDULE LVG
LARGE VOLUME SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Firm delivery service for general purposes. Customers may either purchase gas supply from a Third Party Supplier (TPS) or from Public Service's Basic Gas Supply Service default service as detailed in this rate schedule.

DELIVERY CHARGES:

Service Charge:

$168.50 in each month [$179.66 including New Jersey Sales and Use Tax (SUT)].

Demand Charge (Applicable in the months of November through March):

Charge	Charge Including SUT	
$4.3754	$4.6653	per Demand Therm

Distribution Charges:

Per therm for the first 1,000 therms used in each month		Per therm in excess of 1,000 therms used in each month	
Charges	Charges Including SUT	Charges	Charges Including SUT
$0.033054	$0.035244	$0.050101	$0.053420

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 60 for details of these charges.

Balancing Charge:

Charge	Charge Including SUT	
$0.091830	$0.097914	per Balancing Use Therm

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Societal Benefits include: 1) Social Programs, 2) Demand Side Management Programs, 3) Manufactured Gas Plant Remediation, 4) Consumer Education, and 5) Universal Service Fund. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

(Charges are for illustrative purposes only and are based on the Eighteenth Revised Sheet No. 79 filed with the BPU on October 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 80**

RATE SCHEDULE LVG
LARGE VOLUME SERVICE
(Continued)

Margin Adjustment Charge:
This charge shall credit net revenue associated with Rate Schedule Non-Firm Transportation Gas Service (TSG-NF) to customers on Rate Schedules RSG, GSG, LVG, SLG and TSG-F. Refer to the Margin Adjustment Charge sheet of this Tariff for the current charge.

Green Programs Recovery Charge:
This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs as approved by the Board. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

Tax Adjustment Credit:
This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current charge.

~~The Tax Adjustment Credit will be combined with the distribution charge for billing.~~

Conservation Incentive Program Charge:
This mechanism removes the Company's disincentive for promoting conservation by truing up actual usage to a baseline per customer established in its last approved rate case. Refer to the Conservation Incentive Program sheet of this Tariff for the current charge.

Distribution Adjustment Charge:
This charge is designed to recover Board-approved costs. Refer to the Distribution Adjustment Charge sheet of this Tariff for the current charge.

The Tax Adjustment Credit, the Conservation Incentive Program Charge, and the Distribution Adjustment Charge will be combined with the distribution charge for billing.

The Societal Benefits Charge, the Margin Adjustment Charge, and the Green Programs Recovery Charge ~~and the Conservation Incentive Program Charge~~ will be combined for billing.

COMMODITY CHARGES:

A customer may choose to receive gas supply from either:
a) A TPS who has agreed to the terms and conditions of the Third Party Supplier Requirements portion of this Tariff, or
b) Public Service through its Basic Gas Supply Service default service. Public Service may also supply Emergency Sales Service in certain instances where a customer selected TPS does not deliver sufficient quantities of gas.

Third Party Supply:
A customer that receives gas supply from a TPS will be charged for gas supply according to any agreement between the customer and the TPS. The customer will not be charged for commodity by Public Service, except as provided for in Emergency Sales Service below.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 81**

RATE SCHEDULE LVG
LARGE VOLUME SERVICE
(Continued)

Emergency Sales Service:
In the event that, during any month, a customer's chosen TPS does not deliver the quantities of gas required, or if Public Service cannot confirm that the customer has an eligible TPS, Public Service may supply the deficiencies as Emergency Sales Service.

Emergency Sales Service will be offered at the sole discretion of Public Service, after taking into consideration its other firm supply obligations. Public Service reserves the right to curtail service to any customer if deliveries from customer's TPS pursuant to Third Party Supplier Requirements are curtailed.

If a customer is receiving Emergency Sales Service and does not wish to designate a TPS for future deliveries or customer, for any reason, no longer desires to receive gas supply from a TPS, the customer may receive gas supply pursuant to Public Service's Basic Gas Supply Service-Firm.

The conditions under which Emergency Sales Service will apply are detailed in Section 14 - Third Party Supply Service Provisions of the Standard Terms and Conditions of this Tariff, and the charges for this service are defined on the Emergency Sales Service sheet of this Tariff.

Basic Gas Supply Service:
Customers that do not receive gas supply from a TPS will be supplied under the Basic Gas Supply Service Firm (BGSS-F) default service, which will be applied to all therms billed each month. Refer to the Basic Gas Supply Service – Firm sheet of this Tariff for the current charge for BGSS-F commodity charge.

OTHER CHARGES:

See Special Provisions (f) and (i) below.

BILLING DETERMINANTS:

Therms:
The number of therms used shall be determined by multiplying the number of hundred cubic feet used by the conversion factors which appear on every bill.

Demand Therms:
The Demand Therms shall be the highest winter month (November through March) average daily usage calculated for the current month and all winter months occurring during the preceding 11 months. The customer's winter month average daily usage shall be determined for each billing month during that period of November through March by dividing billed therms, used by the customer, by the actual number of days in the billing period.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 82**

RATE SCHEDULE LVG
LARGE VOLUME SERVICE
(Continued)

Balancing Use Therms:
During each of the billing months of October through May, if the average daily usage of gas in any month exceeds the average daily usage during the preceding billing months of June through September, the therms used in such month in excess of the product of the average daily usage in the preceding months of June through September times the number of days in the billing month shall be the Balancing Use Therms and subject to the Balancing Charge. For new customers and for customers who install additional gas burning equipment, the average daily usage in the preceding June through September time period to be used in the above calculation shall be estimated by Public Service.

Daily Contract Quantity:
The Customer's Daily Contract Quantity (DCQ) for each month shall be calculated by Public Service for twelve (12) months by dividing customer's weather-normalized usage, adjusted for losses, for each of the most recent twelve (12) billing months by the total number of days in each billing month. Public Service may adjust customer's DCQ during the year, due to changes in customer's gas equipment or pattern of usage, or projected usage. For new customers, customer's initial DCQ will be estimated by Public Service, based upon the rating of the customer's gas equipment and expected utilization of the equipment. At the end of each billing period, Public Service will calculate the difference between customer's actual usage, adjusted for losses, and actual TPS supply for the billing period, taking into consideration any adjustments from prior months, and will adjust the DCQ for the second succeeding month by that difference divided by the total number of days in the month, provided that such adjustment will not decrease that month's adjusted DCQ to a level less than zero. Any such adjustment that would result in a particular month's DCQ being less than zero will be carried to a future month.

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill and subject to a late payment charge at the rate of 1.416% per monthly billing period in accordance with Section 8.13 of the Standard Terms and Conditions. Service to a body politic will not be subject to a late payment charge.

TERM:

One year and thereafter until terminated by five days' notice.

Customers who transfer from third party supply to Basic Gas Supply Service may be subject to renewable one year terms. Refer to Section 14 of the Standard Terms and Conditions of this Tariff for additional limitations regarding the term of Basic Gas Supply Service.

SPECIAL PROVISIONS APPLICABLE TO ALL CUSTOMERS:

(a) Service under this rate schedule is not available for resale, except where service is for motor vehicle fuel supplied through compression equipment.

(b) Service supplied under this rate schedule shall be separately metered and shall not be combined with use under any other rate schedule for billing purposes. Customer shall not be eligible to receive service under this rate schedule and any other rate schedule for the same equipment or for equipment supplying a common steam header during the term of the Service Agreement.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 83**

RATE SCHEDULE LVG
LARGE VOLUME SERVICE
(Continued)

(c) Where Public Service is unable to read the meter on a regular basis, Public Service may require the installation of a remote meter reading device at the customer's expense.

(d) **Cogeneration Use:** Applicable to separately metered service for the sequential production of electrical energy and useful thermal energy from the same fuel source by a Qualifying Facility, as defined in Section 201 of the Public Utilities Regulatory Policies Act of 1978 whose cogeneration equipment meets the efficiency standards set forth in Chapter 18 of the Code of Federal Regulations, Sections 292.205 (a) and (b). Customer must document that qualifying status has been granted by the Federal Energy Regulatory Commission.

Service to a qualifying cogeneration facility as set forth above may be exempt from taxes as set forth in Section 15 of the Standard Terms and Conditions.

(e) **Veterans' Organization Service:** Pursuant to N.J.S.A. 48:2-21.41, when natural gas service is delivered to a customer that is a Veterans' Organization, serving the needs of veterans of the armed forces, the customer may apply and be eligible for billing under this Special Provision.

(e-1) Each customer shall be eligible for billing under this Special Provision upon submitting an Application for Veterans' Organization Service under this rate schedule and by qualifying as a Veterans' Organization as defined by N.J.S.A. 48:2-21.41 as "an organization dedicated to serving the needs of veterans of the armed forces that: is chartered under federal law, qualifies as a tax exempt organization under paragraph (19) of subsection (c) of section 501 of the federal Internal Revenue Code of 1986, 26 U.S.C. s.501 (c)(19), or that is organized as a corporation under the 'New Jersey Nonprofit Corporation Act,' N.J.S.~~15~~A. 15:1-1 et seq." Under N.J.S.A. 48: 2-21.41, a qualified Veterans' Organization shall be charged the residential rate for service delivered to the property where the Veterans' Organization primarily operates, if the residential rate is lower than the commercial rate for service at that property.

The customer shall furnish satisfactory proof of eligibility of service under this Special Provision to the Company. Once proof of eligibility is determined by the Company, service under this Special Provision shall begin with the next billing cycle following receipt of the Application.

(e-2) The customer will continue to be billed on this rate schedule. At least once annually, the Company shall review eligible customers' delivery charges under this Special Provision for all relevant periods. If the comparable delivery charges under the Residential Service (RSG) rate schedule are lower than the delivery charges under its current rate schedule, a credit in the amount of the difference will be applied to the customer's next bill.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 84**

RATE SCHEDULE LVG
LARGE VOLUME SERVICE
(Continued)

SPECIAL PROVISIONS APPLICABLE TO CUSTOMERS SELECTING THIRD PARTY SUPPLIERS FOR COMMODITY SERVICE:

(f) Customers who desire to purchase their gas supply from a TPS may request an enrollment package from Public Service that describes the process necessary for the customer to obtain a TPS for gas supply. This package will be provided to the customer at no charge by Public Service.

(g) The customer must contract with a TPS to arrange for deliveries to Public Service of the DCQ, and such TPS agrees to abide by the provisions of the Third Party Supplier Requirements. A customer is limited to one (1) TPS for gas for each account for which the customer receives delivery service.

(h) The customer's TPS is required to notify Public Service of the customer's selection on or before the 10th calendar day of the month to become effective on the first scheduled meter reading date beginning with the first calendar day of the following month, and such selection shall remain in effect for the billing period, subject to the conditions of Emergency Sales Service.

(i) Upon customer return to BGSS, change in TPS or the cessation of delivery service, Public Service shall review the status of customer's imbalance between actual usage and actual TPS deliveries to the customer, less losses, and shall include such imbalances in that TPS's future delivery requirement.

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 15 of the Standard Terms and Conditions for additional details and/or exceptions.

THIRD PARTY SUPPLIER REQUIREMENTS:

TPSs are subject to the Third Party Supplier Requirements of this Tariff.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 85**
Original Sheet No. 86

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 87**

RATE SCHEDULE SLG
STREET LIGHTING SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Lamps, posts, maintenance, and firm delivery service for street lighting purposes. Customers may either purchase gas supply from a Third Party Supplier (TPS) or from Public Service's Basic Gas Supply Service default service as detailed in this rate schedule.

DELIVERY CHARGES:

Monthly Charge Per Unit (Includes lamp, post, maintenance and firm delivery service):

Lamps Installed Prior to January 1, 1993:

	Charges	Charges Including SUT
Single–mantle lamp	$ 13.2351	$ 14.1119
Double–mantle lamp, inverted	13.2351	14.1119
Double-mantle lamp, upright	13.2351	14.1119
Triple–mantle lamp	13.2351	14.1119

Lamps Installed on or after January 1, 1993:

	Charges	Charges Including SUT
Triple–mantle lamp	$ 67.4762	$ 71.9465

Allowance for Lamp Outages:

The Monthly Charge per unit reflects an outage allowance based upon normal operating conditions. No further allowance will be made.

Distribution Charge per Therm:

Charge	Charge Including SUT
$0.053531	$0.057077

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 60 for details of these charges.

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Societal Benefits include: 1) Social Programs, 2) Demand Side Management Programs, 3) Manufactured Gas Plant Remediation, 4) Consumer Education, and 5) Universal Service Fund. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Margin Adjustment Charge:

This charge shall credit net revenue associated with Rate Schedule Non-Firm Transportation Gas Service (TSG-NF) to customers on Rate Schedules RSG, GSG, LVG, SLG and TSG-F. Refer to the Margin Adjustment Charge sheet of this Tariff for the current charge.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs as approved by the Board. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

(Charges are for illustrative purposes only and are based on the Eleventh Revised Sheet No. 87 filed with the BPU on June 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 88**

RATE SCHEDULE SLG
STREET LIGHTING SERVICE
(Continued)

Tax Adjustment Credit:

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current charge.

~~The Tax Adjustment Credit will be combined with the distribution charge for billing.~~

Distribution Adjustment Charge:
This charge is designed to recover Board-approved costs. Refer to the Distribution Adjustment Charge sheet of this Tariff for the current charge.

The Tax Adjustment Credit and the Distribution Adjustment Charge will be combined with the distribution charge for billing.

The Societal Benefits Charge, the Margin Adjustment Charge, and the Green Programs Recovery Charge will be combined for billing.

COMMODITY CHARGES:

A customer may choose to receive gas supply from either:

a) A TPS who has agreed to the terms and conditions of the Third Party Supplier Requirements portion of this Tariff, or
b) Public Service through its Basic Gas Supply Service default service. Public Service may also supply Emergency Sales Service in certain instances where a customer selected TPS does not deliver sufficient quantities of gas.

Third Party Supply:
A customer that receives gas supply from a TPS will be charged for gas supply according to any agreement between the customer and the TPS. The customer will not be charged for commodity by Public Service, except as provided for in Emergency Sales Service below.

Emergency Sales Service:
In the event that, during any month, a customer's chosen TPS does not deliver the quantities of gas required, or if Public Service cannot confirm that the customer has an eligible TPS, Public Service may supply the deficiencies as Emergency Sales Service.

Emergency Sales Service will be offered at the sole discretion of Public Service, after taking into consideration its other firm supply obligations. Public Service reserves the right to curtail service to any customer if deliveries from customer's TPS pursuant to Third Party Supplier Requirements are curtailed.

If a customer is receiving Emergency Sales Service and does not wish to designate a TPS for future deliveries or customer, for any reason, no longer desires to receive gas supply from a TPS, the customer may receive gas supply pursuant to Public Service's Basic Gas Supply Service-Firm.

The conditions under which Emergency Sales Service will apply are detailed in Section 14 - Third Party Supplier Service Provisions of the Standard Terms and Conditions of this Tariff, and the charges for this service are defined on the Emergency Sales Service sheet of this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 89**

RATE SCHEDULE SLG
STREET LIGHTING SERVICE
(Continued)

Basic Gas Supply Service:
Customers that do not receive gas supply from a TPS will be supplied under the Basic Gas Supply Service-Firm (BGSS-F) default service, which will be applied to all therms billed each month. Refer to the Basic Gas Supply Service – Firm sheet of this Tariff for the current charge for the BGSS-F commodity charge.

OTHER CHARGES:

See Special Provision (e) below.

BILLING DETERMINANTS:

Therms:
The number of therms used are shown below for each lamps type.

Single-mantle .... 0.69 therms per day
Double-mantle, inverted .... 0.77 therms per day
Double-mantle, upright.. 1.37 therms per day
Triple-mantle .... 0.77 therms per day

Daily Contract Quantity:
The Customer's Daily Contract Quantity (DCQ) for each month shall be calculated by Public Service for twelve (12) months by multiplying the number of days in the billing month by the above listed daily usage values in therms, adjusted for losses, for each lamp type times the number of customer lamps. If the customer has multiple lamp types then the DCQ would be the sum from all lamp types calculated in the preceding manner. Public Service may adjust customer's DCQ during the year, due to changes in the number and types of customer's lamps.

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill and subject to a late payment charge at the rate of 1.416% per monthly billing period in accordance with Section 8.13 of the Standard Terms and Conditions. Service to a body politic will not be subject to a late payment charge.

TERM:

Five years; written contract required.

Customers who transfer from third party supply to Basic Gas Supply Service may be subject to renewable one year terms. Refer to Section 14 of the Standard Terms and Conditions of this Tariff for additional limitations regarding the term of Basic Gas Supply Service.

SPECIAL PROVISIONS APPLICABLE TO ALL CUSTOMERS:

(a) Service under this rate schedule is not available for resale.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 90**

RATE SCHEDULE SLG
STREET LIGHTING SERVICE
(Continued)

SPECIAL PROVISIONS APPLICABLE TO CUSTOMERS SELECTING THIRD PARTY SUPPLIERS FOR COMMODITY SERVICE:

(b) Customers who desire to purchase their gas supply from a TPS may request an enrollment package from Public Service that describes the process necessary for the customer to obtain a TPS for gas supply. This package will be provided to the customer at no charge by Public Service.

(c) The customer must contract with a TPS to arrange for deliveries to Public Service of the DCQ, and such TPS agrees to abide by the provisions of the Third Party Supplier Requirements. A customer is limited to one (1) TPS for gas for each account for which the customer receives delivery service.

(d) The customer's TPS is required to notify Public Service of the customer's selection on or before the 10th calendar day of the month to become effective on the first scheduled meter reading date beginning with the first calendar day of the following month, and such selection shall remain in effect for the billing period, subject to the conditions of Emergency Sales Service.

(e) Upon customer return to BGSS, change in TPS or the cessation of delivery service, Public Service shall review the status of customer's imbalance between actual usage and actual TPS deliveries to the customer, less losses, and shall include such imbalances in that TPS's future delivery requirement.

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 15 of the Standard Terms and Conditions for additional details and/or exceptions.

THIRD PARTY SUPPLIER REQUIREMENTS:

TPSs are subject to the Third Party Supplier Requirements of this Tariff.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 91**
Original Sheet No. 92

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 93**

RATE SCHEDULE TSG-F
FIRM TRANSPORTATION GAS SERVICE

This rate schedule is limited to customers continuously taking service under this rate schedule since December 1, 1994, with the exception of any new customers for whom commitments by Public Service had been made prior to December 1, 1994.

APPLICABLE TO USE OF SERVICE FOR:

Firm delivery, subject to Public Service's available capacity to provide such service, where the maximum requirement for firm gas is not less than 150 therms per hour and where the customer's Third Party Supplier (TPS) and/or its agent has arranged for the delivery of gas supplies to interconnection points with Public Service's distribution system, from which Public Service may receive and physically transport and deliver the customer's purchased gas supply.

DELIVERY CHARGES:

Service Charge:

$902.42 in each month [$962.21 including New Jersey Sales and Use Tax (SUT)].

Demand Charge (Applicable in the months of November through March):

Charge	Charge Including SUT	
$2.1896	$2.3347	per Demand Therm

Distribution Charges:

Charge	Charge Including SUT	
$0.083696	$0.089241	per therm

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 61 for details of these charges.

Public Service may reduce the Distribution Charge at the beginning of the month and/or during the month to reflect market conditions.

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Societal Benefits include: 1) Social Programs, 2) Demand Side Management Programs, 3) Manufactured Gas Plant Remediation, 4) Consumer Education, and 5) Universal Service Fund. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Margin Adjustment Charge:

This charge shall credit net revenue associated with Rate Schedule Non-Firm Transportation Gas Service (TSG-NF) to customers on Rate Schedules RSG, GSG, LVG, SLG and TSG-F. Refer to the Margin Adjustment Charge sheet of this Tariff for the current charge.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs as approved by the Board. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

(Charges are for illustrative purposes only and are based on the Eleventh Revised Sheet No. 93 filed with the BPU on June 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 94**

RATE SCHEDULE TSG-F
FIRM TRANSPORTATION GAS SERVICE
(Continued)

Tax Adjustment Credit:

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current charge.

~~The Tax Adjustment Credit will be combined with the distribution charge for billing.~~

Distribution Adjustment Charge:
This charge is designed to recover Board-approved costs. Refer to the Distribution Adjustment Charge sheet of this Tariff for the current charge.

The Tax Adjustment Credit and the Distribution Adjustment Charge will be combined with the distribution charge for billing.

The Societal Benefits Charge, the Margin Adjustment Charge and the Green Programs Recovery Charge will be combined for billing.

COMMODITY CHARGES:

A customer must choose to receive gas supply from a TPS who has agreed to the terms and conditions of the Third Party Supplier Requirements portion of this Tariff.

Third Party Supply:
A customer that receives gas supply from a TPS will be charged for gas supply according to any agreement between the customer and the TPS. The customer will not be charged for commodity by Public Service, except as provided for in Emergency Sales Service below.

Emergency Sales Service:
In the event that, during any month, Public Service cannot confirm that the customer has an eligible TPS, or if the TPS no longer satisfies the requirement of the Third Party Supplier Requirement portion of this Tariff, Public Service may supply the deficiencies as Emergency Sales Service. Public Service may supply gas commodity service to such customer as Emergency Sales Service unless and until customer selects another TPS.

Emergency Sales Service will be offered at the sole discretion of Public Service, after taking into consideration its other firm sales obligations. Public Service reserves the right to curtail service to any customer if deliveries from customer's TPS pursuant to Third Party Supplier Requirements are curtailed.

The conditions under which Emergency Sales Service will apply are detailed in Section 14 - Third Party Supply Service Provisions of the Standard Terms and Conditions of this Tariff, and the charges for this service are defined on the Emergency Sales Service sheet of this Tariff.

BILLING DETERMINANTS:

Therms:
The number of therms used shall be determined by multiplying the number of hundred cubic feet used by the conversion factors which appear on every bill. The conversion factor used for the "therm multiplier" shall be on the basis of the actual heating value of the gas used.

Demand Therms:
The Demand Therms shall be the highest winter month (November through March) average daily usage calculated for the current month and all winter months occurring during the preceding 11 months. The customer's winter month average daily usage shall be determined for each billing month during that period of November through March by dividing billed therms, used by the customer, by the actual number of days in the billing period.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 95**

RATE SCHEDULE TSG-F
FIRM TRANSPORTATION GAS SERVICE
(Continued)

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill and subject to a late payment charge at the rate of 1.416% per monthly billing period in accordance with Section 8.13 of the Standard Terms and Conditions. Service to a body politic will not be subject to a late payment charge.

TERM:

One year and thereafter until terminated by five days' notice.

SPECIAL PROVISIONS APPLICABLE TO ALL CUSTOMERS:

(a) Customer will be restricted to the maximum annual, daily and hourly requirements, and the location and equipment specified in the service agreement. Upon request by customer, Public Service may deliver available volumes of gas supply, adjusted for losses, in excess of the maximum requirements, for limited periods. Such deliveries shall not be deemed to constitute a change in the requirements specified in the service agreement.

(b) The customer must contract with a TPS to arrange for deliveries to Public Service of its daily usage, adjusted for losses, and such TPS agrees to abide by the provisions of the Third Party Supplier Requirements. A customer is limited to one (1) TPS for gas for each account for which the customer receives delivery service.

The customer's TPS is required to notify Public Service of the customer's selection prior to the last business day of the month for deliveries to commence on the first (1st) of the next month, and such selection shall remain in effect for the entire month, subject to the conditions of Emergency Sales Service. Customer can change TPSs effective only on the first day of the month.

Details for third party supply can be obtained by referring to Section 14 – Third Party Supplier Service Provisions of the Standard Terms and Conditions of this Tariff.

(c) Metering shall include a recording device, furnished by Public Service. Customer shall furnish an electrical supply for the operation of the recording device.

(d) Service supplied under this rate schedule shall be separately metered and shall not be combined with use under any other rate schedule for billing purposes. Customer shall not be eligible to receive service under this rate schedule and any other rate schedule for the same equipment or for equipment supplying a common steam header.

(e) Service under this rate schedule is not available for resale.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 96**

RATE SCHEDULE TSG-F
FIRM TRANSPORTATION GAS SERVICE
(Continued)

(f) Cogeneration Use: Applicable to separately metered service for the sequential production of electrical energy and useful thermal energy from the same fuel source by a Qualifying Facility, as defined in Section 201 of the Public Utilities Regulatory Policies Act of 1978 whose cogeneration equipment meets the efficiency standards set forth in Chapter 18 of the Code of Federal Regulations, Sections 292.205(a) and (b). Customer must document that qualifying status has been granted by the Federal Energy Regulatory Commission.

Service to qualifying cogeneration facility as set forth above may be exempt from taxes as set forth in Section 15 of the Standard Terms and Conditions.

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 15 of the Standard Terms and Conditions for additional details and/or exceptions.

THIRD PARTY SUPPLIER REQUIREMENTS:

TPSs are subject to the Third Party Supplier Requirements of this Tariff.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff except Section 7.6, Appliance Adjustments.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 97**
Original Sheet No. 98

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 99**

RATE SCHEDULE TSG-NF
NON-FIRM TRANSPORTATION GAS SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Interruptible delivery for general purposes where the maximum requirement for interruptible gas is not less than 150 therms per hour and where the customer has the installed capability to utilize an alternate type of fuel, except as provided for in Special Provision (a). Customers may either purchase gas supply from a Third Party Supplier (TPS) or from Public Service's Basic Gas Supply Service default service as detailed in this rate schedule.

DELIVERY CHARGES:

Service Charge:

$902.42 in each month [$962.21 including New Jersey Sales and Use Tax (SUT)].

Distribution Charges:

Charge	Charge including SUT	
$0.098680	$0.105218	per therm

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 61 for details of these charges.

Public Service may reduce the Distribution Charge at the beginning of the month and/or during the month to reflect market conditions.

This charge does not apply to gas sold to customer by Public Service pursuant to Special Provision (d).

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Societal Benefits include: 1) Social Programs, 2) Demand Side Management Programs, 3) Manufactured Gas Plant Remediation, 4) Consumer Education, and 5) Universal Service Fund. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs as approved by the Board. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

Tax Adjustment Credit:

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current charge.

~~The Tax Adjustment Credit will be combined with the distribution charge for billing.~~

Distribution Adjustment Charge:

This charge is designed to recover Board-approved costs. Refer to the Distribution Adjustment Charge sheet of this Tariff for the current charge.

The Tax Adjustment Credit and the Distribution Adjustment Charge will be combined with the distribution charge for billing.

The Societal Benefits Charge and the Green Programs Recovery Charge will be combined for billing.

COMMODITY CHARGES:

A customer may choose to receive gas supply from either:

a) A TPS who has agreed to the terms and conditions of the Third Party Supplier Requirements portion of this Tariff, or

(Charges are for illustrative purposes only and are based on the Eleventh Revised Sheet No. 99 filed with the BPU on June 1, 2023)

RATE SCHEDULE TSG-NF
NON-FIRM TRANSPORTATION GAS SERVICE
(Continued)

b) Public Service through its Basic Gas Supply Service default service. Public Service may also supply Emergency Sales Service in certain instances as indicated below.

Third Party Supply:
A customer that receives gas supply from a TPS will be charged for gas supply according to any agreement between the customer and the TPS. The customer will not be charged for commodity by Public Service, except as provided for in Emergency Sales Service below.

Emergency Sales Service:
In the event that, during any month, if Public Service cannot confirm that the customer has an eligible TPS, or if the TPS no longer satisfies the Third Party Supplier Requirements of this tariff, Public Service may supply the deficiencies as Emergency Sales Service.

Emergency Sales Service will be offered at the sole discretion of Public Service, after taking into consideration its other firm supply obligations. Public Service reserves the right to curtail service to any customer if deliveries from customer's TPS pursuant to Third Party Supplier Requirements are curtailed.

If a customer is receiving Emergency Sales Service and does not wish to designate a TPS for future deliveries or customer, for any reason, no longer desires to receive gas supply from a TPS, the customer may receive gas supply pursuant to Public Service's Basic Gas Supply Service.

The conditions under which Emergency Sales Service will apply are detailed in Section 14 - Third Party Supplier Service Provisions of the Standard Terms and Conditions of this Tariff, and the charges for this service are defined on the Emergency Sales Service sheet of this Tariff.

Basic Gas Supply Service:
Customers with a maximum requirement of less than 2,000 therms per hour and who~~that~~ do not receive gas supply from a TPS will be supplied under the Basic Gas Supply Service-Interruptible (BGSS-I) default service, which will be applied to all therms billed each month. Refer to the Basic Gas Supply Service – Interruptible sheet of this Tariff for the current charge for BGSS-I commodity charge.

OTHER CHARGES:

See Special Provisions (d) and (e).

BILLING DETERMINANTS:

Therms:
The number of therms used shall be determined by multiplying the number of hundred cubic feet used by the conversion factors which appears on every bill. The conversion factor used for the "therm multiplier" shall be on the basis of the actual heating value of the gas used.

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill and subject to a late payment charge at the rate of 1.416% per monthly billing period in accordance with Section 8.13 of the Standard Terms and Conditions. Service to a body politic will not be subject to a late payment charge.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 101**

RATE SCHEDULE TSG-NF
NON-FIRM TRANSPORTATION GAS SERVICE
(Continued)

TERM:

Unless otherwise agreed upon by customer and Public Service, one year from the commencement date specified in the service agreement required by Special Provision (a) and successive one-year periods thereafter. Service may be terminated by either customer or Public Service by providing no less than one month's notice prior to the expiration of the term.

SPECIAL PROVISIONS APPLICABLE TO ALL CUSTOMERS:

(a) Customer will be required to sign a service agreement and service will be restricted to the maximum annual, daily, and hourly requirements, and the location and equipment specified. Upon request by customer, Public Service may deliver available volumes of gas supply, adjusted for losses, in excess of the maximum requirements, for limited periods. Such deliveries shall not be deemed to constitute a change in the requirements specified in the service agreement. Attached to the service agreement will be a signed affidavit, certifying the specific grade of fuel oil (or oils), or other alternate fuel, that can physically and legally be utilized by the installation being served. This affidavit shall be a prerequisite for receiving service under this rate schedule and shall be furnished by the customer each fall no later than November 1st. The affidavit shall include the percentage of operation which can physically and legally be served by each alternate fuel. The customer will submit, within 30 days of change in operations, a new affidavit to Public Service when such change affects its alternate fuel capability. Additionally, the Affidavit shall require customers using No. 2 Fuel Oil, No. 4 Fuel Oil, jet fuel, or kerosene to provide certification that they have, and will maintain, either seven days of alternate fuel available through on-site storage capacity or additional firm contractual supply to make-up for any storage deficiencies so as to be equal to a seven day supply. Customers providing certification that they will suspend operations during an interruption are exempt from the alternate fuel requirement. Public Service reserves the right to inspect the customer's operation as to alternate fuel capability. Customers that fail to provide an affidavit by November 1st of each year shall continue to be subject to all of the terms of this rate schedule and in addition be subject to the Demand Charge as provided for in Rate Schedule LVG.

(b) Customers who were taking service under former Rate Schedule ISG Special Provision (b) on January 8, 2002 will be provided service under this rate schedule and are exempt from the minimum connected load requirement of 150 therms per hour.

(c) Upon advance notice of eight hours or more, from any hour of any day given to customer by Public Service, customer shall discontinue the use of gas until further notice; customer shall designate personnel who will accept such notification at any hour of any day.

(d) If customer does not discontinue the use of gas after notification pursuant to Special Provision (c) customer shall be charged $1.89 ($2.02 including SUT) per therm for an amount not to exceed one hour's maximum requirement per day of interruption.

The charge for all additional gas used shall be ten times the highest price of the "Absolute" daily ranges for delivery in Transco Zone 6, New York, or Texas Eastern Zone M-3 which are published in *Gas Daily* on the table "Final Daily Price Survey" for each therm of gas used by the customer. This rate shall not be lower than the maximum penalty charge for unauthorized daily overruns as provided for in the FERC-approved gas tariffs of the interstate pipelines which deliver gas into New Jersey.

(Charges are for illustrative purposes only and are based on the Original Sheet No. 101 filed with the BPU on November 1, 2018)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 102**

RATE SCHEDULE TSG-NF
NON-FIRM TRANSPORTATION GAS SERVICE
(Continued)

If a customer persistently does not discontinue the use of gas after notification pursuant to Special Provision (c), in addition to the aforementioned penalty charge, the customer will be notified that it no longer qualifies for service under an interruptible rate schedule. Applicable firm service will be available on a prospective basis subject to the availability of supply and delivery capacity.

Except for pilots, however, Public Service has no obligation to deliver gas at any time following notice pursuant to Special Provision (c) and may discontinue completely all other deliveries of gas to customer during the period of interruption.

(e) If a customer requests a change from this delivery rate schedule to firm service firm service will be available on a prospective basis subject to the availability of supply and delivery capacity. If a customer switches to firm service, they must remain on firm service for at least one year.~~during the months of November through March, the customer will be switched to that firm rate schedule, subject to the availability of supply and delivery capacity, retroactive to November 1 of the current winter period. If the customer was assessed charges under Special Provision (d) and such switch to firm service is approved by PSE&G, the charge for any gas in excess of the one hour's maximum requirement shall be lowered from ten times to one times the highest price of the "Absolute" daily ranges for delivery in Transco Zone 6, New York, or Texas Eastern Zone M-3 which are published in Gas Daily on the table "Final Daily Price Survey" for each therm of gas used by the customer.~~ If necessary, the customer will also be charged for system reinforcement, in accordance with Section 3, Charges for Service of the Standard Terms and Conditions of this Tariff.

(f) Customer may be required to make a deposit toward the total cost of facilities which Public Service installed to provide service if gas equipment or applications were, in the prior five-year period, previously served under Rate Schedules RSG, GSG, LVG or TSG-F for the same customer. Such deposit will be determined as if such gas equipment or applications had been served under Rate Schedule TSG-NF for the entire period served under the above firm rates, utilizing the deposit calculations in existence at the time the customer began service.

(g) Metering shall include a recording device, furnished by Public Service. Customer shall furnish an electrical supply for the operation of the recording device.

(h) Service supplied under this rate schedule shall be separately metered and shall not be combined with use under any other rate schedule for billing purposes. Customer shall not be eligible to receive service under this rate schedule and any other rate schedule for the same equipment or for equipment supplying a common steam header.

(i) Except as provided in Special Provision (a) customer has installed and maintains complete and adequate standby equipment and fuel supply for operation with another fuel when the gas supply is interrupted.

(j) Customers with a maximum requirement of 7,500 therms per hour or greater shall designate personnel physically located at the customer's facility having operational control of the gas usage at that facility who can be directly contacted by telephone or other electronic means at any hour of any day by Public Service. If the customer obtains gas supply from a TPS, these personnel shall be responsible for coordinating the balancing of customer's gas consumption and deliveries by the customer's TPS and shall be the only party that Public Service contacts for all operational coordination requirements including those during periods of suspension or limitation and critical periods as detailed in Sections 6.3.2 and 6.3.3 of the Third Party Supplier Requirements of this tariff. If the customer obtains gas supply from Public Service under BGSS-I default service, Public Service may establish similar operational coordination requirements.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 103**

RATE SCHEDULE TSG-NF
NON-FIRM TRANSPORTATION GAS SERVICE
(Continued)

(k) Service under this rate schedule is not available for resale.

(l) Cogeneration Use: Applicable to separately metered service for the sequential production of electrical energy and useful thermal energy from the same fuel source by a Qualifying Facility, as defined in Section 201 of the Public Utilities Regulatory Policies Act of 1978 whose cogeneration equipment meets the efficiency standards set forth in Chapter 18 of the Code of Federal Regulations, Sections 292.205 (a) and (b). Customer must document that qualifying status has been granted by the Federal Energy Regulatory Commission.

Service to a qualifying cogeneration facility as set forth above may be exempt from taxes as set forth in Section 15 of the Standard Terms and Conditions.

(m) Military Service: United States Department of Defense Military bases may apply for service under this special provision. Under this special provision: 1) a customer must choose to receive gas supply from a TPS who has agreed to the terms and conditions of the Third Party Supplier Requirements of this Tariff; 2) delivery service will not be interrupted with respect to the customer's gas that is delivered to Public Service by the customer's TPS on any day; 3) all service for each service location must be through a single meter; 4) the requirements for an alternate fuel shall not apply; and 5) in lieu of the annual alternate fuel certification required by each November 1st as described in Special Provision (a) above, the customer is required to submit a certification by each November 1st that it has a contract with a TPS to supply its gas requirements each day through the end of the following March.

SPECIAL PROVISIONS APPLICABLE TO CUSTOMERS SELECTING THIRD PARTY SUPPLIERS FOR COMMODITY SERVICE:

(n) The customer must contract with a TPS to arrange for deliveries to Public Service of their daily usage, adjusted for losses, and such TPS agrees to abide by the provisions of the Third Party Supplier Requirements. A customer is limited to one (1) TPS for gas for each account for which the customer receives delivery service.

(o) The customer's TPS is required to notify Public Service of the customer's selection prior to the last business day of the month for deliveries to commence on the first (1st) of the next month, and such selection shall remain in effect for the entire month, subject to the conditions of Emergency Sales Service. Customer can change TPSs effective only on the first day of the month.

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 15 of the Standard Terms and Conditions for additional details and/or exceptions.

THIRD PARTY SUPPLIER REQUIREMENTS:

TPSs are subject to the Third Party Supplier Requirements of this Tariff.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff except Section 7.6, Appliance Adjustments.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS

Original Sheet No. 104
Original Sheet No. 105
Original Sheet No. 106

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 107**

RATE SCHEDULE CIG
COGENERATION INTERRUPTIBLE SERVICE

This rate schedule is limited to customers continuously taking service under this rate schedule or former Rate Schedule CEG since January 8, 2002, with the exception of any new customers for whom commitments by Public Service had been made prior to January 9, 2002.

APPLICABLE TO USE OF SERVICE FOR:

Interruptible gas delivery and supply service for the sequential production of electrical energy and useful thermal energy from the same fuel source by a Qualifying Facility, as defined in Section 201 of the Public Utility Regulatory Policies Act of 1978, and regularly meeting the efficiency standards set forth in Chapter 18 of the Code of Federal Regulations, Sections 292.205 (a) and (b) and where the combined nameplate-rated capacity of the generation equipment is not less than 1.5 megawatts and not greater than 20 megawatts. This size limitation shall not apply to customer's Qualifying Facilities receiving service under this rate schedule prior to January 1, 1993.

DELIVERY CHARGES:

Service Charge:

$199.11 in each month [$212.30 including New Jersey Sales and Use Tax (SUT)].

Distribution Charges:

Charge	Charge including SUT	
$0.088960	$0.094854	per therm for the first 600,000 therms used in each month.
$0.078960	$0.084191	per therm in excess of 600,000 therms used in each month.

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 61 for details of these charges.

This charge does not apply to gas sold to customers by Public Service pursuant to Special Provision (c).

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Societal Benefits include: 1) Social Programs, 2) Demand Side Management Programs, 3) Manufactured Gas Plant Remediation, 4) Consumer Education, and 5) Universal Service Fund. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs as approved by the Board. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

Tax Adjustment Credit:

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current charge.

~~The Tax Adjustment Credit will be combined with the distribution charge for billing.~~

Distribution Adjustment Charge:
This charge is designed to recover Board-approved costs. Refer to the Distribution Adjustment Charge sheet of this Tariff for the current charge.

The Tax Adjustment Credit and the Distribution Adjustment Charge will be combined with the distribution charge for billing.

The Societal Benefits Charge and the Green Programs Recovery Charge will be combined for billing.

(Charges are for illustrative purposes only and are based on the Eleventh Revised Sheet No. 107 filed with the BPU on June 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 108**

RATE SCHEDULE CIG
COGENERATION INTERRUPTIBLE SERVICE
(Continued)

COMMODITY CHARGES:

Customers taking service under this rate schedule are required to receive their commodity service from Public Service. Refer to the BGSS-CIG Commodity Charge sheet of this Tariff for the current charge.

Other Charges:
See Special Provisions (c) and (n).

BILLING DETERMINANTS:

Therms:
The number of therms used shall be determined by multiplying the number of hundred cubic feet used by the conversion factors which appear on every bill. The conversion factor used for the "therm multiplier" shall be on the basis of the actual heating value of the gas used.

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill and subject to a late payment charge at the rate of 1.416% per monthly billing period in accordance with Section 8.13 of the Standard Terms and Conditions. Service to a body politic will not be subject to a late payment charge.

TERM:

One year and thereafter until terminated by five days' notice.

SPECIAL PROVISIONS APPLICABLE TO ALL CUSTOMERS:

(a) Customer must certify that qualifying status has been granted by the Federal Energy Regulatory Commission and will be required to sign a service agreement. Service will be restricted to the maximum annual and hourly requirements, and the location and equipment specified in that service agreement. Upon request by customer, Public Service may deliver available volumes of gas in excess of the maximum hourly requirement for limited periods. Such deliveries shall not be deemed to constitute a change in the requirements specified in that service agreement.

(b) Upon advance notice of eight hours or more, from any hour of any day given to customer by Public Service, customer shall discontinue the use of gas until further notice; customer shall designate personnel who will accept such notification at any hour of any day.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 109**

RATE SCHEDULE CIG
COGENERATION INTERRUPTIBLE SERVICE
(Continued)

(c) If customer does not discontinue the use of gas after notification pursuant to Special Provision (b), the Commodity Charge shall be $1.89 ($2.02 including SUT) per therm for an amount not to exceed one hour's maximum requirement per day of interruption. Use of this amount shall be limited to a per therm quantity not to exceed one hour's maximum requirement per day of interruption.

The charge for all additional gas used shall be ten times the highest price of the "Absolute" daily ranges for delivery in Transco Zone 6, New York, or Texas Eastern Zone M-3 which are published in *Gas Daily* on the table "Final Daily Price Survey." This rate shall not be lower than the maximum penalty charge for unauthorized daily overruns as provided for in the FERC-approved gas tariffs of the interstate pipelines which deliver gas into New Jersey.

If a customer persistently does not discontinue the use of gas after notification pursuant to Special Provision (b), in addition to the aforementioned penalty charge, the customer will be notified that it no longer qualifies for service under an interruptible rate schedule. Applicable firm service will be available on a prospective basis, subject to the availability of supply and delivery capacity.

Except for pilots, however, Public Service has no obligation to supply gas at any time following notice pursuant to Special Provision (b) and may discontinue completely all other deliveries of gas to customer during the period of interruption.

If a customer requests a change from this delivery rate schedule to firm service, firm service will be available on a prospective basis subject to the availability of supply and delivery capacity. If a customer switches to firm service, they must remain on firm service for at least one year, ~~during the months of November through March, the customer will be switched to that firm rate schedule, subject to the availability of supply and delivery capacity, retroactive to November 1 of the current winter period. If the customer was assessed charges under this Special Provision and such switch to firm service is approved by PSE&G, the charge for any gas in excess of the one hour's maximum requirement shall be lowered from ten times to one times the highest price of the "Absolute" daily ranges for delivery in Transco Zone 6, New York, or Texas Eastern Zone M-3 which are published in *Gas Daily* on the table "Final Daily Price Survey" for each therm of gas used by the customer. If necessary, the customer will also be charged for system reinforcement, in accordance with Section 3, Charges for Service of the Standard Terms and Conditions of this Tariff.~~

(d) Metering shall include a recording device, furnished by Public Service. Customer shall furnish an electrical supply for the operation of the recording device.

(e) Service supplied under this rate schedule shall be separately metered and shall not be combined with use under any other rate schedule for billing purposes.

(f) Service will not be supplied under this rate schedule and any other gas rate schedule for the same process or operation at the same location except as specified under Special Provision (i).

(g) Public Service agrees that service under this rate schedule will not be interrupted unless service to the TSG-NF customers receiving BGSS-I default service has already been interrupted.

(h) Gas supplied under this rate schedule is limited to a quantity equal to the lesser of either 0.150 therms for each net kilowatt-hour of cogenerated electric generation fueled by gas or the quantity of gas actually consumed by the cogeneration facility when operated in a cogeneration mode as determined by Public Service. Net cogenerated electric generation is defined as generation output less energy used to run the cogeneration facility's auxiliary equipment. Auxiliary equipment includes, but it is not limited to, forced and induced draft fans, boiler feed pumps and lubricating oil systems.

(Charges are for illustrative purposes only and are based on the Original Sheet No. 109 filed with the BPU on November 1, 2018)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 110**

RATE SCHEDULE CIG
COGENERATION INTERRUPTIBLE SERVICE
(Continued)

(i) Gas supplied in excess of the quantity described in Special Provision (h) will be billed under an applicable rate schedule as determined by Public Service except as specified under Special Provision (c).

(j) Net cogenerated electric generation fueled by natural gas will be determined each month as follows:

(j-1) For facilities which burn two or more fuels simultaneously for cogeneration, net cogenerated electric generation will be allocated between such fuels on the Btu input of each fuel.

(j-2) For facilities which change fuel usage between gas and an alternate fuel for cogeneration, net cogenerated electrical generation fueled by gas will be based on meter readings taken by the customer at the time the fuel change occurs or the portion of the allocated amount determined in Special Provision (h) prorated by the number of hours or days that the customer used gas.

(k) Public Service, at its sole discretion, may utilize readings from customer or Company-owned meters to determine the quantity of gas to which this rate schedule is applicable in lieu of the allocation specified in Special Provision (j-1). The customer shall make available, and Public Service shall have the right to read, inspect and/or test such customer-owned meters during normal working hours. Additional gas, electric and/or useful thermal output meters required to determine the amount of gas to which this rate schedule is applicable will be installed, owned and operated by Public Service. However, Public Service may, at its sole option, use calculated or estimated data to determine such gas usage.

(l) Customer is required to file a monthly report to Public Service containing the total amount of kilowatt-hours produced by the cogeneration facility.

(m) Service under this rate schedule is not available for resale.

(n) **Extended Gas Service:** Gas service under this Special Provision is limited to customers having an executed service agreement for this Special Provision. Customer's executed service agreement must be received by Public Service no later than November 15th for service to be provided for the upcoming winter season. Approval of the customer's request will be provided on a case by case basis so as not to adversely impact Public Service's distribution system. When service under this Rate Schedule is interrupted, service under this Special Provision will be supplied at Public Service's option. When Extended Gas Service is offered by Public Service, the following provisions shall apply:

(n-1) In lieu of the Therm Charge hereinbefore set forth, the following charges shall apply: 1) a Special Delivery Charge which, based upon the marketability of this gas, would fall between a floor price of $0.100 ($0.107 including SUT) per therm and a ceiling price of $0.180 ($0.192 including SUT) per therm for each therm of Extended Gas Service supplied to the customer; and 2) a Commodity Charge which shall be the maximum of the "Common" range value stated in the Final Daily Price Survey section of Platt's Gas Daily for Transco Zone 6 New York for the day(s)~~the actual delivered price of propane to Public Service's BGSS supplier(s) or the highest cost gas purchased or used by Public Service's BGSS supplier(s)~~ when service under this Special Provision is offered~~, whichever is the incremental gas source~~.

(Charges are for illustrative purposes only and are based on the Original Sheet No. 110 filed with the BPU on November 1, 2018)

Date of Issue: Effective:
Issued by SCOTT S. JENNINGS, SVP – Finance, Planning & Strategy – PSE&G
80 Park Plaza, Newark, New Jersey 07102
Filed pursuant to Order of Board of Public Utilities dated
in Docket No.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 111**

RATE SCHEDULE CIG
COGENERATION INTERRUPTIBLE SERVICE
(Continued)

(n-2) A service agreement for this Extended Gas Service shall be executed for each winter season and shall include the customer's maximum daily requirements under this Special Provision and a prepayment equal to four days of the Special Delivery Charge at a rate of $0.150 ($0.160 including SUT) per therm at the customer's maximum daily requirement. Use of gas above the maximum daily requirement, on any day for which Public Service has offered and the customer has requested Extended Gas Service, will be subject to the penalty as stated in Special Provision (c). Such prepayment shall be non-refundable unless and to the extent that Public Service does not offer customer such Extended Gas Service for at least 96 hours, during the winter season. If Public Service, offers such service for less than 96 hours, the refund shall be made on a prorated basis. In addition to such prepayment, a non-refundable application charge of $800.00 ($853.00 including SUT) shall be paid by each customer.

(n-3) Customer will be notified electronically or by phone of the Extended Gas Therm Charge at least eight hours prior to the availability of this service, or prior to a change in the Extended Gas Therm Charge~~, by facsimile machine~~. Following receipt of Public Service's notice, the customer will have two hours within which to electronically notify ~~facsimile to~~ Public Service the customer's acceptance of the Extended Gas Therm Charge for the service. If customer does not accept this service, customer must discontinue the use of gas at the time designated by Public Service, which time shall not be less than eight hours after Public Service's notice to Customer of the availability and the Therm Charge of the Extended Gas Service. Any gas usage by customer following the time designated by Public Service shall be subject to the penalty as stated in Special Provision (c).

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c.57, and is included in the appropriate charges in this rate schedule. See Section 15 of the Standard Terms and Conditions for additional details and/or exceptions.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff except section 7.6, Appliance Adjustments.

(Charges are for illustrative purposes only and are based on the Original Sheet No. 111 filed with the BPU on November 1, 2018)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 112**

RATE SCHEDULE CSG
CONTRACT SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Firm or interruptible delivery service for general purposes where the customer is requesting a discount rate from a Public Service Rate Schedule for delivery service based on an (a) Economically Viable Bypass alternative or (b) Other Considerations.

Public Service will review all applications to verify for completeness within 45 days of receipt. If any data is missing, Public Service will notify customer of the information needed to complete the application. Public Service reserves the right to request additional information as needed on a case by case basis. Once a request is deemed complete, Public Service will have 45 days to complete its analysis and respond to the customer. Once agreement has been reached, Public Service will forward the application to the Board of Public Utilities for review and approval. Once approved by the Board of Public Utilities, the customer agrees that the discounted rate set forth under this rate schedule will not be confidential.

Customers may purchase gas supply from a Third Party Supplier (TPS) or, for customers with a maximum requirement of less than 2,000 therms per hour, from Public Service's Basic Gas Supply Service default service as detailed in this rate schedule.

ECONOMICALLY VIABLE BYPASS

For all customers requesting this tariff service based on an economically viable bypass alternative, the customer must submit to Public Service the following minimum information but not limited to:

1. A bypass feasibility report issued by the interstate pipeline or an independent engineering consultant setting forth:
   i. Maps showing the route of the potential bypass;
   ii. Flow diagrams showing the major components of the bypass from the interstate pipeline interconnection to the customer;
   iii. Engineering studies related to the proposed cost to bypass including estimated costs for: right-of-way; regulatory approvals; material; equipment; structures; construction; overheads; contingencies and tax gross-up applicable to pipeline company facilities;
   iv. The location class, design pressure, size, length, pipe specification, yield strength and wall thickness of the bypass pipeline;
   v. Schedule of all permits from State or Federal agencies and railroads necessary for the bypass;
   vi. Project schedule;
   vii. The cost estimate classification level following AACE International Recommended Practice No.18R-97;
   viii. Statement from the interstate pipeline that the proposed interconnection is operationally viable and that the pipeline can effectuate service as requested.
2. Creditworthiness of customer.
3. Estimated annual therm usage along with all supporting assumptions and calculations.

OTHER CONSIDERATIONS

Service under this rate schedule where the customer is requesting this tariff service based on considerations other than an economically viable bypass alternative will be offered by the Company in circumstances in which it determines in its sole reasonable judgment that such rates are necessary to prevent (i) economic bypass of the Company's distribution system, or (ii) the loss of load that could otherwise be served at rates that exceed marginal costs.

Customer seeking negotiated rates under this provision must provide the Company: (i) such information as the customer deems relevant to its request; (ii) such information as the Company may require given the particular circumstances.

In determining whether to offer individually negotiated rates, terms or conditions under this provision to a particular customer, the Company will consider all relevant information provided by the customer and make a judgment as to whether or not the negotiated rates are necessary to prevent an economic bypass or the loss of load that could otherwise be served at rates that exceed marginal costs.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 112A**

RATE SCHEDULE CSG
CONTRACT SERVICE
(Continued)

ECONOMICALLY VIABLE BYPASS
DELIVERY CHARGES:

Service Charge:

$902.42 in each month [$962.21 including New Jersey Sales and Use Tax (SUT)]

Distribution Charge:

Net Alternative Delivery Cost multiplied by the applicable Net Alternative Delivery Cost Factor divided by the Contracted Monthly Therms rounded to the nearest $0.000000 per therm.

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 61 for details of these charges.

Maintenance Charges:

Equals the Alternative Delivery Cost multiplied by the applicable Alternative Delivery Cost Factor divided by the Contract Monthly Therms rounded to the nearest $0.000000 per therm.

Plus any customer site-specific ongoing or continuing cost not directly related to the operation, maintenance or inspection of the customer's planned by-pass pipeline. This shall include, but not be limited to, periodic payments for rights-of-way, easements, pipeline cost differentials, permits or other such costs. These charges shall be expressed on a monthly levelized basis over the term of service.

Public Service will also take into consideration any operational or deliverability differences that would be reasonably expected between the pipeline and/or service over Public Service's distribution system in determining Delivery Charges. In no event shall the Delivery Charges be lower than an amount sufficient to generate a return on the capital investments made by Public Service and recovery of marginal and embedded costs, including depreciation, to provide service to the customer over the term of each CSG agreement.

Balancing Charge:

Applicable only if the customer is provided Public Service's Basic Gas Supply Service – Firm (BGSS-F) default service.

Charge	Charge Including SUT	
$0.091830	$0.097914	per Balancing Use Therm

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by government. In appropriate circumstances, the Board of Public Utilities may approve a discount from the Societal Benefits Charge. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge and applicable exemptions.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs as approved by the Board. In appropriate circumstances, the Board of Public Utilities may approve a discount from the Green Programs Recovery Charge. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge and applicable exceptions.

(Charges are for illustrative purposes only and are based on the Eighteenth Revised Sheet No. 112A filed with the BPU on October 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 112B**

RATE SCHEDULE CSG
CONTRACT SERVICE
(Continued)

Tax Adjustment Credit:
This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current charge.

~~The Tax Adjustment Credit will be combined with the distribution charge for billing.~~

Distribution Adjustment Charge:
This charge is designed to recover Board-approved costs. Refer to the Distribution Adjustment Charge sheet of this Tariff for the current charge.

The Tax Adjustment Credit and the Distribution Adjustment Charge will be combined with the distribution charge for billing.

The Societal Benefits Charge and the Green Programs Recovery Charge will be combined for billing.

OTHER CONSIDERATIONS
DELIVERY CHARGES:
The Delivery Charges shall be set to be sufficient to recover revenues in excess of marginal costs for Public Service to provide service to the customer under this rate schedule. Delivery Charges will be based on agreement reached with Public Service and approved by the Board of Public Utilities.

COMMODITY CHARGES:
A customer may choose to receive gas supply from either:
a) A TPS who has agreed to the terms and conditions of the Third Party Supplier Requirements portion of this Tariff, or
b) For customers with a maximum requirement of less than 2,000 therms per hour, Public Service through its Basic Gas Supply Service default service. Such supply service may be either firm or interruptible. Public Service may also supply Emergency Sales Service in certain instances as indicated below.

Third Party Supply:
A customer that receives gas supply from a TPS will be charged for gas supply according to any agreement between the customer and the TPS. The customer will not be charged for commodity by Public Service, except as provided for in Emergency Sales Service below.

Emergency Sales Service:
Emergency Sales Service is only available for customers with a maximum requirement of less than 2,000 therms per hour.

In the event that, during any month, if Public Service cannot confirm that the customer has an eligible TPS, or if the TPS no longer satisfies the Third Party Supplier Requirements of this tariff, Public Service may supply the deficiencies as Emergency Sales Service.

Emergency Sales Service will be offered at the sole discretion of Public Service, after taking into consideration its other firm supply obligations. Public Service reserves the right to curtail service to any customer if deliveries from customer's TPS pursuant to Third Party Supplier Requirements are curtailed.

If a customer is receiving Emergency Sales Service and does not wish to designate a TPS for future deliveries or customer, for any reason, no longer desires to receive gas supply from a TPS, the customer may receive gas supply pursuant to Public Service's Basic Gas Supply Service.

The conditions under which Emergency Sales Service will apply are detailed in Section 14 - Third Party Supplier Service Provisions of the Standard Terms and Conditions of this Tariff, and the charges for this service are defined on the Emergency Sales Service sheet of this Tariff.

Basic Gas Supply Service:
A customer with a Maximum Requirement of less than 2,000 therms per hour that does not receive gas supply from a TPS will be supplied, at the customer's option, under either the Basic Gas Supply Service – Firm (BGSS-F) default service or the Basic Gas Supply Service-Interruptible (BGSS-I) default service as applicable based on whether Customer is being provided firm or interruptible service pursuant to this Rate Schedule. Refer to the Basic Gas Supply Service – Firm sheet of this Tariff for the current charge for BGSS-F commodity charge

or to the Basic Gas Supply Service – Interruptible sheet of this Tariff for the current charge for BGSS-I commodity charge.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 112C**

RATE SCHEDULE CSG
CONTRACT SERVICE
(Continued)

OTHER CHARGES:
See Special Provision (f).

MINIMUM ANNUAL DISTRIBUTION CHARGE:
If customer's annual usage is less than 50% of the customer's Contract Monthly Therms multiplied by 12, then the customer will be billed for the difference between the actual annual therms and 50% of the customer's Contract Monthly Therms multiplied by 12 and then multiplied by the Distribution Charge. The Minimum Annual Distribution Charge, if applicable, will be billed at the end of the customer's annualized period. This charge applies to both Economically Viable Bypass customers and Other Consideration customers.

BILLING DETERMINANTS:
Therms:
The number of therms used shall be determined by multiplying the number of hundred cubic feet used by the conversion factor which appears on every bill. The conversion factor used for the "therm multiplier" shall be on the basis of the actual heating value of the gas used.

Balancing Use Therms:
Applicable only if the customer is provided Public Service's Basic Gas Supply Service – Firm (BGSS-F) default service.

During each of the billing months of October through May, if the average daily usage of gas in any month exceeds the average daily usage during the preceding billing months of June through September, the therms used in such month in excess of the product of the average daily usage in the preceding months of June through September times the number of days in the billing month shall be the Balancing Use Therms and subject to the Balancing Charge. For new customers and for customers who install additional gas burning equipment, the average daily usage in the preceding June through September time period to be used in the above calculation shall be estimated by Public Service.

Contract Monthly Therms:
Estimated annual therm usage (see Item 3, Tariff Sheet No. 112) determined as reasonable by Public Service divided by 12 and rounded to the nearest therm.

Alternative Delivery Cost:
a) For Firm Delivery Service: The estimated total up-front cost of the customer's bypass plan, based on a detailed cost estimate provided by the applicable interstate pipeline.
b) For Interruptible Delivery Service: The sum of 90% of the estimated total up-front cost of the customer's bypass plan, based on a detailed cost estimate provided by the applicable interstate pipeline, plus 10% of the incremental installed cost for Public Service to provide interruptible delivery service as estimated by Public Service.

Net Alternative Delivery Cost:
The Net Alternative Delivery Cost is equal to the Alternative Delivery Cost net of any customer contribution made to Public Service to provide service under this Rate Schedule without Public Service tax gross-up effects.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 112D**

RATE SCHEDULE CSG
CONTRACT SERVICE
(Continued)

Distribution Charge Factor: per $ of Net Alternative Delivery Cost

Term	Monthly Factor	Monthly Factor Including SUT
5 Years	$0.025583	$0.027278
10 Years	0.015773	0.016818
20 Years	0.010716	0.011426

Maintenance Charge Factor: per $ of Alternative Delivery Cost

Term	Monthly Charge	Monthly Charge Including SUT
5 Years	$0.000262	$0.000279
10 Years	0.000276	0.000294
20 Years	0.000300	0.000320

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill and subject to a late payment charge at the rate of 1.416% per monthly billing period in accordance with Section 8.13 of the Standard Terms and Conditions. Service to a body politic will not be subject to a late payment charge.

TERM:

Up to twenty years from the commencement date specified in the service agreement required by Special Provision (a), which length to be determined by agreement of the parties or, in the case of an economically viable physical bypass, based on the length of financing offered by the interstate pipeline company. The Distribution Charge and the Maintenance Charges as of the commencement date will remain unchanged for the term of the service agreement. The customer may terminate service by providing no less than one month's notice. Customers shall be required to make a termination payment for all such service terminated prior to the end of the Term equal to 50% of the sum of the Distribution Charge multiplied by the Contract Monthly Therms multiplied by the number of months remaining for the term of the service agreement. The termination payment shall be due to Public Service upon the date the termination becomes effective pursuant to the customer's notice.

SPECIAL PROVISIONS APPLICABLE TO ALL CUSTOMERS:

(a) Customer will be required to sign a service agreement and service will be restricted to the maximum daily capacity of the alternative delivery option used to determine the Monthly Distribution Charge. Deliveries in excess of the maximum specified in such service agreement will require the establishment of an additional new service agreement and related monthly charges, where such charges for such excess capacity shall be based upon the then current costs for such alternative delivery option and the then current pricing factor.

(b) Upon advanced written notice to Public Service, such service agreement shall be transferable to a new customer or owner of the facility at the location specified in the service agreement.

(c) Requests for a change between interruptible delivery service under this rate schedule to or from firm delivery service under this rate schedule will require the establishment of a new service agreement and new term of service based on the then current costs and pricing factor. There shall be no termination payment required related to a change from interruptible delivery service to firm delivery service under this rate schedule. A change from firm delivery service to interruptible delivery service will require a termination payment as detailed above.

(Charges are for illustrative purposes only and are based on the Original Sheet No. 112D filed with the BPU on November 1, 2018)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 112E**

RATE SCHEDULE CSG
CONTRACT SERVICE
(Continued)

(d) For customers with a maximum requirement of 2,000 therms per hour or greater, Public Service reserves the right to discontinue delivery service at any time the total imbalance cash-out amounts unpaid, including amounts billed and amounts not yet billed, by the customer's TPS are greater than 90% of the current credit Security amount held by Public Service for the customer's TPS in accordance with Section 5 of the Third Party Supplier Requirements of this tariff.

(e) Customers with a maximum requirement of 7,500 therms per hour or greater shall designate personnel physically located at the customer's facility having operational control of the gas usage at that facility who can be directly contacted by telephone or other electronic means at any hour of any day by Public Service. These personnel shall be responsible for coordinating the balancing of customer's gas consumption and deliveries by the customer's TPS and shall be the only party that Public Service contacts for all operational coordination requirements including those during periods of suspension or limitation and critical periods as detailed in Sections 6.3.2 and 6.3.3 of the Third Party Supplier Requirements of this tariff.

(f) Where the customer has selected BGSS-I as their gas supply option or is supplied interruptible delivery service under this rate schedule, the following shall apply:

(f-1) The customer shall provide a signed affidavit, certifying the specific grade of fuel oil (or oils), or other alternate fuel, that can physically and legally be utilized by the installation being served. This affidavit shall be a prerequisite for receiving service under this rate schedule and shall be furnished by the customer each fall no later than November 1st. The affidavit shall include the percentage of operation which can physically and legally be served by each alternate fuel. The customer will submit, within 30 days of change in operations, a new affidavit to Public Service when such change affects its alternate fuel capability. Additionally, the Affidavit shall require customers using No. 2 Fuel Oil, No. 4 Fuel Oil, jet fuel, or kerosene to provide certification that they have, and will maintain, either seven days of alternate fuel available through on-site storage capacity or additional firm contractual supply to make-up for any storage deficiencies so as to be equal to a seven day supply. Customers providing certification that they will suspend operations during an interruption are exempt from the alternate fuel requirement. Public Service reserves the right to inspect the customer's operation as to alternate fuel capability. Customers that fail to provide an affidavit by November 1st of each year shall continue to be subject to all of the terms of this rate schedule and in addition be subject to the Demand Charge as provided for in Rate Schedule LVG.

(f-2) Upon advance notice of eight hours or more, from any hour of any day given to customer by Public Service by telephone, ~~telegram~~ or other electronic means~~wise~~, customer shall discontinue the use of gas until further notice; customer shall designate personnel who will accept such notification at any hour of any day.

(f-3) If customer does not discontinue the use of gas after notification pursuant to Special Provision (f-2) customer shall be charged $1.89 ($2.02 including SUT) per therm for an amount not to exceed one hour's maximum requirement per day of interruption. Use of this amount shall be limited to a use rate per hour not greater than 5% of customer's maximum hourly requirement.

The charge for all additional gas used shall be ten times the highest price of the daily ranges for delivery in Transco Zone 6, New York, or Texas Eastern Zone M-3 which are published in *Gas Daily* on the table "Daily Price Survey" for each therm of gas used by the customer. This rate shall not be lower than the maximum penalty charge for unauthorized daily overruns as provided for in the FERC-approved gas tariffs of the interstate pipelines which deliver gas into New Jersey.

(Charges are for illustrative purposes only and are based on the Original Sheet No. 112E filed with the BPU on November 1, 2018)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

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RATE SCHEDULE CSG
CONTRACT SERVICE
(Continued)

If a customer supplied under Rate Schedule BGSS-I persistently does not discontinue the use of gas after notification pursuant to Special Provision (f-2), in addition to the aforementioned penalty charge, the customer will be notified that it no longer qualifies for service under interruptible supply service Rate Schedule BGSS-I. Applicable firm supply service will be available on a prospective basis under Rate Schedule BGSS-F subject to the availability of supply and delivery capacity.

Except for pilots, however, Public Service has no obligation to deliver gas at any time following notice pursuant to Special Provision (f-2) and may discontinue completely all other deliveries of gas to customer during the period of interruption.

(g) Unless otherwise agreed to by Public Service, metering shall include a recording device, furnished by Public Service. Customer shall furnish an electrical supply for the operation of the recording device.

(h) Service supplied under this rate schedule shall be separately metered and shall not be combined with use under any other rate schedule for billing purposes. Customer shall not be eligible to receive service under this rate schedule and any other rate schedule for the same equipment or for equipment supplying a common steam header.

(i) Service under this rate schedule is not available for resale.

SPECIAL PROVISIONS APPLICABLE TO CUSTOMERS SERVED BY THIRD PARTY SUPPLIERS FOR COMMODITY SERVICE:

(j) The customer must contract with a TPS to arrange for deliveries to Public Service of their daily usage, adjusted for losses, and such TPS agrees to abide by the provisions of the Third Party Supplier Requirements. A customer is limited to one (1) TPS for gas for each account for which the customer receives delivery service.

(k) The customer’s TPS is required to notify Public Service of the customer’s selection prior to the last business day of the month for deliveries to commence on the first (1st) of the next month, and such selection shall remain in effect for the entire month, subject to the conditions of Emergency Sales Service. Customers eligible to receive Emergency Sales Service can change TPSs effective only on the first day of the month. Customers not eligible to receive Emergency Sales Service can change TPSs at any time in the event that their TPS fails to deliver supply.

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 15 of the Standard Terms and Conditions for additional details and/or exceptions.

THIRD PARTY SUPPLIER REQUIREMENTS:

TPSs are subject to the Third Party Supplier Requirements of this Tariff.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff except Section 7.6, Appliance Adjustments.

~~**RATE SCHEDULE CSG PERIODIC UPDATE:**~~

~~Twenty-four months from the effective date of this rate schedule, Public Service will file an update to this rate schedule, as necessary.~~

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 114**

THIRD PARTY SUPPLIER REQUIREMENTS

1. GENERAL

A Third Party Supplier (TPS) of natural gas is an entity that has contracted with customers of Public Service to deliver supplies of natural gas to interconnection points with Public Service's distribution system, or is a customer who is self-supplying and acting as a TPS on their own behalf in purchasing and transporting natural gas to interconnection points with Public Service's distribution system, from which Public Service may receive and physically transport and deliver on a firm basis these gas supplies to the customer pursuant to Rate Schedules RSG, SLG, GSG, LVG, TSG-F, or CSG and on an interruptible basis to customers pursuant to Rate Schedules TSG-NF or CSG. In order for an entity to qualify as a TPS it must execute an Application for Service and satisfy Public Service's credit requirements as noted herein. In order for a customer to qualify to self-supply, the Public Service customer of record for gas delivery service must be served on Rate Schedule TSG-NF or CSG and must be the same corporate entity that is purchasing and transporting the natural gas to interconnection points with Public Service's distribution system. A self-suppling customer must meet all of the TPS requirements herein, except the requirement for licensure by the Board of Public Utilities. TPSs, other than qualifying self-supplying customers, must be licensed by the Board of Public Utilities (Board).

A TPS must successfully complete all Electronic Data Interchange testing in order to enroll new customers that receive service under Rate Schedules RSG, GSG, LVG, SLG, TSG-F, TSG-NF, and CSG.

TPSs agree to abide by the Board's regulations and with <u>N.J.A.C.</u> 14:4 *et seq*., *Energy Competition,* including but not limited to Subchapter 7 *Retail Choice Consumer Protection.* Public Service is not responsible for the administration or the enforcement of either of the aforementioned regulations or Code.

2. CUSTOMER CONFIRMATION

By the twenty-second (22nd) of each month, for service to RSG, SLG, GSG, or LVG which is to commence on the first (1st) of the next calendar month, Public Service will provide to each TPS by electronic or other means, as specified by Public Service, a list which includes: (1) those customers who have requested to be served by that particular TPS and have represented that they have a contractual relationship with that TPS, including their required Daily Contract Quantity (DCQ), expressed in therms; (2) former customers' applicable imbalances, expressed in therms; and (3) the TPS's Aggregate Daily Contract Quantity (ADCQ), adjusted for losses, expressed in dekatherms, equal to the sum of the DCQ's of each of the customers of that TPS. TPS will be required to notify Public Service by electronic or other means, as specified by Public Service, by the twenty-second (22nd) of the month as to any corrections or changes to their list of customers, otherwise the list will be assumed to be accurate. Public Service will only amend the list of customers and their respective DCQ's in accordance with the above procedures prior to the next month if a good faith dispute arises concerning the respective TPS's list.

Public Service will provide to each TPS by electronic or other means, as specified by Public Service, a list which includes those TSG-F, TSG-NF, and CSG customers who have requested to be served by that particular TPS and have represented that they have a contractual relationship with that TPS.

3. DELIVERY

3.1 **General:** Subject to the Force Majeure provisions in Section 7, TPS must deliver to Public Service on each day of the month at points specified on Public Service's distribution system, which points are operationally acceptable to Public Service in its sole discretion, the ADCQ for its RSG, SLG, GSG, and LVG customers and the daily or, under certain circumstances, the hourly usage of its TSG-F, TSG-NF, and CSG customers, adjusted for losses (hereinafter collectively referred to as "usage"). Failure to comply with this provision shall subject TPS to the cash-out pursuant to Sections 6.1, 6.2, and/or 6.3.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

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THIRD PARTY SUPPLIER REQUIREMENTS
(Continued)

3.2. **Warranty of Title:** TPS warrants that, at the time of delivery of gas to Public Service, it will have good title to deliver all gas volumes made available.

3.3. **Delivery Control and Possession:** After TPS delivers gas or causes gas to be delivered to Public Service at Public Service's point of interconnection with the applicable interstate pipeline, Public Service will be deemed to be in control and possession of the gas until an equivalent amount of gas, less losses, is delivered to customer at customer's Public Service meter.

3.4. **Delivery Liability:** Public Service shall in no way be liable for any errors in the calculation of the DCQ or ADCQ, nor be responsible for any additional gas costs incurred by TPS due to any error in the calculation of the DCQ or ADCQ.

3.5. **Delivery Allocation:** On each day deliveries of gas by TPS to Public Service shall be first allocated to TPS's ADCQ on such day and any remaining volume shall be allocated to TPS's TSG-F, TSG-NF, and CSG customers.

4. NOMINATION PROCEDURES

4.1. **General:** Unless otherwise provided for under section 4.3, Public Service will provide TPS(s) notice by July 1 of each year of the allocation of receipt capacity by pipeline that it expects to have available for all deliveries by TPS(s) at its city gate interconnections, based on existing contractual commitments, for the twelve (12) month period beginning the following November 1. Each TPS(s) will be allocated the receipt capacity based on the total expected firm and interruptible load versus the amount of available receipt capacity.

TPS will be credited for deliveries to Public Service on each day in accordance with the final daily volume confirmations of the interstate pipelines designated by TPS pursuant to this Sub-section.

4.2. **TPS Nomination Requirements~~ for Customers with a Maximum Requirement of Less Than 7,500 Therms Per Hour~~:** TPS will be required to nominate to Public Service by electronic or other means, as specified by Public Service, the total volume it intends to deliver to Public Service for subsequent delivery, along with the interstate pipelines it intends to utilize for this delivery and any additional information required by Public Service to fully identify such deliveries. TPS shall nominate to Public Service by 2:30 p.m. Eastern Time prior to the day gas is scheduled to flow (ie. the "Gas Day", defined as the 24 hour period commencing at 10:00 AM Eastern Time). TPS will be permitted to submit requests to modify nominations after the 2:30 pm deadline for supplies for the Gas Day, which may include modifications to both pipeline contracts and volumes. Such modifications will be consistent with the prevailing NAESB protocols, of 7:00 PM Eastern Time on the day prior to the Gas Day, and 11:00 AM Eastern Time ("Intra-day 1"), 3:30 PM Eastern Time ("Intra-day 2"), and 8:00 PM Eastern Time ("Intra-day 3") during the Gas Day. Any such requests for modifications to nominations for a Gas Day must be submitted in writing and received by Public Service up until 8:00 PM Eastern Time during the applicable Gas Day. Public Service will not be obligated to accept gas which has not been nominated in accordance with this Section. In any event, Public Service may refuse any revision in the nomination made during the day of delivery for operating reasons, and if, in its sole opinion, such revision is not related to the customer balancing its supplies and usage for the day.

Public Service will accept deliveries of gas for customers on the interstate pipelines of Transco or Texas Eastern. However, due to delivery limitations, Public Service reserves the right to require a reasonable apportionment of deliveries between Transco and Texas Eastern.

~~**4.3.** **TPS Nomination Requirements for Customers with a Maximum Requirement of 7,500 Therms Per Hour and Greater:** TPS will be required to nominate to Public Service using Public Service's electronic bulletin board, at least 24 hours prior to the start of each day, the total volume it intends to deliver to Public Service for subsequent delivery the next day for each customer with a maximum requirement of 7,500 therms per hour and greater. Such~~

~~daily nomination may be changed by the TPS at any time up to and during the day for which the daily nomination is applicable by notification to Public Service.~~

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

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THIRD PARTY SUPPLIER REQUIREMENTS
(Continued)

~~Public Service reserves the right to limit any revision to such daily nomination and shall not be obligated to accept any changes greater than one twenty-fourth (1/24) of the customer's maximum daily usage requirements multiplied by the number of hours remaining for the day. In any event, Public Service may refuse any revision in the nomination made during the day of delivery if, in its sole opinion, such revision is not related to the customer balancing its supplies and usage for the day.~~

~~Public Service will, for each customer provided delivery service, specify the interstate pipeline delivery point(s) at which gas supplies from a TPS shall be delivered. Normally such point(s) will be on the interstate pipeline that is in the closest proximity to each customer.~~

5. CREDIT REQUIREMENTS

5.1. General: Public Service's acceptance of a request for service under these Third Party Supplier Requirements is contingent upon TPS providing Security in an amount determined by~~satisfying a credit appraisal by~~ Public Service. ~~Based on consistent financial evaluation standards, each TPS may be granted, on a non-discriminatory basis, an Unsecured Credit Limit. Public Service shall perform such evaluations no less frequently than once every twelve (12) months.~~

~~If required, a~~A TPS may provide one of the following additional credit assurances to meet its Security obligation: (1) an advance cash deposit; or (2) a standby irrevocable letter of credit~~; or (3) a guarantee, acceptable to Public Service, by a parent Guarantor which satisfies the credit requirements. The total of the amounts offered by these instruments and, if applicable, the Unsecured Credit Limit, is defined as Security~~.

5.2. Credit Amount: The total Security at all times must be of an amount not less than the product of the TPS's Daily Requirements, expressed in dekatherms, and $70.00, plus the amount of balancing cash-out obligations outstanding to Public Service, whether billed or not billed, such total amount rounded down to the next lower multiple of $15,000. Daily Requirements is defined as the sum of the TPS's maximum month ADCQs for RSG, SLG, GSG and LVG customers and the total of the maximum month average daily usage for TSG-F, TSG-NF, and CSG customers, as stated in their respective service agreements. At any time, the maximum month's value shall be the greatest total ADCQ or average daily usage, as applicable, in the prior 12 month period (otherwise known as a rolling 12 month period).

If, at any point in time, the TPS's Daily Requirements decreases, TPS has the option to reduce the level of the Security to the product of the new Daily Requirements and $70.00, after all the outstanding obligations payable to Public Service are satisfied.

In all cases, any required increase in the level of Security must be satisfied within two (2) business days after receipt of the Public Service notice for additional Security requirements to continue service. If such Security is not posted in accordance with the foregoing, then Public Service is not required to continue service.

5.3. Interest: Interest, on cash deposited with Public Service as Security, will be the lower of the average Federal Funds Effective Rate (as published daily on the Federal Reserve website) for the period of time the funds are on deposit or six (6) percent. Cash deposits shall cease to bear interest upon discontinuance of service by the TPS or, if earlier, when Public Service closes the account. When the executed service agreement is terminated or when a portion of the cash deposit is returned to the TPS, such cash deposits will be returned with accrued interest upon payment or deduction of all charges and other debts that the TPS might owe Public Service.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

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THIRD PARTY SUPPLIER REQUIREMENTS
(Continued)

5.4. Failure to Deliver for Customers on Rate Schedules RSG, SLG, GSG, and LVG: In the event that, for a particular TPS, at any time, the sum of the cumulative imbalances, for non Force Majeure reasons, which Public Service has not yet received payment are underdeliveries that exceed three (3) times the ADCQ, Public Service will immediately notify the TPS via telephone, electronic~~facsimile~~, or similar means. If such underdeliveries reach five (5) times the ADCQ, the following will occur: (1) the TPS is no longer eligible for these Third Party Supplier Requirements unless and until the conditions below are satisfied, but not before the first (1st) day of the following month; and (2) for the balance of the current month, the affected TPS's customers will be supplied natural gas by Public Service and will be billed for Emergency Sales Service pursuant to their rate schedules for their DCQ times the number of days remaining in the current month. Such customers will continue to be charged the Emergency Sales Service rate until TPS service commences from an eligible TPS pursuant to Section 14.3 of the Standard Terms and Conditions or from BGSS default service pursuant to Section 14.5 of the Standard Terms and Conditions.

In order to be reinstated as an eligible TPS following an occurrence of an under-delivery event as described above, the former TPS, in addition to meeting all other applicable tariff requirements must post and maintain for a one (1) year period Security in an amount equal to two (2) times that otherwise required pursuant to Section 5.2 of these Third Party Supplier Requirements. At the conclusion of that year and assuming no additional occurrence of an under-delivery event as described above, TPS's requirement regarding maintenance of the Security will be returned to that described in Section 5.2. If an additional under-delivery event as described above occurs during that year period, the TPS will be ineligible for these Third Party Supplier Requirements for an additional one (1) year period.

5.5. Failure to Deliver for Customers on Rate Schedules TSG-F, TSG-NF, and CSG: In the event that, for a particular TPS, at any time, the amount of obligations outstanding to Public Service, whether billed or not billed, exceed 70% of the current level of Security, Public Service will immediately notify the TPS via telephone, electronic~~facsimile~~, or similar means.

At this time the TPS will be given the option to increase the total amount of Security held by Public Service to the required amount as described in Section 5.2 of these TPS Requirements within two (2) business days or to provide immediate payment on outstanding amounts, whether billed or not billed, due to Public Service.

At such time the amount of obligations outstanding to Public Service, whether billed or not billed, exceed 100% of the current level of Security, the TPS is no longer eligible under these Third Party Supplier Requirements unless and until the conditions below are satisfied, but not before the first (1st) day of the following month. The affected TPS's customers eligible for Emergency Sales Service will be supplied natural gas by Public Service for their usage for the remainder of the month. Such customers will continue to be charged the Emergency Sales Service rate until TPS service commences from an eligible TPS or from BGSS default service. Delivery service to customers not eligible for Emergency Sales Service will be ceased until such customers arrange for gas supplies from an eligible TPS.

In order to be reinstated as an eligible TPS following an occurrence of event as described above, the former TPS, in addition to meeting all other applicable tariff requirements must post and maintain for a one (1) year period Security in an amount equal to two (2) times that otherwise required pursuant to Section 5.2 of these Third Party Supplier Requirements. At the conclusion of that year and assuming no additional occurrence of an event in which outstanding obligations, whether billed or not billed, exceed Security as described above, TPS's requirement regarding maintenance of the Security will be returned to that described in Section 5.2.

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THIRD PARTY SUPPLIER REQUIREMENTS
(Continued)

If an additional event in which outstanding obligations, whether billed or not billed, exceed Security as described above occurs during that year period, the TPS will be ineligible under these Third Party Supplier Requirements for an additional one (1) year period.

6. IMBALANCE CASH-OUT PROCEDURES

6.1. TPS Imbalance Cash-out for Customers on Rate Schedules RSG, SLG, GSG, and LVG: On any day that TPS delivers a volume other than the aggregate of the ADCQs, of its RSG, SLG, GSG and LVG customers, the TPS will be subject to a daily cash-out as follows:

6.1.1. Over deliveries: On any day that TPS delivers a volume greater than the aggregate of the ADCQs, of its RSG, SLG, GSG and LVG customers, the TPS will be subject to a daily cash-out as follows:

The TPS will be cashed out each day for over delivered quantity of gas (in dekatherms) at cost based on an index. The index shall be the weighted average of the minimum of the "Common" range values stated in the Final Daily Price Survey section of Platt's Gas Daily for Texas Eastern M-3 and Transco Zone 6 New York for that day. The weights in the calculation shall be the required percentages of deliveries at the Texas Eastern M-3 and Transco Zone 6 New York delivery points.

For over deliveries of the ADCQ of less than 5% the PSE&G will cash out the TPS for the excess gas at 90% the index. For over deliveries of the ADCQ greater than or equal to 5% but less than 15% PSE&G will cash out the TPS for the excess gas at 75% of the index. For over deliveries of the ADCQ greater than or equal to 15% but less than 25%, PSE&G will cash out the TPS for the excess gas at 50% of the index. For over deliveries of the ADCQ greater than or equal to 25%, PSE&G will cash out the TPS for the excess gas at 40% of the index.

6.1.2. Under deliveries: The TPS will be cashed out each day for under delivered quantity of gas (in dekatherms) at cost based on an index. The index shall be the weighted average of the maximum of the "Common" range values stated in the Final Daily Price Survey section of Platt's Gas Daily for Texas Eastern M-3 and Transco Zone 6 New York for that day. The weights in the calculation shall be the required percentages of deliveries at the Texas Eastern M-3 and Transco Zone 6 New York delivery points.

For under deliveries of the ADCQ of less than 5% PSE&G will cash out the TPS for the deficiency at 110 % of the index cost times the under delivered quantity. For under deliveries of greater than or equal to 5%, PSE&G will cash out the TPS for the deficiency at 200% of the index.

6.1.3. Balancing~~Under deliveries~~ during Critical Periods: Upon no less than eight (8) hours' notice, Public Service may on any days that it determines that its gas supply condition is critical, declare such days to be a "Critical Period." For any under deliveries by a TPS greater than two (2) percent of the ADCQ during a Critical Period, the TPS will pay a charge per dekatherm at a rate equal to ten times the daily price index calculated in paragraph 6.1.1. The resulting price index shall not be lower than the maximum penalty charge for unauthorized daily overruns as provided for in the FERC- approved gas tariffs of the interstate pipelines which deliver gas into New Jersey. In addition, Public Service has the right to recover proportionately from undelivered TPSs any penalties or other charges or damages assessed on Public Service as a result of any under deliveries by eligible TPSs. For all over deliveries by an eligible TPS greater than two (2) percent of the ADCQ during a Critical Period, the TPS will be cashed out at the minimum of the "Common" range values stated in the Final Daily Price Survey section of Platt's Gas Daily for Transco Leidy Line Receipts for that day.~~then current Commodity Charge applicable to Basic Gas Supply Service – Interruptible (BGSS-I).~~

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

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THIRD PARTY SUPPLIER REQUIREMENTS
(Continued)

6.2. TPS Imbalance Cash-out for Customers with a Maximum Requirement of Less Than 7,500 Therms Per Hour on Rate Schedules TSG-F, TSG-NF, and CSG: TPS is responsible to deliver gas to Public Service for their applicable customers at the same daily rate that the aggregate of their applicable customers are utilizing gas. The Daily Cash-out Price for over- or under deliveries by a TPS for any day will be the weighted average of the higher of lower of the "Common" range values stated in the Final Daily Price Survey section of Platt's *Gas Daily* for Texas Eastern M-3 and Transco Zone 6 New York for that day. The weights for the weighted average shall be the required percentages of natural gas delivered on the Texas Eastern and Transco pipelines. Under any circumstance, Public Service has the right to recover proportionately from undelivered TPSs any penalties or other charges or damages assessed on Public Service as a result of any underdeliveries by eligible TPSs.

Public Service, in its sole discretion, may refuse to accept any deliveries of gas which it determines to be excess to a TPS's customers' daily usage.

6.2.1. Normal Daily Balancing for Under-deliveries: The TPS will be cashed out each day for the under delivered quantity of gas (in dekatherms) at cost based on an index. The index shall be the weighted average of the maximum of the "Common" range values stated in the Final Daily Price Survey section of Platt's Gas Daily for Texas Eastern M-3 and Transco Zone 6 New York for that day. The weights in the calculation shall be the required percentages of deliveries at the Texas Eastern M-3 and Transco Zone 6 New York delivery points.

PSE&G will cash out the TPS for under deliveries based upon the level of under delivery. For any imbalance level, the total cost will be the sum of costs for all prior levels of under-delivery.

Imbalance Level	Cost to TPS
0% to < 5%	Under delivered volume (dth) < 5% * 1.0 * index
≥ 5% to < 15%	5% ≤ under delivered volume < 15% * 1.25 * index
≥ 15 % to < 25%	15% ≤ under delivered volume < 25% * 1.5 * index
≥ 25%	25% ≤ under delivered volume * 2.0 * index

6.2.2. Normal Daily Balancing for Over-deliveries. The TPS will be cashed out each day for the over delivered quantity of gas (in dekatherms) at cost based on an index. The index shall be the weighted average of the minimum of the "Common" range values stated in the Final Daily Price Survey section of Platt's Gas Daily for Texas Eastern M-3 and Transco Zone 6 New York for that day. The weights in the calculation shall be the required percentages of deliveries at the Texas Eastern M-3 and Transco Zone 6 New York delivery points.

PSE&G will cash out the TPS for under deliveries based upon the level of over delivery. For any imbalance level, the purchase credit will be the sum of credits for all prior levels of over-delivery.

.Imbalance Level	Credit to TPS
0% to < 5%	Over delivered volume (dth) < 5% * 1.0 * index
≥ 5% to < 15%	5% ≤ over delivered volume < 15% * 0.75 * index
≥ 15 % to < 25%	15% ≤ over delivered volume < 25% * 0.5 * index
≥ 25%	25% ≤ over delivered volume * 0.4 * index

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

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THIRD PARTY SUPPLIER REQUIREMENTS
(Continued)

6.2.3. Balancing During Critical Periods: Upon no less than eight (8) hours' notice to the TPS, Public Service may on any day that it determines that its gas supply condition is critical, declare such days to be a "Critical Period". During such a Critical Period all under deliveries by the TPS greater than two (2) percent will be cashed out at ten times the Daily Cash-out Price. The price for under deliveries shall not be lower than the maximum penalty charge for unauthorized daily overruns as provided for in the FERC-approved gas tariffs of the interstate pipelines which deliver gas into New Jersey. All over deliveries of greater than two (2) percent will be cashed out at the minimum of the "Common" range values stated in the Final Daily Price Survey section of Platt's Gas Daily for Transco Leidy Line Receipts for that day.~~the then current Commodity Charge applicable to Basic Gas Supply Service – Interruptible (BGSS-I).~~

6.3. TPS Imbalance Cash-out for Customers with a Maximum Requirement of 7,500 Therms Per Hour and Greater on Rate Schedules TSG-F, TSG-NF, and CSG: TPS is responsible to deliver gas to Public Service for each of their applicable customers at the same daily rate each customer is utilizing gas. Except as provided for in Section 6.3.5 below, or as specified in the applicable TSG-NF or CSG agreement, all balancing and cash-out calculations shall be performed separately for each applicable customer. The basis for the Daily Cash-out Price for over- or under deliveries by a TPS will be the weighted average of the higher or lower of the "Common" range value(s) for Texas Eastern M-3 and/or Transco Zone 6 New York, as applicable. The weights for the weighted average shall be based upon the required delivery on the interstate pipeline(s) by the TPS, as published in Platt's *Gas Daily* on the table "Final Daily Price Survey". Under any circumstance, Public Service has the right to recover proportionately from undelivered TPSs any penalties or other charges or damages assessed on Public Service as a result of any under deliveries by eligible TPSs.

If at any time customer's TPS fails to deliver, or arrange for delivery of a quantity of gas, which is consistent with the quantity of gas being consumed by customer, Public Service, in its sole discretion, may suspend deliveries of gas to customer until such time as the delivery of gas to Public Service is equal to the quantity of gas being consumed by customer commences. Public Service, in its sole discretion, may refuse to accept any deliveries of gas which it determines to be excess to a TPS's customers' daily usage.

6.3.1. Normal Daily Balancing for Under-deliveries: The TPS will be cashed out each day for the under delivered quantity of gas (in dekatherms) at cost based on an index. The index shall be the weighted average of the maximum of the "Common" range values stated in the Final Daily Price Survey section of Platt's Gas Daily for Texas Eastern M-3 and Transco Zone 6 New York for that day. The weights in the calculation shall be the required percentages of deliveries at the Texas Eastern M-3 and Transco Zone 6 New York delivery points.

PSE&G will cash out the TPS for under deliveries based upon the level of under delivery. For any imbalance level, the total cost will be the sum of costs for all prior levels of under-delivery.

Imbalance Level	Cost to TPS
0% to < 5%	Under delivered volume (dth) < 5% * 1.0 * index
≥ 5% to < 15%	5% ≤ under delivered volume < 15% * 1.25 * index
≥ 15 % to < 25%	15% ≤ under delivered volume < 25% * 1.5 * index
≥ 25%	25% ≤ under delivered volume * 2.0 * index

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

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THIRD PARTY SUPPLIER REQUIREMENTS
(Continued)

6.3.2. Normal Daily Balancing for Over-deliveries: The TPS will be cashed out each day for the over delivered quantity of gas (in dekatherms) at cost based on an index. The index shall be the weighted average of the minimum of the "Common" range values stated in the Final Daily Price Survey section of Platt's Gas Daily for Texas Eastern M-3 and Transco Zone 6 New York for that day. The weights in the calculation shall be the required percentages of deliveries at the Texas Eastern M-3 and Transco Zone 6 New York delivery points.

PSE&G will cash out the TPS for under deliveries based upon the level of over delivery. For any imbalance level, the purchase credit will be the sum of credits for all prior levels of over-delivery

. Imbalance Level	Credit to TPS
0% to < 5%	Over delivered volume (dth) < 5% * 1.0 * index
> 5% to < 15%	5% < over delivered volume < 15% * 0.75 * index
> 15 % to < 25%	15% < over delivered volume < 25% * 0.5 * index
> 25%	25% < over delivered volume * 0.4 * index

6.3.3. Balancing During Periods of Suspension or Limitation: If at any time any customer is consuming gas at a rate other than a uniform hourly rate or consuming gas at a rate that doesn't correspond with the customer's TPS' deliveries, and Public Service determines that in its sole judgment that the integrity of all or a portion of its gas distribution system is being jeopardized because of such action, or the interstate pipeline upon which such gas is being delivered to Public Service enforces uniform hourly take restrictions, Public Service may limit the total amount of gas delivered to a TPS's customer to the same hourly rate at which the TPS is delivering gas to the Public Service gas system.

Public Service will provide the TPS two hours' notice that it intends to suspend or limit deliveries of gas to one or more customers, except in the case of an emergency on the Public Service gas distribution system or when the interstate pipeline enforces uniform hourly take provisions, in which case the TPS shall be notified as soon as practicable. Such notice from Public Service shall indicate the action Public Service intends to take with respect to suspending or limiting deliveries to a customer, the estimated time period of such suspension or limitation, and the time when such suspension or limitation shall go into effect.

If, during such a period of suspension or limitation of service, the TPS delivers a quantity of gas that is inconsistent with such suspension or limitation, then all under deliveries by the TPS greater than two (2) percent will be cashed out at five times the Daily Cash-out Price. All over deliveries of greater than two (2) percent will be cashed out at the minimum of the "Common" range values stated in the Final Daily Price Survey section of Platt's Gas Daily for Transco Leidy Line Receipts for that day.~~then current Commodity Charge applicable to Basic Gas Supply Service – Interruptible (BGSS-I).~~

6.3.4. Balancing During Critical Periods: Upon no less than eight (8) hours' notice to the TPS, Public Service may on any day that it determines that its gas supply condition is critical, declare such days to be a "Critical Period". During such a Critical Period all under deliveries by the TPS greater than two (2) percent will be cashed out at ten times the Daily Cash-out Price. The price for under deliveries shall not be lower than the maximum penalty charge for unauthorized daily overruns as provided for in the FERC-approved gas tariffs of the interstate pipelines which deliver gas into New Jersey. All over deliveries of greater than two (2) percent will be cashed out at the minimum of the "Common" range values stated in the Final Daily Price Survey section of Platt's Gas Daily for Transco Leidy Line Receipts for that day.~~then current Commodity Charge applicable to Basic Gas Supply Service – Interruptible (BGSS-I).~~

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

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THIRD PARTY SUPPLIER REQUIREMENTS
(Continued)

6.3.5. Designated Personnel: The customer's designated personnel having operational control of the gas usage at that facility shall be responsible for coordinating the balancing of customer's gas consumption and deliveries by the customer's TPS. Such personnel shall be the only party that Public Service contacts for all operational coordination requirements, including those during periods of Suspension or Limitation and Critical Periods as detailed in Sections 6.3.2 and 6.3.3.

~~**6.3.6 Pooling**: A TPS who is supplying more than one facility under separate CSG and/or TSG-NF accounts, with each facility having a Maximum Requirement of 7,500 therms per hour or greater and with each facility being required to have its gas supplies delivered to the same interstate pipeline delivery point as advised by Public Service pursuant to Section 4.3, may pool gas deliveries to serve the pooled load of all those facilities on the respective pipeline. The TPS shall nominate to Public Service in accordance with Section 4.3 the total gas volume to be delivered to serve the load of the pooled facilities on the respective pipeline. That nomination shall be subject to intraday nomination changes; provided, however, that such prospective changes may be limited to 1/24th of the cumulative maximum daily requirement of the pooled facilities for each remaining hour of the day. Daily imbalance cash-outs will be performed in accordance with Section 6.3, using the pooled gas deliveries versus the pooled gas usage for these facilities.~~

~~A TPS may designate a particular delivered gas supply or supplies to absorb any variation between the pooled gas deliveries and the actual pooled gas usage (swing service), provided that such supply or supplies are delivered under an interstate pipeline service agreement which is approved by the applicable interstate pipeline as being valid for use as a swing service, and that such supply or supplies have been scheduled with the pipeline's tariff provisions and operating procedures applicable to swing services. Prior to its initial utilization of a swing service, the TPS shall notify Public Service of its intention to do so. Such swing service shall not be effective until Public Service has confirmed with the applicable interstate pipeline that the swing service satisfies the pipeline's tariff provisions and operating procedures, and Public Service and the pipeline have established all necessary procedures and communications relating to daily scheduling, confirmations, and related activities.~~

6.4. Cash-out Billing and Payment: Public Service will ~~bill~~ invoice the TPS any cash-out costs and these charges are due within ten (10) days of the date of Public Service's invoice. Such bills will be subject to a late payment charge at the rate of 1.416% per monthly billing period in accordance with Section 8.13 of the Standard Terms and Conditions. Public Service has the right to call on Security in an amount equal to all unpaid cash out costs within 30 days of issuance of the cash-out invoice unless Public Service has agreed in writing to extend the period for repayment. Public Service will notify the TPS of the amount of the Security used and the amount of additional security that the TPS shall be required to post. The TPS is required to replenish this Security withing two (2) business days as described in Section 5.2 of these Third Party Supplier requirements.

It is the obligation of the TPS to provide Public Service with contact information for cash-out billing annually, and timely notification of any subsequent change to those billing contacts.

Notwithstanding the above, Public Service maintains the right to suspend transportation deliveries to any customer under Rate Schedules RSG, SLG, GSG, LVG, TSG-F, TSG-NF, and CSG from a particular TPS, and return such customers to BGSS, if in Public Service's sole opinion that TPS is not satisfying the TPS requirements as specified herein. Such TPS may also be disqualified from enrolling new customers.

7. FORCE MAJEURE

If an interstate pipeline that deliveries gas to PSE&G's system has declared a Force Majeure event, pursuant to the terms of that pipeline's FERC approved tariff, that substantially affects the ability of a TPS ~~will be excused from~~to delivering~~ing~~ the required ADCQ on any given day, Public Service may ~~for Force Majeure events which directly and substantially affect TPS's natural gas deliveries to Public Service. For purposes of these Third Party Supplier Requirements, a Force Majeure event will be any failure of the final pipeline delivering gas to Public Service or an upstream pipeline~~

~~feeding such pipeline, with failure having been classified as a Force Majeure event pursuant to the terms of that pipeline's FERC approved tariff.~~

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

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THIRD PARTY SUPPLIER REQUIREMENTS
(Continued)

~~A legitimate Force Majeure event that curtails TPS's firm transportation service on an upstream pipeline that ultimately feeds a downstream pipeline, which directly and substantially affects a TPS's natural gas deliveries to Public Service, will~~ excuse a TPS from performing pursuant to Sections 6.1, 6.2 and 6.3 of these Third Party Supplier Requirements to the extent of such curtailment, and may cash-out the TPS for related under-deliveries at the higher of the (i) weighted average of the maximum of the "Common" range values stated in the Final Daily Price Survey section of Platt's Gas Daily for Texas Eastern M-3 and Transco Zone 6 New York for that day (the weights in the calculation shall be the required percentages of deliveries at the Texas Eastern M-3 and Transco Zone 6 New York delivery points), or (ii) the Company's average cost of supply for the period in question (inclusive of any pipeline penalties assessed on the Company)~~. If at such time the TPS is delivering gas to customers on other systems, the volume excused from performance on Public Service's system will be no more than a proportionate amount of the affected deliveries curtailed by the Force Majeure event~~. The TPS is responsible for supplying complete information and verifiable proof of all the particulars requested by Public Service related to any such Force Majeure exclusion. The TPS must have a firm, non-interruptible service with the affected pipeline that is covered by the Force Majeure event and must be willing to present such agreements to Public Service.

8. STANDARD TERMS AND CONDITIONS

These Third Party Supplier Requirements are subject to the Standard Terms and Conditions of this Tariff, as applicable.

BILL IMPACTS FOR PUBLIC SERVICE ELECTRIC AND GAS COMPANY ELECTRIC AND GAS CUSTOMERS FROM ITS REQUEST TO CHANGE RATES

The proposed charges for electric delivery service are as follows:

Table # 1a - Electric Service

	RESIDENTIAL SERVICE (RS)	RESIDENTIAL HEATING SERVICE (RHS) (Closed)	RESIDENTIAL LOAD MGMT SERVICE (RLM)	WATER HEATING SERVICE (WH) (Closed)	WATER HEATING STORAGE SERVICE (WHS)
Delivery Charges					
Service Charge: $/mo.					
Service Charge	$8.06	$8.06	$13.94	--	$1.11
Distribution Charges: $/KWHR					
0-600, June-Sept	$0.080977	$0.094808	--	--	--
0-600, Oct-May	0.047232	0.049108	--	--	--
over 600, June-Sept	0.085052	0.100032	--	--	--
over 600, Oct-May	0.047232	0.030342	--	--	--
June-Sept On-Peak (1)	--	--	$0.115849	--	--
June-Sept Off-Peak (2)	--	--	0.020693	--	--
Oct-May On-Peak (1)	--	--	0.020693	--	--
Oct-May Off-Peak (2)	--	--	0.020693	--	--
Common Use (Tariff Special Provision a-4)	--	0.100032	--	-	--
All Use	--	--	--	$0.070845	0.002156
TAC: $/KWHR	($0.007116)	($0.010149)	($0.006545)	$0.000000	$0.000000
DAC: : $/KWHR	$0.001037	$0.001037	$0.001037	$0.001037	$0.001037

Table # 1b – Electric Service

	GENERAL LIGHTING AND POWER SERVICE (GLP)	LARGE POWER AND LIGHTING SERVICE-SECONDARY (LPL-S)	LARGE POWER AND LIGHTING SERVICE-PRIMARY (LPL-P)	HIGH TENSION SERVICE SUB-TRANSMISSION (HTS-S)	HIGH TENSION SERVICE HIGH VOLTAGE (HTS-HV)	BUILDING HEATING SERVICE (HS) (Closed)
Delivery Charges						
Service Charge						
Service Charge	$8.48	$370.81	$370.81	$2,038.02	$1,834.22	$6.50
Unmetered	3.89	--	--	--	--	--
Night Use	8.48	--	--	--	--	--
Primary Alternate	--	--	38.29	--	--	--
Distribution Kilowatt Charges:$/kW						
Annual Demand	$5.3085	$4.0710	$3.2111	$2.0149	$0.8338	--
Demand June – Sept	17.9935	14.0330	15.0302	7.2836	--	--
Distribution Kilowatt-hour Charges: $/kWh						
June-Sept	$0.019028	--	--	--	--	$0.110477
Oct-May	0.004272	--	--	--	--	0.057302
Night Use	0.004272	--	--	--	--	--
All Use	--					--
TAC : $/kWh	($0.002177)	($0.001332)	($0.000767)	($0.000717)	($0.000319)	$0.000000
DAC : $/kWh	$0.001037	$0.001037	$0.001037	$0.001037	$0.001037	$0.001037

Table # 1c - Electric Service

	BODY POLITIC LIGHTING SERVICE (BPL)	PUBLIC STREET LIGHTING SERVICE FROM PUBLICLY OWNED FACILITIES (BPL-POF)	PRIVATE STREET LIGHTING SERVICE (PSAL)
Luminaire Charges	(3)	--	(3)
Maintenance Charges	--	(3)	--
Delivery Charges			
Distribution Kilowatt-hour Charges: $/kWh			
All Use	$0.008701	$0.008936	$0.009297
TAC: $/kWh	$0.000000	$0.000000	$0.000000
DAC: $//kWh	$0.001037	$0.001037	$0.001037

Electric Service Notes:
All Charges are on a monthly basis, include all applicable taxes; and are applied on a per customer, per kilowatt, or per kilowatt-hour basis, as applicable. See Tariff for Provisions of all Rate Schedules.
(1) RLM - On-Peak Hours = 7 A.M. to 9 P.M. (EST) Mon.-Fri.
(2) RLM – Off-Peak Hours = All Other
(3) See Rate Schedules for details.

Table # 2
PROPOSED PERCENTAGE CHANGE BY CUSTOMER CLASS
FOR ELECTRIC SERVICE

Residential	RS	9.3%
Residential Heating	RHS	7.5%
Residential Load Management	RLM	1.7%
Water Heating	WH	11.8%
Water Heating Storage	WHS	6.2%
Building Heating	HS	11.6%
General Lighting & Power	GLP	18.1%
Large Power & Lighting- Sec.	LPL-S	3.4%
Large Power & Lighting- Pri.	LPL-P	6.0%
High Tension-Subtr.	HTS-S	3.6%
High Tension-HV	HTS-HV	1.4%
Body Politic Lighting	BPL	7.3%
Body Politic Lighting-POF	BPL-POF	5.2%
Private Street & Area Lighting	PSAL	7.3%

The percent increases noted above are based upon current Basic Generation Service Residential Small Commercial Pricing (BGS-RSCP) and Delivery Rates in effect April 1, 2024, and assumes that the customer receives BGS-RSCP service from PSE&G.

Table # 3
Residential Electric Service

If Your Average Monthly kWhr Use Is:	And Your Jun. to Sep. Average Monthly kWhr Use Is:	Then Your Present Monthly Bill (1) Would Be:	And Your Proposed Monthly Bill (2) Would Be:	Your Monthly Bill Change Would Be:	And Your Percent Change Would Be:
138	171	$34.22	$39.40	$5.18	15.14%
277	342	63.47	70.72	7.25	11.42
553	684	122.38	133.79	11.41	9.32
650	803	143.36	156.21	12.85	8.96
1,000	1,300	219.92	238.41	18.49	8.41

(1) Based upon current Basic Generation Service Residential Small Commercial Pricing (BGS-RSCP) and Delivery Rates in effect April 1, 2024 except the currently pending TAC rate, and assumes that the customer receives BGS-RSCP service from PSE&G.
(2) Same as (1) except includes changes proposed to take effect September 1, 2024.

Other proposed rate changes include the modifications to the TAC and introduction to the Distribution Adjustment Charge (DAC). For additional electric tariff related changes, see filing for details.

The proposed charges for gas delivery service are as follows:

Table # 4a – Gas Service

	RESIDENTIAL SERVICE RSG	GENERAL SERVICE GSG	LARGE VOLUME SERVICE LVG	STREET LIGHTING SERVICE SLG
Delivery Charges				
Service Charge: $/mo.	$13.10	$30.75	$273.10	
Demand Charge: $/Demand therm			$6.1034 (1)	
Distribution Charge: $/therm				
All Use:	$0.592644			$0.086762
Pre 7/14/97:		$0.529566 (2)		
All Others:		0.529566		
0-1,000 pre 7/14/97:			$0.108979 (2)	
Over 1,000 pre 7/14/97:			0.055176 (2)	
0-1,000 post 7/14/97:			0.108979	
Over 1,000 post 7/14/97:			0.055176	
Off Peak Dist Charge: $/therm				
All Use:	$0.296323 (3)			
Pre 7/14/97:		$0.264783 (2&3)		
All Others:		$0.264783 (3)		
Lamp Charge: $/unit/mo				
Installed Before 1/1/1993:				$16.5583
Installed on and After 1/1/1993:				$84.4192
TAC: $/therm	($0.097603)	($0.083052)	($0.038746)	($0.144998)
DAC: $/therm	$0.000522	$0.000522	$0.000522	$0.000522
SBC: $/therm	$0.073422	$0.073422	$0.073422	$0.073422

Table # 4b – Gas Service

	FIRM TRANSPORTATION TSG-F (Closed)	NON-FIRM TRANSPORTATION TSG-NF	COGENERATION INTERRUPTIBLE CIG (Closed)
Service Charge:$/mo.	$1,072.42	$1,072.42	$285.91
Demand Charge: $/Demand therm	$3.6338 (1)		
Distribution Charge: $/therm			
All Use:	$0.138900	$0.144458	
0-600,000:			$0.127499
Over 600,000:			$0.116836
TAC:$/therm	$0.000000	$0.000000	$0.000000
DAC:$/therm	$0.000522	$0.000522	$0.000522
SBC:$/therm	$0.073422	$0.073422	$0.073422

Gas Service Notes:
All charges are on a monthly basis, include all applicable taxes; and are applied on a per customer, per demand therm, or per therm basis, as applicable.
(1) Applicable in the months of November through March.
(2) Applicable to customers who have taken Third Party Supply (TPS) commodity service continuously since July 14, 1997.
(3) Off-Peak use is applicable in the months of April through October

Table # 5
PROPOSED PERCENTAGE INCREASES BY CUSTOMER CLASS
FOR GAS SERVICE

Residential Service	RSG	13.2%
General Service	GSG	18.7%
Large Volume Service	LVG	8.8%
Street Lighting Service	SLG	(0.1)%
Firm Transportation Gas Service	TSG-F	11.0%
Non-Firm Transportation Gas Service	TSG-NF	4.9%
Cogeneration Interruptible Service	CIG	7.6%

The percent increases noted above are based upon Delivery Rates and the Basic Gas Supply Service (BGSS) charges in effect April 1, 2024, and assumes that the customer receives commodity service from PSE&G.

Table # 6
Residential Gas Service

If Your Average Monthly Therm Use Is:	And Your Avg. Dec. to Mar. Monthly Therm Use Is:	Then Your Present Monthly Bill (1) Would Be:	And Your Proposed Monthly Bill (2) Would Be:	Your Monthly Bill Change Would Be:	And Your Percent Change Would Be:
17	25	$24.88	$30.88	$6.00	24.12%
33	50	41.14	48.64	7.50	18.23
53	100	62.75	72.04	9.29	14.80
87	172	96.55	108.86	12.31	12.75
100	200	110.03	123.54	13.51	12.28
152	300	162.43	180.60	18.77	11.19

(1) Based upon Delivery Rates and Basic Gas Supply Service (BGSS-RSG) charges in effect April 1, 2024 except currently pending TAC rate, and assumes that the customer receives commodity service from PSE&G.
(2) Same as (1) except includes changes proposed to take effect September 1, 2024.

Other proposed rate changes include the modifications to the TAC, introduction of the Social Programs of the gas SBC as well as the DAC. For additional gas tariff related changes, see filing for details.

STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

In the Matter of the Petition of Public Service Electric and Gas Company for Approval of an Increase in Electric and Gas Rates and for Changes in the Tariffs for Electric and Gas Service, B.P.U.N.J. No. 17 Electric and B.P.U.N.J. No. 17 Gas, and for Changes in Depreciation Rates, Pursuant to N.J.S.A. 48:2-18, N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1, and for Other Appropriate Relief

BPU Docket Nos. ER23120924 & GR23120925

DIRECT TESTIMONY OF MICHAEL P. MCFADDEN 9+3 UPDATE

DIRECTOR OF SALES AND REVENUE FORECASTING

April 15, 2024
P-2 R-1

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
DIRECT TESTIMONY
OF
MICHAEL MCFADDEN
DIRECTOR OF SALES AND REVENUE FORECASTING
PSEG SERVICES COMPANY

I. <u>INTRODUCTION</u>

Q. Please state your name and business address.

A. My name is Michael P. McFadden. My business address is 80 Park Plaza, Newark, New Jersey, 07102.

Q. In what capacity are you employed?

A. I am currently employed by PSEG Services Corporation ("PSEG Services"), a subsidiary of Public Service Enterprise Group Incorporated ("PSEG" or "Enterprise"), as the Director of Sales and Revenue Forecasting. I have been employed by Enterprise for 15 years in a number of financial positions, primarily supporting the financial analyses and determination of revenue requirements associated with regulatory filings by Public Service Electric and Gas Company ("PSE&G, or the "Company"). Since June 2021, I have been the Director of Sales and Revenue Forecasting. My credentials are set forth in Schedule MPM-1.

Q. What are the key points in your testimony?

A. In support of PSE&G's December 2023 electric and gas base rate filing with the New Jersey Board of Public Utilities ("BPU" or "Board"), my testimony addresses the following key topics:

1) ***Context for Request and Value to Customers*** – I first provide some context to customer bills, explaining: a) the value the Company provides to its customers compared to peers both in cost, customer satisfaction, and reliability; b) how the

Company's bills compare to the income of median- and low-income families; c) how PSE&G's distribution costs, the subject of this proceeding, compare with those of regional peers; d) how PSE&G's total customer bill compares to that of regional peers; and e) ways customers can control their bills through proposed time of use rates and other programs the Company offers.

2) ***Factors Driving Rate Increase*** – I discuss the key drivers of the Company's rate request, which include recovery of Board-approved capital investments and deferrals, and resets of Board-approved cost recovery clauses. Major drivers include stipulated base programs and deferred investments such as those for Energy Strong II ("ES II"), the extension of the Gas System Modernization Program ("GSMP II"), the Infrastructure Advancement Program ("IAP"), the Clean Energy Future – Energy Cloud Program ("CEF-EC", or "AMI"), the Clean Energy Future – Electric Vehicle Program ("CEF-EV"), and the NJ Transit Mason Substation Project ("Mason Substation") along with other significant capital expenditures.

3) ***Mitigation of Rate Increases*** – I discuss the actions PSE&G has taken to mitigate rate increases. This includes steps taken to control costs charged to customers, a proposal to increase the flow-back of certain tax benefits to customers, and the benefits customers receive through PSE&G's Appliance Service Business.

4) ***Capital Structure and Cost of Capital*** – I discuss the Company's requested return on equity ("ROE") and capital structure that are critical both to the preservation of the Company's credit ratings and access to capital, and also to ensure just and reasonable rates. The allowed ROE and capital structure should appropriately recognize the conditions in the financial markets supporting our request.

5) ***Appliance Service Business ("ASB")*** – I address the significant benefits of the Company's ASB and the Company's request to retain 50 percent of the Gas ASB margins (revenues less expenses), the same percentage allowed on the electric side of ASB, to continue to provide this benefit to customers.

6) ***Pension & OPEB Expense Recovery*** – I discuss the Company's proposal to defer changes in pension and other post-employment benefit ("OPEB") expenses above or below the amount reflected in rates, ensuring recovery from customers, or return to customers, of cost changes outside the Company's control to ensure there are no winners or losers.

7) ***Gas Bad Debt Expense Recovery in Societal Benefits Charge ("SBC")*** – I address the Company's request, first raised in the COVID-19 proceeding,[1] to recover Gas bad debt expenses through a new social component of the SBC in the same manner as is currently done for Electric bad debt expenses.

8) ***Storm Cost Recovery Mechanism*** – I provide details on how costs for significant storm events are currently accounted for and recovered from customers, as well as PSE&G's proposal to recover those costs through a new tariff clause, the "Storm Recovery Charge." The proposal will ensure only prudently incurred costs are recovered from customers in a timely manner through a mechanism that allows for Board-approved increases or decreases outside a base rate case.

9) ***Conservation Incentive Program ("CIP") Baseline Reset*** – I explain the approved CIP mechanism for both electric and gas service and propose the new

[1] *I/M/O the New Jersey Board of Public Utilities Response to the COVID-19 Pandemic*, BPU Docket No. AO20060471, PSE&G filing titled *I/M/O the Petition of Public Service Electric and Gas Company for Approval of Incremental COVID-19 Costs for Recovery Through a New Special-Purpose Clause, and for Authorization to Recover Uncollectible Costs for Gas Through the Societal Benefits Charge* (July 17, 2023).

baseline use (for gas) or revenue (for electric) per customer as a result of this proceeding.

10) ***Embedded Cost of Debt Rate Recovery*** – I discuss the Company's proposal to defer changes in the embedded cost of debt from the rate established at the end of the test year, recognizing the current debt market conditions. The deferral mechanism would apply only to the debt component of rate base approved by the Board.

11) ***Incentive Compensation*** - I explain why recovery of incentive compensation is appropriate, integral to strong operating performance, and benefits customers.

12) ***Deferral Authority on Credit Card and Debit Card Fees, the IT Expenditures Required to Implement TOU Rates and Traffic Control Costs*** – I address the Company's request for deferral authority on incremental expenses the Company will incur if permitted to assume the cost of credit card payments from customers. In addition, the Company proposes to implement changes to its billing system to allow for time of use rates and requests deferral authority for the expenditures that will occur after the test year. Finally, the Company proposes to defer the incremental costs associated with the recent traffic control regulation.

13) ***Test Year and Revenue Requirements*** - Finally, I support the test year and associated calculation of the Company's revenue request in this proceeding and test year and post-test year adjustments.

Q. Why is PSE&G making this base rate filing at this time?

A. This filing is being made, in part, to comply with the BPU's May 22, 2018 Order approving PSE&G's next phase of the Gas System Modernization Program ("GSMP II").[2] The GSMP II Order required the filing of a base rate case by no later than January 1, 2024.[3] In addition, the 'BPU's approval of the Company's ES II filing required the Company to submit a base rate case no later than December 31, 2023.[4] This filing is in compliance with those Orders and seeks approval to increase PSE&G's annual revenue requirements for both its electric and gas operations as discussed later in my testimony.

Q. What is the rate increase being sought?

A. Please see the table below for the breakdown of the net rate increase sought in this proceeding. Beyond the proposed base rate increase, the Company is also seeks: 1) recovery of storm costs through a new clause component rather than through base rates, 2) recovery of gas bad debt expense through a new component of the SBC rather than through base rates, and 3) an adjustment to flow-back certain tax benefits to customers through the Tax Adjustment Credit ("TAC").

[2] *I/M/O the Petition of Public Service Electric and Gas Co. for Approval of the Next Phase of the Gas System Modernization Program and Associated Cost Recovery Mechanism ("GSMP II")*, B.P.U. Docket No. GR17070776, "Decision and Order Approving Stipulation" (May 22, 2018) ("GSMP II Order").

[3] Parallel requirements exist in *I/M/O the Petition of Public Service Electric and Gas Co. for Approval of its Clean Energy Future – Energy Cloud ("CEF-EC") Program on a Regulated Basis*, B.P.U. Docket No. EO18101115, Decision and Order Approving Stipulation (January 7, 2021) ("CEF-EC Order"), and *I/M/O the Petition of Public Service Gas and Electric Co. for Approval of its Clean Energy Future – Electric Vehicle and Energy Storage ("CEF-EVES") Program on a Regulated Basis*, B.P.U. Docket No. EO18101111, Decision and Order Approving Stipulation (January 27, 2021) ("CEF-EV Order").

[4] *I/M/O the Petition of Public Service Electric and Gas Co. for Approval of the Second Energy Strong program ("Energy Strong II")*, B.P.U. Docket Nos. EO18060629 and GO18060630, Final Decision and Order Approving Stipulation (September 11, 2019) ("Energy Strong II Order").

Table 1			
Rate Case Net Impact to Customers			
Overall Total Revenue Impact ($M)	**Electric**	**Gas**	**Total**
Base Rates	$535	$401	$936
Tax Adjustment Credit ("TAC")	-$88	-$98	-$186
Storm Recovery Mechanism	$39	$1	$40
Gas Bad Debt in SBC	$0	$34	$34
Net Total Revenue Impact $	$485	$339	$825
Net Total Bill Impact %	7%	12%	8%

Q. Do you sponsor any schedules as part of your direct testimony?

A. Yes. I sponsor the following schedules that were prepared or compiled under my direction and supervision:

- Schedule MPM-1: Credentials
- Schedule MPM-2 R-1: Determination of Revenue Requirements
- Schedule MPM-3 R-1: Determination of Rate Base
- Schedule MPM-4 R-1: Weighted Average Cost of Capital
- Schedule MPM-5 R-1: Long Term Debt
- Schedule MPM-6 R-1: Revenue Factor
- Schedules MPM-7 R-1 through 18 R-1: Support for components of rate base
- Schedule MPM-19 R-1: Income Statement
- Schedules MPM-20 R-1 through 28 R-1: Support for components of the income statement
- Schedule MPM-29 R-1: *Pro-forma* Distribution Operating Income
- Schedules MPM-30 R-1 through 53 R-1, and the newly added 56 R-1: Support for *pro forma* adjustments to test year operating income

- Schedule MPM-54E R-1 and 54G R-1: revised Electric Baseline Revenue per Customer and Gas Baseline Use per Customer amounts for the Conservation Incentive Program as a result of the revised billing determinants approved in this proceeding.
- Schedule MPM-55 R-1: Interest Rate Adjustment Mechanism

II. <u>CONTEXT FOR REQUEST AND VALUE TO CUSTOMERS</u>

Q. How long has it been since PSE&G's last base rate case?

A. PSE&G filed its last base rate case on January 12, 2018, with new rates effective November 1, 2018. Since that time, all but one of the six other NJ electric and gas utilities have filed two base rate cases.

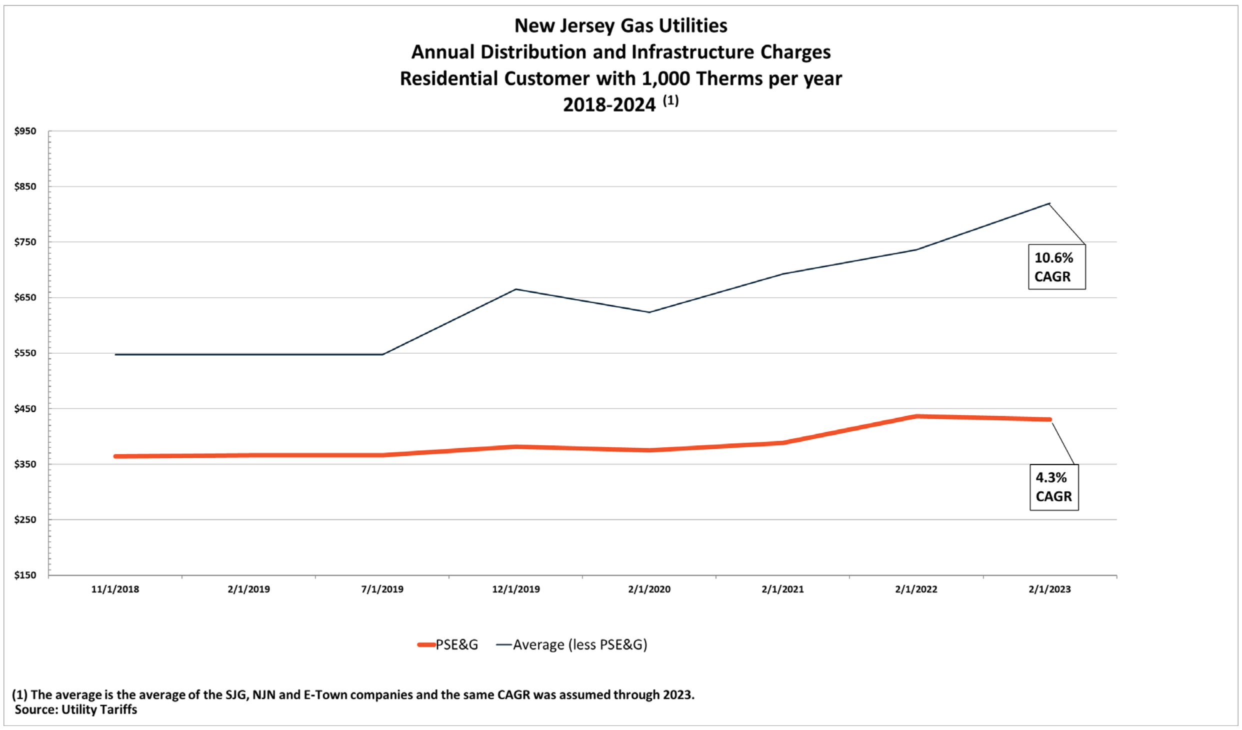
Q. How has PSE&G been able to avoid filing for a rate case until now?

A. This is primarily due to the Company's efforts to control costs. PSE&G takes very seriously its responsibility to customers to manage costs prudently while being good stewards of the electric and gas distribution systems and providing the funds needed to operate and maintain the systems effectively. This is achieved by regularly benchmarking Company costs, exceptional employee performance, and creating appropriate employee incentives to continue to improve upon historic success.

Q. How have PSE&G's Gas distribution rates, the subject of this proceeding, changed since the 2018 base rate case?

A. The Gas distribution rates have increased since 2018 primarily as the result of GSMP II and ES II rate adjustments for work to modernize the gas system and replace cast iron and unprotected steel mains, which provide both reliability and carbon-emissions benefits to customers. The distribution component of a Residential Gas customer bill using 1,000 therms per year has increased at a compound annual growth rate ("CAGR") of 4.3% since 2018. Despite the considerable investment to modernize the gas system, this increase is less than half of the statewide average of 10.6%. PSE&G's distribution rates are considerably less than those of the New Jersey average as PSE&G has been able to control costs and maximize the value of its prior investments.

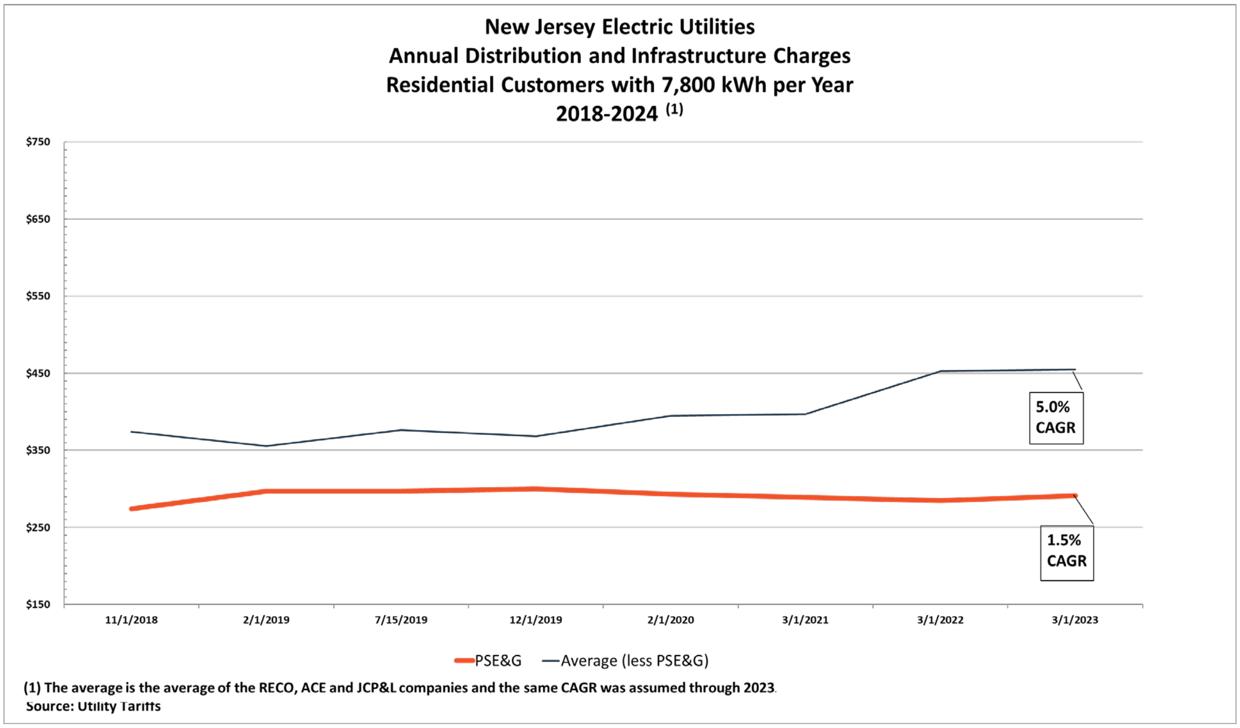
Chart 1



Q. How have PSE&G's Electric distribution rates changed since the 2018 base rate case?

A. The distribution component of a Residential Electric customer bill for a customer using 7,800 kWh per year has increased at a CAGR of 1.5%, well below the statewide comparable average of 5.0%. and below inflation levels. This modest increase is driven primarily by rate increases from the ES II Program to modernize the Company's electric system and to make it more reliable and resilient. As with Gas, the Company has been able to control costs and avoid the need for an earlier base rate case.

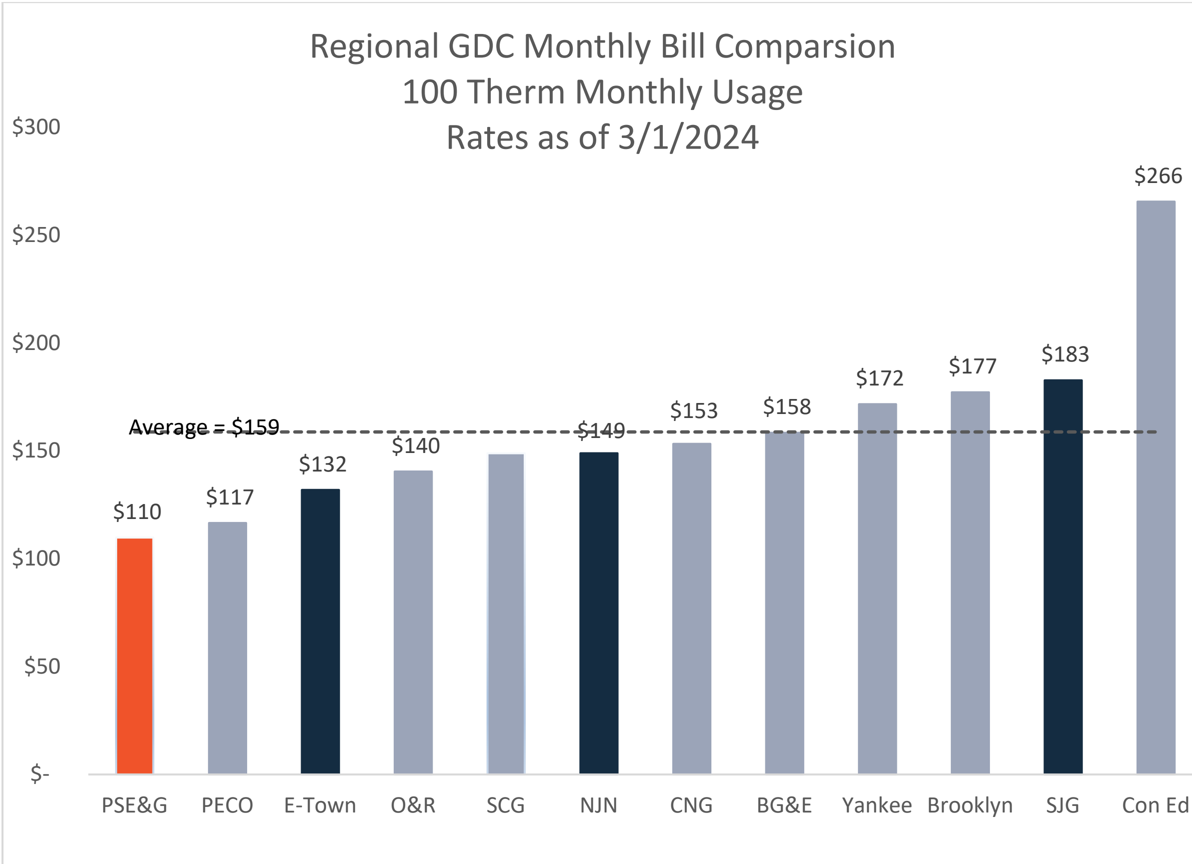
Chart 2



Q. That shows that PSE&G electric and gas distribution charges increased at a relatively lower rate, but how do you compare on a total bill basis?

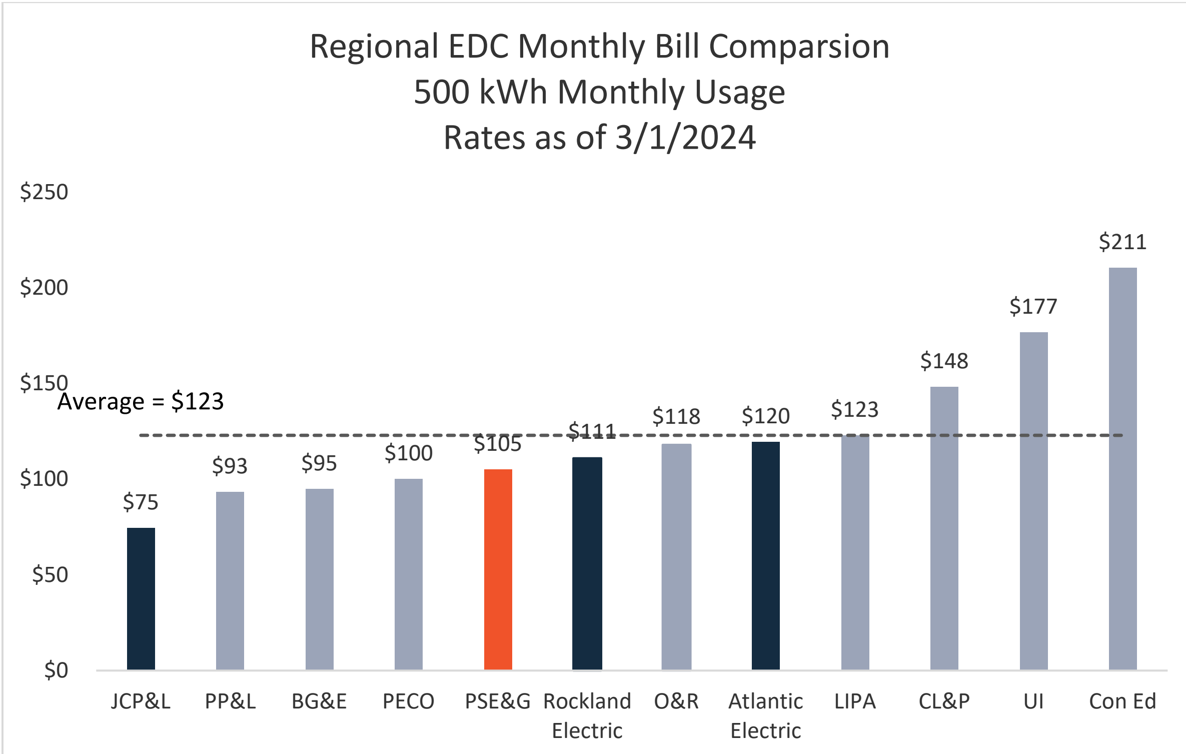
A. PSE&G's bills continue to be lower than the average of its peers.

Chart 3



Regional GDC Monthly Bill Comparsion
100 Therm Monthly Usage
Rates as of 3/1/2024
$300
$250
$200
$150
$100
$50
$-
Average = $159
$110
$117
$132
$140
$149
$153
$158
$172
$177
$183
$266
PSE&G
PECO
E-Town
O&R
SCG
NJN
CNG
BG&E
Yankee
Brooklyn
SJG
Con Ed

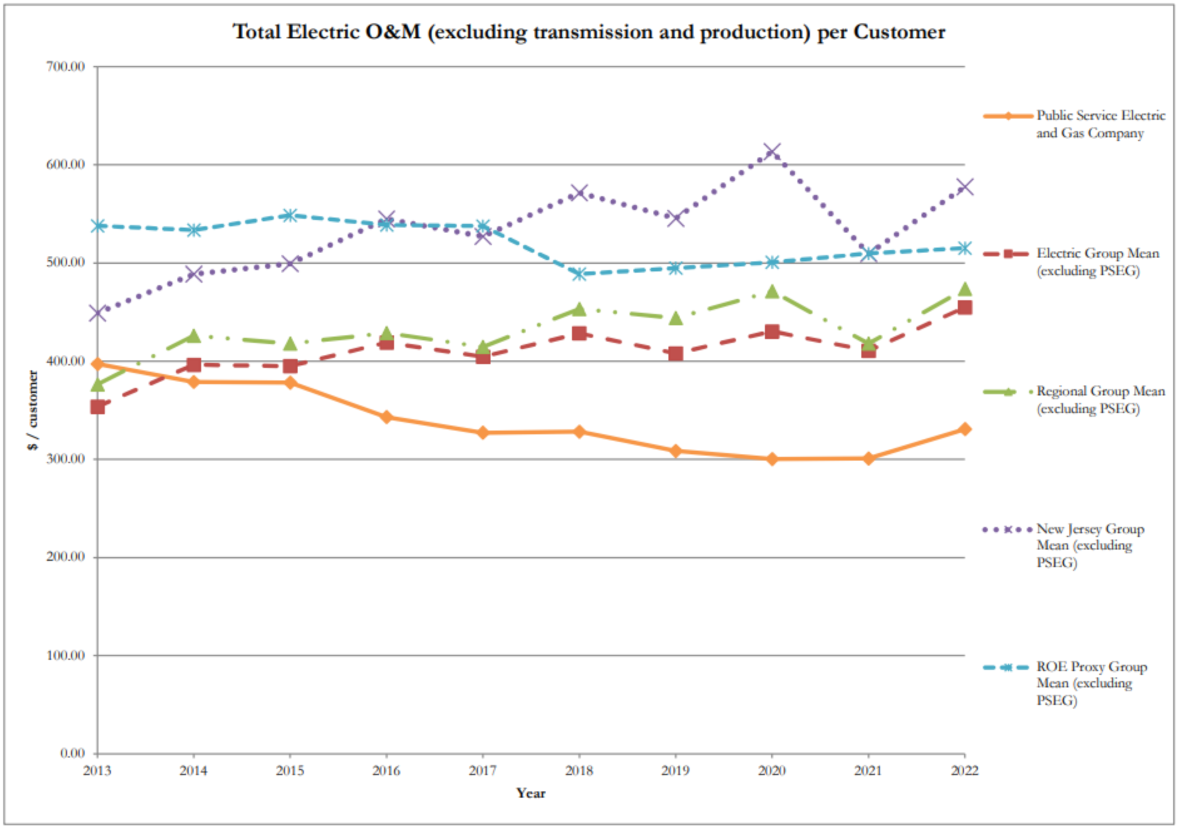
Chart 4



Q. Are customers receiving value from the Company's investments and cost control efforts?

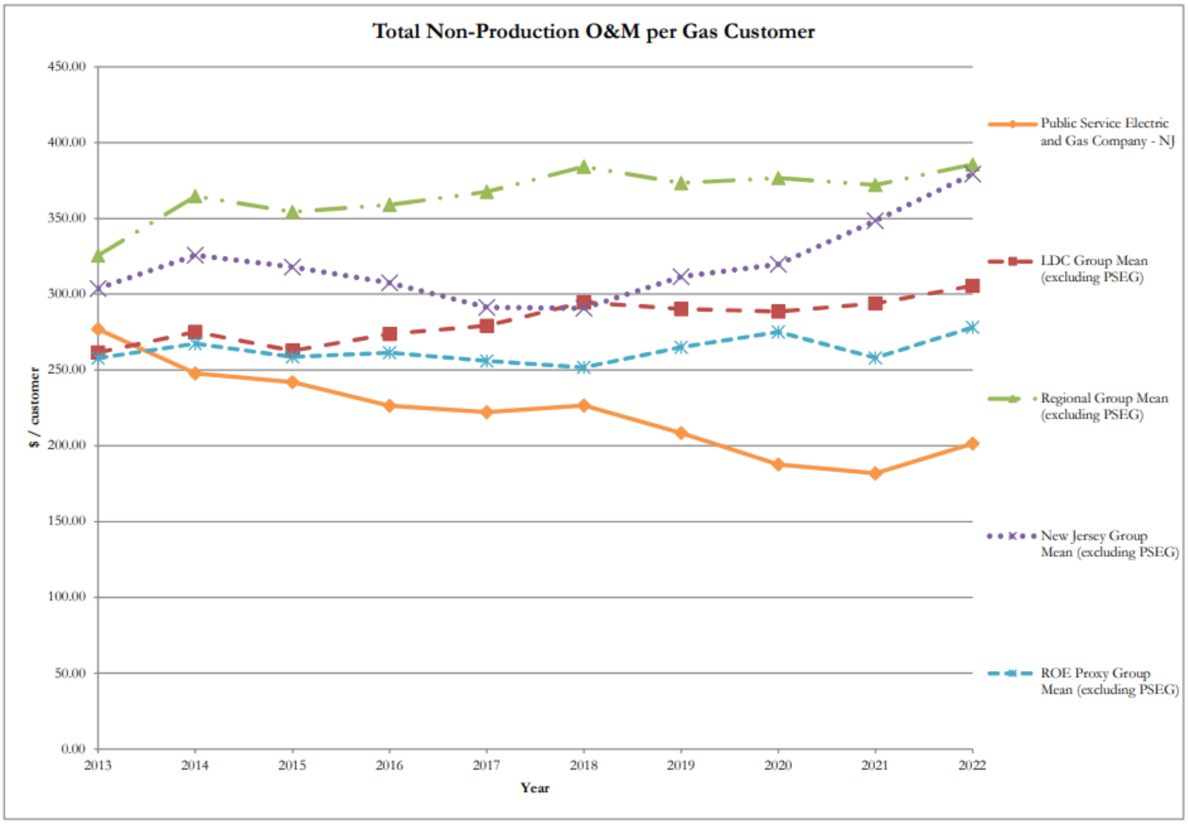
A. Absolutely. PSE&G represents a great value to its customers both in terms of cost and reliability. As shown in the tables below, PSE&G ranks the lowest for total distribution O&M per customer compared to both State, Regional and ROE proxy group peers for both Electric and Gas, and PSE&G has the best rating of cost per customer and reliability for Electric.

1 **Chart 5**


Total Electric O&M (excluding transmission and production) per Customer
700.00
600.00
500.00
400.00
300.00
200.00
100.00
0.00
$ / customer
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
Year
Public Service Electric and Gas Company
Electric Group Mean (excluding PSEG)
Regional Group Mean (excluding PSEG)
New Jersey Group Mean (excluding PSEG)
ROE Proxy Group Mean (excluding PSEG)

2

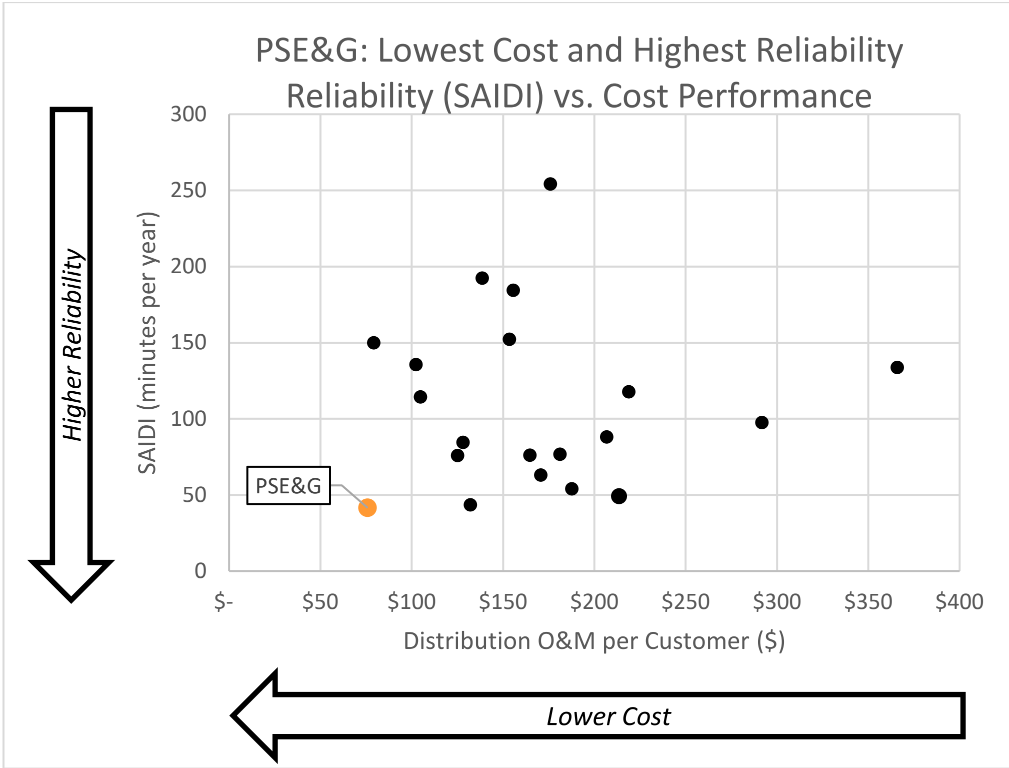
1 **Chart 6**



Total Non-Production O&M per Gas Customer
450.00
400.00
350.00
300.00
250.00
200.00
150.00
100.00
50.00
0.00
$ / customer
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
Year
Public Service Electric and Gas Company - NJ
LDC Group Mean (excluding PSEG)
Regional Group Mean (excluding PSEG)
New Jersey Group Mean (excluding PSEG)
ROE Proxy Group Mean (excluding PSEG)

2

1 **Chart 7**



For more details on the Company's costs and reliability compared to peers, see the testimony of Michael Adams.

Q. Have customers recognized this value?

A. Yes. The Company's J.D. Power Customer Satisfaction results for Residential and Business customers for both Electric and Gas are illustrated in the following charts. In 2022, the Company achieved better than first quartile results in all four categories.

Chart 8

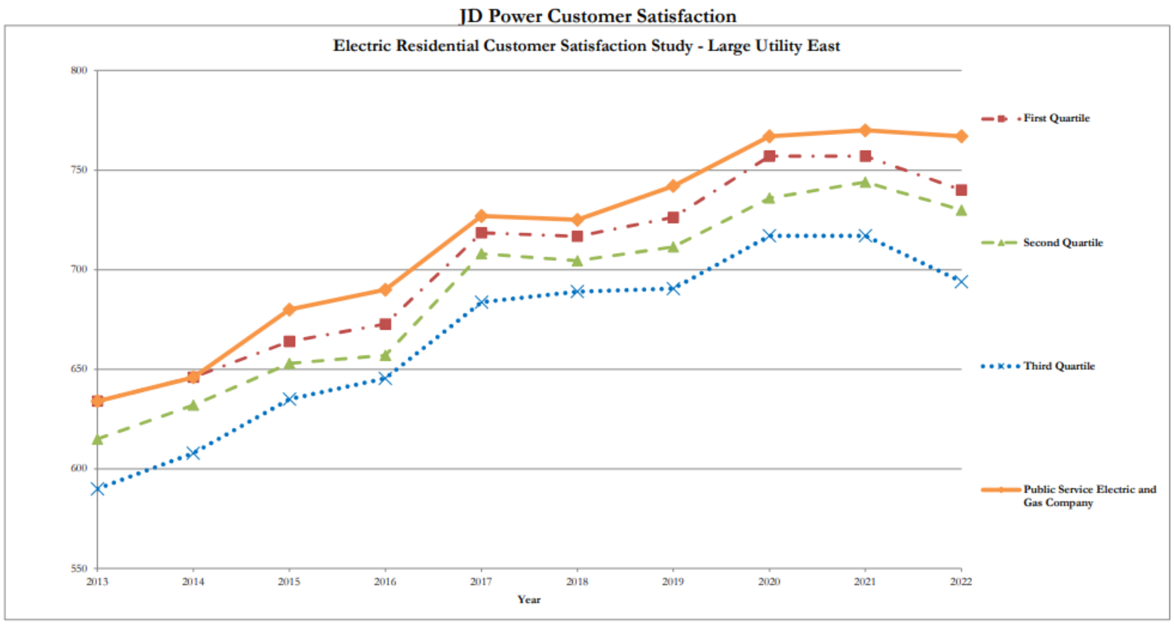


Chart 9

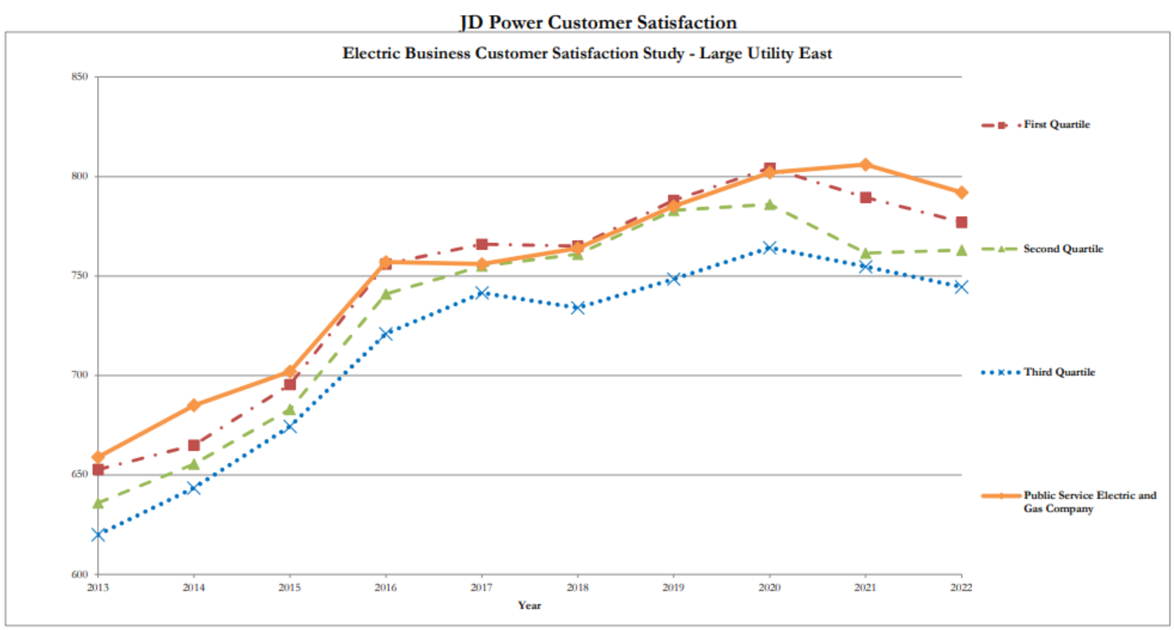


Chart 10

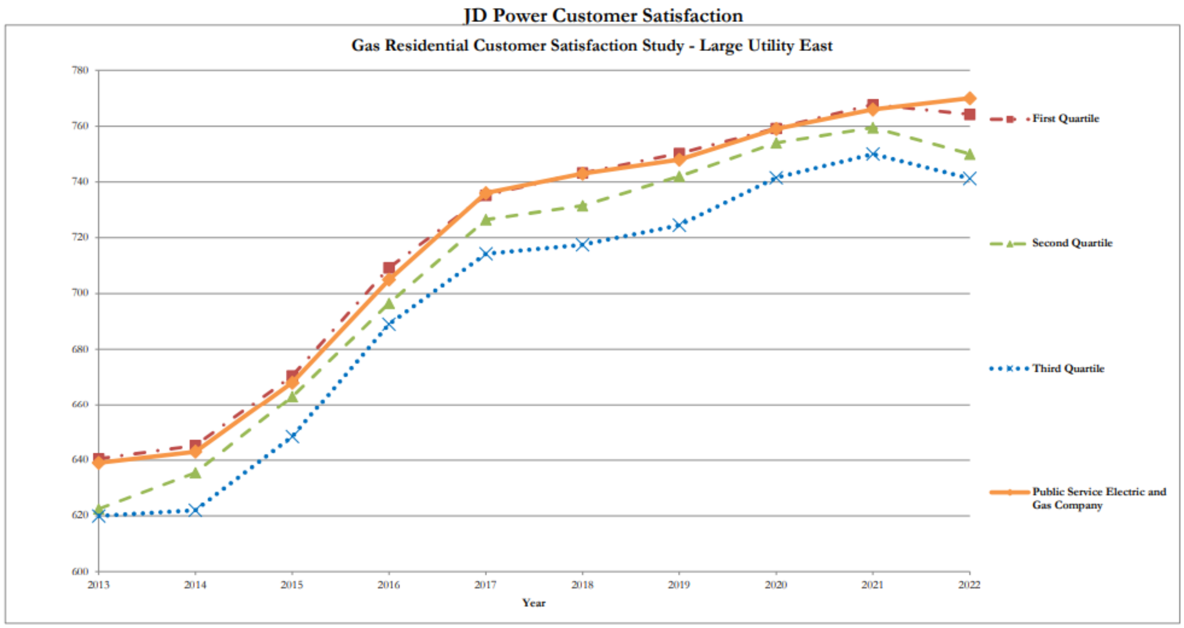
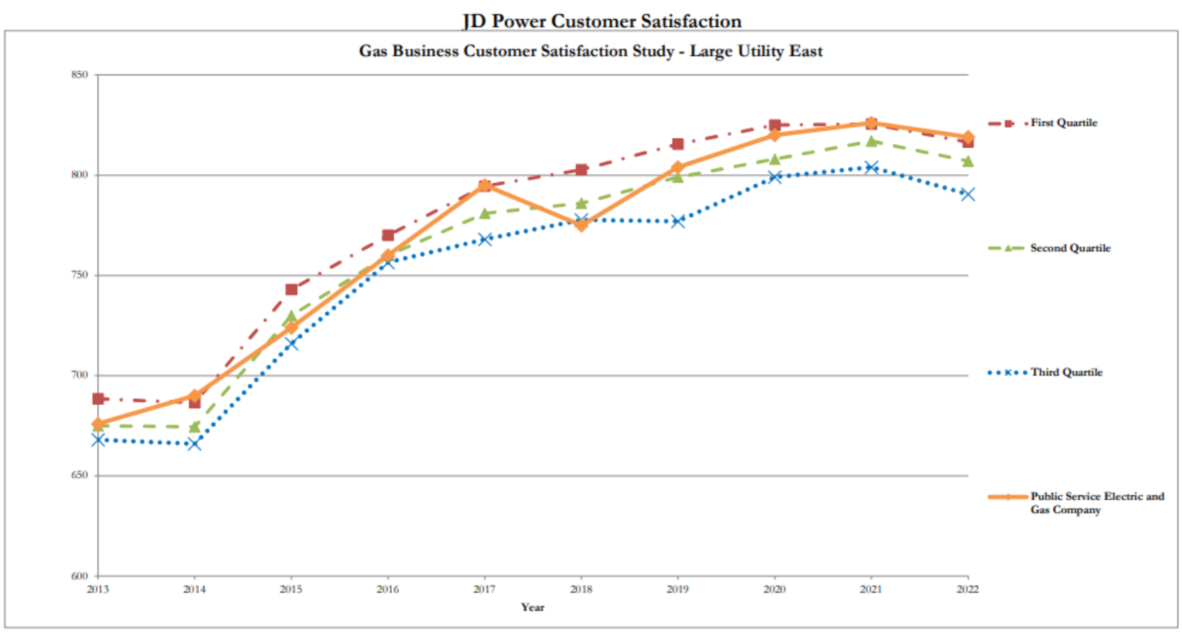


Chart 11



Q. Please describe the efforts the Company has undertaken to protect lower-income customers from the impact of rate increases.

A. The Company is very focused on this vulnerable segment of its customer base. PSE&G's Energy Efficiency programs include special incentives targeted to lower income customers. The Company implements the State's Comfort Partners program, which provides free energy savings measures as well as upgrades to address health and safety problems in the home for lower income customers. PSE&G also introduced a new initiative in its Clean Energy Future – Energy Efficiency program targeted to lower income customers between 250% and 400% of the Federal Poverty Level, and customers in overburdened communities. This included financial incentives to both property owners and tenants in apartments and multifamily properties. The Company promotes these programs through multiple channels, including outreach events, digital and traditional media, bill inserts, social media, and marketing by trade allies.

Q. Are there other assistance programs for lower income customers outside of PSE&G's energy efficiency programs?

A. Yes. PSE&G also advocates for various grants provided to lower-income customers, including the Low Income Home Energy Assistance Program ("LIHEAP"), "Lifeline" for senior and disabled adults, the Universal Service Fund ("USF"), Payment Assistance for Electric and Gas ("PAGE"), and "NJ SHARES."

Q. Please describe what these programs are and who is eligible.

A. LIHEAP is a Federal Block Grant program that helps low-income individuals and households pay for winter heating bills, medically necessary cooling benefits, and weatherization. The Lifeline Program helps customers pay their utility bills with a $225 annual utility credit. To be eligible, a customer must be at least age 65, or at least age 18 and collecting

Social Security Disability. In addition, a single person must make less than $42,000, or a couple less than $49,000 annually. USF is a statewide program administered by the Department of Community Affairs that allows program recipients to pay no more than 3% of their income for electric and 3% for natural gas, or 6% for total electric, including electric heating for customers at or below 60% of the State median income. PAGE is a program for customers earning up to 500% of the Federal Poverty Limits and offers a grant of up to $700 per utility service. NJ SHARES is for customers earning up to 400% of the Federal Poverty Limit and is funded by customer donations which are matched by PSE&G.

Q. How does the Company promote these programs?

A. The Company promotes the use of these services to its customers through bill inserts, community outreach, events, and through its collection correspondence. A dedicated web site with written information and videos is also promoted and all these methods of communication occur in multiple languages where possible and appropriate. PSE&G serves the most diverse demographics in the State and, due to the nature of PSE&G's customer base, has more customers eligible for these low-income programs on a proportionate basis compared to other utilities. Consequently, this customer segment receives special focus.

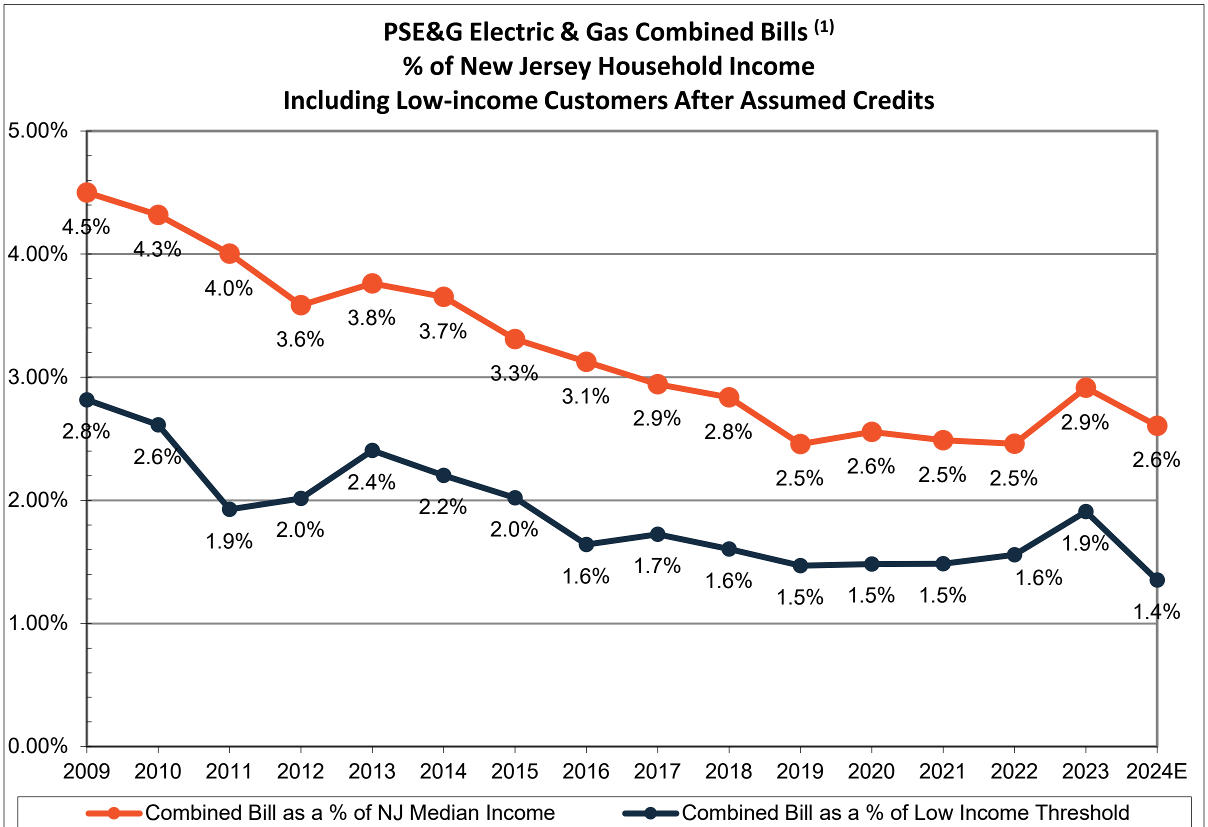
Q. Are there steps PSE&G has taken during the COVID-19 pandemic to help these customers?

A. Yes. PSE&G, its customers, and New Jersey have faced unprecedented challenges as a result of the COVID-19 global pandemic that created difficult economic circumstances for many customers. In response to these challenges, PSE&G developed a comprehensive payment assistance outreach plan utilizing employees and contractors, as well as an external media campaign designed to provide customers the opportunity to garner financial assistance and enter into deferred payment arrangements.

Q. Have you considered the impact of electric and gas rates on these customers?

A. Yes. As illustrated in the chart below, the relative cost of PSE&G's services to a typical combined (that is, electric and gas) residential lower-income customer has dropped significantly since 2009.

Chart 12



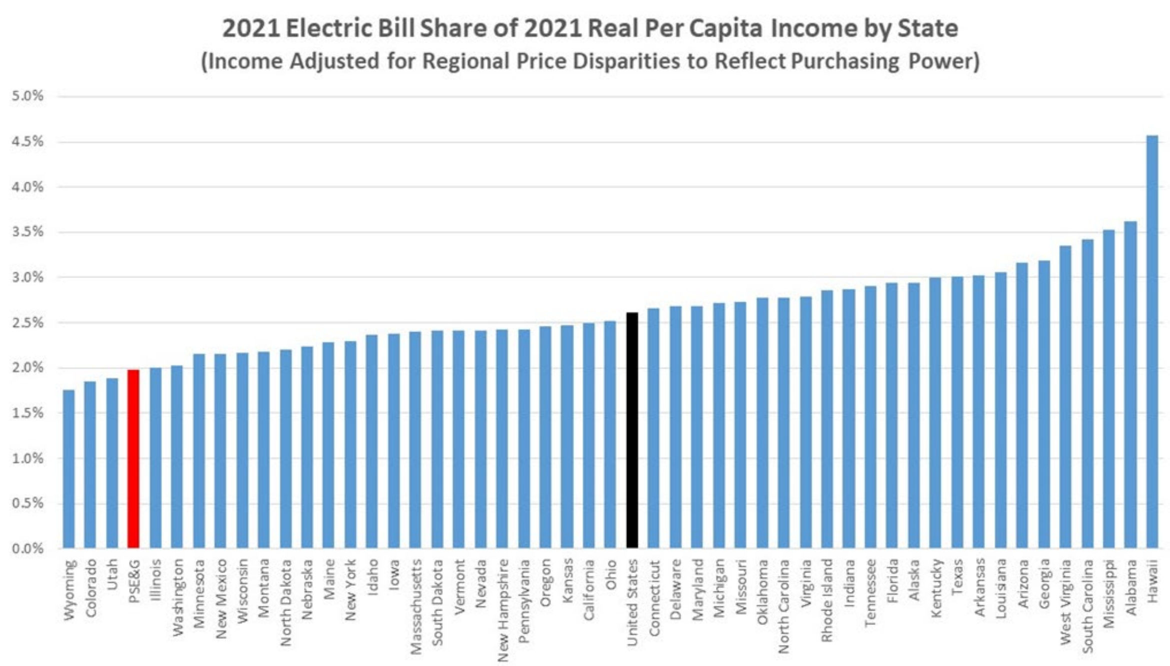
(1) Based on a typical residential electric customer using 740 kilowatt-hours per summer month and 6,920 kilowatt-hours on an annual basis using rates as of June 1 for each year and a typical residential gas heating customer using 172 therms per winter month and 1,040 therms on an annual basis using rates as of January 1 of each year. Notes: NJ Median income source https://fred.stlouisfed.org/series/MEHOINUSNJA646N. 2023 and 2024E are not available, therefore assume 3% annual increase per year over 2022. Income level of USF, the lowest threshold of the three low-income programs, is 175% of the Federal Poverty Line. Assumes the customer also qualifies for LIHEAP and Lifeline. 2022 results were adjusted to normal levels of customer assistance, which was elevated in 2022 due to funds received through the American Recovery Plan.

This chart compares the bill as a percentage of income for a typical combined electric and gas residential customer relative to New Jersey's median income and relative to the income threshold below which customers are considered low-income. As can be seen, for the average residential customer, the cost of service is less than 3% of median income. For lower-income customers, the cost of the bill after LIHEAP, USF, and Lifeline grants relative to an income level of 60% of State median income (the level at which a customer is eligible for these grants), is less than 2% today. So, even with this proposed rate increase, the cost of electricity and gas for all of the Company's customers, including low-income customers, remains a very small portion of overall income for those able to take advantage of these programs.

Q. How does this utility bill portion of overall income compare to other states?

A. Very well. As shown in the chart below, PSE&G's residential electric bill as a percentage of per capita income for NJ is in the top quartile compared to the other states in the US. In other words, PSE&G's total bill represent less share of a customer's wallet than the relative utility bill share in most of the other states.

Chart 13



Source: U.S. Dept. of Commerce, Bureau of Economic Analysis, "Regional Data GDP and Personal Income", June 2023
U.S. Dept. of Energy , Energy Information Agency, "Sales (consumption, revenue, prices & customers", retrieved July 2023.

While PSE&G's bills as a percentage of overall NJ income is very favorable compared to most other states, the Company recognizes the current economic environment and the ongoing need to control costs as much as possible. PSE&G has and will continue to control costs as much as possible to maintain affordable rates for customers without sacrificing reliability.

Q. Beyond cost control efforts, has PSE&G considered any other options for customers to lower their bills?

A. Yes. PSE&G has a robust energy efficiency program open to all customer groups to help customers reduce their usage and overall bill. Further, as discussed in the testimony of Mr. Swetz, PSE&G proposes to implement new voluntary electric time-of-use ("TOU") rate options that will allow customers to reduce their bills (as well as reduce overall system peak demand and the need for additional generation) by shifting usage when they can to off-peak periods. These new proposed TOU rates can be utilized by all residential customers to shift usage away from the system peak demand and will be particularly beneficial to electric vehicle customers that can charge their cars during off-peak hours. Further, PSE&G proposes to offer this TOU program with guaranteed bill protection for customers enrolling in the first 24 months. Customers who opt into the TOU rate options will be eligible for a refund if the total cost of the TOU rate exceeds what they would have been charged on the standard Residential ("RS") rate in the first 12 months of their enrollment. After the first year, the customers may opt-out of the program.

Q. Do you have any final comments on the impact of this filing to customers?

A. Yes. PSE&G recognizes the current economic environment and the need to keep costs to customers as low as possible. However, in addition to the requirement in the GSMP II Order that this case be filed before January 2024, it is important to put this increase in context looking at the utility bill as a percentage of overall income both for low income customers and for customers overall. Further, PSE&G has controlled costs as much as possible, avoiding the need to file a base rate case until now and resulting in a distribution increase over the last five years well below the average for all other NJ electric and gas utilities. The increase is primarily driven by Board approved and traditional utility investments to modernize the electric and gas systems, reduce carbon emissions, and improve reliability and customer satisfaction, and by deferred costs related to major storm events. PSE&G's customers have recognized these benefits as shown in the Company's reliability results and the JD Power results, and thus PSE&G is requesting recovery of these prudent expenditures. Finally, PSE&G will continue to evaluate ways to reduce the impact to customers through additional rate options to send the right price signals to customers to help reduce bills and improve reliability.

III. <u>FACTORS DRIVING THE NEED FOR RATE RELIEF</u>

Q. Why is the Company seeking the requested rate increase?

A. It has been approximately five years since the Company's last base rate case filing, so PSE&G has successfully operated for an extended period of time without having to seek a base rate increase. After five years, and despite the Company's successful execution of its cost mitigation and expense control strategies, there are a number of significant factors that have driven the Company's financial results well below its authorized rate of return and that represent the primary drivers of the rate increase sought in this filing. These factors include recovery of the following:

- Board approved investment programs;
- traditional utility investments;

- insufficient depreciation and cost of removal rates;
- New Business investment with flat sales growth;
- deferred significant storm event costs; and
- working capital requirements

I will address each of these in turn.

A. Board Approved Investment Programs

Q. What are the Board approved infrastructure programs impacting this proceeding?

A. The Board has approved the Company's substantial investments in specific programs with prudency and final recovery to be determined in this proceeding. The Board approved programs that are the subject of this proceeding are:

- NJ Transit Mason Substation;
- GSMP II (as extended);
- Energy Strong II;
- CEF-EC;
- CEF-EV; and
- IAP[5]

Q. How do these programs impact this proceeding?

A. The specifics of each program and its recovery are unique and identified separately below. In general, as discussed in the panel testimony of Company witnesses Mike Schmid and Rick Fonseca, as well as in the testimony of David Johnson, PSE&G seeks a prudency

[5] *I/M/O the Petition of Public Service Electric and Gas Co. for Approval of an Infrastructure Advancement Program (IAP)*, B.P.U. Docket Nos. EO21111211 and GO21111212, Decision and Order Approving Stipulation of Settlement (June 29, 2022) ("IAP Order").

determination and final rate recovery on the NJ Transit Mason Substation, GSMP II, Energy Strong II, and CEF-EC programs. While PSE&G seeks a prudency determination and recovery of investments and expenditures associated with the CEF-EV and IAP programs that are in-service, each program will continue to have investment beyond the end of this proceeding and will require a final prudency determination on all expenditures outside this proceeding in a subsequent rate case.

Q. Please briefly summarize each program and its recovery mechanism.

A. A description of each program or area is set forth below:

a. **New Jersey Transit Mason Substation** – By Order dated November 21, 2017, making use of funds remaining from the original Energy Strong program approved in 2014, the Board approved a plan to demolish the facilities known as the Mason Substation, comprising a number of buildings and electric plant that at the time were owned by the New Jersey Transit Corporation ("NJ Transit"), and to rebuild the facilities under PSE&G ownership.[6] The substation, which is a crucial facility for both NJ Transit and for electric customers in northern New Jersey, suffered severe damage during Superstorm Sandy. The cost of the rebuilt facility is shared between NJ Transit and PSE&G. The Board authorized PSE&G to recover its prudently incurred project cost investment of up to $100 million plus an Allowance for Funds Used During Construction, in a subsequent base rate case. Station assets are placed into service as they become used and useful. To date $60 million has been placed into service and the remaining $40 million is expected to be placed in

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[6] *See I/M/O the Petition of Public Service Electric and Gas Company for Approval of the Construction of the Mason Substation Damaged During Superstorm Sandy*, BPU Docket No. EO16080788, Decision and Order Approving Stipulation (November 21, 2017), at 3-4.

service by November 2024. Therefore, as discussed in the panel testimony Mr. Schmid and Mr. Fonseca, the Company is seeking recovery of its prudently incurred substation-related costs consistent with the Mason Substation Order.

b. **GSMP II** – In the GSMP II Order, the BPU authorized the Company to invest and seek recovery through periodic rate "roll-ins" of up to $1.575 billion in capital costs over a five-year period.[7] The capital investments under GSMP II have enhanced gas system safety and achieved leak reductions. The roll-ins of GSMP II costs, which already have been approved in previous roll-in proceedings, are subject to prudency review in this base rate case.[8] The GSMP II Order also established requirements for "Stipulated Base" expenditures of approximately $300 million and other baseline capital expenditures that were not eligible for recovery through the GSMP II roll-in mechanism and thus will be recovered in this proceeding, adding to the Company's unrecovered capital balance. The Board approved the final GSMP II investment roll-ins by Order issued May 24, 2023.[9] PSE&G's revenue requirement includes all investment associated with the GSMP II Program. All revenues associated with GSMP II projects already rolled into rates are included in Operating Revenues and thus form no part of PSE&G's incremental revenue request in this proceeding. On October 11, 2023, the Board approved a two-and-a-half-year extension of GSMP II for $902 million ($752M for accelerated recovery

[7] A limited amount of O&M costs relating to the amortization of cost offsets from methane leak reductions were included in the GSMP II Rate Mechanism. GSMP II Order at p. 10.
[8] GSMP II Order at p. 8.
[9] *I/M/O the Petition of Public Service Electric and Gas Co. for Approval of the Next Phase of the Gas System Modernization Program and Associated Cost Recovery Mechanism ("GSMP II") (December 2022 GSMP Rate Filing)*, B.P.U. Docket No. GR22120749, Decision and Order Approving Stipulation (May 24, 2023).

and $150M for Stipulated Base) starting January 1, 2024 ("GSMP II Extension").[10] GSMP II Extension will not have any rate roll-ins during the test year and thus no revenue adjustment is required. However, as described in more detail below, PSE&G will make a rate base adjustment to exclude GSMP II Extension accelerated recovery investment in the test year from the request in this case; that investment will be recovered in a future rate adjustment to ensure the investment is not double-counted. See Schedule MPM-18 R-1 for the rate base adjustment.

c. **Energy Strong II –** The Company was authorized in the Energy Strong II Order to invest up to $691.5 million ($641 million for electric and $50.5 million for gas). The rate adjustments relating to Energy Strong II costs are subject to prudency review in this base rate case.[11] The Energy Strong II Order also authorized recovery of up to $150.5 million ($100 million for electric and $50.5 million for gas) of incremental costs for specified Energy Strong II projects to the extent incurred (also known as Stipulated Base), in the Company's next base rate case. The Company is effectively and reasonably managing the Energy Strong II Program as described in the panel testimony of Mr. Schmid and Mr. Fonseca. PSE&G's proposed revenue requirement includes all investment associated with the Energy Strong II Program. Likewise, all revenues associated with the Infrastructure Improvement Program Charges for Energy Strong II projects already rolled into rates, or that will

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[10] *I/M/O of the Petition of Public Service Electric and Gas Company for Approval of the Next Phase of the Gas System Modernization Program and Associated Cost Recovery Mechanism ("GSMP II")*, BPU Docket No. GR17070776, and *I/M/O the Petition of Public Service Electric and Gas Company for Approval of the Next Phase of the Gas System Modernization Program and Associated Cost Recovery Mechanism ("GSMP III")*, BPU Docket No. GR23030102, Decision and Order Approving Settlement (October 11, 2023) ("GSMP II Extension Order").

[11] Energy Strong II Order at 8.

be rolled into rates during the test year, are included in Operating Revenues, and thus form no part of the Company's incremental revenue request in this proceeding.

d. **CEF-EC** – By Order dated January 7, 2021, the Board approved PSE&G's CEF-EC proposal authorizing installation of 2.2 million advance metering infrastructure ("AMI") meters and related infrastructure and information technology over an approximately four-year period.[12] The Board approved deferral of actual investment up to $707 million and expenses of $71 million, or a total of $778 million for total CEF-EC expenditures. The CEF-EC Order also allowed for the recovery of prudent legacy meter stranded costs, recognizing that the acceleration of the AMI deployment will result in legacy meters being replaced before they are fully depreciated. Finally, the CEF-EC Order called for a *pro forma* revenue requirement adjustment in this proceeding to account for future savings at the completion of the AMI deployment. The CEF-EC Order allowed for deferral of program-related costs without any recovery until this base rate case. The CEF-EC program description and status are detailed in the testimony of Company Witness David Johnson. The details of the CEF-EC impact to rate base are shown on Schedule MPM-16 R-1. The proposed amortization of the CEF-EC deferrals is shown on Schedule MPM-47 R-1, and the *pro forma* revenue requirement adjustment is shown on Schedule MPM-48 R-1 and described in more detail below. Consistent with the CEF-EC Order, in this rate case PSE&G seeks recovery of prudently incurred actual AMI expenditures as well as stranded costs related to legacy meters.

[12] *See* CEF-EC Order.

e. **CEF-EV** – By Order dated January 27, 2021, the Board approved PSE&G's CEF-EV program, in which the Company was authorized to invest up to $166.2 million to implement its CEF-EV program and to incur up to $38 million of incremental O&M expenses associated with the program.[13] The CEF-EV program description and status are detailed in the testimony of Company Witness Karen Reif. Consistent with the CEF-EV Order, in this rate case PSE&G seeks recovery of prudently incurred actual investments and CEF-EV related O&M expenses. The details of the CEF-EV impact to rate base are shown on Schedule MPM-17 R-1. The details of the proposed amortization of the CEF-EV deferrals are shown on Schedule MPM-49 R-1 and described in more detail below. In addition, while not a factor impacting the rate request in this proceeding, the CEF-EV Order allowed for annual roll-in filings for investment not expected to be in-service by six months after the end of the test year in this base rate case. The testimony of Company witness Mr. Swetz details the template for those future roll-in filings.

f. **IAP** – The Company was authorized in the IAP Order to invest up to $351.0 million ($281.2 million for electric and $69.8 million for gas) to be recovered through an accelerated rate adjustment mechanism, designated the IAP Rate Mechanism.[14] The IAP program description and status are detailed in the testimony of panel witnesses Mr. Schmid and Mr. Fonseca. The Board also required stipulated base expenditures of $160.0 million on incremental costs outside the IAP Rate Mechanism to be recovered in the Company's next base rate case if found to be reasonable and prudent. While this program is not complete and final prudency on

[13] *See* CEF-EV Order.
[14] *See* IAP Order.

all expenditures outside of this proceeding will not occur until a future base rate case proceeding, PSE&G estimates $45 million of stipulated base expenditures in service through the end of the test year on May 31, 2024 and a total of $72 million in service up to 6 months beyond the end of the test year; PSE&G seeks to recover those costs in this proceeding. In addition, as described in more detail below, PSE&G will make a rate base adjustment to exclude IAP investment in the test year from the request in this case; that investment will be recovered in a future rate roll-in to ensure the investment is not double-counted. See Schedule MPM-15 R-1 for the rate base adjustment.

Q. Why was the authorized interim recovery of costs associated with these programs insufficient?

A. The Company was approved for interim rate adjustments for only a portion of its Energy Strong II, GSMP II and IAP investments. PSE&G seeks recovery of the investment in these programs that is not subject to interim recovery, referred to as Stipulated Base. The Company was authorized by the Board to make these investments with recovery to commence in a base rate case proceeding. For the NJ Transit Mason Substation, CEF-EC, and CEF-EV programs, there was no interim recovery approved before this proceeding and recovery for all in-service expenditures will commence from this rate case proceeding.

Q. Are there any adjustments to the GSMP II, Energy Strong II, or IAP interim rate adjustments to ensure recovery of investments is not double-counted?

A. Yes. As described in more detail below, a *pro forma* adjustment is being proposed to annualize any interim rate adjustments during the test year to ensure the Company does not double count the revenues associated with any of these programs. These adjustments will increase the Company's Operating revenue as if the interim rates were in effect for the entire test year, which reduces PSE&G's request. There were no rate adjustments during the test year for the gas business as all rate adjustment occurred by the June 1, 2023 start of the test year. There are ES II and IAP rate adjustments during the test year for electric. Please see Schedule MPM-44 R-1 for the adjustment.

B. Traditional Utility Investments

Q. Have the Company's non-program-related investments impacted PSE&G's request in this proceeding?

A. Yes. From the conclusion of PSE&G's prior base rate case through the start of the current test year on June 1, 2023, the Company has invested $5.8 billion ($2.4 billion for electric and $3.4 billion for gas) in service to support safe, proper, and reliable service. To put that amount into context, the Company's approved total rate base balance in the 2018 base rate case was $9.5 billion ($5.5 billion for electric and $4.0 billion for gas). While some of that investment is associated with Board approved programs detailed above, the majority is associated with traditional utility base investments. These investments include accelerating the replacement of the aging cast iron and unprotected steel piping in the Company's system and modernizing the gas system to reduce methane emissions and improve safety and reliability, as well as improving the performance of the electric system by retiring certain older substations and investing in circuits prone to outages. Details concerning PSE&G's base capital investments are discussed by panel witnesses Mr. Schmid and Mr. Fonseca. This capital investment far exceeds the amount the Company is recovering in depreciation expense in current rates, increasing PSE&G's rate base and the depreciation expense needed to recover this investment. PSE&G is seeking recovery of and on all prudent investment in the system in this proceeding.

C. Insufficient Depreciation and Cost of Removal Rates

Q. Please explain the impact of depreciation on PSE&G's need for rate relief.

A. It is widely acknowledged that aging infrastructure is one of our nation's greatest challenges. Since depreciation rates are the mechanism through which a utility recovers the dollars expended for its capital projects, establishing the appropriate depreciation rates for a utility is critical to establishing just and reasonable rates. Properly set depreciation rates allow the Company to recover its investments timely, charge those costs to the customers who benefited from their use, and fund new capital construction. Company witness Mr. John Spanos has conducted a detailed evaluation of PSE&G's assets and developed new depreciation rates based on that evaluation to recover the costs of replacing aging infrastructure over its useful life and account for the cost to remove assets in the future. As described in Mr. Spanos' testimony, the Company's current depreciation rates are insufficient, largely due to the fact that the rates are not permitting the Company to recover its cost to remove and retire plant for which there is no more useful life (i.e., cost of removal). Prior reductions in the accrual for cost of removal have resulted in under-collection of those costs. The Company is proposing new depreciation rates that properly account for cost of removal and will allow the Company to appropriately recover its expected costs as it replaces aging infrastructure See Schedule MPM-41 R-1 for the impact of the proposed depreciation rates.

D. Flat Sales Despite Customer Growth

Q. How have PSE&G's sales changed since the last rate case?

A. On a weather-normalized basis, electric sales have slightly declined while gas sales have slightly increased. However, customers have steadily increased, so on a per customer basis, weather-normalized sales for both electric and gas have declined.

Q. Has this decline in sales meaningfully impacted the Company's margin (revenues less expenses)?

A. No. The Company's margin has been maintained due to the Conservation Incentive Program ("CIP").

Q. Please describe the CIP.

A. The CIP mechanism was approved by the Board in the Clean Energy Future – Energy Efficiency matter on September 23, 2020 in Dockets Nos. GO18101112 and EO18101113 ("CEF-EE Order").[15] The CIP rate mechanism provides a rate adjustment related to changes in the average revenue per customer when compared to a baseline revenue per customer, removing the disincentive for the Company to encourage customers to conserve energy. Because of the CIP, flat to declining sales growth is not a factor requiring PSE&G to request rate relief.

Q. What is the impact of a base rate case filing on the CIP?

A. Anytime a base rate case is filed, the CIP baselines will reset. As described in more detail below, PSE&G will reset the CIP baselines in this proceeding to the approved billing

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[15] *I/M/O the Petition of Public Service Electric and Gas Company for Approval of Its Clean Energy Future-Energy Efficiency ("CEF-EE") Program on a Regulated Basis*, Order Adopting Stipulation, BPU Docket Nos. GO18101112 and EO18101113 (September 23, 2020).

determinants for this test year of June 2023 through May 2024. This will shift the recovery of the revenue from the CIP accrual to base rates, increasing rates in this proceeding (but significantly lowering the CIP accrual for future years). Generally, this is just a transition of recovery from the CIP to base rates. However, the CIP is recovered or refunded to customers on a one-year lagged basis, so when base rates increase, the CIP accrual will subsequently decline, but the CIP rate in effect will remain, resulting in a net increase in rates to customers. The details of the *pro forma* adjustment to remove the CIP accrual currently included in operating revenues for recovery in base rates is shown in Schedule MPM-50 R-1.

E. Major Storm Event Recovery

Q. Please describe the regulatory asset PSE&G seeks to recover in connection with Major Storm Events.

A. The Company seeks to recover $110 million of deferred major storm costs incurred by the Company since the last rate case. As described in detail in the testimony of panel witnesses Mr. Schmid and Mr. Fonseca, that $110 million is the result of six Major Storm Events on the following dates:

- August 4-13, 2020 (Tropical Storm Isaias/State of Emergency) $72M;
- June 3, 2020 (Derecho/thunderstorms) $15M;
- July 17-18, 2019 (Major Storm) $12M;
- September 1-28, 2021 (Hurricane Ida/State of Emergency) $8M;
- Jan. 31- Feb. 23, 2021 (February 2021 Snow Storms/State of Emergency) $2M; and
- Jan 9-11, 2024 (Storms/State of Emergency) $2M

Q. Is the Company recovering any of these costs through base rates?

A. No, it is not. In the 2018 base rate case, the Company deferred all major storm event costs prior to and during the test year. Those costs, along with other regulatory assets were resolved through a black box settlement, with amortization of the agreed upon total regulatory assets over a five-year period. Because the test year Major Storm Events were deferred, there were no Major Storm Event costs reflected in the test year expenses and thus nothing in base rates to recover any post-test year Major Storm Events.

Q. Can you summarize your request for Major Storm Event costs?

A. The Company is seeking recovery of all prudently incurred Major Storm Event costs that have been deferred since the last rate case. These costs were incurred in preparation for and response to Major Storm Events that are outside the Company's control. As described in more detail below in Section IX, the Company is seeking a Storm Recovery Charge to recover these costs going forward.

F. Working Capital

Q. What is Working Capital?

A. Working Capital is the average amount of capital over and above investments in plant and other separately identified rate base items provided by investors of PSE&G to bridge the gap between the time expenditures are required to provide service and the time collections are received for that service. Each rate base working capital requirement consists of three components: cash (Lead/Lag), materials and supplies, and prepayments. The amounts included in the test year are described in more detail below.

Q. How has Working Capital changed since the last rate case?

A. The primary driver of the large increase in working capital is related to the Company's cash working capital needs. As described in the testimony of Company witness Mr. Adams, the cash working capital requirement is comprised of a lead-lag study and net asset liability analysis. Since the last rate case, the cash working capital requirements from the lead-lag study have increased due to a significant increase in the collection lag from customers. Since 2020 the Company's Accounts Receivable balance has increased significantly. While the Company is working with customers to address their arrears, there remains a significant lag in revenue recoveries, increasing working capital needs. This working capital requirement is not for recovery of uncollected bad debt, but recognition of an ongoing lag in revenue recovery. Further, since the last rate case, the Company has successfully managed its pension and OPEB plans, which results in net pension and OPEB income and an offsetting entry to record a pension asset. Each of those are reflected in this rate case (crediting the 2024 pension and OPEB income to customers and recovering the corresponding pension asset which is part of working capital).

Q. Why have Materials and Supplies increased?

A. The increase in inventory is primarily a result of ensuring material availability for planned increases for system maintenance and capital work. Due to extended lead times and supply chain constraints, PSE&G has restructured its approach to purchasing inventory material. The Company has diversified the supplier base in many material categories in an effort to increase material availability and reduce lead times. The Company also implemented more enhanced material forecasting models that have translated into increased inventory levels to support operations. Raw material and labor shortages stemming from the pandemic combined with increased demand industry-wide has also resulted in price increases impacting inventory values.

Conductors and transformers are especially vulnerable to fluctuations in the metals markets, and commodities like aluminum and copper have been very volatile the last few years. PSE&G's strategy to diversify suppliers also includes use of international vendors, which adds cost to accommodate overseas shipping and logistics.

IV. MITIGATION OF THE RATE INCREASES

Q. Has PSE&G taken steps to minimize the rate change requested?

A. Yes. I will describe in this section some of the successful cost-containment efforts made to enable the Company to limit its total O&M expense since its last test year in 2018. The Company takes very seriously its responsibility to customers to manage its costs prudently and to be good stewards of the electric and gas distribution systems and the customer funds needed to operate and maintain them effectively. It is important to note, however, that while maintaining a much lower cost structure, PSE&G has preserved operational performance – safety, reliability, and customer satisfaction – that is, generally, top quartile in the industry, as noted above and more comprehensively in the testimony of Michael Adams.

Q. Please discuss the steps that the Company has taken to limit the rate increase.

A. The Company has taken a number of steps to mitigate the magnitude of the rate increases proposed in this proceeding. First, the Company proposes to flow-back to customers significant tax benefits to replace expiration of the unprotected Excess Deferred Income Taxes ("EDIT") refunded to customers through the TAC as a result of the 2018 base rate case. Second, the Company has contained the growth of distribution-related O&M expenses, including electric and gas distribution operating costs, while reducing certain administrative and general ("A&G") costs, including pension and benefits costs. Third, PSE&G has managed its interest costs as prudently as possible and is anticipating approximately the same long-term debt rate as in the 2018 rate case by the end of the test year despite the significant rise in interest rates. Finally, the Company's Appliance Service Business has grown its net margins (revenues less expenses), which reduces the revenue request in this proceeding. All of these factors have enabled the Company to reduce the rate request that it otherwise would have made.

A. Tax Adjustment Credit ("TAC")

Q. Please describe the current TAC.

A. As discussed in the testimonies of Company witnesses Mr. Pardo and Mr. Swetz, the TAC is a mechanism approved in the 2018 base rate case to flow-back certain tax benefits to customers. The TAC allowed for the flow back to customers of the Federal Tax benefit associated with EDIT and the Historic Safe Harbor Adjusted Repair Expense ("SHARE") as outlined in the 2018 rate case order below:[16]

Table 2

Tax Flow-Through Balances				
$000				
	Electric	Gas	Total	Amortization
Excess deferred tax (EDIT) flowback - Protected	424,259	326,618	750,877	ARAM
EDIT flowback - Unprotected (Rate Base Related)	175,105	213,929	389,034	5 yr
EDIT flowback - Unprotected (Non-Rate Base Related)	56,308	59,971	116,279	5 yr
Histroic SHARE flowback	130,493	287,201	417,694	10 yr
Total	**786,165**	**887,719**	**1,673,884**	

The TAC also required the flow-back of January – March 2018 income tax recovery, the flow-through of the Current SHARE, a return on the increase in rate base as a result of the flow back

[16] *I/M/O the Petition of Public Service Electric and Gas Company for Approval of an Increase in Electric and Gas Rates and for Changes in Tariffs for Electric and Gas Service, B.P.U.N.J. No. 16 Electric and B.P.U.N.J. No. 16 Gas, and for Changes in Depreciation Rates, Pursuant to N.J.S.A. 48:2-18, N.J.S.A 48:2-21 and N.J.S.A. 48:2-21.1, and for Other Appropriate Relief*, BPU Docket Nos. ER18010029 & GR18010030; *I/M/O the New Jersey Board of Public Utilities' Consideration of the Tax Cuts and Jobs Act of 2017*; BPU Docket No. AX18010001; *I/M/O Public Service Electric and Gas Company for Approval of Revised Rates (Effective on an Interim Basis April 1, 2018) to Reflect the Reduction Under the Tax Cuts and Jobs Act of 2017*, BPU Docket No. ER18030231, Decision and Order Adopting Initial Decision and Stipulation (October 29, 2018) (the "2018 Rate Case Order") at Stipulation ¶ 15.

at the Company's Weighted Average Cost of Capital ("WACC"), and the payment of interest at WACC on the non-rate base related EDIT.

Q. What is meant by "protected" and "unprotected" EDIT?

A. As discussed in the testimony of Mr. Pardo, EDIT can be classified in two categories: (1) those restricted by the normalization provisions of the Tax Cuts and Jobs Act (sometimes referred to as "protected" EDIT); and (2) those that are not (sometimes referred to as "unprotected" EDIT).

Q. What is the status of the Flow-Through Balances approved in the 2018 rate case outlined in the table above?

A. The protected EDIT is amortized to customers using the IRS-mandated Average Rate Assumption Method ("ARAM") and will continue to be refunded to customers through the TAC. As discussed in the testimony of Mr. Pardo, the historic SHARE was designed so one third of the accumulated balance would be refunded over the first approximately five years ending December 31, 2023 and the remaining two thirds would be refunded over the remaining five-year period ending December 31, 2028. The unprotected EDIT balance will primarily be refunded by the end of 2023 and fully refunded by the end of 2024. The unprotected EDIT represents the largest annual amortization, and its completion has resulted in a significant reduction in the amount to be refunded to customers through the TAC.

Q. Is the Company proposing any adjustment to the TAC in this proceeding?

A. As discussed in the testimony of Mr. Pardo, there are tax deductions for what is referred to as Mixed Service costs that are not subject to IRS normalization rules and can be flowed-back to customers. The Company is proposing to flow back both the historic deferred tax balance associated with the Mixed Service deduction as well as the future deductions it will claim. This is consistent with the existing Historic SHARE flow-back to customers through the TAC (although PSE&G is proposing a more accelerated refund of Mixed Service costs to customers than the 10-year period for the SHARE). This represents a significant benefit to customers and lowers the Company's revenue request.

Q. Are there any other changes to the TAC?

A. Yes. As discussed in the testimony of Mr. Pardo, the Company is proposing to refund a pre-set amount for the current period SHARE and Mixed Service deductions, with any difference between the actual and pre-set amount deferred for refund to customers in a future proceeding. This has the benefit of providing consistency in the flow-back to customers to avoid rate swings from changes in the current deduction and will potentially provide an additional balance to flow-back to customers at the end of the amortization of the historic Mixed Service deduction to mitigate future increases to customers when the amortization is complete. To this point, as discussed in the testimony of Mr. Swetz, the Company also proposes to shape the amortization of the historic Mixed Service flowback to decline over an approximately five-year period to avoid a significant impact to customers after the final year of the amortization. Further, as also discussed by Mr. Swetz, the Company is proposing an adjustment to the Gas allocation of the TAC among customer classes so that all of the refund is attributed to firm customers. Finally, as discussed in the testimonies of Mr. Pardo and Mr. Swetz, the Company is proposing to include the impact of any changes in deferred taxes associated with the Corporate Alternative Minimum Tax ("CAMT") through the TAC. For more details on the TAC components, please see the testimony of Mr. Pardo. For details on the calculation of the TAC, proposed rates, and bill impacts, see the testimony of Mr. Swetz.

B. Cost Containment Measures – O&M

Q. Does PSE&G describe in this filing the actions that the Company has taken to control electric and gas operating distribution-related O&M expenses?

A. Yes, Mr. Schmid and Mr. Fonseca describe these actions in detail in their panel testimony. In general, the Company seeks to measure and optimize distribution-related O&M expenses by regularly benchmarking costs and setting targets to improve results year after year. This fosters an environment of continuous improvement and results in a continuous focus on cost control and operational improvement.

These cost control efforts have helped to offset increases in distribution-related O&M costs due to inflation, including cost increases to satisfy regulatory requirements, and other cost increases since the Company's last rate case. Mr. Schmid and Mr. Fonseca's panel testimony on PSE&G's electric and gas operations provides examples of how PSE&G seeks to manage these costs while obtaining strong operating results. One example of cost containment is PSE&G's treatment of wages.

Q. Has the Company taken measures to control wages?

A. Yes. In the area of wages and benefits, the Company has controlled distribution-related O&M growth by regularly assessing its compensation levels to keep them competitive with the market while providing appropriate incentives to employees to focus on key operational metrics and critical business initiatives. The objective has been to ensure employee compensation programs remain market competitive and continue to enable the Company to attract, retain, and develop a talented and diverse workforce. Prior to 2023, PSE&G has generally provided average annual merit/wage increases between 2.5% to 3% to employees. In 2023, annual merit/wage increases averaged 3.5% to 4% in line with current market competitive conditions. The Company is currently evaluating its compensation programs, including but not limited to merit/wage increases, to ensure it remains market competitive. PSE&G also manages union employee costs through a rigorous collective bargaining process. In March 2023, the Company reached a new four-year bargaining agreement with all of its unions that set merit increases between 3% and 4% for the agreements' terms, below recent inflationary levels.

Q. Has the Company taken any other steps to control wages?

A. Yes. In 2022, the Company initiated a Voluntary Exit Incentive Program ("VEIP") for non-represented employees that will result in the voluntary retirement of approximately 240 employees (of which 185 are from the utility and service company) by December 31, 2023, the majority of whom are Final Average Pay (FAP) pension participants. The VEIP offered two weeks of severance pay to eligible non-represented employees for every year of service up to a maximum of 52 weeks, in line with current separation plan provisions. While a portion of these severance benefits will be paid in the test year, PSE&G proposes a *pro forma* adjustment to remove these non-recurring expenses so they are never collected from customers. The Company anticipates savings by 1) not filling all vacated positions, and 2) reducing pension liability, since any external replacements of positions that are vacated will participate in the Cash Balance Pension plan.

C. Cost Containment Measures – A&G (Pension and Benefits)

Q. How has PSE&G's control of pension costs mitigated the impact of the rate increase sought in this filing?

A. PSE&G has a long history of successfully controlling pension costs, and the considerable control the Company has exercised over this expense has translated into an estimated proposed revenue requirement for Pension and Other Post-Employment Benefits ("P&OPEB") *income* of approximately $9 million for calendar year 2024.[17] It should also be noted that the proposed revenue requirement would be relative to PSE&G's pension and OPEB liability of $4.2 billion based on year-end 2022. Even if the estimated income were to decline or even switch to an expense due to market conditions once the 2024 amount is known, it would still be extremely modest compared to the liability.

Q. Please describe the steps that the Company has taken to control P&OPEB costs.

A. PSE&G was among the first utilities in the country to close a Final Average Pay Pension Plan ("FAP") to new entrants and move to a Cash Balance Pension Plan construct for all new hires starting in the mid-1990s. Further, in 2011, the Company froze the FAP benefit structure for existing non-represented employees, which was calculated utilizing the five highest years of compensation through 2011 and created a new FAP benefit structure for existing non-represented employees, which was calculated utilizing the seven highest years of compensation, reducing pension expense and future liability. Since its last base rate case, PSE&G has adopted several cost measures that helped to further lower P&OPEB costs and reduce ongoing volatility. To highlight several:

- Diversifying the investment portfolio to include real assets, such as real estate and infrastructure, to reduce volatility;
- Adjusting the pension plan asset allocation strategy to reduce the funded status sensitivity to interest rate movements;
- Splitting the plan into "active" and "inactive" which allowed for a lengthening of the aggregate amortization period, reducing expense and volatility;

[17] This estimate will be known and measurable before the end of the test year.

- As noted above, offering a voluntary early retirement plan, eliminating future compensation costs, and reducing associated volatility;
- Negotiating the allowance of a Defined Contribution-only pension offering for the Company's unions that will reduce future pension costs and volatility;
- Reducing medical expenses by transitioning Medicare-eligible retirees to a private exchange for procurement of health insurance and providing an annual credit to retirees by way of deposits into a notional Healthcare Reimbursement Account (HRA); and
- With approval from the BPU, implementing a five-year smoothing of the actuarial gains/(losses) associated with pension asset performance, which reduced 2023 pension expense by $55 million and also reduces the volatility of future pension expense levels.

Based on the investment returns that the Company has achieved in the past, the expected actuarial returns on pension funds in the test year, and the changes noted above that have assisted in improving the funding levels of the plans, PSE&G's pensions and OPEB are currently projected to result in projected income (negative expense) for the test year and calendar year 2024.

Q. Has the management of the returns on the pension funds also lowered expenses?

A. Yes. The management of the Company's pension funds has been exemplary over the long term. For the most recently available 10-year period ending June 30, 2023, PSE&G is in the top quartile ranking in the Trust Universe Comparison Service ("TUCS") rankings for trust returns. TUCS is a report published by Wilshire, an independent investment consulting firm, designed for trusts to evaluate their performance; the ranking reflects all decisions including asset allocation, policy guidelines, and manager selection. The Company's asset allocation decisions and investment manager selections have resulted in annualized long-term returns that exceed the industry median by more than 1% over the ten years through June 30, 2023. This superior management has resulted in higher actual returns and fund balances. As a result, this leads to lower costs in the test year.

Q. As a result of these measures, what is the P&OPEB expense in the test year and are you proposing any *pro forma* adjustments related to P&OPEB expense?

A. As a result of these actions, as well as present market conditions and other factors, the Company projects approximately $57 million of income from P&OPEB in the test year. This is a reduction to the revenue requirement request. However, the test year does not reflect the most recent go forward pension and OPEB revenue requirement. The P&OPEB expense is determined in January for the calendar year. As a result, the 2024 full calendar year expense is now known and measurable. The Company proposes a *pro forma* adjustment to use the known annual 2024 P&OPEB expense. The 2024 actual results are P&OPEB income, which would be a reduction to the revenue requirement request. However, the Company cannot offset such a reduction in revenue requirements and make itself whole by taking that cash out of the P&OPEB funds. Additionally, the reduction in revenue requirement reduces operating cash flow and adversely impacts PSE&G's credit metrics. P&OPEB income is an actuarial result of the actions PSE&G took to reduce costs, as described above. Since the P&OPEB income is non-cash, the net offset is to record an asset. Each of these items impacts the request in this rate case, with P&OPEB income reducing revenue requirements and the pension asset included in working capital. The Company does not have access to the pension income that would reduce its revenue request in this proceeding and thus should be allowed a working capital adjustment to account for the net pension asset that is driving the pension income.

If a working capital adjustment is not reflected for the P&OPEB asset (net of the impact of smoothing as agreed to in the Pension Accounting Order[18]), the P&OPEB income reflected in the revenue requirement should be $0 as the Company does not have access to the cash associated with the income. Either of these two treatments ensure symmetry between the paper P&OPEB income under the plan and the corresponding P&OPEB asset – with either both included in calculating revenue requirements, or both excluded.

Q. Are you making any other proposal with regard to P&OPEB expense?

A. Yes. As described in more detail later in my testimony, the Company proposes that any difference between the utility P&OPEB income amount credited to customers in this proceeding and actual results be deferred for recovery or refund in a subsequent base rate case proceeding. P&OPEB costs have significant annual volatility driven by factors outside the Company's control, such as market gains and losses and changes in interest rates. The Company has done a very effective job managing P&OPEB costs as noted above. The Pension Accounting Order does help reduce volatility, but significant volatility in annual pension costs remains. Deferring any amount above or below the amount reflected in the revenue requirement in this rate case will allow flexibility in the amount incorporated in rates. A reconciliation mechanism also protects customers and the Company from significant swings in the pension income, so neither is a winner or loser based on short-term market fluctuations.

[18] *I/M/O Public Service Electric and Gas Company's Request for an Accounting Order Authorizing the Company to Modify Its Pension Accounting for Ratemaking Purposes*, BPU Docket No. ER22090549, Decision and Order Approving Stipulation (February 17, 2023) ("Pension Accounting Order").

D. Cost Containment Measures – Interest Expense

Q. Please describe the steps taken to control the Company's interest costs.

A. As of May 31, 2024, PSE&G's embedded cost of long-term debt is estimated to be 4.00%, comparable to the embedded cost of long-term debt as of June 30, 2018 of 3.96%, which was the amount used to establish the cost of capital in the Company's 2018 Distribution Base Rate Case. Despite headwinds due to the inflationary environment, the Company has been able to maintain the embedded cost of debt at virtually the same reduced level set in the 2018 rate case. This result is primarily due to issuing long-dated debt during the historically low interest rate environment experienced over the past decade, strong PSE&G credit ratings, and solid execution of PSE&G's financing plan.

At present and for the foreseeable future, all companies will be faced with a higher interest rate environment. For example, in August 2023, PSE&G issued long-term debt at coupons for a 10-year bond of 5.20% and a 30-year bond at 5.45%, which is well above the Company's current embedded cost of debt. Given the prevailing current interest rate environment, this filing includes the estimated May 31, 2024 embedded cost of 4.00% rather than the February 29, 2024 actual cost of 3.87%, which has not changed since October 31, 2023. However, the final embedded cost rate will be the actual embedded cost as of May 31, 2024, the last month of the test year. In addition, as explained in more detail later in my testimony, the Company is seeking to defer any change in the embedded cost of debt after the test year given the volatile interest rate market.

E. Appliance Service Business

Q. Has the Company's Appliance Service Business helped to reduce rates?

A. Yes. PSE&G is the only utility in the State that continues to have an Appliance Service Business ("ASB") within the utility structure. As a result of this structure, the majority of the pre-tax earnings of this business are captured in the revenue requirement-setting process of each PSE&G base rate case, including this one. As discussed in more detail below, the Company is proposing to retain 50% of the Gas ASB margins in this proceeding in the same manner as allowed for an Electric utility under the New Jersey Administrative Code. Even with the proposed 50% sharing of all ASB margins, the test year reflects a significant benefit to Electric and Gas customers of approximately $47 million of margin (revenue less expenses) that will offset PSE&G's revenue requirement and is comparable to the margin returned to customers in the last base rate case.

F. Summary Impact of Cost Savings

Q. Please summarize the cost mitigation efforts the Company has accomplished to limit the rate request in this proceeding.

A. The Company has been very successful in controlling costs to limit the impact to customers. While an increase is unavoidable, PSE&G has taken notable steps to limit the impact: 1) PSE&G is the only utility in NJ flowing back significant tax credits to benefit customers, allowed by the Company's strong balance sheet and disciplined cash management; 2) the Company's P&OPEB currently remains a credit to customers, even with the recent downturn in markets; 3) PSE&G is the only NJ utility still providing ASB through the utility, representing a significant benefit to customers in net margin and operational savings; and 4) PSE&G continues to contain utility expenses to reduce the inevitable increase in expense due to inflation and wage increases. PSE&G has been able to accomplish this without sacrificing reliability and customer satisfaction. This is exemplified in the testimony of Mike Adams on how PSE&G compares to its peers in cost, reliability, and customer satisfaction.

V. CAPITAL STRUCTURE AND THE COST OF CAPITAL

Q. Does PSE&G have a need to maintain sufficient financial integrity to raise capital effectively?

A. Yes. The Company's financial integrity depends on, among other things, an approved return on equity ("ROE") that reflects the cost of capital required by investors, and a capital structure that is supportive of the Company's strong credit quality. The current authorized ROE is 9.60% and was set in the Company's last base rate case. As Company witness Ann Bulkley testifies, the Company's overall ROE should be reset at 10.4%, reflecting current market and business conditions. PSE&G proposes to apply its ROE to a capital structure reflecting a common equity component of 55.5%, to support targeted credit statistics, maintain a strong investment grade credit rating, and earn a just and reasonable return for investors.

Q. What is the Company's cost of capital and on what capital structure is PSE&G seeking to have those cost rates applied?

A. PSE&G seeks an overall rate of return of 7.55% that is derived from a capital structure composed of 55.5% equity, 44.29% long-term debt, and 0.21% customer deposits. The embedded cost rate for the Company's long-term debt is estimated to be 4.00% by the end of the test year. Customer deposits are accumulated at a rate of 5.06% as of January 1, 2024. The proposed ROE is 10.4%, as discussed in Ms. Bulkley's testimony.

A. Return on Equity

Q. How did Ms. Bulkley determine an appropriate cost of equity?

A. Ms. Bulkley derived her cost of equity using an analysis of a proxy group of companies that receive a similar percentage of operating income from regulated operations as PSE&G, and possess a set of operating risk characteristics that are substantially comparable to the Company. She then estimated the Company's Cost of Equity ("COE") by applying several traditional COE estimation methodologies to a proxy group of comparable utilities, including Discounted Cash Flow ("DCF"), Capital Asset Pricing Model ("CAPM"), Empirical CAPM ("ECAPM"), and Bond Yield Risk Premium ("BYRP" or "Risk Premium") analysis. The COE estimation models produce a wide range of results. Based on this analysis, Ms. Bulkley established a range of 10.00% to 11.00% as reasonable and recommended 10.40% based on underlying market conditions and the business, financial, and regulatory risk factors facing PSE&G, including the Company's significant capital expenditures.

Q. Beyond the results of Ms. Bulkley's COE analysis, is there anything else the Board should consider?

A. Yes. While the Company fully supports Ms. Bulkley's analysis and 10.4% ROE recommendation, PSE&G also recognizes that COE estimation models are complex, with each methodology resulting in a wide range of results and different consultants can have different results based on the assumptions employed for each test. In the Company's 2009 base rate case, the parties to the proceeding settled to a 10.30% ROE and in 2018 settled to a 9.60% ROE, both of which were approved by the Board. Without getting into the complexity of each COE methodology, below is a summary of the market conditions for the current and prior PSE&G rate case:

Table 3

Change in Market Conditions Since Company's Last Rate Case					
PSE&G Rate Cases	**Decision Date**	**Federal Funds Rate**	**30-Day Average of 30-Year Treasury Bond Yield**	**Core Inflation Rate**	**Authorized / Proposed ROE**
2018 Rate Case	10/29/2018	2.20%	3.29%	2.13%	9.60%
2023/24 Rate Case	10/31/2023	5.33%	4.84%	4.13%	10.40%

Q. How do these factors impact a utility's ROE?

A. As described in the testimony of Ms. Bulkley, these factors impact the assumptions on risk used to calculate the COE methodologies. At a high-level, a US Treasury bond is considered risk-free and thus a premium above that rate would be needed for any investor to invest in PSE&G over a risk-free treasury bond. As interest rates rise, utility stocks can become less desirable as the premium needed to take on the additional risk declines. As a result, it would be expected that the ROE would increase as interest rates are increasing. Also, in terms of risk, the high Federal Funds Rate and Inflation rate indicate more risk to investors in the future as costs (and interest rates) may continue to rise. As such, market conditions require higher equity returns than at the time the 2018 ROE was approved.

Q. Is there more uncertainty surrounding the electric and gas utility industries in NJ compared to the last rate case?

A. Yes. There have been several BPU Orders, Governor's Executive Orders, legislative acts, and the Energy Master Plan focused on significant expansion of electric vehicle adoption, solar targets, electrification, and the future of the natural gas business as the State promotes the transition to a cleaner environment. PSE&G supports the State's promotion of the transition to a cleaner environment, and it can present opportunities for growth for the

Company. However, it also represents significant uncertainty and risk to investors. The BPU is preparing to initiate a proceeding on the future of the natural gas industry. While the electric business has growth opportunities, the significant expansion of electric vehicles and conversion of gas heating to electric will require significant capital investment to ensure the reliability of the distribution system as customers depend on it more than ever. Capital investment will also be required to account for increasing amounts of supply coming from cleaner, more distributed sources as well as potential shifts in the Company's peak. The uncertainty of the impacts of the transition on the utility industry should be taken into consideration when determining the Company's risk and ROE.

Q. Are there any other factors that should be considered by the Board in determining the Company's ROE?

A. Yes. The Company's exemplary operating performance should be considered. As noted above and more extensively in Mr. Adams' testimony, PSE&G has delivered top quartile service (reliability) and customer satisfaction, at the lowest O&M and A&G costs compared to NJ and other peers.

B. Capital Structure and Credit Ratings

Q. Please explain the basis for the 55.5% equity ratio sought by the Company.

A. The Company is targeting a capital structure having a 55.5% equity ratio, because this ratio is important to provide support for PSE&G's current credit rating. PSE&G is committed to strong investment-grade credit ratings in order to ensure consistent access to the capital markets at reasonable costs. PSE&G ended 2022 with a 55.1% equity ratio and its current senior secured credit ratings are "A" from S&P and "A1" from Moody's; the credit rating outlooks are stable from both rating agencies. The Company plans to manage its capital structure consistent with its equity ratio approved for ratemaking, so would expect to move toward 55.5% later in 2024. The 55.5% equity percentage was determined by evaluating the equity level needed to maintain certain credit statistics (i.e., Funds from Operation to Debt ("FFO to Debt"), or as Moody's calculates, Cash flow from Operating activities – pre working capital ("CFO pre-WC") to Debt) for a sustained period. Moody's credit opinion indicates that the FFO to Debt range for PSE&G's current rating is between 17% and 20%. While a 54% equity ratio was approved in the 2018 base rate case, the Company has increased its equity ratio to support its credit rating. The Company seeks approval of a 55.5% equity ratio to maintain strong credit ratings in a volatile market environment.

Q. Why is it important to maintain the Company's current credit ratings?

A. PSE&G has approximately $14 billion of long-term debt outstanding as of February 29, 2024. PSE&G also has a significant capital program and several billion dollars of long-term debt maturing in the coming years. Strong credit ratings are essential to executing financing plans and accessing the capital markets on reasonable terms at all times, especially during periods where market volatility can be prevalent. Volatility can limit market access and increase credit spreads.

Markets have experienced significant volatility in recent years that continues to persist. In March 2020, capital markets were not accessible due to uncertainty related to the COVID-19 pandemic. It required substantial government intervention to restore confidence and re-open markets. In early 2022, the Federal Reserve began to battle high levels of inflation, causing significant market uncertainty as rising interest rates impacted the economy. During 2022, volatility translated into periods of reduced market access, where issuers needed to be concerned with "actionable" days. In 2022, a considerable number of the business days were not "actionable", resulting in issuers competing more intensely for capital during periods when markets were open. Later in March 2023, markets were not accessible due to a crisis of confidence in the banking system. Intervention by the Federal Reserve to backstop deposits and assume responsibility for failed banks was required to help stabilize markets. Markets re-opened to issuers but continue to remain susceptible to further developments that could impact the regional banking sector. Impacts to the bank sector have the potential to spill over to the wider economy. Overall, market conditions remain characterized by volatility and are highly susceptible to political, banking, and economic developments, and have proven very dependent on economic data and Federal Reserve response.

The Company has had a strong history of raising low-cost financing, which has directly benefited customers in the form of lower interest expense – both in its infrastructure filings as well as this base rate case proceeding. As noted previously, the Company's cost of debt has remained relatively constant since the 2018 base rate case. This value translates into keeping customer rates low. Overall, preserving the Company's current credit ratings is the most desirable course of action for the reasons cited above, including the importance of executing the Company's debt financing plan during volatile periods.

Q. What key metrics and factors do the rating agencies assess in determining the Company's credit rating?

A. Funds from Operations to Debt (FFO/Debt) represents a key credit measure used by the ratings agencies. Moody's refers to FFO / Debt as CFO pre-WC to Debt. FFO/Debt is a measure of cash flow leverage and indicates a company's ability to support its debt level. For the purpose of demonstrating sound financial management, PSE&G tends to focus on the calculation of FFO to Debt from Moody's more so than S&P's calculation. S&P's analysis follows a "family" approach that develops a corporate credit rating based on a consolidated business and financial profile. S&P uses a top-down approach; Moody's, in contrast, uses a bottom-up approach, which analyzes the business and financial profile of an entity. Given this approach, Moody's credit opinion provides the more useful insights into a subsidiary credit rating.

Q. How has your credit rating changed since the last rate case in 2018?

A. In October 2021, Moody's downgraded PSE&G's rating on senior secured debt to A1 from Aa3. PSE&G's senior secured credit ratings from Moody's of A1 and S&P of A are now both in the same 'A' rating category. The below table reflects PSE&G's Senior Secured ratings since 2018:

Table 4

Year – End	S&P	Moody's
2018	A	Aa3
2019	A	Aa3
2020	A	Aa3
2021	A	A1 (one notch downgrade)
2022	A	A1
2023 (Current)	A	A1

Q. What factors led to the downgrade in the Company's credit rating?

A. As indicated during the 2018 base rate case, federal tax reform in 2017 was credit negative for regulated utilities including PSE&G. The loss of bonus depreciation and the decision to flow back excess deferred income taxes to customers placed downward pressure on credit metrics. Moody's credit research referenced weakening financial metrics with limited financial cushion for PSE&G. In 2020, the decline in CFO pre-WC to Debt below the downgrade threshold of 19% was notable driven by impacts related to Tropical Storm Isaias and COVID-19. In May 2021, Moody's changed PSE&G's credit rating outlook from stable to negative, noting the decline in metrics. In October 2021, Moody's downgraded PSE&G's rating on senior secured debt to A1 from Aa3. Since 2021, PSE&G's credit ratings have remained unchanged while the Company has executed substantial capital programs, supported by a regulatory equity ratio of 55.1% at year-end 2021 and year-end 2022, with a plan to manage capital structure consistent with an equity ratio approved for ratemaking, so would expect to target 55.5% later in 2024.

Q. Has PSE&G managed its finances to maintain a strong credit rating?

A. Yes. PSE&G has managed to maintain a strong credit profile. This has been achieved through disciplined financial management, including limited dividends to the parent company Public Service Enterprise Group ("PSEG"). From 2019 through 2023, PSE&G demonstrated disciplined financial management while experiencing storms, most notably Tropical Storm Isaias, and the COVID-19 pandemic. As a result of these events, PSE&G incurred significant unexpected costs. These incremental costs were financed consistently with PSE&G's capital structure, which required more retained equity. In addition, PSE&G increased its equity ratio to 55% from 54%, which required more retained equity.

Q. Has Moody's threshold for a credit upgrade or downgrade changed since the last rate case?

A. Yes. Moody's updated its upgrade threshold for CFO pre-WC to debt. In summary, Moody's "raised the bar" for the "Aa3" rating from 19% to 20%. See the table below.

Table 5

Moody's CFO pre-WC to debt			
	Senior Secured Credit Rating	Factors that could lead to an upgrade	Factors that could lead to a downgrade
June 2018	Aa3	excess of 26%	falls below 19%
October 2023	A1	above 20%	below 17%

Moody's credit opinion on PSE&G from October 2023 includes the following:

> **Factors that could lead to an upgrade**
> A rating upgrade could be considered if PSE&G's financial profile improves such that its CFO pre-WC to debt is maintained above 20% on a sustained basis. In addition, if the regulatory environment improves, resulting in a meaningful improvement in the utility's business risk and that there is greater certainty and visibility for the utility's cash flow generation, the rating could be upgraded.
>
> A rating upgrade could be considered if PSE&G's financial profile improves such that its CFO pre-WC to debt, including the adjustment related to energy efficiency investment, is maintained above 20% on a sustained basis. In addition, if the regulatory environment improves, resulting in a meaningful decrease in the utility's business risk and greater certainty and visibility with regard to the utility's cash flow generation, the rating could be upgraded.
>
> **Factors that could lead to a downgrade**
> A downgrade could be considered if the regulatory environment deteriorates such that the regulatory lag increases significantly. In addition, if its CFO pre-WC to debt ratio, including energy efficiency investment, remains below 17%, its rating could be downgraded.

Q. Has Moody's conveyed its expectation of the CFO-pre-WC to debt ratio it intends PSE&G to retain to maintain its current rating?

A. Yes. In the PSE&G Credit Opinion from October 2023, Moody's included the following:

> PSE&G is pursuing a substantial capital investment program over the next five years that will grow its rate base. We expect its cash flow from operations before changes in working capital (CFO pre-WC) to debt ratio, including the adjustment related to its energy efficiency spending, to be around 18% over the next two to three years.

At year-end 2022, "CFO pre-WC" to Debt was approximately 18%, while the regulatory equity ratio was approximately 55%. A 55% regulatory ratio was important to help deliver Moody's expectations of CFO pre-WC to debt, as referenced in its credit opinion from October 2023.

Q. Do you believe the current approved equity percentage of 54% is sufficient for PSE&G to maintain its current credit rating?

A. PSE&G's current credit rating would be challenged at the 54% equity ratio, which prompted the Company to increase to 55.1%. PSE&G has been gradually increasing its equity ratio above 54%, which was approved in the 2018 distribution base rate case, as we have sought to support PSE&G's credit profile. As shown in the table below, our FFO to debt ratio dropped below the 17% floor in 2020 and increasing PSE&G's regulatory equity ratio to over 55% has been an important measure to help support the current credit profile.

Table 6

Year	Year-End Regulatory Equity Ratio	Moody's CFO pre-WC to Debt
2019 Actual	54.6%	18.2%
2020 Actual	54.5%	16.7%
2021 Actual	55.1%	17.5%
2022 Actual	55.1%	18.1%
2023 Actual	55.4%	17.4%

Q. Has the Company informed Board Staff or the New Jersey Division of Rate Counsel ("Rate Counsel") that it was increasing its common equity percentage above the approved amount in the last rate case?

A. Yes. In July 2021, PSE&G reached an agreement to lower transmission rates with the Board and Rate Counsel. During the settlement process, PSE&G advised the parties that the

Company would increase its equity ratio from 54% to approximately 55% due in part to the lower cash flows due to the reduction in the Transmission ROE agreed to in the settlement. At the end of 2021 and 2022, PSE&G's equity ratio was 55.1%. The actual regulatory equity ratio will vary monthly based on monthly earnings and financing activities.

Q. Please explain the basis for the 55.5% equity ratio sought by the Company.

A. The 55.5% equity target was determined by evaluating the capital structure needed to maintain key credit statistics for a sustained period. More specifically, Moody's credit opinion indicates that the CFO pre-WC to Debt range for PSE&G's current rating is between 17% and 20%. The 55.5% equity ratio is expected to support an FFO/Debt level that targets the upper end of the guidance for our credit metrics, which includes sufficient cushion above the low end of the range (17%) for downside risks.

Q. Why is it important to target above the 17% floor for the credit rating range?

A. As made evident by the last four years, unexpected events will impact the Company's cash flow, most recently major storm events and the COVID-19 pandemic. To illustrate the need for some financial flexibility, in 2020 Tropical Storm Isaias and the COVID-19 pandemic adversely impacted the Company's CFO pre-WC to Debt by approximately 2.5%. While those events will not occur every year, unexpected events that impact cash flow can and will occur, so it is important to maintain sufficient cushion above the 17% threshold to help protect the Company's credit profile against unexpected events and cash flow uncertainty.

Q. Are there other factors besides unexpected events that support increasing common equity to 55.5%?

A. Yes. First, PSE&G is unique in the State in flowing back significant tax benefits. This is a significant benefit to customers (and revenue reduction to the Company) of over $200 million per year on average since 2019. The Company is able to flow this amount back to customers because of its disciplined financial management but it does impact the Company's cash flow, and given the size of the credit to customers, any lag in adjusting rates can cause a notable impact on the Company's cash flow. PSE&G also has the highest proportion of low-income customers compared to the other electric and gas utilities in the State and experienced a significant impact on collections during the COVID-19 pandemic, with its Accounts Receivable balance greater than 90 days increasing from $116 million in March 2020 to $442 million in March 2022, an increase of more than 350%, far more than any other New Jersey utility experienced. Finally, PSE&G forecasts a substantial capital program to modernize its system to meet the State's clean energy goals and maintain safe and reliable service.

Q. Can you summarize the basis for the requested 55.5% common equity ratio?

A. Yes. PSE&G has demonstrated strong financial management to support strong credit ratings in a very challenging environment. However, recent years have shown that the 54% common equity amount approved in the last rate case is not sufficient, as PSE&G has proactively increased its common equity ratio to above 55% to support a FFO/Debt ratio to support the Company's credit profile. A 55.5% equity ratio allows PSE&G to better manage a substantial capital investment program, flowing back excess deferred taxes, and to account for unexpected events, such as major storm events, that are becoming more frequent and can have a significant impact on cash flow. The Company forecasts a substantial capital program necessary to meet State goals and maintain safe and reliable service and must have access to financial markets to fund those investments at the lowest rates possible. Maintaining the current credit rating will ensure the best possible execution of PSE&G's financing plans under a range of possible market conditions, and therefore it is critical that the Board approves a 55.5% common equity ratio to support PSE&G's credit profile.

VI. APPLIANCE SERVICE BUSINESS ("ASB")

Q. Can you briefly describe the Appliance Service Business?

A. PSE&G has been servicing appliances in its territory for over a century. The current services offered are for:

1) Appliance Repair Service and Maintenances Services, referred to as "APSO";
2) Replacement Parts Service Contracts, referred to as "Contracts";
3) Water Heater Replacement; and
4) Central Heating and Central Air Conditioning Replacement ("HVAC").

The majority of the work is performed by PSE&G's workforce with the exception of water heating replacement, which is conducted by contractors retained by the Company.

Q. How is the margin from ASB treated for ratemaking?

A. The revenues and expenses associated with the appliance service business are included in the income statement for the utility. The margin (revenues less expenses) in the test year is included for ratemaking purposes in accordance with *N.J.A.C.* 14:4-3.6(r), which has separate regulations for electric and gas utilities. For gas public utilities, the total ASB margins are currently treated above-the-line for ratemaking purposes and credited to customers. For electric public utilities and related competitive business segments of electric public utilities, 50 percent of the total margins are recorded in respective competitive service revenue accounts and treated above-the-line for ratemaking purposes.

Q. Since PSE&G is both an electric and gas utility, how are margins split between the two businesses?

A. In the 2018 rate case, the revenues and expenses were split between electric and gas based on the fuel type for the appliances under contract and being repaired or replaced. Starting in 2023, PSE&G has modified that approach to allocate ASB margins based on a pre-set 55% electric and 45% gas allocation.

Q. Why change the allocation methodology?

A. There are a few reasons why a pre-set allocation is more appropriate at this time.

First, for ratemaking purposes, it adjusts the calculation as if PSE&G consisted of standalone electric and gas utilities for allocating the net benefit of the business. A customer in PSE&G's electric-only service territory can have services for gas appliances, and vice versa. In this instance where an electric-only customer has work completed on gas appliances, that customer is contributing to the net ASB margins, but none of that credit is flowing back to that customer as it will be allocated to PSE&G's gas customers only. The pre-set allocation based on number of customers adjusts the allocation as if we were stand-alone electric and gas utilities and is the same allocation applied to Common Plant for decades. Also, since the approval of the CIP after the 2018 rate case, the primary driver of margin for the utilities is the number of customers, since the CIP is calculated on a per customer basis. Switching to an allocation based on the number of customers aligns the ASB margin with the driver of margin for the electric and gas utility.

Second, the allocation by appliance fuel type does not factor in the nature of the service being provided. While the majority of ASB margins are allocated to the gas utility based on appliance fuel type, the majority of the materials being replaced for the Contract and APSO services are for electrical components. Based on recent history, approximately 60% of the parts repaired and replaced for gas-fueled appliances are for electric components. While using this approach would still directly allocate margins between electric and gas based on the work performed, it would significantly shift ASB margin from gas to electric and create the same cross-subsidization issue as the current allocation by fuel type. For these reasons, PSE&G did not implement this approach, but it supports allocating more margin to electric, which the Company is doing to a lesser extent by allocating based on the number of customers.

Finally, the allocation methodology takes into consideration the State's policy goals targeting increased electrification. The allocation of ASB margins between electric and gas customers in the 2018 rate case was approximately 35% to electric and 65% to gas. That allocation is expected to increase by the end of the test year to approximately 40% electric and 60% gas if margins were allocated by appliance fuel type. As the State moves toward electrification, it is likely the allocation to electric appliances will continue to increase. Since ASB margins are allocated to customers based on the test year amount in a rate case, electric customers will not receive any benefit from the shift in allocation between electric and gas until a subsequent rate case. Implementing the pre-set 55% Electric and 45% Gas allocation at this time will credit electric customers now with the expected shift to more electric appliances in the short-term and will help lower costs to electric customers where costs are expected to increase while the State pursues its electrification and clean energy goals. While PSE&G made this allocation change in 2023, the Company will continue to monitor the driver of the ASB margins and the most appropriate allocation to customers in the future, especially as the electric and gas utilities evolve to meet the State's clean energy goals.

Q. Does ASB provide a benefit to PSE&G's customers by being part of the utility?

A. Absolutely. ASB provides significant financial and operational benefits to customers.

Financial benefits of ASB. The margins from this business help reduce costs to all our customers. For this test year ending May 31, 2024, PSE&G projects annual net margins of $47 million ($26 million to electric and $21 million to gas) to be returned to customers, reducing the annual revenue request in this proceeding. As a reduction to base rates, that amount will be implicitly refunded to customers every year until the conclusion of the Company's next base rate case, when the amount will be reset. This is a significant benefit to customers and includes the proposed retention of 50% of gas margins discussed in more detail below.

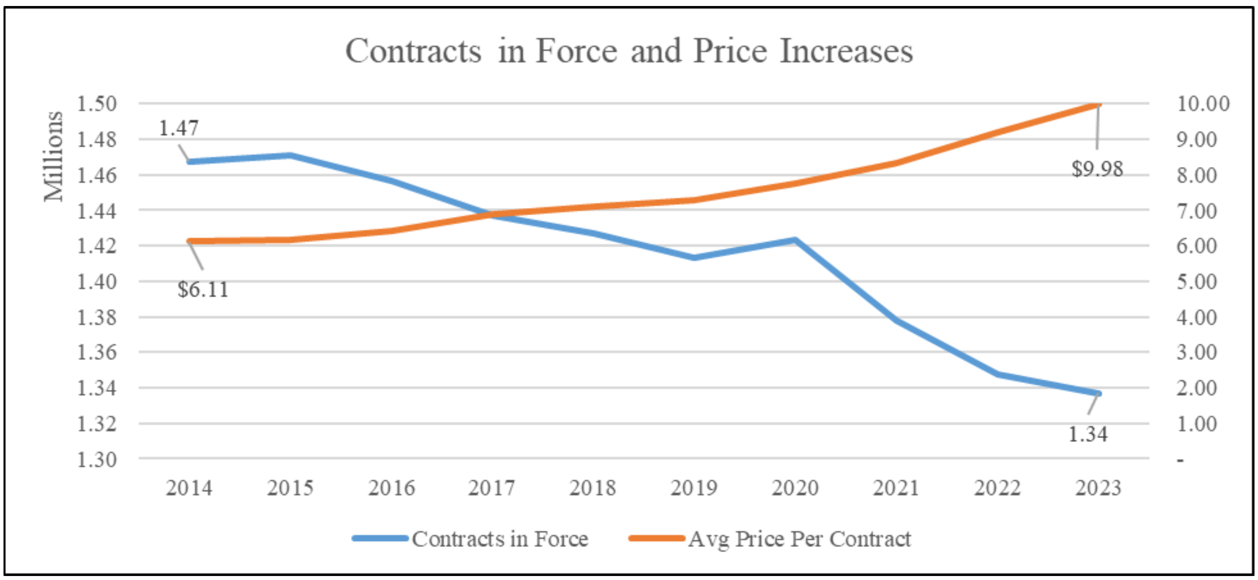
Operational benefits of ASB. Having ASB in the utility also has operational benefits. Appliance service technicians are skilled labor that also perform emergency response duties (including responding to emergency calls about gas leaks, carbon monoxide, and fires) as well as meter services, such as meter installations and replacements, and turn on and shutoff services. This work is referred to as regulatory work and the majority is on emergency response in the peak winter season. If not for the ASB Competitive Service business, the Company would have inefficiencies with the workforce due to the inconsistent nature of the work that is weather driven. For example, there are a greater volume of gas leak and appliance diagnostic responses in the winter months as compared to the non-winter months. The need to staff for the peak workload would result in a material increase in costs to our customers.

Q. **Are there challenges in increasing ASB margins going forward?**

A. Yes. PSE&G has been very successful in managing this business, which has benefited customers through a revenue reduction from margins and through more efficient workforce management. However, the number of customers purchasing Contract services has been declining. Other than a temporary increase in 2020, the number of customers purchasing

Contracts services has been in decline since 2015. On top of a decline in demand for the business, the Company faces challenges in the supply chain, leading to cost increases and part shortages. While PSE&G can continue to increase Contract prices to offset the costs, the increases only occur once each year and will likely result in a reduction in customer contracts, creating more margin risk. Despite these challenges, PSE&G has been able to increase margins through price increases, and growth in the HVAC business since the last rate case. However, yearly price increases are not a long-term strategy, as continual increases will only hasten the decline in the number of customers.

Chart 14



Q. Are there challenges amplified by the current ratemaking structure?

A. Yes. As mentioned above, the ASB margins included for ratemaking purposes follow *N.J.A.C.* 14:4-3.6(r), which requires 50% of electric margins and 100% of gas margins in the test year returned to customers. Once included in rates, the Company is essentially refunding that amount to customers every year until the margins are reset in a future rate case. As a result, if ASB margins drop below the amount in the test year, the Company would lose money as a result of continuing this business.

Q. How does the Company propose to address this challenge?

A. The Company proposes to retain 50% of the total net margins from the provision of ASB services to its gas customers in the same manner as allowed for its electric customers. While *N.J.A.C.* 14:4-3.6(r) provides rules for ratemaking for electric utilities and gas utilities, it does not specify the treatment for a combined electric and gas utility and the Board can approve this ratemaking treatment to account for the uniqueness of PSE&G's combined electric and gas business. The Company believes that good cause exists for the BPU to approve this ratemaking treatment for the following reasons:

- Given the decline in ASB customers since 2020, the Gas ASB represents more risk than reward going forward;
- The request to retain 50% of the margins is consistent with the ratemaking already allowed for electric margins;
- ASB would still represent a $47 million reduction to our requested annual revenue increase, even at 50% margins for both Electric ASB and Gas ASB;
- Maintaining ASB in the utility provides operational benefits to customers by reducing staffing needs that would only be used for emergency work in the winter period; and
- As the only utility in NJ still providing this service, the N.J.A.C. regulations apply only to PSE&G, but they do not address a combined electric and gas utility.

PSE&G is proud of this business, its skilled workforce, and the value that it generates for customers, both through direct financial benefit in the ratemaking process, and through support of the important services we provide, particularly during emergencies and in challenging weather conditions. However, if there is more risk than reward potential associated with this business, PSE&G will be forced to consider restructuring or exiting this business.

VII. <u>P&OPEB EXPENSE RECOVERY</u>

Q. Is the Company proposing a change in the accounting treatment of P&OPEB expense (or income) in this proceeding?

A. Yes. The Company proposes that any volatility in the P&OPEB income (or expense) above or below the amount set for recovery in this proceeding be deferred for recovery or refund in a subsequent rate case proceeding.

Q. Please briefly describe P&OPEB accounting.

A. Pension expense represents an employer's annual cost for maintaining employees' pension benefits, while OPEB expense reflects the annual expense recognition for retiree healthcare and other post-retirement benefits. Employers that provide a pension plan must calculate and disclose plan assets and liabilities on the balance sheet, and record pension expense on the income statement. Pension expense is comprised of individual components calculated by the plan's actuary. These components include service cost (the P&OPEB earned by employees who are active in the relevant year), interest cost, expected return on plan assets, and amortizations of both prior service cost and actuarial gains / losses.

Q. How are these P&OPEB components reflected on the income statement?

A. The Service Cost component of expense is reflected in the operating section of the income statement. The other components of expense are reflected in non-operating earnings for GAAP. This accounting treatment is due to the concept that the Service Cost component of expense reflects the cost associated with pension benefits earned during the year. The other components of expense are mostly related to the plan's assets, liabilities, historical plan changes, and actuarial assumptions, and are impacted by financial market performance and interest rates. For ratemaking purposes, all components are included as operating and recovered or refunded to customers.

Q. **What is the funding level of the Company' pension obligation?**

A. As of July 31, 2023, the qualified pension plans were funded at approximately 93%.

Q. **Has the Company been successful managing the investment strategy of the pension asset?**

A. Yes. As I have stated previously, the Company has been very successful in managing the investment strategy of the pension assets, as illustrated by the expected P&OPEB income of approximately $32 million for 2024 ($30 million of pension income and $2 million of OPEB), which is positively impacted by the funded status of the pension plans (difference between pension liability and pension assets). This estimated income is after accounting for the Board's February 2023 Pension Accounting Order. If not for the Pension Accounting Order, the projected P&OPEB income would decline by $55 million in 2023 and become an expense.

Q. **Can there be significant annual fluctuations in the pension non-service income?**

A. Yes. The pension non-service income is subject to market performance and given the size of PSE&G's pension assets and liabilities, can reflect significant annual changes.

Q. How did the Board's Pension Accounting Order address the volatility of pension costs?

A. In its February 2023 Pension Accounting Order, the Board granted PSE&G the authority to use a calculated value that recognizes changes in fair value in a systematic and rational manner, to "smooth" returns on assets in the Company's pension trust, for purposes of calculating the amortization of net gain or loss component of pension expense. This methodology change results in a timing difference between PSE&G's recognition of the impact of changes in the market-related value of assets in calculating its pension expense for ratemaking purposes versus its current methodology. PSE&G was therefore authorized to (1) record a regulatory asset or liability to account for the difference in the amortization of net gain or loss component of pension expense (or income) between PSE&G's current methodology and this alternative methodology ("smoothing"), and (2) submit for recovery or return in rates the pension expense or income utilizing the proposed methodology for computing the amortization of net gains or losses. Adopting a calculated method for determining the market related value of plan assets in PSE&G's pension trust for purposes of calculating pension expense, like the majority of PSE&G's peer companies and the State of New Jersey itself, will reduce the volatility of PSE&G's income statement and customer rates; improve the usefulness of the information presented to financial statement users; and improve comparability of results for PSE&G and its peers.

Q. Does the Pension Accounting Order address the volatility in pension non-service income?

A. While the Pension Accounting Order does reduce the volatility resulting from market fluctuations, there remains significant volatility that can occur based on market changes. The Pension Accounting Order only impacts the gain or loss amortization component of expense. There remains significant cost volatility with respect to the expected return on assets component of pension expense.

Q. **How does the Company's proposal address this volatility?**

A. The proposal would defer any variances between the required actuarial expense/income recorded on the FERC income statements and the amount refunded to customers as a result of this proceeding. This would ensure that neither the customers nor the Company would win or lose based on market fluctuations outside of the amount refunded to customers in this case.

Q. **Does this proposal just shift market performance risk to customers?**

A. No. While it would allow for recovery of a decline in P&OPEB income, it would also allow an increase in the refund of market gains as well. Fluctuations will occur both up and down and this proposed accounting treatment will ensure variances are equally shared.

Q. Does this proposal incent PSE&G to take excessive risk with its pension investments?

A. No. The management of the investments of the pension plan are subject to fiduciary standards that require the highest level of prudence and care, and all decisions are made in the best interests of plan beneficiaries. In fact, a glide path strategy for the investment allocation of PSE&G's pension asset was adopted and designed to reduce risk by increasing fixed income investments as the funded status of the plan improves. In addition, the pension and OPEB programs cover non-PSE&G employees, whose pension costs are not subject to rate recovery. The Company is therefore incented to manage the entire pension plan to ensure optimal financial results.

Q. Is there precedent in New Jersey for this accounting treatment?

A. Yes. New Jersey American Water utilized deferred accounting for P&OPEB expense in its most recent rate case, deferring any change from the amount proposed in rates in the same manner as PSE&G proposes in this proceeding.

VIII. <u>GAS BAD DEBT RECOVERED IN SBC CLAUSE</u>

Q. How are gas bad debt expenses currently recovered from customers?

A. Gas bad debt expenses are currently recovered in base rates. An average uncollectible rate is included in the revenue factor used to gross-up the revenue increase request in the Company's prior base rate case as well as in post rate case infrastructure program rate adjustments and the gas TAC. There is no true-up between the actual gas bad debt expense incurred and the recovery through base rates (and the TAC).

Q. Does the recovery of gas bad debt expense treatment differ from the recovery of electric bad debt expense?

A. Yes. Electric bad debt expense is recovered through the Social Programs component of the electric Societal Benefits Charge.

Q. Are there any differences between the two businesses that warrant the separate treatment?

A. No. The majority of PSE&G's customers are combined electric and gas customers, so non-payment would impact the Accounts Receivable balance of both businesses, in the same manner. Setting aside the different mechanisms for recovery, there is no difference to PSE&G between non-payment from an electric customer and a gas customer or a combined electric and gas customer, as in all cases it is cash not received by the Company. It would be more logical and less confusing to use the same recovery mechanism without regard to which business the Accounts Receivable balance is attributed.

Q. Which recovery mechanism is better?

A. Recovery of bad debt expenses through the SBC, as is done for the electric business, is the most appropriate method. Through the SBC, all bad debt expenses can be reviewed for prudency and only prudently incurred costs are recovered. Conversely, with base rate recovery, there will always be a mismatch between bad debt expense recovered and the expense incurred so the Company is either recovering too much or too little.

Q. **What is PSE&G's proposal in this proceeding?**

A. As described in the testimony of Mr. Swetz in the COVID-19 proceeding in BPU Docket No. AO20060471, the Company proposes that gas bad debt expenses be recovered through a new Social Programs component of the Gas SBC, consistent with the recovery of electric bad debt expense. For details on the proposed new component of the Gas SBC, please see the testimony of Mr. Stephen Swetz. See Schedule MPM-46 R-1 for a *pro forma* adjustment to remove the recovery of gas bad debt from the rate case request so that it can be recovered in the proposed new Social Programs component of the Gas SBC.

As a result of the COVID-19 Order, PSE&G and other New Jersey utilities were permitted to defer the significant increase in gas bad debt expense above the amount included in base rates from March 9, 2020 through March 15, 2023. The Company's proposal in this proceeding does not include deferred COVID-19 bad debt which is being addressed in a separate proceeding.

IX. STORM COST RECOVERY

Q. Has PSE&G incurred any major storm expenses since the last base rate case in 2018?

A. Yes. As discussed in more detail in the panel testimony of Mr. Schmid and Mr. Fonseca, the Company has incurred approximately $110 million in incremental O&M expense for preparation and/or restoration efforts associated with six major storm events from July 2018 through February 29, 2024.

Q. What is the definition of a "Major Storm Event"?

A. A Major Storm Event is defined in N.J.A.C. 14:5-1.2 and includes a weather event such as a thunderstorm, tornado, hurricane, heat wave, snow, or ice storm which either affects at least ten percent of the customers in one of the Company's operating areas or results in the declaration of a state of emergency. As discussed in more detail below, the Company is proposing to expand the definition for Major Storm Event costs to include prudent, significant pre-staging costs that are incurred in preparation for a projected Major Storm Event that may not ultimately occur.

Q. How does the Company currently account for the incremental O&M costs associated with Major Storm Events?

A. Consistent with the way in which the Company has accounted for incremental O&M costs associated with Major Storm Events since 2010, the Company defers these costs for future recovery in a manner to be determined by the BPU.

Q. Were base rates set to recover any Major Storm Events that occurred after the conclusion of the 2018 base rate case?

A. No. In the 2018 base rate case, the Company used a *pro forma* adjustment to remove the $25.247 million in Major Storm Event incremental O&M that occurred in the July 2017 through June 2018 test year in that proceeding.[19] As a result, there is no base rate recovery of incremental O&M for post 2018 Major Storm Events in the Company's current base rates.

[19] Schedule SSJ-40 R-2, of Exhibit P-2 12+0 Testimony of Scott Jennings from the 2018 base rate case (*I/M/O the Petition of Public Service Electric and Gas Company for Approval of an Increase in Electric and Gas Rates and for Changes in Tariffs for Electric and Gas Service, B.P.U.N.J. No. 16 Electric and B.P.U.N.J. No. 16 Gas, and for Changes in Depreciation Rates, Pursuant to N.J.S.A. 48:2-18, N.J.S.A 48:2-21 and N.J.S.A. 48:2-21.1, and for Other Appropriate Relief*, BPU Docket Nos. ER18010029 & GR18010030 (filed January 12, 2018)).

Q. Is the Company proposing to use deferral accounting for Major Storm Event costs rather than base rate recovery?

A. Yes. The use of deferral accounting for the costs ensures that customers will pay no more and no less than the Company's actual costs associated with events that are beyond the Company's control and impossible to predict. This protects both the Company and customers. For example, assume the test year Major Storm Event costs were reflected in base rates instead of deferral accounting. Customers would have been paying over $25 million in rates even if no Major Storm Events occurred, such as in 2022. While the Company would have the benefit of collecting above actual costs in all years but 2020, in that year it would have incurred a massive loss due to the over $87 million in deferred costs incurred as a result of Tropical Storm Isaias. The Company should not profit from the absence of Major Storm Events, nor should it be penalized for prudently incurred incremental expenses associated with Major Storm Events.

Q. Is the Company proposing any changes to Major Storm Event recovery in this proceeding?

A. Yes. Deferral accounting, coupled with an annual surcharge mechanism, is the most appropriate means of recovering Major Storm Event costs by protecting the Company from significant financial harm from major weather events outside its control as well as ensuring customers only pay for actual, prudently incurred costs. First, this would allow for a prudence review of the deferrals within a reasonable time after they are incurred instead of reviewing all Major Storm Events that occur between rate cases at the same time. Second, these interim rate proceedings can help the Company maintain its credit ratings (which have benefited customers) as well as prevent any rate shock that could arise if the Company were permitted to recover the costs of all post-test year events at the same time. Finally, the use of a surcharge provides a mechanism to stop the amortization when recovery of the deferral is completed. As a result, the Company is proposing that a new clause, "the Storm Recovery Charge," be created to recover the approximately $110 million in deferred storm costs incurred since the last rate case as well as any future prudently incurred storm costs. For more details on the new clause, please see the testimony of Company witness Mr. Swetz.

Q. Are you proposing any other change to the manner in which costs associated with major storm events are recovered from customers?

A. Yes. Based upon the severity of weather forecasts, the Company may prepare in advance for a storm by procuring and/or mobilizing contractor crews prior to the onset of adverse weather, with the intention of deploying those crews to shorten the duration of customer interruptions. Given the difficulty of moving people and equipment under adverse weather conditions, and the competition among regional utilities to secure adequate emergency support when storms are forecast, the Company simply cannot wait until the impact of an imminent storm is certain; by then it is too late. Therefore, "pre-staging costs" must be recoverable, including any costs to retain contractors to assist with restoration efforts that would otherwise leave for storm duty in another jurisdiction. If the actual weather does not end up meeting the definition of a Major Storm Event, the Company should nonetheless by provided an opportunity to recover prudently incurred "pre-staging costs" incurred to respond to potential storms. The Company proposes that under the Major Storm Events cost recovery clause that it is proposing in this proceeding, it should be permitted to include recovery of pre-staging costs that exceed, in any one instance, $250,000. Permitting the deferral and recovery of such pre-staging costs will encourage the Company to prepare more prudently for future storms.

X. CONSERVATION INCENTIVE PROGRAM ("CIP")

Q. How and when was the CIP approved?

A. PSE&G filed for approval of its Clean Energy Future – Energy Efficiency Program ("CEF-EE Program") on October 11, 2018 ("CEF-EE Petition"). Subsequent to the CEF-EE Petition, on June 10, 2020, the Board approved a framework ("Framework Order")[20] for the performance targets; program administration; cost recovery (including lost revenue treatment); evaluation, measurement, and verification ("EM&V"); and filing and reporting standards for implementation of New Jersey's EE and peak demand reduction ("PDR") programs. The Framework Order allowed utilities the option of seeking a lost revenue adjustment mechanism ("LRAM") or the Conservation Incentive Program to address lost revenue recovery as provided for in the Clean Energy Act ("CEA"). On September 23, 2020, the Board approved a stipulation resolving all matters associated with the CEF-EE Petition, which included approval of the CIP mechanism.

Q. What is the purpose of the CIP and how does it work?

A. The CIP mechanism provides for rate adjustments related to changes in the average use per customer when compared to a baseline, removing the Company's disincentive to encourage customers to conserve energy that exists under traditional ratemaking. The CIP applies to both the Company's electric ("ECIP") and gas ("GCIP") businesses. The ECIP margin deficiency to be collected from customers or the margin excess to be refunded to customers is calculated each month by applicable rate schedule by subtracting the baseline revenue per customer ("BRC") from the actual revenue per customer and multiplying the resulting revenue per

[20] *I/M/O the Implementation of P.L. 2018, c. 17 Regarding the Establishment of Energy Efficiency and Peak Demand Reduction Programs*, B.P.U. Docket No. QO19010040 et al., Order Directing the Utilities to Establish Energy Efficiency and Peak Demand Reduction Programs (June 10, 2020) ("Framework Order").

customer by the actual number of customers for the month. The GCIP margin deficiency to be collected from customers or the margin excess to be refunded to customers is calculated each month by applicable rate schedule by subtracting the baseline use per customer ("BUC") from the actual use per customer and multiplying the resulting use per customer by the actual number of customers and per therm margin rate for the month.

Q. Are you proposing any adjustments to the CIP in this proceeding?

A. Yes, there are two adjustments that must be made in a base rate case proceeding associated with the CIP. First, a base rate case proceeding will establish new baseline use (gas) or revenue (electric) per customer figures that will go into effect upon approval of this proceeding. Second, a *pro forma* adjustment must be made to the test year income statement to remove the CIP accrual to account for the reset of the CIP baseline.

Q. Please explain the resetting of the BUC and BRC.

A. Aspects of the CIP tariff that interrelate with PSE&G's base rate revenue recoveries must be updated when new base rates are determined in a base rate case. The CIP is designed to adjust for changes in the average use per customer compared to the amount approved to set base rates, and thus the baseline for the CIP must be aligned with the approved billing determinants used to set base rates in this proceeding. In addition to the updated BUC and BRC, the date for determining incremental large customers should be set at June 1, 2024, the first day following the end of the test year. An adjustment to the number of customers is allowed under Rate Schedule Large Volume Gas ("LVG") to account for new customers with significant loads. The calculation of the LVG customer adjustment is the aggregate connected load for all new active customers that exceed 1,200 cubic feet per hour ("CFH") divided by 600 CFH.

Please see Schedule MPM-54E R-1 and MPM-54G R-1 for the updated BRC and BUC based on the actual results from June 1, 2023 – February 29, 2024 and a forecast from March 1, 2024 – May 31, 2024. The revised baselines will be updated with actual results when available.

Q. Why does the Company need a *pro forma* adjustment for the test year CIP accrual?

A. The CIP mechanism trues up actual revenues to the BUC and BRC set in the prior base rate case. The accrual from that difference between the actual BUC and BRC and the baseline BUC and BRC is recorded to income and is included as part of test year operating revenue. As a result, the test year revenues are not reflective of the actual test year billing determinants that will set the revised BUC and BRC. Therefore, the impact of the CIP accrual, positive or negative, must be eliminated from the income statement to reflect the test year revenues at the actual billing determinants that will set the revised BUC and BRC. The details associated with the elimination of the test year CIP accrual are reflected in Schedule MPM-50 R-1.

XI. EMBEDDED COST OF DEBT RATE RECOVERY

Q. How does the Company recover interest expense in base rates?

A. Interest expense is recovered as the Company's electric and gas rate base multiplied by the long-term debt component of its capital structure and then by the embedded cost of long-term debt. Each of these components will be approved by the Board in this proceeding based on results as of the end of the test year and approved post-test year adjustments.

Q. Can there be significant movements in interest rates?

A. Yes. This is highlighted by recent sharp movements in interest rates attributed to federal reserve policy seeking to lower inflation and other market factors. At the beginning of 2022, the 10-year treasury was approximately 2% and in less than two years, the 10-year treasury has recently been near 5%. Further, the outlook for interest rates is expected to be higher for some time – and certainly during the initial period when rates set in this case will go into effect -- due to a variety of market factors. As of May 31, 2024, PSE&G's embedded cost of long-term debt is estimated to be 4.00% based on expected additional financings in the test year. Quite simply, in the current and expected interest environment, any new financing given the level of treasury rates would be expected to significantly exceed the embedded cost of long-term debt.

Q. Has the impact of interest expense increased since the last rate case and do you expect it to continue to grow?

A. Yes. While the path of future interest rates is difficult to predict, the materiality of interest expense will continue to increase as debt grows to finance PSE&G's capital investment program needed to meet the State's clean energy targets and maintain safe and reliable service. PSE&G's long-term debt outstanding has grown significantly since the last rate case (debt outstanding was approximately $9 billion at the end of 2018 and is approximately $14 billion as of February 29, 2024). PSE&G supports the State's transition to a cleaner environment, but that transition will require significant capital investment to the distribution system that will be financed by the Company's approved capital structure, significantly increasing PSE&G's long-term debt balance and overall interest expense. In addition to financing new capital investments, approximately $1.1 billion of the existing long-term debt will come due in 2024 and 2025.

Q. What are the implications of interest rate increases on the rate setting process?

A. Upon setting new rates, PSE&G would not be expected to recover the cost of debt for a period of time that is difficult to predict. The rate setting process should provide the

Company an opportunity to earn its allowed return in at least the first-year new base rates go into effect, which is why post-test year pro forma adjustments have been approved by the Board for known and measurable expenses. The current interest rate environment and the need to refinance existing debt after the end of the test year will likely result in the Company's interest expense exceeding its revenue recovery within the first year that new rates go into effect. This treatment could also enable the Company to stay out of rate cases longer than it otherwise would, thereby deferring impacts to customers.

Q. What is the Company's proposal to address changes in interest expense after the test year?

A. The Company proposes a new interest cost reconciliation mechanism to defer the difference between the actual embedded cost of debt and the rate approved by the Board in this proceeding. Please see Schedule MPM-55 R-1 for the proposed calculation of the deferral. The interest cost reconciliation mechanism avoids the need for a *pro forma* adjustment that would increase costs to customers in this proceeding and will provide the Company an opportunity to earn its allowed return. The mechanism also ensures the Company recovers no more or less than its allowed interest expense and can be reevaluated in a future base rate case.

Q. Will the proposed mechanism allow the Company to defer the incremental interest expense on increases in its outstanding long-term debt balance outside of a rate case?

A. No, it will not. Increases in the Company's rate base and associated long-term debt balance will continue to be recovered through the base rate case process and will not be part of the deferral mechanism. The deferral accounts only for changes in the Company's embedded cost of debt. The rate base balance and long-term debt percentage in the mechanism will be the amounts approved by the Board in this proceeding. As a result, the Company will still bear the risk of increases in interest expense associated with investments that have not been approved by the Board.

Q. Would this mechanism be symmetrical and allow for potential refunds to customers?

A. Yes. As the market has shown over the past few years, interest rates can rapidly change downwards (such as during the COVID-19 pandemic) or upwards (such as during periods of inflation and other market crises). If interest rates decline again in the future and reduce the Company's embedded cost of debt, those amounts would similarly be deferred for future refund to customers. Rate movements will be influenced by the prevailing economic environment, which could vary from a re-acceleration of inflation to a hard landing of the U.S. economy. Rate movements could also be driven by a shock to the system such as a pandemic, banking crisis, or global conflict. Fluctuations in interest rates can be higher or lower, and the proposed accounting treatment will ensure variances are shared between the Company and customers.

Q. Does this proposal shelter customers from the execution risk of financing plans to customers?

A. Yes. A long-term bond is priced using a treasury rate and a credit spread. For reference, in August 2023, PSE&G issued 10-year debt with a coupon of 5.20%, reflecting a 10-year treasury as the reference rate plus a credit spread of 103 basis points. Generally, the cost of debt is driven by the treasury component, which is determined by the macroeconomic environment. The credit spread is driven by market volatility, highlighting the need for strong investment grade credit ratings to maintain access to the markets on reasonable terms. Despite the interest rate environment, PSE&G utilizes its credit rating and the strong capabilities of its bank group to run a competitive book building process to obtain the lowest-possible price.

Further, the deferral mechanism will apply only to the approved long-term debt balance in this proceeding and therefore the Company—and not customers—bears the risk on its increased interest expense as its outstanding long-term debt balance increases between rate cases.

Q. Are you proposing any other adjustments associated with the embedded cost of long-term debt?

A. Yes. For the Company's future infrastructure investment program ("IIP") rate adjustment filings, such as GSMP II Extension, IAP and the proposed future CEF-EV rate adjustments, the embedded cost of long-term debt should be the actual rate at the time the Company submits its update for actual results in the associated proceeding. Every IIP rate adjustment filing includes an initial forecast that is trued-up with actual results before new rates are implemented, and the actual embedded cost of long-term debt can be updated at that time. In addition, the WACC in the Company's Green Program Recovery Charge ("GPRC") and TAC should be updated monthly, consistent with the monthly return calculation for each program with a return component. For the GPRC, the size of the programs (such as for the Clean Energy Future – Energy Efficiency II filing) have significantly increased, causing a more significant impact on the debt costs to finance that investment. With regard to the TAC, the Company has voluntarily proposed to flow-back tax benefits to customers on an accelerated basis, reducing customer bills in this proceeding, but lowering the Company's cash flow, which impacts the need and timing for additional financing. As a result, it is appropriate to use the actual long-term debt rate in the calculation of the Company's return in those proceedings.

XII. INCENTIVE COMPENSATION

Q. Please briefly describe the Company's compensation philosophy.

A. PSE&G maintains a compensation structure designed to attract and retain a talented and diverse workforce to operate safely, reliably, and cost-effectively. The Company's compensation structure (salary ranges, incentive compensation targets, and related factors) is regularly benchmarked to enable the Company to attract and retain its management team and overall workforce.

Q. Does the Company base part of employee compensation on the achievement of various incentives?

A. Yes. Similar to industry peers and the vast majority of companies, PSE&G has a compensation program that is a mix of fixed base pay and incentive pay. The incentive pay is dependent upon achieving established goals. For PSE&G these goals are primarily operational and customer focused. The incentive pay program is designed to encourage employees to focus on the goals that have enabled PSE&G to achieve the levels of reliability, safety, and operational excellence that I have described previously. Included in test year expenses are approximately $39 million ($20 million for electric and $19 million for gas) associated with incentive compensation for PSE&G as well as the Service Company allocation to PSE&G to support the utility. Of that amount, approximately $10 million ($5 million electric and $5 million gas) is provided to officers and relates to a mix of targets, including operational performance, but mostly weighted towards financial results. Of the remaining $29 million, $20 million ($10 million each for electric and gas) relates to achieving operational metrics and strategic goals, with the remainder related to achieving financial goals, all of which ultimately benefit customers as discussed more fully below.

Q. Please explain why the Board should approve the recovery of PSE&G's incentive compensation at this time.

A. As a preliminary matter, it should be recognized that an incentive compensation program is not a "bonus" program as that term is commonly understood. As discussed more fully below, it is the combination of fixed compensation and variable compensation that permits the Company to provide a level of overall compensation necessary to attract and retain qualified personnel. In addition, while there are certain metrics that might be characterized as "financial," these metrics actually benefit both shareholders and customers. For example, containing O&M costs benefits shareholders in the year(s) costs are contained, but also helps keep down test year costs that are ultimately recovered from customers through rate cases, thereby lowering customer rates from what they otherwise would be. That is an incontestable benefit to customers, and it is the product of properly incented employees and a properly incented management team. Also, meeting earnings targets enables investors to have confidence in the Company, which helps to keep the cost of capital down. Finally, including financial goals in an at-risk compensation program ensures that employees are properly encouraged to attempt to achieve operational goals in a cost-effective manner. So, fundamentally, there is benefit for all parties – including, demonstrably, PSE&G's customers -- when financial targets are achieved. Nevertheless, as the Company demonstrates below, the majority of PSE&G's variable compensation metrics relate to operational metrics that directly benefit customers and the achievement of which produces tangible, positive effects on the service provided by the Company.

Q. How does the Company's incentive compensation structure correlate variable compensation to operational performance?

A. The annual variable compensation structure is designed so that the majority of the targets relate to operational metrics. Those metrics are focused on Reliability (e.g., SAIDI and other metrics), customer satisfaction (J.D. Power scores and other metrics), and other operational metrics. The metrics have two components that are scored – Part A, which is to compare the Company to peers, generally with a target of top quartile performance, and Part B, which measures whether the Company did better than the prior year, driven by PSE&G's focus on Continuous Improvement. As a result, the incentives are clearly aligned with the needs of customers as the metrics are directly focused on providing strong service.

Q. You stated that PSE&G's incentive compensation program employs metrics that directly benefit the Company's customers. Please explain that statement.

A. The "scorecard" that the Company employs to determine incentive compensation contains metrics that directly benefit customers. PSE&G tracks many operational and customer service metrics and approximately 12 of them are directly included in the variable compensation calculation. These include important operational and customer-facing metrics such as SAIDI, gas leaks per mile, damages per locate requests, JD Power Customer Satisfaction surveys of both electric and gas customers, and other measures.

Clearly, therefore, PSE&G's employees are provided incentive compensation if they achieve operational targets that benefit customers. As a result, the Company's incentive compensation program should be fully recoverable because it delivers clear and tangible benefits to our customers.

Q. Is the incentive compensation program an essential component of overall compensation?

A. Yes. Not only are these programs among the most important tools that management uses to attract and retain talent, align interests, incent performance, and ensure the delivery of high-quality service to customers, but the variable compensation structure has also delivered tangible benefits to customers, as described above. The Company's compensation philosophy is to target total compensation at the median of companies it competes with for talent. Without the incentive compensation program, which is a common component of compensation among PSE&G's peers, the Company would need to increase the fixed base salary cost to attract and retain the caliber of talent needed to achieve its goals. Taking that approach would result in a similar overall level of compensation and a similar overall level of prudent labor expense, even if key metric(s) were not achieved in a given year. Using incentive compensation is a more effective means to motivate employees to achieve targeted results.

Q. Does the Company's workforce expect that incentive compensation will be part of the overall package of compensation and benefits?

A. Yes. Today's workforce fully expects that a portion of their compensation will be tied to the attainment of stated performance objectives. To attract and retain top talent, the Company must continue to offer a compensation structure that is, in part, incentive based.

Q. Are there negative consequences associated with the disallowance of some or all of the Company's incentive compensation costs?

A. Yes. Obviously, to the extent a portion of these costs are disallowed, the Company would not be able to recover its cost of service. But there are larger ramifications. PSE&G's overall compensation program, including incentive compensation, seeks to set salaries around the mean of companies with whom it competes for our talented workforce. To the extent these costs were not incurred, the Company would no longer be aligned with industry and regional compensation benchmarks and would therefore expect incremental turnover, inability to attract quality employees, and a deterioration of service over time. The Company's incentive compensation is a prudent cost and PSE&G requests full recovery of its $36 million of incentive compensation expense.

XIII. <u>DEFERRAL REQUESTS – CREDIT AND DEBIT CARD FEES, IMPLEMENTATION COSTS FOR TIME OF USE RATES AND TRAFFIC CONTROL REGULATION COSTS</u>

Q. Is the Company proposing an adjustment to reflect a requested change to the treatment of credit card fees?

A. Yes. As demographics change and the percentage of customers using the digital platforms for paying their bills increases, the need to eliminate the charge for credit and debit cards becomes more important. Since 2010, the percent of payments received via check has dropped from over 52% to 17% and continues to decline each year. Currently, while other payment transaction fees are considered normal business expenses and allowed recovery, the credit card and debit card processing fees are not allowed to be recovered through rates, and each is charged as a pass-through fee to customers at the time of payment. This is the number one reason for dissatisfaction as reported by customers when asked about the billing and payments process for PSE&G.

Customers expect seamless electronic payment options. PSE&G provides the ability to pay via its website, mobile app, phone, and text. The Company has expanded customers' ability to communicate and transact business through digital channels and the Board has recognized and encouraged this additional digital access. For payments, these channels lend themselves to payments via credit and debit cards. As the utility industry and technology continues to modernize, payment methods need to as well.

Q. Is there a disparity in the manner the Company treats credit and debit card payments versus other forms of payments?

A. Yes. Within the existing bill and payment options available to customers, there is already a disparity in the unit cost of those transactions, yet credit and debit card fees are the only transaction costs singled out for non-recovery. In-person payments at Customer Service Centers are much more expensive than a mailed check, and sending a paper bill via mail is more expensive than receiving an email, yet PSE&G does not charge individually for these options. The different options are available to all customers who then choose the method that best works for them. The Company proposes treating credit card processing fees as it does the other payment and delivery fees within the billing process, thereby leveling the playing field – among the various payment options.

Q. What is the Company's proposal for credit card transaction fees?

A. The Company proposes to assume the cost for credit card transactions rather than requiring the payment from individuals using a credit or debit card. By assuming the payment, the Company anticipates the cost per transaction will be reduced from the current rate of $3.50 per payment to $2.60. However, this will result in a prudent cost to the utility (just as the cost to process all other forms of payment is prudent) that is not captured in the test year and would not represent the Company's go-forward expenses. Since it is unknown at this time how many customers will pay via credit card once the transaction fee is removed, the Company is proposing to defer those incremental expenses until the next base rate case as participation ramps up. After the conclusion of the next base rate case, the Company will stop the deferral mechanism and the costs would be recovered in the same manner as all other bill processing costs.

Q. Is there another significant cost the Company will occur outside this test year that requires deferral authority?

A. Yes. As discussed in the Direct Testimonies of Mr. Stephen Swetz and Company witness Ahmad Faruqui, the Company is proposing a Pilot Residential and Commercial Time of Use Rate. The TOU rates will utilize AMI to design a rate structure that will encourage customers to shift their usage to off-peak periods, lowering their bills and peak demand on the electric system, which will avoid the need for additional utility infrastructure and generation costs. This is particularly important with the growth in electric vehicles, which can have a significant impact on customer usage and peak demand. To encourage participation, the Company is also proposing a one-year pilot that will refund customers if TOU rates are higher than they would have been charged under RS Rates. However, implementing TOU rates and the ability to compare those rates to the RS rates and issue a refund will require significant changes to the existing billing system, resulting in significant incremental capital and O&M costs that will be incurred after approval of this proceeding.

Q. What is the Company's proposal for the expenditures necessary to implement TOU rates?

A. The Company proposes that the Board provide the Company approval to defer these costs and place them in a regulatory asset as separate and identifiable accounts for recovery of costs deemed prudent in the Company's next base rate case, in the same manner as costs related to the implementation of AMI in the CEF-EC Program. The regulatory asset will include capital costs inclusive of return on the average monthly rate base recorded at PSE&G's pre-tax overall WACC in effect at the time of the deferral. Incremental TOU-related O&M costs will be deferred separately without a return, for recovery in the Company's next base rate case.

The prudency of the TOU Pilot's costs, including those deferred and placed in the regulatory asset, will be reserved for review and determination in the Company's next base rate case.

Q. What is the traffic control regulation and how will it impact PSE&G?

A. On August 7, 2023, the New Jersey Department of Community Affairs adopted new regulations titled "Managing and accounting for outside employment of off-duty law enforcement officers."[21] These regulations created new requirements related to any entity's utilization of off-duty law enforcement officers for purposes that include security and traffic safety control. These new requirements will increase PSE&G's costs for security and traffic control safety as the Company utilizes off-duty law enforcement officers in every township and county in which it operates. The costs incurred annually associated with security and traffic control safety for PSE&G's capital and O&M work is expected to be significant, and this new regulation will have a direct impact to the Company's financials.

Q. How will this regulation impact the Company's financials?

A. As discussed in the panel testimony of Mr. Schmid and Mr. Fonseca, the new regulation will require the Company to maintain "working capital" type balances with municipalities in order for the municipalities to have sufficient pre-funded cash on hand from PSE&G to pay for the costs of the off-duty officers. This will have both a working capital requirement on the Company's cash flow as it will need to create and maintain the required pre-funded municipal trust balances as well as an incremental administrative cost compared to the test year to monitor the balances with each municipality. The Company is currently in negotiations with certain

[21] N.J.A.C. 5:30–8.6.

municipalities on the implementation of the regulation, including the pre-funded trust balance and how and when it is utilized.

Q. How does the Company propose to handle the incremental costs as a result of this new regulation?

A. Based on discussions with municipalities and counties that began in earnest in 2024, the Company is seeking deferral authority for incremental costs specific to this regulation for the recovery of all prudently incurred costs in its next base rate case. If costs become known by the end of the test year, the Company may propose a pro forma adjustment in its 12+0 update for the incremental costs as a result of these discussions.

Q. What costs is the Company proposing to defer?

A. The costs proposed to be deferred would be the carrying costs on the pre-funded balances associated with this regulation (monthly total pre-funded trust balance multiplied by the difference between the Company's approved monthly WACC and any interest it receives (if applicable) on the pre-funded trust balance) plus administrative costs to monitor the balances (staff supporting the balances will charge a distinct work order to track only the costs associated with maintaining the pre-funded trust balances in accordance with the regulation).

XIV. TEST YEAR AND REVENUE REQUIREMENTS – ADJUSTMENTS TO BASE ELECTRIC AND GAS DISTRIBUTION RATES

Q. Please describe the test year that is being utilized in this proceeding.

A. The test year in this proceeding is the twelve-month period beginning June 1, 2023 and ending May 31, 2024. The filing consists of nine months of actual data (through February 29, 2024) and three months of estimated data. Actual data is supported by the Company's accounting records, while projected data is based on the Company's financial and capital budget for the period ending May 31, 2024. The Company will update for twelve months of actual data through May 31, 2024 by July 15, 2024, which is consistent with the Company's anticipated rate effective date of September 1, 2024, and ensures the Board and the parties will be able to review twelve months of actual data sufficiently in advance of the estimated rate effective date.

Q. Please discuss the schedules that you are providing to support the revenue requirement.

A. The determination of revenue requirements is premised on the June 2023 through May 2024 test year described above with appropriate *pro forma* adjustments. *Pro forma* adjustments to the test year have been proposed to reflect the expense level of certain items for the twelve months ending August 30, 2025 (the "rate year"), which is the first full year that rates are proposed are anticipated to be effective on September 1, 2024. The costs to be recovered include expenses of running the business (including O&M expenses and taxes) as well as return of and on the capital invested that is necessary to run the business (*i.e.*, depreciation and amortizations, interest expense, and a fair return on equity invested). Plant additions that are expected to be in service within six months beyond the end of the test year (through November 30, 2024) have been included in rate base.

Set forth below is a description of the schedules identified in the introduction section of my testimony. The schedules reflect information for both electric distribution and gas distribution.

Determination of Revenue Requirements—Schedule MPM-02 R-1

Q. Are you presenting a schedule that shows the revenue requirement in this case?

A. Yes. Schedule MPM-02 R-1 shows the determination of the revenue requirement increase being requested in this proceeding. Based upon rate bases of $9.4 billion and $8.7

billion for electric distribution and gas distribution, respectively, *pro forma* operating income of $329.7 million and $371.1 million for electric and gas, respectively, and a required rate of return of 7.55%, the increase in required revenue requested is $535.1 million for electric distribution and $401.4 million for gas distribution.

Utility Rate Base—Schedule MPM-03 R-1

Q. Please describe the schedule depicting the Company's rate base.

A. Schedule MPM-03 R-1 presents projected total electric and gas utility rate bases as of May 31, 2024 and November 30, 2024. Electric rate base is expected to be $9.2 billion by May 31, 2024 and $9.4 billion as of November 30, 2024. Gas rate base is expected to be $8.6 billion by May 31, 2024 and $8.7 billion as of November 30, 2024. The rate bases consist primarily of the utility's investment in distribution plant, net of the accumulated provision for depreciation of utility plant plus distribution working capital, accumulated deferred income taxes, the consolidated tax adjustment, and the exclusion of IAP and GSMP II (as extended) investment that will be recovered in a separate rate adjustment proceeding in accordance with the orders in those matters. Rate base also includes the regulatory assets associated with the CEF-EC and CEF-EV investments as described below. Rate base represents the investment necessary to provide safe, adequate, proper, and reliable service to customers and is therefore a crucial factor in setting future distribution rates. The components of the Company's distribution rate bases are supported by Schedules MPM-07 R-1 through MPM-18 R-1 and will be addressed below.

Revenue Factor—Schedule MPM-06 R-1

Q. Are you presenting a schedule that depicts the revenue factor for the electric and the gas operation?

A. Yes. The electric revenue factor utilized by the Company in this proceeding is projected to be 1.3947. The factor includes the 9% State of New Jersey Corporate Business Tax, the 21% Federal income tax, and the assessments for the Board of 0.217589% and the Division of Rate Counsel (Rate Counsel) of 0.045540%. The gas revenue factor is the same rate assuming approval by the BPU of transitioning the gas bad debt from base rates to a new component of the gas SBC. If the recovery of gas bad debt expense through the SBC is not approved, the gas revenue factor should include the uncollectible rate at 1.70% (resulting in a revenue factor of 1.4189). This is the forecasted uncollectible expense as the historic rate has been skewed by the COVID-19 deferral and the significant increase in the reserve as a result of the moratorium on shutoffs.

Utility Plant in Service—Schedule MPM-07 R-1

Q. Please describe the schedule showing utility plant in service.

A. The electric utility and gas utility plant in service, as shown on Schedule MPM-07 R-1, is estimated to be $12.8 billion and $12.4 billion respectively on May 31, 2024 and $13.1 billion and $12.9 billion respectively on November 30, 2024.

Plant-In-Service Additions from May 31, 2024 through November 30, 2024—Schedule MPM-08 R-1

Q. Are you also presenting a schedule that shows additions to plant in service?

A. Yes. Schedule MPM-08 R-1 provides the direct additions to plant in-service from the actual June 1, 2023 balance projected through November 30, 2024. Additions are expected to total approximately $1.8 billion for electric and $1.7 billion for gas. The additions are primarily distribution plant.

Accumulated Depreciation—Schedule MPM-09 R-1

Q. Please describe the schedule that presents Accumulated Depreciation.

A. Electric and gas plant in service have estimated useful lives, which normally extend over many operating periods. The systematic recovery of these investments is accomplished by the recognition in rates of annual depreciation charges, with the accumulated depreciation used to reduce rate base utility plant investments. This has been, and continues to be, an acceptable way of developing rate base because the accumulated depreciation balance recognizes that these amounts have already been charged to customers.

The accumulated depreciation balance reflects the recognition of annual depreciation charges projected through November 30, 2024 based upon the current BPU-approved electric and gas distribution depreciation rates. Please note that PSE&G is also presenting a study performed by Mr. John Spanos of Gannett Fleming that proposes changes to the existing depreciation rates. The Company has included the annualization of the depreciation expense, described in more detail in schedule MPM-41 R-1, as a rate base deduction using a mid-year convention.

Customer Advances for Construction—Schedule MPM-10 R-1

Q. Is distribution rate base reduced to reflect advances by customers for construction?

A. Yes, it is. Because the costs of construction related to advances made by the Company's electric and gas utility customers are capitalized and included in the distribution rate bases, it is appropriate to reduce distribution plant costs for these advances. As shown on

Schedule MPM-10 R-1, electric and gas distribution rate base has been reduced by $63.9 million and $24.9 million, respectively, based upon a 13-month average of the most current available actual advances—the period February 2023 through February 2024.

Working Capital

Q. What is "Working Capital?"

A. Working Capital is the average amount of capital over and above investments in plant and other separately identified rate base items provided by investors of PSE&G to bridge the gap between the time expenditures are required to provide service and the time collections are received for that service. The Company's proposed working capital allowance is $1.2 billion for electric rate base and $702.8 million for gas rate base. Each rate base working capital requirement consists of three components: cash (Lead/Lag), materials and supplies, and prepayments.

Cash (Lead/Lag) Working Capital

Q. Are the amounts shown for Working Capital supported by any analyses?

A. Yes, they are. The cash (Lead/Lag) working capital allowances reflected on Schedule MPM-03 R-1 of $884.9 million and $586.0 million that I have included in the electric and gas rate bases, respectively, are the result of detailed Lead/Lag studies supported by Mr. Michael Adams, in separate testimony and supporting schedules.

Materials and Supplies—Schedule MPM-11 R-1

Q. How are Materials and Supplies reflected in the filing?

A. I have included $298.0 million and $116.7 million of materials and supplies necessary for ongoing utility electric and gas operations, respectively, in rate base. This is a representative balance of general store items held in inventory for operating and maintenance and capital purposes. As discussed above on the factors driving the need for rate relief, there has been a significant increase in the Company's inventory balance driven by the need to diversify suppliers and have more equipment on hand due to supply shortages and inflation on material costs, particularly transformers. Since October 2023, the balance has increased over 20%. While Materials and Supplies is typically a 13-month average of the most current available actual balance, that approach would underestimate the balance given the escalating costs. As a result, the Company updated the calculation of materials and supplies to use the latest available monthly balance (currently as of February 2024) rather than a historic average.

Q. Are you proposing any adjustment to the actual monthly balance?

A. Yes. The current material and supply balance includes new AMI meters that will be used for the CEF-EC program and that will be installed by the end of 2024. Since this balance is not representative of the go forward material and supply balance the Company will maintain, an adjustment is made to reduce the meter inventory to the steady-state balance that will be maintained once the AMI implementation is complete.

Prepayments—Schedule MPM-12 R-1

Q. Does the Company's filing reflect an allowance for prepayments of costs?

A. Yes, it does. The Company is required to make advance payments for the BPU and Rate Counsel assessments, prior to their being charged to operating expenses. Such prepayments occur every year and therefore require a permanent, ongoing investment by the Company to fund them. Accordingly, I have included the average electric and gas utility prepayment requirements of $0.5 million and $0.1 million, respectively, in rate base. These levels are based upon a 13-month average as of February 2024.

Accumulated Deferred Taxes—Schedule MPM-13 R-1

Q. Have you incorporated Accumulated Deferred Income Taxes into your rate base calculation?

A. Yes. Company witness Mr. Pardo discusses Accumulated Deferred Taxes in his testimony. I have incorporated Mr. Pardo's Accumulated Deferred Tax Balance shown on Schedule CP-3 R-1. The net accumulated deferred taxes amount to a $1.7 billion reduction to electric rate base and a $1.7 billion reduction to gas rate base. These amounts are based upon the plant in service balances reflected in the respective rate bases as of November 30, 2024. For more details, please see the testimony of Mr. Pardo.

Consolidated Tax Adjustment—Schedule MPM-14 R-1

Q. Does the Company's filing recognize the Board's most recent policy concerning Consolidated Tax Adjustment ("CTA")?

A. Yes, it does. The Company believes that, as others representing PSE&G have testified in the past, the imposition of a CTA is a flawed and inappropriate regulatory adjustment. Nevertheless, Company witness Mr. Pardo has calculated a CTA and discusses the basis for that adjustment in his testimony. I have incorporated Mr. Pardo's CTA adjustment as shown on Confidential Schedule CP-5 R-1. This adjustment decreases electric distribution rate base by $3.7 million and results in no change to gas distribution rate base due to a cumulative tax loss. For details on the calculation of the Consolidated Tax Adjustment, please see the testimony of Mr. Pardo.

IAP Rate Base Adjustment-Schedule MPM-15 R-1

Q. Why is there an IAP Adjustment?

A. The IAP program was approved for recovery of investments through a separate mechanism outside of a base rate case. Because the Company has IAP investments that will occur during the test year but will be recovered through an IAP rate adjustment proceeding outside of the test year in accordance with the IAP Order, the IAP investments must be excluded from rate base to avoid double recovering the investment.

Q. What is the adjustment?

A. The adjustment is simply to back out all investment, cost of removal expenditures, accumulated depreciation, and accumulated deferred income taxes associated with the IAP that will be recovered in a separate IAP rate adjustment proceeding, which is expected to be investment placed in service from February 1, 2024 through November 30, 2024.

Q. What is the impact of this adjustment?

A. As a result of this adjustment, electric and gas rate base has been reduced by $40.9 million and $0.4 million, respectively, as of November 30, 2024.

CEF-EC Rate Base Adjustment-Schedule MPM-16 R-1

Q. What is the CEF-EC rate base adjustment?

A. The CEF-EC rate base adjustment accounts for the CEF-EC regulatory asset on CEF-EC related plant in-service that is or will be placed into service within six months of the end of the test year. Paragraph 22 of the CEF-EC stipulation approved by the Board states: “the Company will book a regulatory asset (“CEF-EC Regulatory Asset”) comprised of: 1) its CEF-EC capital investment (“CEF-EC Investment Deferral”), and 2) the associated stranded costs

("Stranded Cost Deferral") on legacy meters in accordance with paragraphs 23 and 24 below."[22]

Q. How is the CEF-EC Regulatory Asset calculated?

A. Per paragraph 23 of the CEF-EC stipulation approved by the Board, the CEF-EC Investment Deferral is calculated as:

> *CEF-EC Monthly Investment Deferral = (((Pre-Tax Cost of Capital /12) * Average Monthly Rate Base) + Monthly Depreciation and/or Amortization Expense) + (Average Monthly Investment Deferral Balance * (WACC /12))*[23]

Paragraph 13 of the Stipulation authorized the two phases of AMI deployment, which incorporate a geographic strategic approach designed to maximize installation efficiency and customer satisfaction.[24] To minimize the inefficiencies of dispersed meter deployment, these phases have proceeded geographically regardless of the age of any particular legacy meter at the time of its removal. Paragraph 24 of the CEF-EC stipulation stated the Stranded Cost Deferral will be calculated as:

> *Stranded Cost Deferral = Accelerated Depreciation Expense associated with Legacy Meters – Depreciation Expense on Legacy Meters at the Approved Depreciation Rate as Determined in the 2018 Base Rate Case*[25]

Further, paragraph 28 of the CEF-EC Stipulation states,

> The CEF-EC Program investment that is placed into service, but not yet reflected in customer base rates, will record a monthly accrual of a deferred return that will be capitalized and included in the plant balance as described in paragraph 23 above. For ratemaking purposes, depreciation expense will not begin on CEF-EC Program investment until reflected in base rates in the Next Base Rate Case. Since depreciation expense must be booked when the investment is placed in service for tax and financial reporting purposes, the Company will defer the depreciation in the CEF-EC Program investment regulatory asset.[26]

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[22] CEF-EC Order at Stipulation ¶ 22.
[23] *Id.* ¶ 23.
[24] *Id.* ¶ 13.
[25] *Id.* ¶ 24.
[26] *Id.* ¶ 28.

Q. Did the CEF-EC Order allow for investment beyond the end of the test year?

A. Yes. Paragraph 21 of the CEF-EC Stipulation states:

> The Parties also agree that reasonable and prudent costs associated with the CEF-EC Program investment that are likely to be in-service by the end of six (6) months after the end of the test year in the Company's Next Base Rate Case shall be reflected in the rates established in that case, consistent with the *Board's Elizabethtown* Water.[27]

Q. Does the CEF-EC Order discuss the recovery of the regulatory asset?

A. Yes. Paragraph 26 of the Stipulation approved by the Board states "The Parties agree that the revenue requirement in the Next Base Rate Case or a subsequent base rate case, if applicable, will include a return of and on the CEF-EC Regulatory Asset defined in paragraphs 22-24 above to the extent that is deemed prudent."[28] The recovery "of" the CEF-EC Regulatory asset is described below in Schedule MPM-47 R-1. This adjustment to rate base is to account for the return "on" the CEF-EC Regulatory Asset derived from the CEF-EC investment in the same manner as Allowance for Funds Used During Construction ("AFUDC") is added to rate base when a project is placed into service.

Q. What is the impact of this adjustment?

A. As a result of this adjustment, electric rate base has been increased by $219.0 million as of November 30, 2024.

CEF-EV Rate Base Adjustment-Schedule MPM-17 R-1

Q. What is the CEF-EV Adjustment?

A. The CEF-EV rate base adjustment accounts for the CEF-EV regulatory asset on CEF-EV related plant in-service that is or will be placed into service within six months of the end of the test year. As stated in paragraph 22 of the CEF-EV Stipulation approved by the Board:

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[27] *Id.* ¶ 21 (internal footnote omitted).
[28] *Id.* ¶ 26.

> The Company will invest in EV infrastructure as described in paragraph 15 above. Until being rolled into base rates, as described further below, those CEF-EV related capital costs shall be deferred and placed in a regulatory asset, for recovery in the Company's next base rate case, to be filed no later than January 1, 2024 (the "Next Base Rate Case").[29]

Q. How is the CEF-EV Regulatory Asset calculated?

A. Per paragraph 26 of the CEF-EV stipulation approved by the Board, the CEF-EV Investment Deferral is calculated as:

> *CEF-EV Monthly Investment Deferral = (((Pre-Tax Cost of Capital /12) * Average Monthly Rate Base) + Monthly Depreciation and/or Amortization Expense) + (Average Monthly Investment Deferral Balance * (WACC /12))*[30]

Further, paragraph 30 of the CEF-EV Stipulation states,

> The CEF-EV investment that is placed into service, but not yet reflected in customer base rates, will record a monthly accrual of a deferred return that will be capitalized and included in the plant balance. For ratemaking purposes, depreciation expense will not begin on CEF-EV investment until reflected in base rates in the Next Base Rate Case or any subsequent base rate case or rate case reopener. Since depreciation expense must be booked when the investment is placed in service for tax and financial reporting purposes, the Company will defer the depreciation in the CEF-EV investment regulatory asset.[31]

Q. Did the CEF-EV Order allow for investment beyond the end of the test year?

A. Yes. Paragraph 23 of the CEF-EV Stipulation states:

> The reasonable and prudent costs associated with the CEF-EV investment that are likely to be in-service by the end of six (6) months after the end of the test year in the Company's Next Base Rate Case shall be reflected in the rates established in that case, consistent with the Board's *Elizabethtown Water* standards.[32]

Q. Does the CEF-EV Order discuss the recovery of the regulatory asset?

A. Yes. Paragraph 28 of the Stipulation approved by the Board states

> The revenue requirement in the Next Base Rate Case or a subsequent base rate case, if applicable, will include a return of and on the CEF-EV Regulatory Asset defined in paragraph 25 above. The return on the deferred investment will be based on the

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[29] CEF-EV Order at Stipulation ¶ 22.
[30] *Id.* ¶ 26.
[31] *Id.* ¶ 30.
[32] *Id.* ¶ 23 (internal footnote omitted).

approved WACC in the Next Base Rate Case, or subsequent base rate case, adjusted for income taxes and BPU and Rate Counsel assessment fees. The return of the deferred investment will be based on the Board approved depreciation/amortization rates determined in the Next Base Rate Case or any other appropriate period approved by the Board.[33]

Q. What is the impact of this adjustment?

A. As a result of this adjustment, electric rate base has been increased by $42.1 million as of November 30, 2024.

Q. Does the CEF-EV Order discuss recovery for investment beyond the end of the six-month post-test-year period?

A. Yes. The CEF-EV Order allows for annual rate adjustment filings to recover investments placed into service more than six months after the end of the test year. The Company's proposal for the methodology and schedule of those annual rate adjustment filings is set forth in the testimony of Mr. Swetz.

GSMP II Extension Rate Base Adjustment-Schedule MPM-18 R-1

Q. Why is there a GSMP II Extension Adjustment?

A. The GSMP II Extension was approved for recovery of investments through a separate mechanism outside of a base rate case.[34] Because the Company has GSMP II Extension investments that will occur during the test year but will be recovered through a GSMP II Extension rate adjustment proceeding outside of the test year in accordance with the GSMP II Extension Order, the GSMP II Extension investments must be excluded from rate base to avoid double recovering the investment.

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33 *Id.* ¶ 28.
34 *See* GSMP II Extension Order.

Q. What is the adjustment?

A. The adjustment is simply to back out all investment, cost of removal expenditures, accumulated depreciation, and accumulated deferred income taxes associated with the GSMP II Extension that will be recovered in a separate GSMP II Extension rate adjustment proceeding, which is expected to be investment placed in service through November 30, 2024.

Q. What is the impact of this adjustment?

A. As a result of this adjustment, gas rate base has been reduced by $269.2 million as of November 30, 2024.

Electric and Gas Distribution Operating Income

Q. Please describe the schedules for Electric and Gas Operating Income.

A. Schedules MPM-19 R-1 through MPM-28 R-1 present a complete picture of PSE&G's electric and gas distribution operations. These schedules contain sales, distribution operating revenues, and number of billed customers by class of business for the electric and gas distribution businesses of the Company. Also included are O&M expenses by primary function, depreciation and amortization, taxes other than income taxes, and current and deferred income taxes. Schedule MPM-19 R-1 presents the income statements for these business segments. This information has been provided for the twelve-months ending May 31, 2024, which is the test year based on nine months of actual data and three months of forecast.

Pro-forma Distribution Operating Income—Schedule MPM-29 R-1

Q. Are you proposing to adjust Test Year Operating Income?

A. Yes. Schedule MPM-29 R-1 is a summary of *pro forma* adjustments to the test year electric and gas utility operating income. These *pro forma* adjustments adjust test period operating income for known or measurable changes to expense and income levels so as to reflect the expected expense and income levels for the rate year, which is the first twelve months after new rates are set as a result of this proceeding. Adoption of these adjustments by the Board will provide the Company with a realistic opportunity to earn a reasonable return on its electric and gas investment when the rates are in effect.

The Company's revenue requirements determination includes 22 adjustments to its test period electric distribution operating income. The *pro forma* adjustments reduce the test period electric operating income by \$145.3 million after-tax. On the gas distribution side there are 20 adjustments that reduce the test period operating income by \$90.8 million. There are 25 *pro forma* adjustments in total (17 combined electric and gas adjustments, 5 electric only and 3 gas only). Each of the *pro forma* adjustments will be discussed in more detail below.

Adjustment No. 1: Wages—Schedule MPM-30 R-1

Q. Please address your adjustments for Wages.

A. These adjustments to operating income of a reduction of \$7.7 million and \$7.2 million for electric and gas, respectively, represent the adjustment to the test year to reflect wage increases applicable to the rate year. These increases are to the labor costs applicable to Bargaining Unit employees; Management, Administrative, Secretarial, and Technical ("MAST") employees; and Service Company employees charged to PSE&G. The increases are based on labor charges to electric distribution and gas distribution during the test year.

The Company recently negotiated Bargaining Union increases for the twelve-month period ending May 31, 2024 as well as the Rate Year ending August 31, 2025. These contracts contain agreed-upon annual wage increases of 3.0% each year. The wage increases are effective on May 1, 2024 and May 1, 2025. For MAST employees, average wage increases of 3.5% were implemented in March of 2023 and 4.0% in March of 2024 as projected in the original filing. While no final decisions have been reached as to future years, best current projections are an increase of 4.0% in March of 2025.

The Board should continue its consistent practice of recognizing the importance of test year labor adjustments. The Company's employees are a critical element in meeting the service and reliability needs of our customers, and this adjustment to the test year ensures the Company's rates will reasonably reflect the cost of this workforce when rates are in effect.

Adjustment No. 2: Payroll Taxes—Schedule MPM-31 R-1

Q. Explain the adjustment for Payroll Taxes.

A. The reductions to operating income of $0.5 million and $0.5 million for electric and gas, respectively, result from the increase to operating expense associated with payroll taxes consistent with the wage adjustments made above. This adjustment reflects increases in the Federal Insurance Contribution Act Tax ("FICA") for increases in taxable wages and taxable wage ceiling levels. Based on the Company's historic average, additional payroll taxes for the wage adjustment in Schedule MPM-30 R-1 are calculated utilizing a composite 6.88% tax rate.

Adjustment No. 3: Interest Synchronization (Tax Savings) Schedule—MPM-32 R-1

Q. Please describe the Interest Synchronization Adjustment.

A. The Board, in the past, has adopted an adjustment to synchronize the Federal income tax savings associated with interest in the test year with the tax savings based on interest calculated using the weighted cost of debt in the capital structure utilized to support rate base.

As can be seen on Schedule MPM-32 R-1, the interest-bearing components of PSE&G's capitalization supporting rate base produce synchronized interest expenses of $1.6 million more than the interest expense in the test year for electric and $6.6 million more than interest expense in the test year for gas, resulting in tax savings of $0.5 million for electric and tax savings of $1.9 million for gas.

Adjustment No. 4: Pension and Fringe Benefits—Schedule MPM-33 R-1

Q. Please describe the adjustment for Pension and Fringe Benefits.

A. The adjustments to test year operating income for pension costs and fringe benefits amount to a decrease of $11.7 million for electric and $7.1 million for gas, reflecting the expected change in these costs over the test period amounts. The adjustment encompasses expenses associated with pensions, OPEB, medical, dental, thrift, long-term disability, insurance, and workers compensation for employees providing support services to PSE&G.

As noted earlier, PSE&G has pension income that is increasing operating revenues and decreasing the revenue increase requested in this case, despite PSE&G not having access to the pension income. The pension and OPEB *pro forma* adjustments reflect the expected income for 2024, which will be known and measurable before the end of the test year. While the 2024 pension income is expected to be less than in the test year, pension and OPEB are still projected to be income, reducing the revenue requirement paid by customers.

While the Company has also previously described the numerous steps PSE&G has taken to reduce fringe benefit costs, these costs have continually increased, in particular medical costs. Other fringe benefit costs are escalated based primarily on contract renewals, including those for benefit administration costs, compliance, and consulting work.

The Board should continue to recognize that the Company's employees are critical to meeting the service and reliability needs of our customers. The ability to offer a package of wages and benefits will allow the Company to attract and retain the skilled employees that are needed. The revenue to cover those costs must be provided.

Adjustment No. 5: Electric / Gas Company Owned Life Insurance ("COLI") Interest Expense—Schedule MPM-34 R-1

Q. Please describe the adjustment required to reflect Company Owned Life Insurance.

A. In an effort to reduce a portion of the expenses associated with certain employee benefit plans, PSE&G has invested in COLI policies. COLI is a corporate owned investment in cash value life insurance, which provides an income stream to the Company.

A portion of the Company's workforce is covered by policies with the Company as owner and beneficiary. The cash value of the insurance contracts earns a return, which the Company utilizes to offset benefit expenses. The Company, as owner, is permitted to borrow against the policy during its life without interfering with the policy's accumulation of earnings. The policy provides life insurance proceeds upon the death of the insured sufficient to settle any outstanding loans.

The earnings associated with the growth in the policy's cash surrender value have produced a net credit to benefits expense. For the test year, the credit to Administrative and General Expense combined with tax savings is $3.9 million for electric distribution and $1.1 million for gas distribution. Interest expense on funds borrowed from the policies is directly related to the $2.4 million for electric distribution and $0.8 million for gas distribution in benefits attributable to the policies. My adjustment to the test year, which is in line with prior rate cases, is to include the gross interest cost of $2.4 million for electric and $0.8 million for gas, thereby reducing operating income to properly account for all aspects, both benefits and costs, of the COLI.

Adjustment No. 6: Weather Normalization —Schedule MPM-35 R-1

Q. Is an adjustment necessary to reflect the results of Weather Normalization?

A. Yes. This pro-forma adjustment is required to adjust test year actual results to reflect normal weather based on weather patterns over a 20-year period as measured at Newark Liberty International Airport. Because actual weather patterns during the time the rates will be in effect are assumed to be normal, this adjustment to the test year is an appropriate rate setting procedure. The use of unadjusted weather-related actual sales levels would result in overstating or understating the revenue requirement compared to normal. Schedule MPM-35 R-1 shows the adjustments necessary to reflect normal weather for the period June 2023 through May 2024. This schedule shows a comparison of the distribution revenue for the nine months of actual results and three months of forecast revenues that are based upon normal weather to twelve months of normal weather. Distribution revenue represents the base rate revenue from the sale of a kWh, kW, or therm, excluding clauses and supply. In order to adjust the actual results to a normal sales level, an increase to test period revenue of $3.4 million for electric is required since the first nine months of the test year, June 2023 to February 2024, were warmer than normal. This is the same weather impact included in the billing determinants data in the testimony of Mr. Swetz. An increase to test period revenue of $57.6 million for gas, is required since the first nine months of the test year, June 2023 to February 2024, were warmer than normal.

Adjustment No. 7: Gains/Losses on Sales of Property—Schedule MPM-36 R-1

Q. Please describe the adjustment to reflect Gains/Losses on Sales of Property.

A. This adjustment allocates one-half of the gain on sales of property, net of associated income taxes, to customers based on a five-year average. The use of a five-year average provides a representative amount of gains for ratemaking purposes, avoiding the distortion that would occur if an abnormally high or low level of gains is recognized in the test period. The Company has included the five-year average ending February 2024 as representative and appropriate for this proceeding. The adjustment to operating income for the customers' share of the five-year average gain is an increase of $44,000 for electric and $207,000 for gas.

Adjustment No. 8: Real Estate Taxes—Schedule MPM-37 R-1

Q. Is the Company presenting an adjustment for Real Estate Taxes?

A. Yes. This adjustment of $0.7 million decrease for electric and $0.2 million decrease for gas adjusts the test year operating expense to be representative of the level of property tax expense that is expected to be accrued in the twelve-month period following the date new base rates go into effect. The increase in property tax expense between the rate year and the test year is consistent with actual experience. Accordingly, electric and gas operating income is reduced by the aforementioned amounts.

Adjustment No. 9: Insurance Premiums—Schedule MPM-38 R-1

Q. Please describe the adjustment necessary to reflect the Company's Insurance Expense.

A. There are items for which PSE&G carries outside insurance policies (*i.e.*, Corporate Property, Excess Liability Insurance, and Director's & Officers Insurance) for which it pays premiums of approximately $6.9 million for electric and $4.0 million for gas for the year. This adjustment before taxes of $669,000 for electric and $330,000 for gas increases the test year operating expense by $481,000 and $238,000 and is representative of the level of insurance expense that is expected to be accrued in the rate year. The increase in insurance expense between the rate year and the test year reflects input from our insurance carriers and actual experience.

Adjustment No. 10: ASB Margin—Schedule MPM-39 R-1

Q. Please describe the ASB margin adjustments that are necessary to reflect the proposed treatment of PSE&G's appliance service business.

A. For the reasons described in Section VI above, the Company is proposing that Gas ASB margins be accounted for as 50% above the line, in the same manner as is done for Electric ASB Margin. After adjusting for tax effect this results in a decrease to operating income of $15.3 million for gas.

Adjustment No. 11: TSG-NF Margin—Schedule MPM-40 R-1

Q. Please describe the adjustment for the TSG-NF Margin.

A. A reduction to gas operating income in the amount of $0.8 million is being made. This adjustment is discussed in the testimony of Mr. Swetz.

Adjustment No. 12: Depreciation Annualization and Proposed Rate Change — Schedule MPM-41 R-1

Q. Is the Company proposing adjustments related to Depreciation Annualization and to reflect a proposed change in depreciation rates?

A. Yes. This adjustment is to allow for the recovery of the depreciation expense associated with the total investment in Plant in Service in rate base approved in this proceeding. As described above, the Company is requesting rate base as of November 30, 2024. Essentially, the depreciation expense in the test year represents the depreciation expense on the average plant in service in the test year. The actual depreciation expense as a result of this rate case proceeding will be a full year's depreciation expense on the approved plant in service as of

November 30, 2024. To arrive at the appropriate depreciation expense for the approved plant in-service, the depreciation expense in the last month used to determine rate base for this proceeding (November 30, 2024) is annualized by multiplying the balance by twelve. The difference between the annualized depreciation expense and the Test Year depreciation expense produces the pre-tax adjustment. It should be noted that the proposed annualization of depreciation expense is also incorporated in Accumulated Depreciation (Schedule MPM-09 R-1) as a rate base deduction using a mid-year convention. Therefore, this adjustment is simply to sync depreciation expense with the approved rate base balance. Accordingly, test year expense is increased $7.0 million for electric and $29.5 million for gas.

In addition, the Company has proposed new electric and gas distribution depreciation rates, including cost of removal, based on an Electric Depreciation Study and a Gas Depreciation Study, supported by the testimony of Mr. Spanos.

The proposed depreciation rates have also been annualized for estimated electric and gas plant balances for the month prior to the rate year. The difference between the annualized rate year expense based on the proposed rates versus the annualized expense based on current rates is an additional pre-tax adjustment, which increases depreciation expenses by $62.9 million for electric and by $74.3 million for gas. As a result, the total annualization of depreciation expense at the proposed depreciation rates results in a reduction to operating income of $50.2 million for electric and $74.6 million for gas.

Adjustment No. 13: Test Year Amortization Adjustments - Schedule MPM-42 R-1

Q. Please describe the adjustment of Test Year Amortizations.

A. This schedule is to adjust operating income for amortizations that are ending during the test year. In the 2018 base rate case, the Signatory Parties agreed to an amortization of $65.605

million over a five-year period addressing all of the deferral recovery requests in that proceeding.[35] The 2018 base rate case was approved as effective November 1, 2018, so the five year amortization ended on October 31, 2023. This adjustment is to remove the amortization expense from the start of the test year through October 31, 2023 so that the test year operating income does not reflect any of this expense that will not occur going forward. In addition, test year operating income reflects amortization expense on IT capital. However, recovery of IT capital associated with the CEF-EE Program and Community Solar Program are recovered separately through the Green Program Recovery Charge. As a result, the IT amortization for these programs must be excluded from base rate recovery. The adjustment represents an increase in operating income of $17.3 million for electric and $5.9 million for gas.

Adjustment No. 14: Rate Case & Management Audit Expenses– Schedule MPM-43 R-1

Q. How does the Company propose to treat rate case expense?

A. This adjustment seeks recovery of all prudently incurred rate case and management audit expenses. As the Company was required to submit this rate case as a result of the GSMP II Order, among other Orders, it is appropriate for the Board to allow for recovery of the expenses required to complete the filing. The Company is seeking to remove all rate case expenses incurred during the test year and recover those expenses as a regulatory asset over a three-year period. In addition, regulated utilities are subject to Management and Affiliate Transaction audits and an audit of PSE&G commenced in 2021. The BPU awarded the audit contract to Overland Consulting for $1.6 million. The Company deferred the $1.6 million cost of the audit paid to Overland and is seeking recovery of the regulatory asset in this proceeding,

[35] 2018 Rate Case Order at Stipulation ¶ 6.

also over a three-year period. The total adjustment for both rate case expenses and the recovery of the management audit costs represents a decrease in operating income of $166,000 for electric and $141,000 for gas.

Adjustment No. 15: ES II / IAP Revenue Adjustment – Schedule MPM-44 R-1

Q. Please discuss the adjustment the Company proposes for ES II and IAP rate adjustments during and after the test year.

A. The Company proposes an adjustment to increase test year Operating Income so it reflects the full annual impact of the ES II and IAP rate adjustments rolled into rates during the test year.

Q. Why is this adjustment necessary?

A. When the ES II and IAP rate adjustments occur, base rates will be increased to collect the annual revenue requirement of the rate adjustment. The revenue increase will be added to current rates at the time this proceeding is concluded, which will include the annualized impact of the ES II and IAP adjustments in the test year. The revenue increase from the rate case will be based on the operating income during the test year. For the ES II and IAP rate adjustments that occur during the test year, base rates will be increased for the annual revenue requirement, but only a portion of the revenues from that rate increase will be captured in the test year operating revenue as these rate adjustments become effective. This adjustment is necessary to adjust test year operating revenue to coincide with base rates at the conclusion of the rate case.

Q. What are the ES II and IAP rate adjustments that have occurred and will occur during this proceeding?

A. In accordance with the ES II Order, rates changed November 1, 2023 as a result of the fourth rate adjustment filing (Rate Adjustment #4) based on investments through July 31, 2023.[36] The fifth rate adjustment filing (Rate Adjustment #5), was submitted on November 1, 2023 based on anticipated investment through December 31, 2023 for rates effective May 1, 2024.[37] Rate Adjustment #5 will be updated with actual investment through December 31, 2023 by February 21, 2024.

The first IAP rate adjustment was submitted on November 1, 2023 for rates effective May 1, 2024 based on plant in service through January 31, 2024.[38] The first Rate Adjustment will be updated with actual investment through January 31, 2024 by February 21, 2024.

Q. How was the adjustment calculated?

A. The goal of the adjustment is to ensure that test year Operating Income reflects the current rates in effect before the proposed rates from this proceeding are implemented. For the base rate changes implemented during the test year, this adjustment multiplies the rates for the adjustment by the billing determinants for the test year prior to the implementation date. Using IAP as an example, the adjustment would apply the increase in base rates from the IAP change effective May 1, 2024 to the actual weather normalized billing determinants from June 1, 2023 through April 30, 2024. An adjustment is not needed from May 1, 2024 forward as the revenue will already be included in the test year operating revenue as a result of the IAP rate adjustment.

[36] *I/M/O the Petition of Public Service Electric and Gas Company for Approval of Electric Rate Adjustments Pursuant to the Energy Strong II Program*, BPU Docket No. ER23050273, Decision and Order Approving Stipulation (October 25, 2023).
[37] *I/M/O the Petition of Public Service Electric and Gas Company for Approval of Electric Rate Adjustments Pursuant to the Energy Strong II Program*, BPU Docket No. ER23110784 (filed November 1, 2023).
[38] *I/M/O the Petition of Public Service Electric and Gas Company for Approval of Electric Rate Adjustments Pursuant to the Infrastructure Advancement Program*, BPU Docket No. ER23110783 (filed November 1, 2023).

Q. Is an adjustment required for the rate adjustments prior to the start of the test year?

A. No. For all adjustments prior to the start of the test year, the full annual revenue associated with the adjustments will be reflected in the operating income in the test year.

Q. What is the impact of this adjustment?

A. As a result of the proposed adjustment, operating income will increase by $19.9 million for electric and $0.0 million for Gas.

Adjustment No. 16: BGS Administration Labor Costs to the BGS Charge Reconciliation Charge – Schedule MPM-45 R-1

Q. Why is the Company proposing an adjustment to O&M Expense related to labor costs for Basic Generation Service ("BGS") administration?

A. This adjustment is being made to remove labor costs associated with the administration of BGS from the Company's operations and maintenance expense as it will be recovered within the Company's reconciliation charge upon the conclusion of this proceeding. The adjustment also includes labor costs associated with the administration of BGS which have historically been charged to transmission, but will be recovered within the Company's distribution operations and maintenance expense upon the conclusion of this proceeding.

Q. Why is this adjustment necessary?

A. On July 15, 2020, the BPU issued an Order of Implementation, effective July 25, 2020, requiring Electric Distribution Companies ("EDCs") to file a plan for implementation of the fourteen (14) accepted recommendations from the Final Report filed by Liberty Consulting

Group, Inc.[39]. One of the accepted recommendations was to track direct administrative costs that are common across all EDCs and related to the provision of BGS, and recover those costs through their BGS Reconciliation charge(s) following their respective next base rate cases. As this is PSE&G's first base rate case since that Board Order, this adjustment is being made to remove these BGS related administrative expenses from the test year so that they can be recovered through the BGS reconciliation charge. Additionally, on November 18, 2020, the Board issued an order in BPU Docket No. ER20030190 removing the costs associated with transmission from the BGS Auction process. As this is PSE&G's first base rate case since that Board Order, this adjustment is being made to remove these BGS related administrative expenses from the Company's transmission rates for inclusion in the test year so that they can be recovered through the Company's distribution rates. The Company began recording these costs to its distribution operations and maintenance expense prospectively effective January 1, 2024 and as a result, this adjustment includes the costs recorded to transmission from June 1, 2023 through December 31, 2023.

Q. What is the impact of this adjustment?

A. As a result of the proposed adjustment, operating income will decrease by $671,000 for electric.

Adjustment No. 17: Gas Bad Debt in SBC – Schedule MPM-46 R-1

Q. Please discuss the adjustment the Company is proposing for gas bad debt.

A. As discussed in Section VIII above, the Company proposes to move base rate recovery for gas bad debt expenses from base rates to a new Social Programs component of the Gas

[39] *I/M/O the Request for Proposal for a Financial Audit of the New Jersey Electric Distribution Companies' Basic Generation Administrative Expense and Other Related Expenses*, Docket No. EA17010004, Order of Implementation (July 15, 2020).

SBC, the same recovery mechanism utilized for recovery of Electric bad debt expenses. As a result of the proposed adjustment, operating income will increase by $25.8 million for gas. This adjustment will be offset by the proposed gas bad debt SBC component discussed in further detail in the testimony of Mr. Swetz.

Adjustment No. 18: Clean Energy Future-Energy Cloud Amortization – Schedule MPM-47 R-1

Q. What is the CEF-EC regulatory asset?

A. As discussed above in Schedule MPM-16 R-1, the Company was authorized to record a regulatory asset comprised of its capital investment (CEF-EC Investment Deferral) and associated stranded costs (Stranded Cost Deferral).[40] In addition, as stated in paragraph 27 of the CEF-EC stipulation, "The Parties agree that the Company will defer incremental AMI-related O&M costs associated with the CEF-EC implementation into a separate regulatory asset ("CEF-EC O&M Regulatory Asset"), without a return, for recovery in the Company's Next Base Rate Case."[41]

Q. Is there any adjustment to the CEF-EC regulatory asset balances the Company wants to discuss?

A. Yes. Meter testing costs originally classified as part of the $707 million of estimated CEF-EC Program investment were determined not to qualify for capitalization and were recorded as an expense. The Company excluded the meter testing expenditures from the CEF-EC Program investment, so the Company is not earning a return on this investment, but the

[40] CEF-EC Order at Stipulation ¶ 22.
[41] *Id.* ¶ 27.

Company is seeking recovery of these prudently incurred expenditures that were always a component of the CEF-EC Program.

Q. How is the Company seeking to recover the CEF-EC regulatory assets?

A. For the CEF-EC Investment Deferral, the Company proposes to recover the regulatory asset over the life of the meter, which for AMI was set at 20 years in the CEF-EC Order.[42] For non-AMI meters, the depreciation rate (inclusive of cost of removal) is approximately 10%, so the Company proposes a 10 year recovery period for the Stranded Cost Deferral.[43] The Company will include the unamortized balance as a component of the Company's rate base in any future subsequent base rate case in accordance with the CEF-EC Order that allowed for a return of and on the regulatory asset.[44] The Company proposes to recover the Meter Testing expenses and CEF-EC O&M Regulatory Asset over a five-year period, the same period proposed for other deferrals in this proceeding and the approved amortization period for the 2018 base rate case amortization.

Q. What is the impact of this adjustment?

A. As a result of the proposed adjustment, operating income will decrease by $20.9 million for electric.

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[42] CEF-EC Order ¶ 23(c).

[43] See 2018 Rate Case Order at Stipulation Attachment B at 1 (showing total depreciation rate of 9.89 for electric account 370.00 ("Meters")).

[44] *Id.* ¶ 26.

Adjustment No. 19: Clean Energy Future-Energy Cloud Revenue Reduction – Schedule MPM-48 R-1

Q. Is there an additional *pro forma* adjustment associated with the CEF-EC Program?

A. Yes. The implementation of AMI is forecasted to result in operational efficiencies and reductions in O&M. Some savings are reflected in the test year. See testimony of Mr. Johnson. However, the majority of these savings will occur after the AMI implementation is complete, which is not expected until after the end of the test year in this proceeding. In accordance with the CEF-EC Order, the Company is proposing an adjustment to its revenue request in this proceeding only to account for future O&M savings as a result of AMI that are not reflected in the test year.[45] This adjustment will not be implemented in a subsequent base rate case in which the actual O&M savings from the AMI implementation will be reflected in the test year.

Q. What is the impact of this adjustment?

A. As a result of the proposed adjustment, operating income (after taxes) will increase by $5.2 million for electric.

Adjustment No. 20: Clean Energy Future – Electric Vehicle Amortization – Schedule MPM-49 R-1

Q. What is the CEF-EV regulatory asset?

A. As discussed above in Schedule MPM-17 R-1, the Company was authorized to record a regulatory asset on its CEF-EV investment ("CEF-EV Regulatory Asset"). In addition, as stated in paragraph 29 of the CEF-EV Stipulation, "The Company will defer incremental CEF-

[45] CEF-EC Order ¶ 19.

EV-related O&M costs as described above in paragraph 15 ("CEF-EV O&M Regulatory Asset"), with a monthly carrying charge at the prior month 2-year treasury rate plus 60 basis points, for recovery in the Company's Next Base Rate Case."[46]

Q. How is the Company seeking to recover the CEF-EV Regulatory Asset?

A. For the CEF-EV Regulatory Asset, the Company proposes to recover the non-IT related expenditures over a 30-year life, the approved life in the deferral mechanism for Make-Ready – Service Upgrade Pole to Meter investment and the approximate weighted average life of the non-IT related investments. For the regulatory asset associated with the IT expenditures and the CEF-EV O&M Regulatory Asset, the Company proposes a five-year life, the same period proposed for other deferrals in this proceeding and the approved amortization period for the 2018 base rate case amortization.

Q. What is the impact of this adjustment?

A. As a result of the proposed adjustment, operating income will decrease by $3.9 million for electric.

Adjustment No. 21: Conservation Incentive Program Accrual Adjustment – Schedule MPM-50 R-1

Q. Please discuss the adjustment the Company proposes for the Conservation Incentive Program Accrual Adjustment.

A. The Company proposes an adjustment to test year Operating Income so that it removes the impact of the CIP accrual recorded during the test year.

[46] CEF-EV Order at Stipulation ¶ 29.

Q. Why is this adjustment necessary?

A. As discussed above, the CIP mechanism trues up actual revenues to the BUC and BRC set in the prior base rate case. The accrual from that difference between the actual BUC and BRC and the baseline BUC and BRC is recorded to income and is included as part of test year operating revenue. As a result, the test year revenues are not reflective of the actual test year billing determinants that will set the revised BUC and BRC. Therefore, the impact of the CIP accrual, positive or negative, must be eliminated from the income statement to reflect the test year revenues at the actual billing determinants that will set the revised BUC and BRC.

Q. What is the impact of this adjustment?

A. As a result of the proposed adjustment, operating income will decrease by $67.6 million for electric and $49.3 million for gas.

Adjustment No. 22: TAC Return Reset – Schedule MPM-51 R-1

Q. Please describe the need for the TAC Return adjustment being proposed.

A. Pursuant to the Order in PSE&G's last base rate case, PSE&G and the parties to that Order agreed that the return on the increase in rate base related excess deferred income taxes, including the ADIT associated with the Historic SHARE, will be reset at the conclusion of subsequent rate cases.[47] In accordance with that agreement, the Company will be resetting the return on the unamortized balances. The ADIT in the rate case will reflect all of the tax flowbacks that PSE&G has previously refunded to customers, resulting in increased rate base and return on rate base. Accordingly, the Company's operating revenue will reflect the earnings realized through the TAC flowbacks. The proposed adjustment will have a neutral

[47] 2018 Rate Case Order ¶ 20.

effect as the adjustment will allow PSE&G to reduce the earnings in the TAC and move them to base rates through this proceeding.

Q. What is the impact of this adjustment?

A. As a result of the proposed adjustment, operating income will decrease by $19.3 million for electric and $22.6 million for gas. However, this impact will be offset in the TAC.

Adjustment No. 23: Deferred Compensation & Severance Expense Adjustment – Schedule MPM-52 R-1

Q. Please discuss the adjustment the Company is proposing for Deferred Compensation & Severance Expense.

A. This adjustment is to increase operating income for the impact of deferred compensation and severance payments incurred during the test year. As noted in Section IV above, the Company initiated a Voluntary Exit Incentive Program for non-represented employees that will result in the voluntary retirement of 185 utility and service company employees by December 31, 2023. The Company offered two weeks of severance pay to eligible non-represented employees for every year of service up to a maximum of 52 weeks. In addition, there are non-recurring deferred compensation costs outside of the VIEP. This *pro forma* is to remove the severance and deferred compensation expense and any associated tax savings so that there is no impact to customers from the severance and deferred compensation payments.

Q. What is the impact of this adjustment?

A. As a result of the proposed adjustment, operating income will increase by $0.8 million for electric and $0.4 million for gas.

Adjustment No. 24: Tax Impact of Bad Debt – Schedule MPM-53 R-1

Q. Please discuss the adjustment the Company is proposing for the tax impact of bad debt.

A. This schedule is to adjust tax expense to remove the impact of the pandemic and the moratorium on bad debt expense. The tax impact on bad debt is calculated as the bad debt expense less write-offs, multiplied by the federal tax rate. In general, the bad debt expense and write-offs move in sync (such that the reserve will increase as write-offs increase and vice versa), resulting in a minimal impact to tax expense. However, this trend reversed during the pandemic when the reserve increased significantly, while write-offs declined, resulting in a tax expense increase. While the Company deferred its increase in the bad debt reserve during the moratorium for recovery in the COVID-19 proceeding, it did not defer the significant negative tax impact. The impact will reverse over time as the write-offs and bad debt reserve get back in sync. However, the test year does reflect a tax benefit from bad debt as the write-offs are forecasted to exceed the bad debt expense. This adjustment will ensure the tax impact of bad debt as a result of the moratorium is excluded from customer rates (since the negative impact during the moratorium was absorbed by the Company and excluded from the COVID-19 deferral request, and thus the offsetting positive benefit must be excluded from the test year.

Q. What is the impact of this adjustment?

A. As a result of the proposed adjustment, operating income will decrease by $5.6 million for electric and $3.0 million for gas.

Adjustment No. 25: BPU and Rate Counsel Assessments – Schedule MPM-56 R-1

Q. Please discuss the adjustment the Company is proposing for the BPU and Rate Counsel Assessments.

A. Each year, the Company receives assessment invoices from the Board and Rate Counsel. These assessments state that they are predicated on rates established by the State of New Jersey and are applied to each revenue dollar reported on the Company's Annual Report filed the previous year. The 2024 assessment invoices were received in early 2024 and included assessment rates of 0.00217589228476 for the Board and 0.0004554 for Rate Counsel. The invoices applied those rates to the 2022 revenues reported in the Company's Annual Report filed in 2023. The cumulative Board and Rate Counsel assessments for 2024 are $13.7 million and $6.4 million for electric and gas, respectively. The test year is estimated to reflect $13.2 million and $5.4 million for electric and gas, respectively. As a result, annualizing the known 2024 BPU and Rate Counsel assessment results in a reduction to test year operating income of $0.4 million and $0.7 million for electric and gas, respectively.

Q. Does this conclude your direct testimony?

A. Yes, it does.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

DETERMINATION OF REVENUE REQUIREMENTS
($000)

	ELECTRIC	GAS	TOTAL
Rate Base	$ 9,447,599	$ 8,726,426	$ 18,174,024
Rate of Return	7.55%	7.55%	7.55%
Operating Income Requirement	$ 713,294	$ 658,845	$ 1,372,139
Pro-Forma Operating Income	$ 329,653	$ 371,060	$ 700,713
Operating Income Deficiency	$ 383,641	$ 287,785	$ 671,426
Revenue Factor	1.3947	1.3947	
Revenue Requirements	**$ 535,064**	**$ 401,374**	**$ 936,438**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

ELECTRIC RATE BASE
($000)

	Balance at May 31, 2024	Balance at November 30, 2024
Plant In Service	12,774,715	13,129,898
Plant Held for Future Use	489	489
Accumulated Depreciation Reserve	(3,185,722)	(3,284,367)
Customer Advances	(63,907)	(63,907)
Net Plant	9,525,575	9,782,113
Working Capital:		
Cash (Lead/Lag)	884,882	884,882
Materials and Supplies	297,953	297,953
Prepayments	500	500
Net Working Capital	1,183,336	1,183,336
Deferred Taxes	(1,694,431)	(1,734,284)
Consolidated Tax Adjustment	(3,740)	(3,740)
IAP	(11,136)	(40,899)
CEF-EC	167,558	219,016
CEF-EV	30,277	42,056
Total Electric Rate Base	**9,197,438**	**9,447,599**

GAS RATE BASE
($000)

	Balance at May 31, 2024	Balance at November 30, 2024
Plant In Service	12,373,478	12,882,853
Plant Held for Future Use	96	96
Accumulated Depreciation Reserve	(2,718,778)	(2,833,188)
Customer Advances	(24,910)	(24,910)
Net Plant	9,629,886	10,024,852
Working Capital:		
Cash (Lead/Lag)	586,016	586,016
Materials and Supplies	116,688	116,688
Prepayments	116	116
Net Working Capital	702,820	702,820
Deferred Taxes	(1,706,913)	(1,731,586)
Consolidated Tax Adjustment	-	-
IAP	(82)	(414)
CEF-EC	-	-
CEF-EV	-	-
GSMP II EXT	(24,870)	(269,246)
Total Gas Rate Base	**8,600,841**	**8,726,426**

* 9 Months Actual - 3 Months Forecast

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

WEIGHTED AVERAGE COST OF CAPITAL
($Millions)

	Amount	Percent	Embedded Cost	Weighted Cost
Long-Term Debt	$ 13,664	44.29%	4.00% *	1.77%
Customer Deposits	66	0.21%	5.06%	0.01%
Common Equity	17,125	55.50%	10.40%	5.77%
Total	$ 30,856	100.00%		7.55%

* this is a forecasted rate as of May 31, 2024 due to the current interest rate environment, but will be replaced with the actual May 31, 2024 rate in the 12+0 update.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

EMBEDDED COST OF LONG TERM DEBT
2/29/2024
INCLUDING NET UNAMORTIZED PREMIUM - INCLUDING AMOUNT DUE WITHIN ONE YEAR

PSE&G LONG TERM DEBT	COST OF BOND YIELD BASIS	PRINCIPAL AMOUNT OUTSTANDING	PLUS NET UNAMORTIZED PREMIUM/ (DISCOUNT)	PLUS NET UNAMORTIZED SELLING EXPENSE	PLUS NET UNAMORTIZED PREMIUM/ (DISCOUNT) & SELLING EXPENSE	PRINCIPAL AMOUNT AND UNAMORTIZED PREMIUM/ (DISCOUNT) & SELLING EXPENSE- NET	WEIGHT IN % OF PRINCIPAL AMOUNT AND UNAMORTIZED PREMIUM/ (DISCOUNT) & SELLING EXPENSE- NET	COST IN PERCENT
SERIES DUE 6/1/37	8.053%	$7,462,900.00	$0.00	$0.00	$0.00	$7,462,900.00	0.0546%	0.0044%
SERIES DUE 7/1/37	5.033%	$7,537,800.00	$0.00	$0.00	$0.00	$7,537,800.00	0.0552%	0.0028%
SERIES D DUE 7/1/35	5.373%	$250,000,000.00	($297,500.00)	($810,615.92)	($1,108,115.92)	$248,891,884.08	1.8215%	0.0979%
SERIES D DUE 12/1/36	5.838%	$250,000,000.00	($451,209.52)	($925,832.68)	($1,377,042.20)	$248,622,957.80	1.8195%	0.1062%
SERIES E DUE 5/1/37	5.922%	$350,000,000.00	($299,902.28)	($1,307,267.64)	($1,607,169.92)	$348,392,830.08	2.5496%	0.1510%
SERIES G DUE 11/1/2039	5.501%	$250,000,000.00	($419,978.43)	($1,138,257.51)	($1,558,235.94)	$248,441,764.06	1.8182%	0.1000%
SERIES G DUE 3/1/2040	5.638%	$300,000,000.00	($766,896.32)	($1,376,893.22)	($2,143,789.54)	$297,856,210.46	2.1798%	0.1229%
SERIES H DUE 5/1/2042	4.076%	$450,000,000.00	($1,753,148.66)	($2,367,539.30)	($4,120,687.96)	$445,879,312.04	3.2631%	0.1330%
SERIES H DUE 9/1/2042	3.765%	$350,000,000.00	($1,051,985.14)	($1,964,709.49)	($3,016,694.63)	$346,983,305.37	2.5393%	0.0956%
SERIES H DUE 1/1/2043	3.924%	$400,000,000.00	($1,601,059.89)	($2,210,292.40)	($3,811,352.29)	$396,188,647.71	2.8994%	0.1138%
SERIES I DUE 3/15/2024	3.915%	$250,000,000.00	($83.24)	($6,925.04)	($7,008.28)	$249,992,991.72	1.8295%	0.0716%
SERIES I DUE 6/1/2044	4.147%	$250,000,000.00	($1,601,805.49)	($1,540,839.03)	($3,142,644.51)	$246,857,355.49	1.8066%	0.0749%
SERIES J DUE 8/15/2024	3.339%	$250,000,000.00	($20,493.52)	($87,340.54)	($107,834.06)	$249,892,165.94	1.8288%	0.0611%
SERIES J DUE 11/15/2024	3.275%	$250,000,000.00	($84,811.57)	($136,514.82)	($221,326.39)	$249,778,673.61	1.8279%	0.0599%
SERIES K DUE 5/15/2025	3.179%	$350,000,000.00	($43,523.65)	($71,219.05)	($114,742.70)	$349,885,257.30	2.5605%	0.0814%
SERIES K DUE 5/1/2045	4.172%	$250,000,000.00	($879,312.19)	($1,416,855.07)	($2,296,167.26)	$247,703,832.74	1.8128%	0.0756%
SERIES K DUE 11/1/2045	4.249%	$250,000,000.00	($184,268.75)	($1,456,008.09)	($1,640,276.84)	$248,359,723.16	1.8176%	0.0772%
SERIES K 3.80% DUE 2046	3.913%	$550,000,000.00	($1,791,297.40)	($3,555,807.40)	($5,347,104.80)	$544,652,895.20	3.9859%	0.1560%
SERIES L 2.25% DUE 2026	2.443%	$425,000,000.00	($355,191.53)	($782,858.83)	($1,138,050.36)	$423,861,949.64	3.1019%	0.0758%
SERIES L 3.00% DUE 2027	3.200%	$425,000,000.00	($398,410.84)	($1,029,424.10)	($1,427,834.94)	$423,572,165.06	3.0998%	0.0992%
SERIES L 3.60% DUE 2047	3.689%	$350,000,000.00	($202,364.59)	($2,451,597.13)	($2,653,961.72)	$347,346,038.28	2.5420%	0.0938%
SERIES M 3.70% DUE 2028	3.917%	$375,000,000.00	($594,410.40)	($1,174,066.44)	($1,768,476.84)	$373,231,523.16	2.7314%	0.1070%
SERIES M 4.05% DUE 2048	4.178%	$325,000,000.00	($1,621,177.16)	($2,358,609.31)	($3,979,786.47)	$321,020,213.53	2.3493%	0.0981%
SERIES M 3.65% DUE 2028	3.817%	$325,000,000.00	($23,445.43)	($1,050,499.02)	($1,073,944.45)	$323,926,055.55	2.3706%	0.0905%
SERIES M 3.20% DUE 2029	3.412%	$375,000,000.00	($761,783.19)	($1,452,895.27)	($2,214,678.46)	$372,785,321.54	2.7281%	0.0931%
SERIES M 3.85% DUE 2049	3.939%	$375,000,000.00	($53,513.75)	($2,819,633.78)	($2,873,147.53)	$372,126,852.47	2.7233%	0.1073%
SERIES M 3.20% DUE 2049	3.320%	$400,000,000.00	($2,459,449.37)	($3,006,464.73)	($5,465,914.10)	$394,534,085.90	2.8873%	0.0959%
SERIES N 2.45% DUE 2030	2.638%	$300,000,000.00	($404,509.28)	($1,333,707.64)	($1,738,216.92)	$298,261,783.08	2.1828%	0.0576%
SERIES N 3.15% DUE 2050	3.240%	$300,000,000.00	($398,128.47)	($2,348,267.02)	($2,746,395.49)	$297,253,604.51	2.1754%	0.0705%
SERIES N 2.70% DUE 2050	2.798%	$375,000,000.00	($1,335,365.35)	($2,979,634.74)	($4,315,000.09)	$370,684,999.91	2.7128%	0.0759%
SERIES N 2.05% DUE 2050	2.156%	$375,000,000.00	($2,639,586.64)	($2,913,786.33)	($5,553,372.97)	$369,446,627.03	2.7037%	0.0583%
SERIES N 0.95% DUE 2026	1.264%	$450,000,000.00	($401,247.91)	($1,188,301.38)	($1,589,549.29)	$448,410,450.71	3.2816%	0.0415%
SERIES N 3.00% DUE 2051	3.085%	$450,000,000.00	($397,010.29)	($3,652,223.52)	($4,049,233.81)	$445,950,766.19	3.2636%	0.1007%
SERIES N 1.90% DUE 2031	2.081%	$425,000,000.00	($774,001.09)	($2,317,836.99)	($3,091,838.08)	$421,908,161.92	3.0876%	0.0643%
SERIES P 3.10% DUE 2032	3.296%	$500,000,000.00	($754,816.87)	($3,283,976.87)	($4,038,793.74)	$495,961,206.26	3.6296%	0.1196%
SERIES P 4.90% DUE 2032	5.090%	$400,000,000.00	($227,688.91)	($2,684,671.06)	($2,912,359.97)	$397,087,640.03	2.9060%	0.1479%
SERIES P 4.650% DUE 2033	4.842%	$500,000,000.00	($421,714.05)	($3,450,935.88)	($3,872,649.92)	$496,127,350.08	3.6308%	0.1758%
SERIES P 5.125% DUE 2053	5.234%	$400,000,000.00	($228,693.42)	($3,583,169.50)	($3,811,862.91)	$396,188,137.09	2.8994%	0.1517%
SERIES P 5.200% DUE 2033	5.399%	$500,000,000.00	($613,105.17)	($3,490,077.65)	($4,103,182.82)	$495,896,817.18	3.6291%	0.1959%
SERIES P 5.450% DUE 2053	5.574%	$400,000,000.00	($973,251.79)	($3,513,890.35)	($4,487,142.14)	$395,512,857.86	2.8945%	0.1613%
TOTAL PSE&G LONG TERM DEBT		**$13,765,000,700.00**	**($27,286,141.55)**	**($73,239,444.73)**	**($100,525,586.28)**	**$13,664,475,113.72**	**100.0000%**	**3.8668%**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

REVENUE FACTOR

	ELECTRIC	GAS
Revenue Increase	100.0000	100.0000
Uncollectible Rate		0.0000
BPU Assessment Rate	0.217589	0.2176
Rate Counsel Assessment Rate	0.045540	0.0455
Income before State of NJ Bus. Tax	99.7369	99.7369
State of NJ Bus. Income Tax	8.9763	8.9763
Income Before Federal Income Taxes	90.7606	90.7606
Federal Income Taxes	19.0597	19.0597
Return	71.7008	71.7008
Revenue Factor	**1.3947**	**1.3947**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

ELECTRIC UTILITY PLANT IN-SERVICE
($000)

	Test Year May 31, 2024	Six-Months Ending November 30, 2024
Beginning Balance	$ 11,674,130	$ 12,774,715
Total Direct Additions	1,358,063	447,761
Total Transfers to Plant In-Service	(622)	0
Retirements:		
Distribution	(168,985)	(75,858)
General	(15,777)	(4,620)
Intangible	0	0
Common Plant	(72,094)	(12,100)
Total Retirements	(256,856)	(92,578)
Total Electric Utility Plant In-Service	**$ 12,774,715**	**$ 13,129,898**

GAS UTILITY PLANT IN-SERVICE
($000)

	Test Year May 31, 2024	Six-Months Ending November 30, 2024
Beginning Balance	$ 11,353,980	$ 12,373,478
Total Direct Additions	1,172,456	554,547
Total Transfers to Plant In-Service	(132)	0
Retirements:		
Production - Gas	0	0
Storage	0	0
Transmission	0	0
Distribution	(76,649)	(30,000)
General	(13,846)	(3,806)
Intangible	(3,345)	(1,466)
Common Plant	(58,986)	(9,900)
Total Retirements	(152,827)	(45,172)
Total Gas Utility Plant In-Service	**$ 12,373,478**	**$ 12,882,853**

* 9 Months Actual - 3 Months Forecast

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

ADDITIONS TO ELECTRIC PLANT IN-SERVICE
($000)

	Test Year May 31, 2024	Six-Months Ending November 30, 2024
Distribution	$ 1,139,311	$ 360,924
General	110,393	17,369
Intangible	85,404	40,388
Customer Operations	22,253	29,080
Land & Land Rights	703	-
Total Direct Additions	**$ 1,358,063**	**$ 447,761**

ADDITIONS TO GAS PLANT IN-SERVICE
($000)

	Test Year May 31, 2024	Six-Months Ending November 30, 2024
Production - Gas	$ 3,618	$ -
Storage	5,927	-
Transmission	2,186	939
Distribution	1,077,728	495,851
General	62,424	18,384
Intangibles	2,364	15,580
Customer Operations	18,207	23,793
Land & Land Rights	3	0
Total Direct Additions	**$ 1,172,456**	**$ 554,547**

* 9 Months Actual - 3 Months Forecast

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

ACCUMULATED DEPRECIATION OF ELECTRIC UTILITY PLANT
($000)

	Test Year May 31, 2024	Six-Months Ending November 30, 2024
Beginning Balance	$ 3,165,769	$ 3,185,722
Distribution	276,428	133,801
General	36,898	13,931
Customer Operations	25,860	11,895
Total Charge to Depreciation Expense	339,186	159,627
Amortization of Intangibles	7,595	8,198
Total Depreciation Expense	346,781	167,825
Retirements	(256,857)	(92,578)
Cost of Removal (Net)	(119,618)	(47,114)
Other	49,646	35,589
Net Increase	19,953	63,723
Annualization of Depreciation		34,922
Balance - Accumulated Depreciation	**$ 3,185,722**	**$ 3,284,367**

ACCUMULATED DEPRECIATION OF GAS UTILITY PLANT
($000)

	Test Year May 31, 2024	Six-Months Ending November 30, 2024
Beginning Balance	$ 2,669,747	$ 2,718,778
Production - Gas	2	1
Storage	286	316
Transmission	1,267	748
Distribution	203,787	108,451
General	18,864	9,622
Customer Operations	21,159	9,733
Total Charge to Depreciation Expense	245,365	128,871
Amortization of Intangibles	2,621	2,327
Total Depreciation Expense	247,986	131,198
Retirements	(152,827)	(45,172)
Cost of Removal (Net)	(46,225)	(27,302)
Other	97	3,784
Net Increase	49,031	62,509
Annualization of Depreciation		51,902
Balance - Accumulated Depreciation	$ 2,718,778	$ 2,833,188

* 9 Months Actual - 3 Months Forecast

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

CUSTOMER ADVANCES FOR CONSTRUCTION - ELECTRIC DISTRIBUTION *
($000)

Extension of Electric Lines	$	(63,907)
Total Electric Customer Advances for Construction	**$**	**(63,907)**

CUSTOMER ADVANCES FOR CONSTRUCTION - GAS DISTRIBUTION *
($000)

Extensions/Deposits	$	(24,910)
Total Gas Customer Advances for Construction	**$**	**(24,910)**

* 13-month Actual Average Balance (Feb. 2023 - Feb. 2024)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

WORKING CAPITAL - MATERIALS AND SUPPLIES
($000)

	Electric	Gas
Materials and Supplies *	$ 297,953	$ 116,688
Total Materials and Supplies	**$ 297,953**	**$ 116,688**

* Based on last month of actuals (Feb. 2024), and not on 13-month actual average balance

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

WORKING CAPITAL - PREPAYMENTS
($000)

	Electric	Gas
BPU & Rate Counsel Assessment	500	116
Total Prepayments	**$ 500**	**$ 116**

* 13-month Actual Average Balance (Feb. 2023 - Feb. 2024)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

ACCUMULATED DEFERRED TAXES
($000)

	Test Year May 31, 2024		Balance Ending November 30, 2024	
Electric	$	(1,694,431)	$	(1,734,284)
Gas	$	(1,706,913)	$	(1,731,586)

* 9 Months Actual - 3 Months Forecast

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

CONSOLIDATED TAX ADJUSTMENT

	Electric	Gas	Total
CTA Adjustment	(3,740)	-	$ (3,740)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

IAP RATE BASE ADJUSTMENT (ELECTRIC & GAS)
$000

	Test Year May 31, 2024	Six-Months Ending November 30, 2024
ELECTRIC		
Plant In-Service as of:	5/30/2024	11/30/2024
Rate Base as of:	5/30/2024	11/30/2024
Gross Plant	9,698	36,515
Cost of Removal Expenditures	3,069	6,704
Accumulated Depreciation	260	727
Accumulated Deferred Taxes	(1,891)	(3,047)
Total	11,136	40,899
Rate Base Reduction	**(11,136)**	**(40,899)**
GAS		
Plant In-Service as of:	5/30/2024	11/30/2024
Rate Base as of:	5/30/2024	11/30/2024
Gross Plant	-	-
Cost of Removal Expenditures	114	572
Accumulated Depreciation	-	-
Accumulated Deferred Taxes	(32)	(158)
Total	82	414
Rate Base Reduction	**(82)**	**(414)**

* 9 Months Actual - 3 Months Forecast

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

CEF-EC RATE BASE ADJUSTMENT (ELECTRIC ONLY)
$000

	Test Year May 31, 2024	Six-Months Ending November 30, 2024
ELECTRIC		
Plant In-Service as of:	5/30/2024	11/30/2024
Rate Base as of:	5/30/2024	11/30/2024
CEF-EC Investment Deferral:		
Deferred Depreciation	21,333	36,043
Deferred Interest	7,388	11,477
Carrying Charge Interest	838	1,517
Deferred Equity Return	29,502	45,825
Carrying Charge Return	2,405	4,354
Total	61,467	99,215
Stranded Cost Deferral:		
Accelerated Depreciation Expense	201,780	245,179
Depreciation Expense As Approved	(95,688)	(125,378)
Total	106,092	119,801
Rate Base Addition	**167,558**	**219,016**

* 9 Months Actual - 3 Months Forecast

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

CEF-EV RATE BASE ADJUSTMENT (ELECTRIC ONLY)
$000

	Test Year May 31, 2024	Six-Months Ending November 30, 2024
ELECTRIC		
Plant In-Service as of:	5/30/2024	11/30/2024
Rate Base as of:	5/30/2024	11/30/2024
Unamortized Investment	22,887	31,346
Depreciation & Amortization	3,507	4,753
Deferred Return	3,309	5,013
Carrying Charges	573	945
Total	30,277	42,056
Rate Base Addition	**30,277**	**42,056**

* 9 Months Actual - 3 Months Forecast

EXHIBIT P-2 R-1
SCHEDULE MPM-18 R-1

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

GSMPII EXT RATE BASE ADJUSTMENT (GAS ONLY)
$000

	Test Year May 31, 2024	Six-Months Ending November 30, 2024
GAS		
Plant In-Service as of:	5/30/2024	11/30/2024
Rate Base as of:	5/30/2024	11/30/2024
Gross Plant	23,986	258,558
Cost of Removal Expenditures	1,230	13,576
Accumulated Depreciation	38	913
Accumulated Deferred Taxes	(384)	(3,800)
Total	24,870	269,246
Rate Base Reduction	**(24,870)**	**(269,246)**

* 9 Months Actual - 3 Months Forecast

EXHIBIT P-2 R-1
SCHEDULE MPM-19 R-1

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

INCOME STATEMENT
($000)

ELECTRIC	**May 31, 2024**
Electric Operating Revenues	$ 3,758,875
Electric Operating Expenses:	
Operation Expense	$2,742,464
Maintenance Expense	$150,511
Depreciation Expense	$305,886
Amortization of Limited Term Plant	$23,297
Amortization of Property Losses	$19,042
Taxes Other Than Income Taxes	$26,070.867
Income Taxes	$16,630
Accretion Expense	$0
Total Electric Utility Operating Expenses	$3,283,900.989
Electric Utility Operating Income	$ 474,974

GAS	**May 31, 2024**
Gas Operating Revenues	$2,161,393
Gas Operating Expenses:	
Operation Expense	$1,408,940
Maintenance Expense	46,577
Depreciation Expense	229,126
Amortization of Limited Term Plant	13,928
Amortization of Regulatory Asset	20,788
Amortization of Property Losses	6,242
Amortization of Excess cost of removal	-
Taxes Other Than Income Taxes	18,289
Income Taxes	(44,333)
Total Gas Utility Operating Expenses	$1,699,557
Gas Utility Operating Income	$461,836
Net Utility Operating Income	$936,810

* 9 Months Actual - 3 Months Forecast

EXHIBIT P-2 R-1
SCHEDULE MPM-20 R-1

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

DISTRIBUTION SALES BY CLASS OF BUSINESS
(KWh/Therms - 000)

Line		May 31, 2024 Electric	Gas
1	Residential	13,307,293	1,435,489
2	Commercial	22,270,532	917,757
3	Industrial	3,556,006	86,157
4	Firm Transportation Service		23,363
5	Non-Firm Transportation Service		124,946
6	Cogeneration Interruptible		28,946
7	Cogeneration Contracts		0
8	Contract Service Gas		725,056
9	Street Lighting	332,238	695
10	Total Sales to Customers	39,466,069	3,342,410
11	Interdepartmental	7,434	603
12	Total Sales	39,473,502	3,343,014

* 9 Months Actual - 3 Months Forecast

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

REVENUE BY CLASS OF BUSINESS
($000)

Line		Electric	May 31, 2024 Gas	Total
1	Residential	$ 2,465,760	$ 1,503,265	$ 3,969,025
2	Commercial	1,926,450	588,873	2,515,323
3	Industrial	211,206	39,244	250,450
4	Firm Transportation Service		4,105	4,105
5	Non-Firm Transportation Service		23,068	23,068
6	Cogeneration Interruptible		12,006	12,006
7	Cogeneration Contracts		-	0
8	Contract Service Gas		8,542	8,542
9	Street Lighting	82,545	590	83,135
10	Total Revenue from Sales to Customers	$ 4,685,961	$ 2,179,693	$ 6,865,655
11	Interdepartmental	1,191	447	1,639
12	Total Revenue from Sales	$ 4,687,153	$ 2,180,141	$ 6,867,294

* 9 Months Actual - 3 Months Forecast

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

AVERAGE CUSTOMERS BILLED BY CLASS OF BUSINESS

Line		May 31, 2024 Electric	Gas
1	Residential	2,001,524	1,714,741
2	Commercial	302,495	154,005
3	Industrial	8,075	5,746
4	Firm Transportation Service		31
5	Non-Firm Transportation Service		138
6	Cogeneration Interruptible		9
7	Cogeneration Contracts		0
8	CSG		21
9	Street Lighting	11,064	16
10	Total Customers	2,323,159	1,874,707
11	Interdepartmental	1	1
12	Total Customers	2,323,160	1,874,708

* 9 Months Actual - 3 Months Forecast

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

EXPENSES
($000)

Electric

Production Expenses		May 31, 2024
Other Power Supply Expenses:		
Purchased Power	$	2,127,128
System Control/Load Dispatch	$	485
Total Other Power Supply Expenses	$	2,127,613
Distribution		
Operation	$	57,587
Maintenance		150,511
Total Distribution	$	208,098

Gas

Production Expenses		
Gas Supply		
Natural Gas City Gate Purchases	$	910,653
Fuel Gas - Raw Materials		68,898
Other Gas Purchases		(1,544)
Other Gas Supply Expenses		122
Total Gas Supply	$	978,129
Gas Production		
Operation	$	-
Maintenance		2,279
Total Gas Production	$	2,279
Other Power Generation		
Liquefied petroleum gas expenses		565
Total Other Power Generation	$	565
Other Storage		
Operation	$	870
Maintenance		3,551
Total Other Storage	$	4,421
Total Production Expenses	$	985,394
Transmission		
Operation	$	226
Maintenance		5,292
Total Transmission	$	5,518
Distribution		
Operation	$	107,004
Maintenance		35,455
Total Distribution	$	142,459

* 9 Months Actual - 3 Months Forecast

EXHIBIT P-2 R-1
SCHEDULE MPM-24 R-1

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

CUSTOMER ACCOUNTS AND INFORMATION
($000)

	May 31, 2024		
	Electric	**Gas**	**Total**
Customer Accounts Expenses			
Operation:			
Meter Reading Expenses	$ 16,205	$ 11,748	$ 27,953
Customer Records and Collection Expenses	$ 85,015	$ 65,848	$ 150,862
Uncollectible Accounts	$ 83,604	$ 35,846	$ 119,451
Misc. Customer Accounts Expenses	$ 106,598	$ 108	$ 106,706
Total Customer Accounts Expenses	$ 291,423	$ 113,549	$ 404,972
Cust. Service and Informational Expenses			
Operation:			
Supervision	$ -	$ -	$ -
Customer Assistance Expenses	$ 161,967	$ 112,156	$ 274,123
Misc. Cust. Service and Info. Expenses	$ 2,222	$ 3,601	$ 5,823
Total Cust. Service and Info. Expenses	$ 164,189	$ 115,757	$ 279,946
Sales Expenses			
Operation:			
Demonstration and Selling Expenses	$ 931	$ 768	$ 1,699
Misc. Sales Expenses	$ 59	$ 48	$ 108
Total Sales Expenses	$ 990	$ 816	$ 1,807
Total Customer Accounts and Information	$ 456,602	$ 230,122	$ 686,724

* 9 Months Actual - 3 Months Forecast

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

ADMINISTRATIVE AND GENERAL SALARIES AND EXPENSES
($000)

	May 31, 2024		
	Electric	Gas	Total
Salaries & Wages	$ 9,256	$ 9,364	$ 18,620
Supplies & Expenses	2,086	1,210	3,295
Outside Services	65,040	55,406	120,445
Property Insurance	1,748	310	2,057
Injuries and Damages	12,794	11,278	24,072
Pensions & Fringe Benefits	(11,306)	2,317	(8,990)
Regulatory Expenses	13,876	5,246	19,122
Duplicate Charge	(3,466)	(693)	(4,158)
General Advertising	2,208	1,778	3,986
Other Miscellaneous General	3,170	2,903	6,074
Rents	5,256	2,906	8,162
Maintenance	0	-	0
Total Administrative and General Salaries & Expenses	$ 100,662	$ 92,024	$ 192,686

* 9 Months Actual - 3 Months Forecast

EXHIBIT P-2 R-1
SCHEDULE MPM-26 R-1

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

DEPRECIATION AND AMORTIZATION
($000)

ELECTRIC

Line		May 31, 2024
	Depreciation	
1	Electric	$305,886
	Amortization	
2	Electric	$42,339
	Total Electric Depreciation and Amortization	**$348,225**

GAS

Line		May 31, 2024
	Depreciation	
1	Gas	$229,126
	Amortization	
2	Gas	$40,958
	Total Gas Depreciation and Amortization	**$270,084**

* 9 Months Actual - 3 Months Forecast

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

TAXES OTHER THAN INCOME TAXES
($000)

		May 31, 2024		
Line		**Electric**	**Gas**	**Total**
1	Real Estate	$ 13,470	$ 4,607	$ 18,077
2	FICA	339	368	707
3	State Unemployment	11,920	12,944	24,864
4	Federal Unemployment	70	76	146
5	Miscellaneous Municipal and State Taxes	272	294	565
6	Total	$ 26,071	$ 18,289	$ 44,360

* 9 Months Actual - 3 Months Forecast

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

CURRENT AND DEFERRED INCOME TAXES
($000)

	May 31, 2024		
	Electric	**Gas**	**Total**
Net Income Taxes	$ 16,630	$ (44,333)	$ (27,702)

* 9 Months Actual - 3 Months Forecast

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

PRO-FORMA DISTRIBUTION OPERATING INCOME
($000)

#		Schedule #	Electric	Gas	Total
Test Year Distribution Operating Income			**$ 474,974**	**$ 461,836**	**$ 936,810**
#	**Pro-Forma Adjustments:**	**Schedule #**			
1	Wages	MPM-30 R-1	$ (7,691)	$ (7,224)	$ (14,915)
2	Payroll Taxes	MPM-31 R-1	(542)	(509)	(1,051)
3	Interest Synchronization (Tax Savings)	MPM-32 R-1	460	1,865	2,324
4	Pension & Fringe Benefits	MPM-33 R-1	(11,746)	(7,091)	(18,837)
5	COLI Interest Expense	MPM-34 R-1	(2,434)	(816)	(3,250)
6	Weather Normalization	MPM-35 R-1	3,359	57,617	60,976
7	Gains/Losses on Sales of Property	MPM-36 R-1	44	207	252
8	Real Estate Taxes	MPM-37 R-1	(700)	(159)	(859)
9	Insurance	MPM-38 R-1	(481)	(238)	(719)
10	ASB Margin	MPM-39 R-1	-	(15,265)	(15,265)
11	TSGNF Margin Sharing	MPM-40 R-1	-	(764)	(764)
12	Depreciation Rate Change	MPM-41 R-1	(50,211)	(74,624)	(124,836)
13	Test Year Amortization Adjustments	MPM-42 R-1	17,276	5,933	23,209
14	Rate Case & Management Audit Expenses	MPM-43 R-1	(166)	(141)	(307)
15	Energy Strong II / IAP Revenue Adjustment	MPM-44 R-1	19,868	-	19,868
16	BGS Admin Charge To Recon	MPM-45 R-1	(671)	-	(671)
17	Gas Bad Debt Adjustment	MPM-46 R-1	-	25,770	25,770
18	CEF-EC Amortization	MPM-47 R-1	(20,894)	-	(20,894)
19	CEF-EC Revenue Reduction	MPM-48 R-1	5,165	-	5,165
20	CEF-EV Amortization	MPM-49 R-1	(3,943)	-	(3,943)
21	CIP Revenue Accrual Adjustment	MPM-50 R-1	(67,558)	(49,342)	(116,900)
22	TAC Revenue Accrual Adjustment	MPM-51 R-1	(19,250)	(22,628)	(41,877)
23	Deferred Compensation & Severance	MPM-52 R-1	785	361	1,146
24	Tax Impact of Bad Debt Adjustment	MPM-53 R-1	(5,611)	(2,990)	(8,601)
25	BPU/Rate Counsel Assessment	MPM-56 R-1	(378)	(738)	(1,116)
	Total Pro-Forma Adjustments		**$ (145,321)**	**$ (90,776)**	**$ (236,097)**
Total Pro-Forma Distribution Operating Income			**$ 329,653**	**$ 371,060**	**$ 700,713**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 1
Wages
($000)

	Electric	Gas	Total
Bargaining Unit Employees	$ 4,968	$ 4,908	$ 9,877
MAST Employees	3,200	3,162	6,362
Service Company Employees Charged to PSE&G	2,530	1,978	4,508
Operating Expense Increase before Taxes	$ 10,699	$ 10,048	$ 20,747
Income Taxes	3,007	2,825	5,832
Operating Income Increase (Decrease) After Taxes	**$ (7,691)**	**$ (7,224)**	**$ (14,915)**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 2
Payroll Taxes
($000)

	Electric	Gas	Total
Bargaining Unit Employees	$ 350	$ 346	$ 696
MAST Employees	225	223	448
Service Company	178	139	318
Operating Expense Increase before Taxes	$ 754	$ 708	$ 1,462
Income Taxes	212	199	411
Operating Income Increase (Decrease) After Taxes	**$ (542)**	**$ (509)**	**$ (1,051)**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 3
Interest Synchronization (Tax Savings)
($000)

	Percent	Embedded Cost	Weighted Cost	
Electric Rate Base				$ 9,447,599
Debt Components:				
Long Term Debt	44.29%	4.00%	1.77%	
Customer Deposits	0.21%	5.06%	0.01%	
Total Weighted Cost of Debt				1.78%
Annualized Interest Expense				$ 168,382
Less: Test Period Interest Expense				166,747
Net Interest Expense Increase / (Decrease)				$ 1,635
Income Tax Rate				28.11%
Operating Income Increase (Decrease) After Taxes				$ 460

	Percent	Embedded Cost	Weighted Cost	
Gas Rate Base				$ 8,726,426
Debt Components:				
Long Term Debt	44.29%	4.00%	1.77%	
Customer Deposits	0.21%	5.06%	0.01%	
Total Weighted Cost of Debt				1.78%
Annualized Interest Expense				$ 155,529
Less: Test Period Interest Expense				148,895
Net Interest Expense Increase / (Decrease)				$ 6,634
Income Tax Rate				28.11%
Operating Income Increase (Decrease) After Taxes				$ 1,865

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 4
Pension and Fringe Benefits
($000)

	Electric	Gas	Total
Rate Year			
Pensions	$ (19,144)	$ (14,790)	$ (33,934)
Pensions - Service Company	$ 2,064	$ 1,595	$ 3,659
OPEB	$ (1,214)	$ (999)	$ (2,213)
OPEB - Service Company	$ 405	$ 352	$ 757
Medical	$ 18,130	$ 18,286	$ 36,416
Medical - Service Company	$ 4,197	$ 3,269	$ 7,466
Dental	$ 652	$ 673	$ 1,325
Dental - Service Company	$ 167	$ 130	$ 297
Thrift	$ 4,763	$ 4,891	$ 9,654
Thrift - Service Company	$ 1,421	$ 1,107	$ 2,528
Long Term Disability	$ 361	$ 368	$ 729
Long Term Disability - Service Company	$ 141	$ 110	$ 251
Group Life Insurance	$ 206	$ 212	$ 419
Group Life Insurance - Service Company	$ 75	$ 59	$ 134
Workers Compensation	$ 1,487	$ 1,515	$ 3,001
Workers Compensation - Service Company	$ 86	$ 67	$ 153
Benefits Other	$ 2,102	$ 2,111	$ 4,213
Benefits Other - Service Company	$ 507	$ 395	$ 902
	$ 16,408	$ 19,350	$ 35,758
Less: Test Year			
Pensions	$ (22,434)	$ (15,584)	$ (38,018)
Pensions - Service Company	$ 1,912	$ 1,332	$ 3,244
OPEB	$ (12,359)	$ (9,965)	$ (22,324)
OPEB - Service Company	$ 203	$ 174	$ 377
Medical	$ 17,631	$ 18,871	$ 36,502
Medical - Service Company	$ 3,830	$ 3,115	$ 6,945
Dental	$ 611	$ 658	$ 1,269
Dental - Service Company	$ 153	$ 115	$ 268
Thrift	$ 4,615	$ 4,969	$ 9,584
Thrift - Service Company	$ 1,231	$ 949	$ 2,181
Long Term Disability	$ 342	$ 366	$ 708
Long Term Disability - Service Company	$ 130	$ 103	$ 232
Group Life Insurance	$ 184	$ 199	$ 384
Group Life Insurance - Service Company	$ 53	$ 55	$ 108
Workers Compensation	$ 1,494	$ 1,600	$ 3,094
Workers Compensation - Service Company	$ 52	$ 50	$ 102
Benefits Other	$ 2,036	$ 2,186	$ 4,223
Benefits Other - Service Company	$ 385	$ 291	$ 676
	$ 69	$ 9,486	$ 9,555
Increase in Test Year Operating Expenses	$ 16,339	$ 9,864	$ 26,203
Income Taxes	$ 4,593	$ 2,773	$ 7,366
Operating Income Increase (Decrease) After Taxes	**$ (11,746)**	**$ (7,091)**	**$ (18,837)**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 5
COLI Interest Expense
($000)

	Electric	Gas	Total
Net Credit in Test Year			
Administrative & General Expenses	(3,427)	(984)	(4,412)
Tax Savings on COLI	(442)	(148)	(591)
Total Benefit	(3,870)	(1,133)	(5,002)
Interest Charges	2,434	816	3,250
Net Benefit	$ (1,436)	$ (317)	$ (1,752)
Operating Income Increase (Decrease) After Taxes	**$ (2,434)**	**$ (816)**	**$ (3,250)**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 6
Weather Normalization
($000)

	Electric	Gas	Total
Actual Distribution Revenues	$ 984,697	$ 838,641	$ 1,823,337
Weather Normalized Distribution Revenues	$ 989,369	918,787	1,908,156
Increase (Decrease) in Test Year Margin Revenue	$ (4,672)	$ (80,147)	$ (84,819)
Income Taxes	(1,313)	(22,529)	(23,843)
Operating Income Increase (Decrease) After Taxes	$ 3,359	$ 57,617	$ 60,976

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 7
Gains/Losses on Sales of Property
($000)

	Electric	Gas	Total
Five-Year Average - Book Gain/(Loss)	$ 123	$ 577	$ 700
Income Taxes	35	162	197
Net Income/(Loss)	$ 88	$ 415	$ 503
Operating Income Increase (Decrease) After Taxes	**$ 44**	**$ 207**	**$ 252**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 8
Real Estate Taxes
($000)

	Electric	Gas	Total
Rate Year Property Taxes	$ 14,444	$ 4,828	$ 19,272
Test Year Property Taxes	$ 13,470	$ 4,607	$ 18,077
Operating Expense Increase Before Taxes	$ 974	$ 221	$ 1,195
Income Taxes	274	62	336
Operating Income Increase (Decrease) After Taxes	**$ (700)**	**$ (159)**	**$ (859)**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 9
Insurance
($000)

	Electric	Gas	Total
Insurance Premium Expense	$ 6,933	$ 4,047	$ 10,981
Test Year Insurance Premium Expense	6,264	3,717	9,981
Operating Expense Increase Before Taxes	$ 669	$ 330	$ 1,000
Income Taxes	188	93	281
Operating Income Increase (Decrease) After Taxes	**$ (481)**	**$ (238)**	**$ (719)**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 10
ASB Margin
($000)

	Electric	Gas	Total
ASB Margin by Appliance	$ 52,197	$ 42,468	$ 94,665
ASB Margin % Above-the-Line	50%	50%	
Above the Line ASB Margin	$ 26,098	$ 21,234	$ 47,333
ASB Margin in Test Year	$ 26,098	$ 42,468	$ 68,567
ASB Above-the-Line Margin	$ -	$ (21,234)	$ (21,234)
Income Taxes	-	(5,969)	(5,969)
Operating Income Increase (Decrease) After Taxes	**$ -**	**$ (15,265)**	**$ (15,265)**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 11
TSG-NF Margin - Gas
($000)

	Electric	Gas	Total
Operating Income Decrease Before Taxes	$ -	$ (1,063)	$ (1,063)
Income Taxes	-	299	299
Operating Income Increase (Decrease) After Taxes	**$ -**	**$ (764)**	**$ (764)**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 12
Depreciation Rate Change
($000)

	Electric	Gas	Total
Annualization of Depreciation Expense	$ 312,854	$ 258,630	$ 571,484
Test Year Depreciation Expense	$ 305,886	$ 229,126	$ 535,012
Annualization of Current Depreciation Rates	$ 6,968	$ 29,504	$ 36,472
Depreciation Expense at Proposed Rates	$ 375,731	$ 332,929	$ 708,660
Operating Expense Increase (Decrease) for Proposed Rates	$ 62,877	$ 74,299	$ 137,176
Operating Income Increase (Decrease) Before Taxes	$ (69,845)	$ (103,803)	$ (173,648)
Income Taxes	$ (19,633)	$ (29,179)	$ (48,812)
Operating Income Increase (Decrease) After Taxes	**$ (50,211)**	**$ (74,624)**	**$ (124,836)**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 13
Test Year Amortization Adjustments
($000)

	Electric	Gas	Total
Test Year Amortizations			
BRC Settlement	$ 20,040	$ 7,296	$ 27,335
Community Solar	$ 164	$ -	$ 164
CEF-EE IT	$ 3,828	$ 957	$ 4,784
Test Year Amortizations Total	$ 24,031	$ 8,253	$ 32,284
Operating Expense Increase Before Taxes	$ (24,031)	$ (8,253)	$ (32,284)
Income Taxes	$ (6,755)	$ (2,320)	$ (9,075)
Operating Income Increase (Decrease) After Taxes	**$ 17,276**	**$ 5,933**	**$ 23,209**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 14
Rate Case & Management Audit Expenses
($000)

	Electric	Gas	Total
Rate Case Expenses	$ 433	$ 319	$ 752
Management Audit Expenses	$ 880	$ 720	$ 1,600
Amortization Period	3	3	3
Annual Amortization	$ 438	$ 346	$ 784
Test Year Rate Case Expense	$ 207	$ 150	$ 356
Operating Expense Decrease Before Taxes	$ (231)	$ (197)	$ (428)
Income Taxes	$ (65)	$ (55)	$ (120)
Operating Income Increase (Decrease) After Taxes	**$ (166)**	**$ (141)**	**$ (307)**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 15
Energy Strong II / IAP Revenue Adjustment
($000)

	Electric	Gas	Total
ESII Roll-In #4 (Annualizing Revenue from Jun23 - Oct23)	8,792	-	8,792
IAP Roll-In #1 (Annualizing Revenue from Jun23 - Mar24)	5,642	-	5,642
ESII Roll-In #5 (Annualizing Revenue from Jun23 - Apr24)	13,202	-	13,202
Operating Revenue Increase Before Taxes	27,636	-	27,636
Income Taxes	(7,769)	-	(7,769)
Operating Income Increase (Decrease) After Taxes	**$ 19,868**	**$ -**	**19,868**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 16
BGS Administrative Expense Adjustment
($000)

	Electric	Gas	Total
BGS Administrative Expense	$ 934	$ -	$ 934
Operating Expense Decrease Before Taxes	$ 934	$ -	$ 934
Income Taxes	263	-	263
Operating Income Increase (Decrease) After Taxes	**$ (671)**	**$ -**	**$ (671)**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 17
Gas Bad Debt Adjustment
($000)

	Electric	Gas	Total
Gas Bad Debt	$ -	$ (35,846)	$ (35,846)
Operating Expense Decrease Before Taxes	$ -	$ (35,846)	$ (35,846)
Income Taxes	-	(10,076)	(10,076)
Operating Income Increase (Decrease) After Taxes	**$ -**	**$ 25,770**	**$ 25,770**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 18
Amortization of CEF-EC Program Regulatory Assets
($000)

	Electric	Gas	Total
CEF-EC Regulatory Assets			
CEF-EC Monthly Investment Deferral	$ 99,215	$ -	$ 99,215
Meter Testing O&M	$ 17,449	$ -	$ 17,449
Stranded Cost Deferral	$ 119,801	$ -	$ 119,801
O&M Regulatory Asset	$ 35,924	$ -	$ 35,924
Total CEF-EC Regulatory Assets	$ 272,388	$ -	$ 272,388
Amortization Period			
CEF-EC Monthly Investment Deferral	20	0	20
Meter Testing O&M	5	0	5
Stranded Cost Deferral	10	0	10
O&M Regulatory Asset	5	0	5
Annual Amortization			
CEF-EC Monthly Investment Deferral	$ 4,961	$ -	$ 4,961
Meter Testing O&M	$ 3,490	$ -	$ 3,490
Stranded Cost Deferral	$ 11,980	$ -	$ 11,980
O&M Regulatory Asset	$ 7,185	$ -	$ 7,185
Total Annual Amortization	$ 27,615	$ -	$ 27,615
Carrying Charge:			
Average Deferred Balance During Test Year	$ 26,686	$ -	$ 26,686
Deferred Tax Benefit	$ (7,501)	$ -	$ (7,501)
Average Net of Tax Deferred Cost Balance	$ 19,185	$ -	$ 19,185
Weighted Average Cost of Capital	7.55%	7.55%	7.55%
Annual Amortization Carrying Charge	$ 1,448	$ -	$ 1,448
Test Year Expense	$ -	$ -	$ -
Operating Expense Increase Before Taxes	$ 29,064	$ -	$ 29,064
Income Taxes	$ 8,170	$ -	$ 8,170
Operating Income Increase (Decrease) After Taxes	**$ (20,894)**	**$ -**	**$ (20,894)**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 19
CEF-EC Revenue Reduction
($000)

	Electric	Gas	Total
Future Savings Revenue Offset	$ (7,185)	$ -	(7,185)
Income Taxes	(2,020)	-	(2,020)
Operating Income Increase (Decrease) After Taxes	**$ 5,165**	**$ -**	**$ 5,165**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 20
Amortization of CEF-EV Program Regulatory Assets
($000)

	Electric	Gas	Total
CEF-EV Regulatory Assets			
Residential Smart Charging	$ 25,824	$ -	$ 25,824
Mixed Use	$ 5,779	$ -	$ 5,779
DCFC & C&I Rebate	$ 6,031	$ -	$ 6,031
IT Systems	$ 4,422	$ -	$ 4,422
O&M	$ 14,733	$ -	$ 14,733
Total CEF-EV Regulatory Assets	$ 56,790	$ -	$ 56,790
Amortization Period			
Residential Smart Charging	30	0	30
Mixed Use	30	0	30
DCFC & C&I Rebate	30	0	30
IT Systems	5	0	5
O&M	5	0	5
Annual Amortization			
Residential Smart Charging	$ 861	$ -	$ 861
Mixed Use	$ 193	$ -	$ 193
DCFC & C&I Rebate	$ 201	$ -	$ 201
IT Systems	$ 884	$ -	$ 884
O&M	$ 2,947	$ -	$ 2,947
Total Annual Amortization	$ 5,086	$ -	$ 5,086
Carrying Charge:			
Average Deferred Balance During Test Year	$ 7,367	$ -	$ 7,367
Deferred Tax Benefit	$ (2,071)	$ -	$ (2,071)
Average Net of Tax Deferred Cost Balance	$ 5,296	$ -	$ 5,296
Weighted Average Cost of Capital	7.55%	7.55%	7.55%
Annual Amortization Carrying Charge	$ 400	$ -	$ 400
Test Year Expense	$ -	$ -	$ -
Operating Expense Increase Before Taxes	$ 5,485	$ -	$ 5,485
Income Taxes	$ 1,542	$ -	$ 1,542
Operating Income Increase (Decrease) After Taxes	**$ (3,943)**	**$ -**	**$ (3,943)**

EXHIBIT P-2 R-1
SCHEDULE MPM-50 R-1

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 21
CIP Revenue Accrual Adjustment
($000)

	Electric	Gas	Total
CIP Revenue Accrual in Test Year	$ 93,975	$ 68,635	$ 162,610
Operating Expense Decrease Before Taxes	$ 93,975	$ 68,635	$ 162,610
Income Taxes	26,416	19,293	45,710
Operating Income Increase (Decrease) After Taxes	**$ (67,558)**	**$ (49,342)**	**$ (116,900)**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 22
TAC Revenue Accrual Adjustment
($000)

	Electric	Gas	Total
TAC Revenue Accrual in Test Year	$ 26,847	$ 32,071	$ 58,918
Operating Expense Decrease Before Taxes	$ 26,847	$ 32,071	$ 58,918
Income Taxes	7,597	9,443	17,040
Operating Income Increase (Decrease) After Taxes	**$ (19,250)**	**$ (22,628)**	**$ (41,877)**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 23
Deferred Compensation & Severance Expense
($000)

	Electric	Gas	Total
Removal of Deferred Compensation in Test Year	$ 3,918	$ 3,596	$ 7,514
Removal of Severance Expense in Test Year	$ (5,010)	$ (4,099)	$ (9,109)
Operating Expense Decrease Before Taxes	$ (1,092)	$ (503)	$ (1,595)
Income Taxes	(307)	(141)	(448)
Operating Income Increase (Decrease) After Taxes	**$ 785**	**$ 361**	**$ 1,146**

EXHIBIT P-2 R-1
SCHEDULE MPM-53 R-1

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 24
Tax Impact of Bad Debt Adjustment
($000)

	Electric	Gas	Total
Tax Bad Debt in Test Year	$ 5,611	$ 2,990	$ 8,601
Operating Expense Decrease After Taxes	$ 5,611	$ 2,990	$ 8,601
Operating Income Increase (Decrease) After Taxes	**$ (5,611)**	**$ (2,990)**	**$ (8,601)**

Schedule MPM-54E R-1

2023 Rate Case - Baseline Revenue / Customer				
Month	**RS & RHS**	**RLM**	**GLP**	**LPLS**
Jun	$20.1	$21.6	$98.5	$1,813.2
Jul	$49.2	$93.1	$200.7	$2,862.0
Aug	$62.2	$109.9	$217.8	$3,668.3
Sep	$59.4	$133.5	$226.4	$3,938.9
Oct	$40.3	$87.4	$215.2	$3,913.1
Nov	$19.2	$18.4	$57.1	$1,826.6
Dec	$19.0	$22.5	$44.8	$868.6
Jan	$25.5	$22.6	$47.9	$796.8
Feb	$27.9	$28.5	$47.2	$877.6
Mar	$23.4	$22.2	$42.8	$812.1
Apr	$21.1	$20.8	$45.1	$801.4
May	$17.3	$17.6	$42.1	$742.1
TOTAL ANNUAL	**$384.7**	**$598.2**	**$1,285.6**	**$22,920.8**

Schedule MPM-54G R-1

2023 Rate Case - Baseline Use / Customer			
	RSG	**GSG**	**LVG**
Oct	44.9	72.0	2,148.2
Nov	90.8	197.2	3,596.9
Dec	147.0	350.9	5,610.7
Jan	181.2	420.5	6,581.8
Feb	158.4	368.6	6,261.6
Mar	120.2	296.7	5,346.5
Apr	65.9	147.4	3,205.2
May	39.8	98.2	1,883.3
Jun	21.4	57.8	1,171.4
Jul	18.7	47.4	1,311.2
Aug	16.9	51.0	1,286.4
Sep	18.8	48.1	1,319.6
Total	**924.0**	**2,155.8**	**39,722.8**

Interest Cost Reconciliation

$M

		Sep-24	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25
ln 1	Approved Rate Base - E	9,448	9,448	9,448	9,448	9,448	9,448	9,448	9,448	9,448
ln 2	Approved Rate Base - G	8,726	8,726	8,726	8,726	8,726	8,726	8,726	8,726	8,726
ln 3	Approved LTD %	44.29%	44.29%	44.29%	44.29%	44.29%	44.29%	44.29%	44.29%	44.29%
ln 4	Approved Annual LTD Rate	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%
ln 5	Actual Annual LTD Rate	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%
ln 6 = ln 1 * ln 3 * (ln 5 - ln 4) / 12	Mmonthly Interest Deferral - E	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
ln 7= ln 2 * ln 3 * (ln 5 - ln 4) / 12	Monthly Interest Deferral - G	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
ln 8 = ln 6 + ln 7	**Total Monthly Interest Deferral**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**
ln 9 = ln 8 + prev ln 9	**Cumulative Interest Deferral**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**

Interest Cost Reconciliation

$M

		Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26
ln 1	Approved Rate Base - E	9,448	9,448	9,448	9,448	9,448	9,448	9,448	9,448	9,448
ln 2	Approved Rate Base - G	8,726	8,726	8,726	8,726	8,726	8,726	8,726	8,726	8,726
ln 3	Approved LTD %	44.29%	44.29%	44.29%	44.29%	44.29%	44.29%	44.29%	44.29%	44.29%
ln 4	Approved Annual LTD Rate	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%
ln 5	Actual Annual LTD Rate	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%
ln 6 = ln 1 * ln 3 * (ln 5 - ln 4) / 12	Mmonthly Interest Deferral - E	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
ln 7= ln 2 * ln 3 * (ln 5 - ln 4) / 12	Monthly Interest Deferral - G	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
ln 8 = ln 6 + ln 7	**Total Monthly Interest Deferral**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**
ln 9 = ln 8 + prev ln 9	**Cumulative Interest Deferral**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**

Interest Cost Reconciliation

$M

		Mar-26	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Nov-26
ln 1	Approved Rate Base - E	9,448	9,448	9,448	9,448	9,448	9,448	9,448	9,448	9,448
ln 2	Approved Rate Base - G	8,726	8,726	8,726	8,726	8,726	8,726	8,726	8,726	8,726
ln 3	Approved LTD %	44.29%	44.29%	44.29%	44.29%	44.29%	44.29%	44.29%	44.29%	44.29%
ln 4	Approved Annual LTD Rate	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%
ln 5	Actual Annual LTD Rate	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%
ln 6 = ln 1 * ln 3 * (ln 5 - ln 4) / 12	Mmonthly Interest Deferral - E	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
ln 7= ln 2 * ln 3 * (ln 5 - ln 4) / 12	Monthly Interest Deferral - G	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
ln 8 = ln 6 + ln 7	**Total Monthly Interest Deferral**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**
ln 9 = ln 8 + prev ln 9	**Cumulative Interest Deferral**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**

Interest Cost Reconciliation

$M

		Dec-26	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27
ln 1	Approved Rate Base - E	9,448	9,448	9,448	9,448	9,448	9,448	9,448	9,448	9,448
ln 2	Approved Rate Base - G	8,726	8,726	8,726	8,726	8,726	8,726	8,726	8,726	8,726
ln 3	Approved LTD %	44.29%	44.29%	44.29%	44.29%	44.29%	44.29%	44.29%	44.29%	44.29%
ln 4	Approved Annual LTD Rate	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%
ln 5	Actual Annual LTD Rate	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%
ln 6 = ln 1 * ln 3 * (ln 5 - ln 4) / 12	Mmonthly Interest Deferral - E	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
ln 7= ln 2 * ln 3 * (ln 5 - ln 4) / 12	Monthly Interest Deferral - G	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
ln 8 = ln 6 + ln 7	**Total Monthly Interest Deferral**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**
ln 9 = ln 8 + prev ln 9	**Cumulative Interest Deferral**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**

Interest Cost Reconciliation

$M

		Sep-27	Oct-27	Nov-27	Dec-27	Jan-28	Feb-28	Mar-28	Apr-28	May-28
ln 1	Approved Rate Base - E	9,448	9,448	9,448	9,448	9,448	9,448	9,448	9,448	9,448
ln 2	Approved Rate Base - G	8,726	8,726	8,726	8,726	8,726	8,726	8,726	8,726	8,726
ln 3	Approved LTD %	44.29%	44.29%	44.29%	44.29%	44.29%	44.29%	44.29%	44.29%	44.29%
ln 4	Approved Annual LTD Rate	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%
ln 5	Actual Annual LTD Rate	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%
ln 6 = ln 1 * ln 3 * (ln 5 - ln 4) / 12	Mmonthly Interest Deferral - E	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
ln 7= ln 2 * ln 3 * (ln 5 - ln 4) / 12	Monthly Interest Deferral - G	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
ln 8 = ln 6 + ln 7	**Total Monthly Interest Deferral**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**
ln 9 = ln 8 + prev ln 9	**Cumulative Interest Deferral**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**

Interest Cost Reconciliation

$M

		Jun-28	Jul-28	Aug-28	Sep-28	Oct-28	Nov-28	Dec-28
ln 1	Approved Rate Base - E	9,448	9,448	9,448	9,448	9,448	9,448	9,448
ln 2	Approved Rate Base - G	8,726	8,726	8,726	8,726	8,726	8,726	8,726
ln 3	Approved LTD %	44.29%	44.29%	44.29%	44.29%	44.29%	44.29%	44.29%
ln 4	Approved Annual LTD Rate	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%
ln 5	Actual Annual LTD Rate	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%
ln 6 = ln 1 * ln 3 * (ln 5 - ln 4) / 12	Mmonthly Interest Deferral - E	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
ln 7= ln 2 * ln 3 * (ln 5 - ln 4) / 12	Monthly Interest Deferral - G	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
ln 8 = ln 6 + ln 7	**Total Monthly Interest Deferral**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**
ln 9 = ln 8 + prev ln 9	**Cumulative Interest Deferral**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**

EXHIBIT P-2 R-1
SCHEDULE MPM-56 R-1

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 25
BPU/Rate Counsel Assessment
($000)

Electric

	BPU	Rate Counsel	Total
2024 Annualized Assessment	$ 11,335	$ 2,372	$ 13,708
Less: Assessment Included in Test Year Operating Expenses	10,667	2,515	13,182
Operating Expense Increase Before Taxes	$ 668	$ (143)	$ 526
Income Taxes	188	(40)	148
Operating Income Increase (Decrease) After Taxes	$ (481)	$ 103	$ (378)

Gas

	BPU	Rate Counsel	Total
2024 Annualized Assessment	$ 5,310	$ 1,111	$ 6,422
Less: Assessment Included in Test Year Operating Expenses	4,365	1,029	5,395
Operating Expense Increase Before Taxes	$ 945	$ 82	$ 1,027
Income Taxes	266	23	289
Operating Income Increase (Decrease) After Taxes	$ (679)	$ (59)	$ (738)

STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

In the Matter of the Petition of
Public Service Electric and Gas Company
for Approval of an Increase in Electric and Gas
Rates and for Changes in the Tariffs for
Electric and Gas Service, B.P.U.N.J.
No. 17 Electric and B.P.U.N.J. No. 17
Gas, and for Changes in Depreciation Rates,
Pursuant to N.J.S.A. 48:2-18,
N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1, and
for Other Appropriate Relief

BPU Docket Nos. ER23120924 & GR23120925

DIRECT PANEL TESTIMONY

OF

MICHAEL A. SCHMID
VICE PRESIDENT – ASSET MANAGEMENT AND PLANNING
AND
RICARDO G. FONSECA
SENIOR DIRECTOR UTILITY FINANCE

April 15, 2024
P-3 R-1

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
DIRECT PANEL TESTIMONY
OF
MICHAEL A. SCHMID
VICE PRESIDENT – ASSET MANAGEMENT AND PLANNING, AND
RICARDO G. FONSECA – SENIOR DIR UTILITY FINANCE

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Michael A. Schmid. My business address is 80 Park Plaza, Newark, New Jersey 07102.

Q. By whom are you employed and in what capacity?

A. I am employed by Public Service Electric and Gas Company ("PSE&G", "Public Service" or "Company") as Vice President - Asset Management and Planning.

Q. Please describe your professional responsibilities with respect to electric and gas delivery service.

A. I am responsible for ensuring the reliability of PSE&G's electric and gas delivery assets and overseeing various functions that support the provision of safe, adequate, proper and reliable electric and gas delivery service. My position is responsible for the overall management of electric and gas delivery assets and system performance. A summary of my qualifications and business experience is provided in Schedule PANEL-1.

Q. Please state your name, affiliation and business address.

A. My name is Ricardo G. Fonseca, and I am the Senior Director of Utility Finance for PSE&G. My business address is 80 Park Plaza, Newark, New Jersey 07102.

Q. Please describe your responsibilities as Senior Director of Utility Finance.

A. As the Senior Director of Utility Finance, I am responsible for PSE&G's business planning process, financial reporting and forecasting, and capital governance process. My position is responsible for the long range financial plan, short term financial forecasting, ensuring adherence to our capital governance processes, overseeing the Company's capital operations and maintenance ("O&M") spending plans, execution tracking and variance analysis. A summary of my qualifications and business experience is provided in Schedule PANEL-1.

Q. What is the purpose of your direct testimony?

A. In support of PSE&G's base rate filings for its electric and gas operations before the New Jersey Board of Public Utilities ("Board" or "BPU") Company witness Schmid will: describe the Company's electric and gas distribution operations, including a discussion of PSE&G's record of system safety, reliability and operational performance. He will also describe PSE&G's capital budgeting process and the practices followed by the Company to ensure the reasonableness of its base capital spending and accelerated infrastructure program-related capital expenditures, from planning and budgeting through the completion of construction. Company witness Fonseca supports the test year and post-test year period forecasts of electric and gas distribution capital expenditures and supports the test year electric and gas distribution-related expense component of total operations and maintenance ("O&M")

costs, including the major drivers of the distribution-related expense and the Company's efforts to mitigate those costs.[1]

Q. How is this panel testimony organized?

A. In addition to this Introduction section, the panel testimony is organized as follows:

II. Electric and Gas Distribution Operations and Performance;

III. Capital Expenditures;

IV. Operations and Maintenance Expense;

V. Appliance Service Business; and

VI. Gas Tariff Changes.

Q. Does the panel sponsor any schedules as part of your direct testimony?

A. Yes. We sponsor the following schedules, which were prepared by us or under our supervision and direction:

- Schedule PANEL-1 describes our professional qualifications and business experience;
- Schedule PANEL-2(a) R-1 sets forth electric capital expenditure levels by major category during the test year and post-test year;
- Schedule PANEL-2(b) R-1 sets forth gas capital expenditure levels by major category during the test year and post-test year;
- Schedule PANEL-3 R-1 contains the major event reports for the six storms that occurred since the Company's last base rate case as well as the cost detail summaries for each major event.
- Schedule PANEL-4(a) R-1 contains the annual and quarterly reports of the Energy Strong II Program Independent Monitor;

[1] As discussed by Company witness Michael McFadden, the test year consists of the twelve month period starting on June 1, 2023 through May 31, 2024, with adjustments to reflect changes in capital expenditures through November 30, 2024 and changes in certain expenses and revenues through August 31, 2025. Our testimony does not address any post-test year adjustments for electric or gas distribution operating costs; those adjustments are addressed by Mr. McFadden.

- Schedule PANEL-4(b) R-1 contains a copy of the most recent Energy Strong Program II Electric and Gas Quarterly Report;
- Schedule PANEL-4(c) R-1 contains a copy of the most recent Gas System Modernization Program Monthly Report;
- Schedule PANEL-4(d) contains a copy of the most recent report of the Infrastructure Advancement Program Independent Monitor;
- Schedule PANEL-4(e) R-1 contains a copy of the most recent semi-annual report for the Infrastructure Advancement Program;
- Schedule PANEL-5(a) R-1 sets forth total test year electric distribution-related O&M expense as well as expense by major cost category;
- Schedule PANEL-5(b) R-1 sets forth total test year gas distribution-related O&M expense as well as expense by major cost category.

Q. In your previous response you reference both test year and post-test year periods. What are those periods in this proceeding?

A. The test year in this proceeding consists of the twelve months ending May 31, 2024, and the post-test year period with respect to additional capital expenditures is the six months ending November 30, 2024.

II. ELECTRIC AND GAS DISTRIBUTION OPERATIONS AND PERFORMANCE

A. Overview of Electric and Gas Delivery Organizations

1. Electric Distribution System

Q. Please provide an overview of PSE&G's electric distribution system.

A. PSE&G is the largest electric utility provider in New Jersey. The Company's electric distribution service territory covers an approximately 2,600-square-mile corridor from Bergen to Gloucester Counties serving approximately 2.3 million customers in more than 230 urban, suburban and rural communities, including the State's three largest cities. Since the Company's last electric rate case, many areas in the service territory have required significant investment, including new substations, switching stations and circuits to maintain service quality and reliability. The Company's electric distribution business operates and maintains over 40,760 conductor miles of primary distribution circuits, over 6,235 conductor miles of sub-transmission circuits, approximately 864,019 poles, and approximately 341,905 transformers. The Company's electric distribution business operates 50 switching stations, 240 substations, 474 sub-transmission circuits and 2,339 primary distribution circuits. Between 2018 and 2022, PSE&G installed 173 new primary (13kV and 4 kV) distribution circuits, 33 new sub-transmission (26 kV) circuits, seven new transmission supplied distribution substations and eight new switching stations. Section III of my testimony provides further details on the capital expenditures the Company has undertaken since its last electric base rate case.

Q. Has PSE&G's service territory experienced an increase in the number of electric customers since the Company's last base rate case in 2018?

A. From 2017 through 2022, the Company's annual average number of electric delivery customers has increased at a growth rate of approximately 1% per year, from 2,186,980 to 2,296,304. Over the five-year period from January 1, 2018 through January 1, 2023, the Company has invested an average of approximately $135 million per year to serve electric new business.

Q. Please describe the workforce and organizational structure that supports the electric distribution system.

A. The employees who physically construct, maintain and operate PSE&G's electric distribution system are organized in the following main areas: (1) Electric Operations; (2)

Asset Management & Planning, (3) Centralized Services; and (4) Delivery Projects and Construction ("DP&C").

Electric Operations consists of the men and women who physically construct, maintain and operate the distribution system. These employees are based in four operating divisions (the Southern, Central, Metro, and Palisades Divisions), each of which has multiple reporting locations to minimize travel time. These employees have primary responsibility for hands-on distribution and service activities. Personnel at these locations perform engineering, construction, operations, inspections, maintenance and repair, emergency response, meter services, and administrative activities.

Personnel in Asset Management & Planning include technical experts and specialists in various areas, and are located at the Company's General Office in Newark, the Edison Training and Development Center, and the Hadley Road office in South Plainfield, as well as all operating headquarters.

Centralized Services consist of multiple departments that support electric and gas operations. The organization includes the centralized work planning & cultural department as well as utility operations services. Employees are located in multiple locations within the PSE&G territory. This organization encompasses all the cultural transformation initiatives and departments that provide service, materials & equipment and overall support to utility operations.

The DP&C organization manages and executes new construction projects. This organization is not specific to a particular geographic area or location. DP&C engineers manage and execute various types of projects statewide. Most employees report directly to that day's work site. The organization includes an "Electric Mobile Division" whose field workforce is supplemental to that of the four geographic Divisions, and an expanded "Projects and Construction Management" group that manages and oversees the work, and ensures adherence to planned schedules and costs. This organization combines flexibility and efficiency with strong planning and oversight to ensure a solid execution of all planned capital projects.

2. Gas Distribution System

Q. Please provide an overview of PSE&G's gas distribution system.

A. PSE&G is the largest gas utility provider in New Jersey. Its gas service territory covers approximately 2,300 square miles serving approximately 1.9 million customers in 267 urban, suburban and rural communities, including the State's three largest cities. To meet the needs of customers within this sizeable area, the Company's gas business operates and maintains over 18,150 miles of gas mains of various sizes from 3/4 inch to 42 inches in diameter; over 1.27 million service lines that total over 17,400 miles in length; and line valves, pressure regulators, meters, and associated instrumentation and corrosion protection systems. In addition, gas distribution operations encompass 56 metering and regulating stations, three Liquid Propane Air ("LPA") peak shaving plants, one Liquid Propane Gas ("LPG") storage facility, one Liquefied Natural Gas ("LNG") peak shaving facility, and 54 miles of intrastate transmission lines. Since the Company's last gas base rate case, it has made significant investments in many areas of our service territory, including the replacement of more than 495 miles of cast iron mains, 214 miles of unprotected steel mains and over 81,000 services. Section III of my testimony provides details on the capital expenditures the Company has undertaken since its last gas base rate case.

Q. Has PSE&G's service territory experienced an increase in the number of gas customers since the Company's last base rate case in 2018?

A. From 2017 through 2022, the Company's annual average number of gas delivery customers has increased at a growth rate of approximately 1% per year, from 1,784,484 to 1,857,109. Over the five-year period from January 1, 2018 through January 1, 2023, the Company has invested an average of approximately $97 million per year to serve gas new business.

Q. Please describe the workforce and organization structure that supports the gas distribution system.

A. The employees who construct, maintain and operate the gas distribution system and service customers' requirements are based in twelve (12) field headquarters throughout the service territory, strategically located to provide rapid response to emergencies 24 hours a day, seven days a week. These employees have primary responsibility for hands-on distribution and service activities. Personnel based at these locations perform construction, operation, maintenance and repair activities across the entire gas service territory. These services include new and replacement main and service installations, leak detection and repair, system design and maintenance, meter and after-meter safety services, surveys and inspections, and administrative activities associated with this work. The Company also has personnel in Asset Management and Planning that support delivery of gas into the distribution and transmission systems and are located at the General Office in Newark, at the Gas System Operations Center in Bridgewater, and at the peak shaving plants. The Asset Management and Planning employees in the General Office in Newark include employees who are responsible for asset strategy; planning & design; technical support to field operations; and management of the transmission and distribution integrity management programs.

B. Electric and Gas Delivery Performance, Safety and Reliability

Q. Please describe PSE&G's goals pertaining to the safety, reliability and operational performance of the Company's electric and gas distribution system.

A. PSE&G's business model for both electric and gas distribution reflects three fundamental goals, and the Company strives to instill these goals in all employees and contractors: (i) safety and reliability; (ii) cost control; and (iii) customer satisfaction. Simply put, PSE&G strives to provide safe, reliable and cost effective service at a very high level of customer satisfaction.

The Company's recent and planned capital investments are aligned with the State's Energy Master Plan goals and are designed to: mitigate the increasing impacts of climate change on core utility infrastructure, ensure the reliability of PSE&G's system in the wake of increasingly volatile weather, and ensure the Company's systems are poised to support new technologies and greener energy resources and jobs. PSE&G is committed to advancing the State's climate, decarbonization, and jobs goals. This is evident from: 1) the Company's evolving climate/decarbonization strategy, and 2) the Company's capital investments over the last several years, including investments to modernize and increase the resiliency of PSE&G's electric and gas distribution systems with programs such as the Second Phase of the Gas System Modernization Programs ("GSMP II"), as extended, the Energy Strong II Program ("ES II"), and the Infrastructure Advancement Program ("IAP"). Consistent with the Company's evolving climate/decarbonization strategy, PSE&G also has made significant investments in its Clean Energy Future ("CEF") programs.

The capital expenditures and distribution-related O&M expenses we discuss in this filing are consistent with these goals.

Q. How does PSE&G ensure that it meets its goals?

A. The Company relies on a combination of external and internal indicators. PSE&G reviews, monitors and assesses organizational performance based on metrics that rely largely on common industry standards and objective measures in the following key areas: safety, reliability, cost containment, and customer satisfaction. Some metrics are common to both gas and electric, while others are unique to either electric or gas operations. In all instances, there is a continuous improvement goal intended to encourage improved results year after year. The Company also has goals that are regulatory and clean energy based. Targets for gas and electric Annualized Energy Efficiency Energy Savings are approved by the BPU and Open Leaks is a metric specific in gas operations in which results are shared with the BPU semi-annually.

Q. Please describe some of the common safety goals for electric and gas distribution.

A. Common metrics for electric and gas distribution are those tied to Occupational Safety and Health Administration ("OSHA") measures such as the OSHA recordable incidence rate, which tracks the number of OSHA recordable injuries, and the OSHA Days Away Rate, which measures and tracks the severity of injuries. Because the Company strives to be within the top decile in this category, PSE&G purposely sets very challenging targets. Our Company-wide results for 2021 were top decile for OSHA Days Away Rate, but not for OSHA Recordable Incident Rate. Per our latest benchmarking data[2], PSE&G achieved top quartile in 2021. As illustrated in the charts below, both our OSHA Recordable Incidence Rate and our OSHA Days Away from Work rate (which is a measure of severity) were at or near top quartile performance in five of the past six years.

[2] 2022 OSHA data will be provided in a future update.

Chart 1

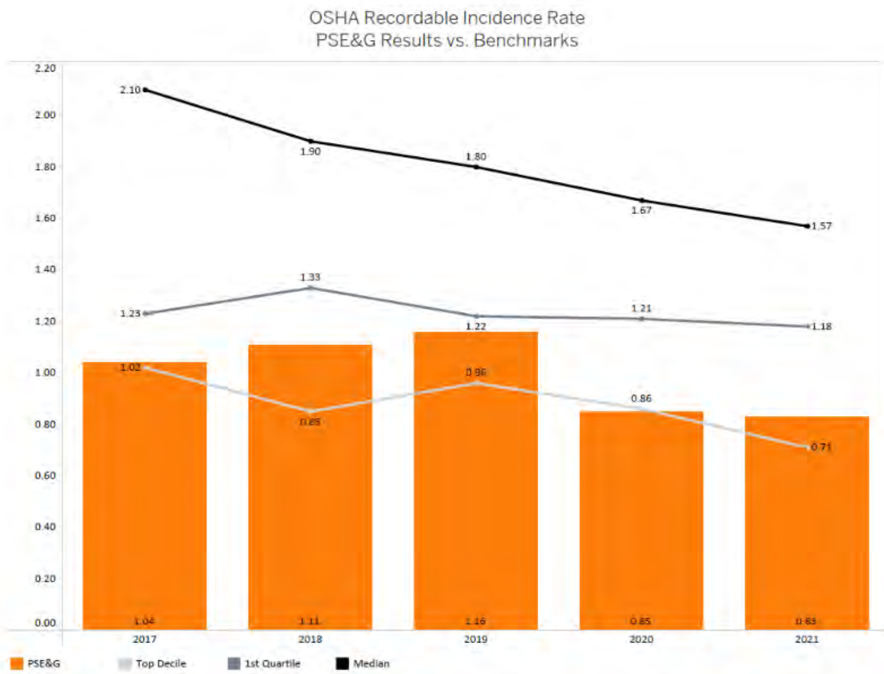
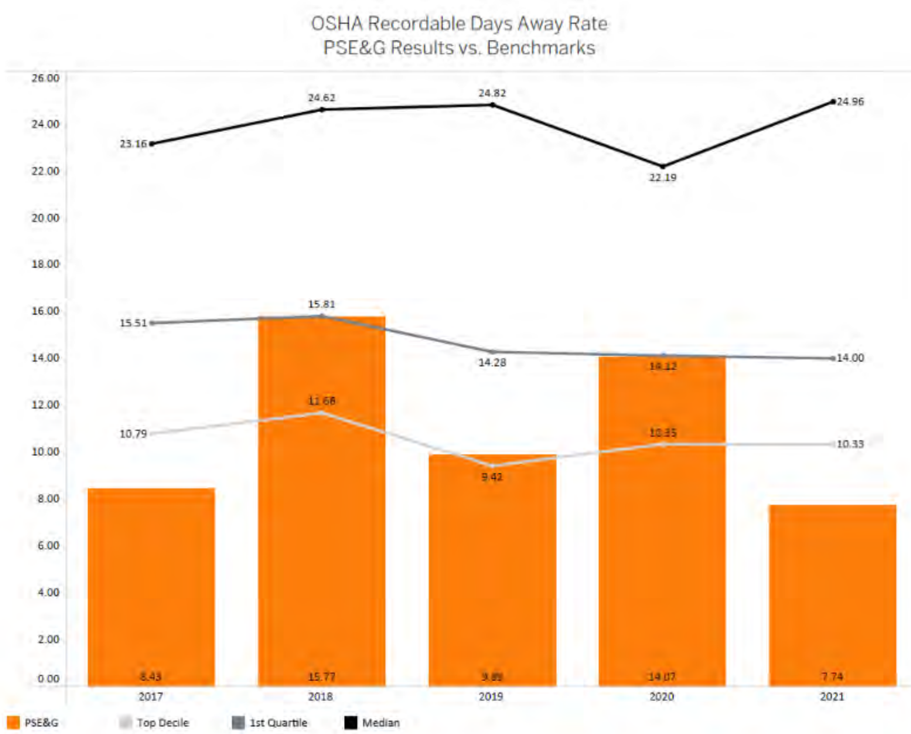
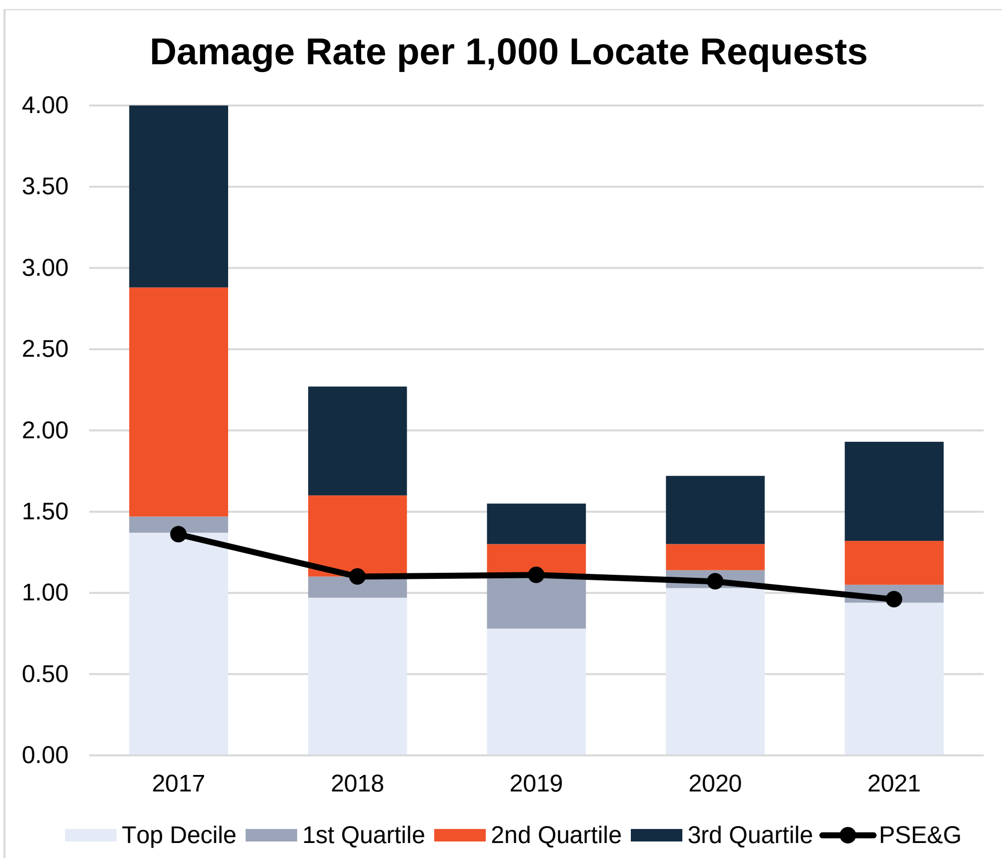


Chart 2



For the combined operations, we also measure "Damages Per 1,000 Locate Requests," which calculates the number of overall damages to gas and electric facilities per 1,000 locate requests, *i.e.*, mark-outs. The State of New Jersey requires that the location of underground installations, such as electrical and natural gas lines, be identified and marked out prior to work that involves any digging operation. Activities covered by this requirement include excavations or trenching, blasting, installation of tents, sign posts or fence posts, amongst others. Results indicate that since 2011 PSE&G's total damage rate for electric and gas combined is in the top quartile of peer panel companies.

Chart 3



Q. How does PSE&G measure the reliability of its electric distribution system?

A. The Company relies primarily on three metrics established by the Institute of Electrical and Electronic Engineers ("IEEE") to measure reliability:

System Average Interruption Duration Index ("SAIDI").
This index is based on the amount of time the average PSE&G customer experiences a sustained outage (being without power for more than five minutes) in a given year.

System Average Interruption Frequency Index ("SAIFI").
This metric represents the number of times the average PSE&G customer experiences a sustained outage in a given year; and

Customer Average Interruption Duration Index ("CAIDI").
This index represents the average outage time when customers are impacted by a sustained outage. It is determined by dividing SAIDI by SAIFI.

The Board's regulations set forth a minimum reliability level and annual reporting requirement[3] for SAIFI and CAIDI. Because the Board's annual reliability performance level targets are generally set using an individual utility's five year average, PSE&G's required targets are higher than other NJ EDCs as a result of the Company's strong historical performance, as I discuss below. The Company also measures SAIDI, with targets to improve results for all three measures as compared to the Company's past performance year after year. Beyond the requirements contained in the Board's regulations, the Company is similarly required to report system performance using these measures as part of the reporting requirements that apply to the Company's Energy Strong II Program, which is discussed later in my testimony.

[3] Each year, like all other electric utilities in New Jersey, PSE&G is required to submit an Annual System Performance Report to the Board.

Q. What do these reliability measures show?

A. The Company's performance of these indicators is addressed in detail in the testimony of Company witness Michael J. Adams. The indicators show that PSE&G has a strong and well-established track record of outstanding reliability and has continued to build upon that since the last rate case. Mr. Adams reviewed PSE&G's reported System Average Interruption Duration Index ("SAIDI"), System Average Interruption Frequency Index ("SAIFI"), and Customer Average Interruption Duration Index ("CAIDI") to those of the other New Jersey electric companies as reported to the Energy Information Administration ("EIA") via Form 861 and to the IEEE via IEEE's annual benchmarking survey. Mr. Adams' study illustrates that for the years 2013 through 2021, PSE&G's SAIDI, SAIFI, and CAIDI reported to EIA were consistently below (better than) that of the other New Jersey electric companies that reported comparable metrics. Therefore, PSE&G's electric customers, on average, experienced interruptions of service less frequently than, and the interruptions experienced were of shorter durations than, those experienced by the customers of the other New Jersey utilities.

The results were the same based on a review of IEEE's annual benchmarking survey. PSE&G's reported SAIFI was in the first quartile of all utilities' SAIFI reported to the IEEE during each of the years 2013 to 2022, indicating that, at the very least, PSE&G was in the top 25% of all utilities surveyed. PSE&G's reported CAIDI and SAIDI were also in the first quartile when compared to the companies participating in the IEEE study.

Q. Can you discuss PSE&G's responsiveness to major storm events and emergencies?

A. PSE&G takes pride in maintaining public safety and responding rapidly to major storm events and large scale system emergencies, and working in close collaboration with state, county, and municipal organizations as well as the BPU in accomplishing these goals. The Company's response during these critical times illustrates PSE&G's commitment to providing customers with safe and reliable service and PSE&G's ability to respond to widespread damage and outages.

Since the last base rate case, the State of New Jersey has experienced a number of significant weather events requiring extraordinary preparation, recovery and restoration efforts and associated costs, including Tropical Storm Isaias, Hurricane Ida, the February 2021 Snow Storms, the June 2020 Derecho, the July 2019 Major Storm, and the January 2024 Major Storm. See Schedule PANEL-3 R-1 for the major event reports PSE&G provided to the Board for the six storms that occurred since the Company's last base rate case and the cost detail summaries for each. The Company also continues make storm hardening and resiliency investments on its system to better protect customers and the Company's systems against the effects of increasingly frequent major storms in our service territory. The hardening and OK resiliency efforts since 2018 include the raising and rebuilding of substations located in the FEMA flood zone, additional circuit sectionalizing to minimize customer impact and the conversion of open wire to spacer type construction for better performance during weather events. The Company's proposed treatment of the expenditures associated with the Company's storm recovery efforts since its last base rate case is discussed by Mr. McFadden and Mr. Swetz.

Q. Has PSE&G received any industry awards related to PSE&G's electric distribution reliability performance?

A. PSE&G is a participant in PA Consulting Group's national utility benchmarking program and has received the regional award for the most reliable utility in the Mid-Atlantic region/service area every year since 2002 (for 2001 performance forward), including in 2023 for performance in 2022. In 2018, PSE&G became the first public utility in the United States to obtain Support Anti-terrorism by Fostering Effective Technologies ("SAFETY") Act liability protections from the U.S. Department of Homeland Security for the deployment of physical security measures that are designed to detect, deter and recover from acts of terrorism.

In 2018, PSE&G was the recipient of the Edison Electric Institute ("EEI") Emergency Assistance Award for outstanding work assisting customers impacted by Hurricane Irma. EEI also recognized PSE&G in 2022 with the Edison Award in recognition of efforts to protect New Jersey communities and customers from extreme weather conditions. In 2022, PSE&G ranked first in the East among large utilities for both gas and electric utility residential customer satisfaction studies according to the J.D. Power 2022 studies.

Q. What indicators does PSE&G rely on to measure gas distribution safety and reliability?

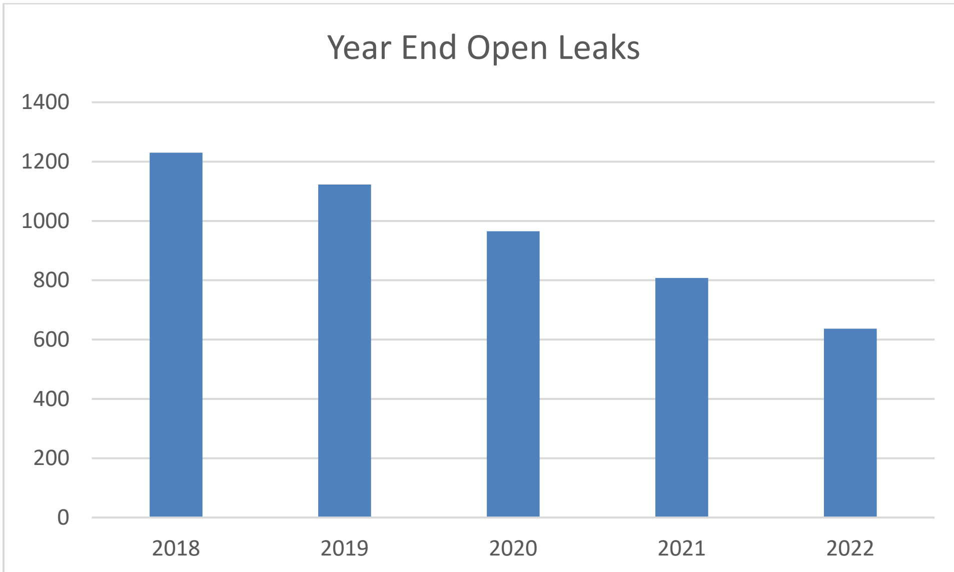
A. The primary performance indicators for gas distribution are (i) gas leak reports per mile; (ii) cast iron breaks per mile; (iii) open leaks; (iv) gas damages per 1,000 locate requests; and (v) leak response time rates. The Company tracks leak data and reports it to the Board. The Company also reports the estimated volume of methane emissions from the distribution system annually as part of the Company's US EPA Greenhouse Gas Reporting Program: Subpart W reporting. Additionally, the Company tracks the following metrics of gas system safety and reliability on the Gas T&D Engineering scorecard: the number of verified times the system pressure exceeds the MAOP (Maximum Allowable Operating Pressure) (not including Utilization Pressure systems); the number of localized areas experiencing unplanned pressures below design minimum (not including Utilization Pressure systems); and the number of metering and regulating ("M&R") station or Plant outages due to unplanned events.

Q. What do these measures show?

A. Every year since 2010, PSE&G has maintained cast iron main leak and break rates and unprotected steel main leak rates below the upper performance limit ("UPL") established following the Company's 2006 rate case, with the single exception of the high pressure cast iron main leak rate in 2014, which exceeded the UPL by 0.094 leaks/mile or approximately 47 leaks as a result of a very severe winter. Additionally, since 2010 the year end open Class 2 leak total has never exceeded the UPL of 1,500 leaks.

Regarding open leaks, the Gas System Modernization Program, discussed later in my testimony, stipulated that from September 30, 2015 through September 30, 2018, the Company is required to reduce its September 30, 2015 inventory of open leaks by sixty percent. The Company has far exceeded that requirement. Through September 30, 2018, this active leak inventory as stipulated in the GSMP case was reduced by 2,365 leaks or 94%. In the GSMP II program the Company is required to reduce its year-end open leak inventory by one (1) percent for each year of the program subject to a year end cap on total open leaks. The Company has again far exceeded that requirement. From January 2019 to December 2022, the year end open leaks has averaged 47% below the cap on open leaks set in the stipulation and as of December 2022 was 61% below the cap. Please see the chart below for year-end open leaks for all classes of leaks.

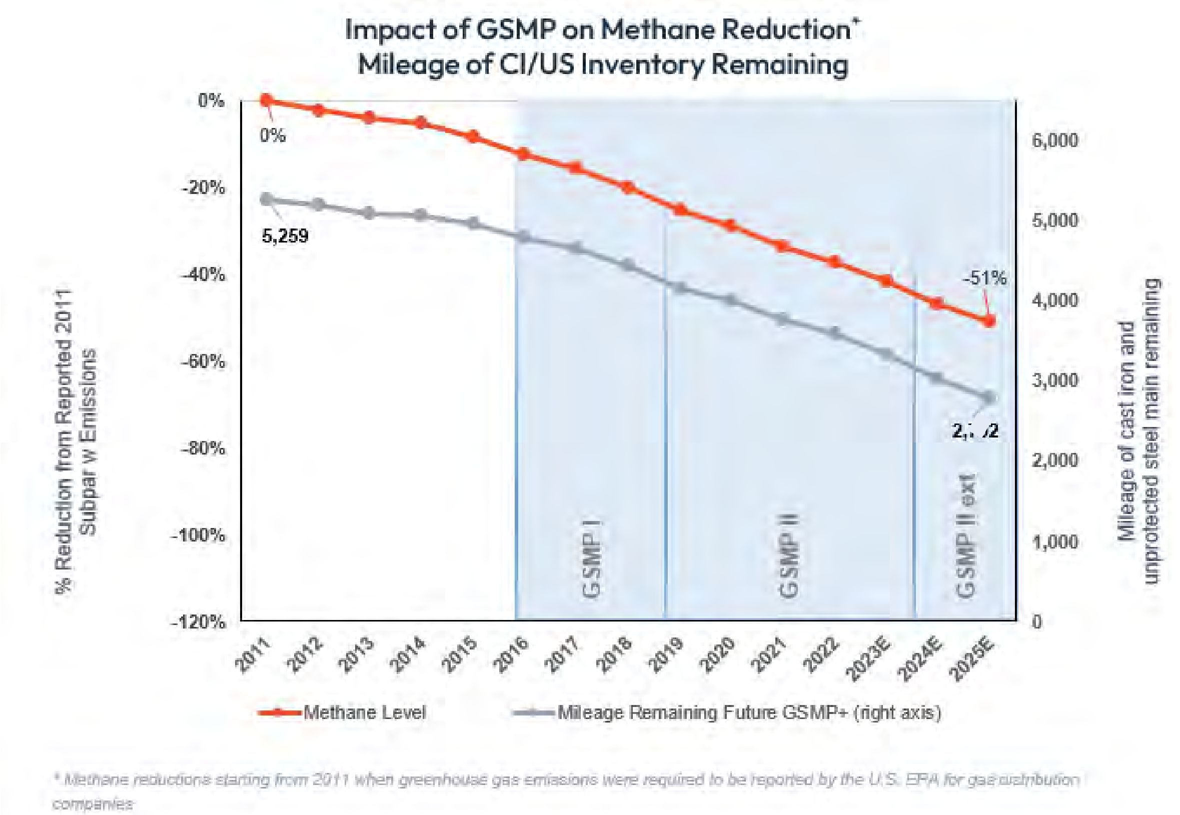
Chart 4



With respect to leak response times, in 2022 the Company's gas service technicians, inclusive of those who perform appliance service work, responded to over 73,618 emergency leak calls, with a 99.98% response rate within 60 minutes, which is top decile performance within our peer group. All identified leaks and hazards were made safe for our customers. Additionally, in 2022 our technicians handled over 211,000 heating related calls in both a timely and expeditious manner. We continue to offer safety checks of gas appliances for proper installation and ventilation and have actively promoted, through bill inserts, customer awareness of the dangers and causes of carbon monoxide poisoning. We conducted 5,063 emergency calls for suspected carbon monoxide emissions on customer premises in 2022. On 37% (1,875) of those calls, our responders found measurable levels of carbon monoxide present. In each instance, PSE&G responders made the premises safe.

The Company has reduced methane emissions approximately 6% annually since 2018 or a total of approximately 145,000 metric tons of Carbon Dioxide equivalent (CO2e). This correlates to the decline in miles of cast iron and unprotected steel main and services in the distribution system as a result of the Company's accelerated replacement programs. Please see the chart below demonstrating the relationship between the main replacement under GSMP programs and methane emissions.

Chart 5



The annual number of overpressure excursions has declined from 9 in 2018 to 5 in 2022. There have been no areas experiencing unplanned pressures below design minimum in the years from 2018 through 2022 and only 2 occasions of unplanned M&R station or plant outages in this timeframe, with the last occurrence in 2020.

Q. Please discuss the Company's efforts to promote New Jersey's energy policy goals.

A. The Company recognizes and understands that many of our customers have redefined how they go about their day-to-day activities, including how and where they work, study, and even fuel their vehicles. This shift makes the provision of safe, reliable, resilient, and sustainable energy all the more important in meeting the evolving needs of the Company's customers, and aligning with the state's goals for a clean energy future. To date, PSE&G has recognized the evolution of the state's energy policies and the Energy Master Plan and aligned its investment and operating policies accordingly, including by accelerating the modernization and decarbonization aspects of the Company's strategy with programs such as:

1. The Infrastructure Advancement Program ("IAP"), which includes "last mile" improvements (or improvements to the portion of the grid that brings power from substations to customers' homes and businesses) and updates to PSE&G's aging electric substations and gas M&R stations.

2. The Energy Strong programs, which serve to further strengthen the Company's statewide electric and gas systems to better withstand storms, improve reliability and significantly enhance resiliency. The latest iteration of the program – Energy Strong II – includes investments to harden the electric infrastructure from the effects of major weather events, improve resiliency, allow for faster restoration of outages and ensure safe and reliable service by replacing facilities when they reach the end of their service lives. Hardening work under Energy II includes rebuilding or eliminating 16 stations in flood zones, building or modernizing six M&R stations and upgrading the construction standard on some distribution circuits. Resiliency work includes technology investments that will improve field communications, make the system smarter and more efficient, and allow the grid to handle more solar and other distributed green energy sources.

3. The Gas System Modernization Programs ("GSMP"), addresses the potential safety and environmental concerns associated with leaks from aging cast iron and unprotected steel pipe in PSE&G's inventory as well as inside gas meter sets, consistent with the state's

Energy Master Plan, New Jersey's Global Warming Response Act, the 80X50 Report,[4] and federal legislation, and consistent with Governor Murphy's 2023 Executive Orders related to the State's Clean Energy goals.

4. The Clean Energy Future Programs ("CEF"), such as the CEF-Energy Efficiency Program ("CEF-EE"), CEF-Energy Cloud ("CEF-EC") (deployment of advanced metering infrastructure), and CEF-Electric Vehicles ("CEF-EV") Programs. Together, these initiatives form the basis for a clean and resilient energy future.

5. PSE&G has supported state goals on solar develop since the last rate case through ongoing customer solar interconnections. As of November 1st of 2023, PSE&G has interconnected over 83,000 solar installations with a cumulative capacity of over 1,400 MW (AC) which represents a 106% and 81% increase from 2018 in installations and capacity, respectively. These numbers reflect PSE&G's commitment to support clean energy while maintaining safe and reliable service to all customers.

Q. Please address cost containment efforts.

A. To contain increasing operating costs, the Company has employed a variety of cost control efforts to minimize customer rate impacts, while continuing efforts to provide safe, reliable and quality service to our customers. I highlight specific examples of capital and O&M-related management efforts below in sections III and IV, respectively.

[4] New Jersey's Global Warming Response Act 80x50 Report, https://dep.nj.gov/wp-content/uploads/climatechange/nj-gwra-80x50-report-2020.pdf , rel. October 15, 2020.

Q. Please address customer satisfaction.

A. In general, J.D. Power customer satisfaction results demonstrate PSE&G's strong performance and focus on improvement. PSE&G is included in J.D. Power's Customer Satisfaction Studies in the "Large Utility East" segment. J.D. Power conducts customer satisfaction surveys of (1) electric residential customers; (2) electric business customers; (3) gas residential customers; and (4) gas business customers. As discussed by Company witness Mr. Adams, among electric residential customers PSE&G was ranked in the first quartile for customer satisfaction in every year during the period 2013-2022, except for 2013 and 2014, when it ranked in the second quartile. In the most recent J.D. Power results for the calendar year 2022, electric residential customers ranked PSE&G in the first quartile (and first overall). PSE&G was ranked in the first or second quartile by its electric business customers during each of the years 2013 through 2022, including rankings in the first quartile (and second overall) by its electric business customers in the most recent survey, i.e., 2022.

Q. Does Mr. Adams also provide data on gas customer satisfaction?

A. Yes. PSE&G was ranked in the first or second quartile by its gas residential customers in each of the years 2013 through 2022. In fact, PSE&G's gas residential customer satisfaction rating improved year-over-year for nine straight years, from 2014 to 2022. In the most recent results released by J.D. Power for the calendar year 2022, gas residential customers ranked PSE&G in the first quartile (and first overall). Finally, PSE&G's gas business customer satisfaction rating improved year-over-year each year from 2019 to 2021 and was ranked in the first quartile (and third overall) in 2022.

Q. Has PSE&G received any industry awards related to PSE&G's gas distribution safety performance?

A. Yes, PSE&G has received multiple industry awards related to gas distribution safety performance since the last rate case as follows:

2022:

- American Gas Association (AGA) 2022 Leading Indicator Safety Award, in recognition of proactive commitment to enhancing safety
- AGA 2022 INDUSTRY LEADER ACCIDENT PREVENTION – Mega, for achieving a DART- incident rate below the industry average for its company type

2021:

- AGA 2021 INDUSTRY LEADER ACCIDENT PREVENTION – Mega, for achieving a DART- incident rate below the industry average for its company type
- 2021 bronze award in the communications category of the Chartwell Best Practices Award competition for PSE&G's 2020 gas-safety customer education campaign.

2020:

- AGA 2020 INDUSTRY LEADER ACCIDENT PREVENTION – Mega, for achieving a DART- incident rate below the industry average for its company type

2019:

- AGA 2019 INDUSTRY LEADER ACCIDENT PREVENTION – Mega, for achieving a DART- incident rate below the industry average for its company type

2018:

- PSE&G became the first public utility in the United States to obtain SAFETY Act liability protections from the U.S. Department of Homeland Security for the deployment of physical security measures that are designed to detect, deter and recover from acts of terrorism.
- AGA 2018 INDUSTRY LEADER ACCIDENT PREVENTION – Mega, for achieving a DART- incident rate below the industry average for its company type.

Q. Please summarize your conclusions regarding PSE&G's electric and gas distribution operational performance.

A. As an organization, PSE&G is focused on providing safe and reliable service, controlling costs, and delivering a high level of customer satisfaction. The Company continually strives to improve performance year after year to meet these goals, and has been successful in these efforts. This is evident in the two charts below from 2021. Chart 6 below illustrates PSE&G's electric SAIDI performance compared to distribution O&M while Chart 7 shows our leak response rate compared to distribution O&M. These charts demonstrate our commitment to providing excellent service at reasonable costs.

Chart 6

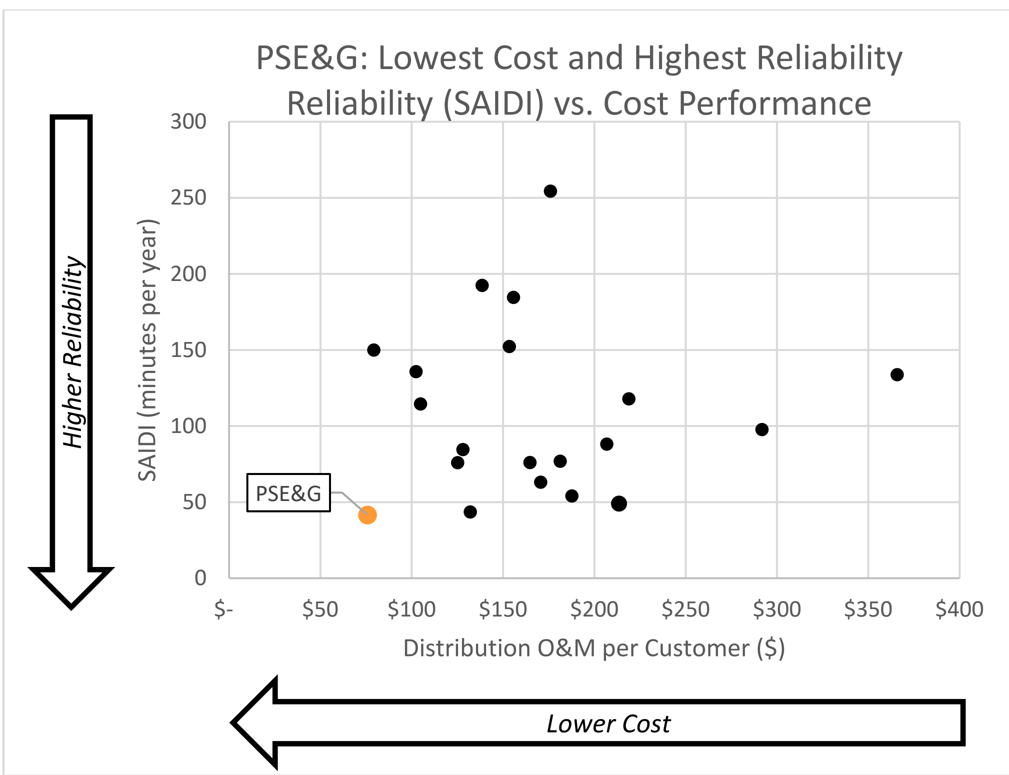
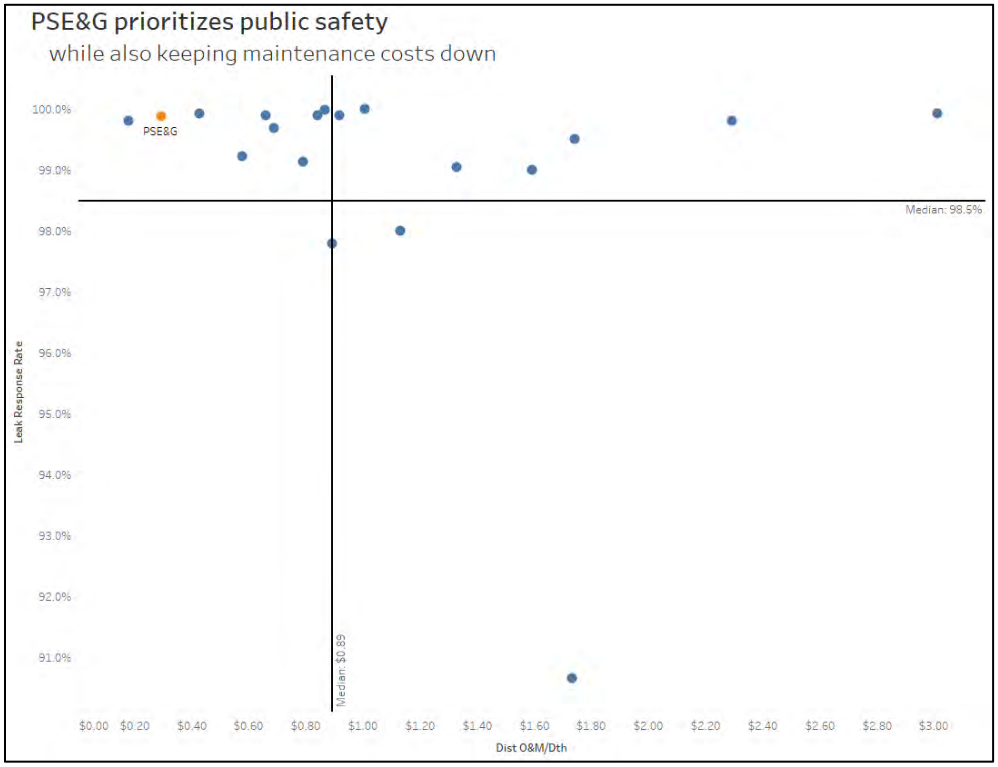


Chart 7



III. CAPITAL EXPENDITURES

A. Electric and Gas Capital Budget Process/Cost Controls

Q. How does PSE&G develop its capital budget and review, approve and monitor electric capital expenditures?

A. PSE&G has an extensive, multi-layer process to develop its annual capital plan and review, approve and monitor capital expenditures from project inception to completion. The Company’s capital processes have been reviewed favorably by an independent monitor, Pegasus Global Holdings, Inc. (“Pegasus”) that was retained for the Energy Strong I and Energy Strong II Programs after consultation with Board Staff and the New Jersey Division of Rate Counsel (“Rate Counsel”).

Q. Why has an independent monitor considered PSE&G's capital review process?

A. The May 21, 2014 BPU Order ("Energy Strong I Order") in BPU Docket Nos. EO13020155 and GO13020156 approving the Company's initial Energy Strong Program – an accelerated infrastructure replacement program – required the Company to retain an independent monitor to review Energy Strong project development and implementation. The September 11, 2019, BPU Order in BPU Docket Nos. EO18060629 and GO18060630 ("Energy Strong II Order") (collectively, with the Energy Strong I Order, the "Energy Strong Orders"), which authorized the Company to undertake a second phase of the Energy Strong Program, similarly required the retention of an independent monitor. The Energy Strong II Order authorized the Company to continue making reliability and resiliency investments, including rebuilding and raising critical electrical equipment, installing stronger poles and wires, deploying advanced technology, building backup pipes, modernizing critical gas equipment, and improving customer service. While the requirement to retain the independent monitor derives from the Energy Strong Orders, the processes reviewed by Pegasus apply uniformly to all capital investments, not just those related to Energy Strong I and II.

Q. Has the Energy Strong independent monitor, Pegasus, documented its review?

A. Yes. The Energy Strong Orders required that the independent monitor review and report to Board Staff and Rate Counsel on cost effectiveness, efficiency, appropriate cost assignment, and other information. Since the retention of Pegasus, all of the monitor's annual and quarterly reports ("Pegasus Reports") have been submitted to Board Staff and Rate Counsel, and non-confidential copies of these reports are included herein as Schedule PANEL-4(a) R-1.

Q. What do the Pegasus Reports demonstrate?

A. Among other things, the findings contained in the Pegasus Reports support the conclusion that PSE&G's capital budgeting processes and cost control practices are comprehensive, sound, and effective. These findings are contained in Schedule PANEL-4(a) R-1.

Q. Please describe the development of the Company's capital plan.

A. To develop the annual capital budget, each year's spending for individual proposed projects is compiled and placed into one of three project categories: (i) tariff/legal projects, which are generally non-discretionary and identified through external parties (*e.g.*, to support new service, or dictated by environmental or regulatory requirements); (ii) minimum projects, which are projects required to assure immediate continuity of safe and reliable basic utility service (*e.g.*, pole replacements, replacement of defective/failed facilities); and (iii) priority projects, which are discretionary projects. Spending in all categories is based on cost estimates submitted by subject matter experts from various departments (*e.g.*, project managers, project cost engineers, system planners) within the organization. Once the annual budget is developed, it is then reviewed and approved by the Company's Utility Review Board ("URB"), which consists of senior officers of PSE&G, as well as senior officers from other key support areas.

Q. Are there additional approvals needed before a project or program in the annual capital plan can proceed?

A. Yes. Aside from the capital planning and budgeting process, specific approval must be obtained for any project or program within the capital plan. All PSE&G major capital investments, whether undertaken as base capital spending or pursuant to an accelerated infrastructure program such as Energy Strong, must be approved at the appropriate management level within the Company. The extent of approval and documentation required is largely dependent on the expected dollar value of the investment. PSE&G's Utility Capital Review Board ("URB") reviews and approves blanket spending (aggregated spending on projects with similar repetitive work, *e.g.,* electric distribution poles, gas pipe, meters) in which individual items are each less than $5 million, and specific project investment requests where capital requests are less than $20 million. In addition, any capital investment exceeding 5% of previously approved amounts must be reported to the URB, and any investment exceeding 10% of previously approved amounts requires re-approval. The URB is required to review project alternatives and to recommend for approval projects requiring consideration by the Company's Capital Review Committee ("CRC"). The CRC is responsible for reviewing, analyzing, and approving (to the extent not otherwise required by the Company's Board of Directors, in which case the CRC recommends approval to that body) capital investments greater than $20 million. To be reviewed by the CRC, approval must have been previously given by the URB. For projects greater than $50 million, the CRC will recommend approval to the Company's Chief Operating Officer ("COO"), and for projects greater than $100 million, the Company's Board of Directors will review, analyze and approve projects accordingly.

For CRC meetings, the PSE&G Finance Department (part of PSEG Services Corporation, the Company's services company) has the responsibility to assure completeness of all project financial analyses, record CRC authorizations, and ensure project closeouts are completed. Notably, the Company uses a phased-funding approach to releasing funds for projects based on acceptable progress, and for continued project justification.

Q. Please explain how capital projects are selected and optimized.

A. The process used by PSE&G to select and prioritize electric and gas distribution capital spending plans has been in place since 2004. PSE&G selects projects by evaluating various factors, including whether the project is legally mandated, its operational requirements, and the extent to which the project supports the continued provision of safe, adequate, proper, and reliable utility service. The risk associated with not funding and performing each proposed investment is also evaluated to identify potential adverse consequences of not performing the work. PSE&G then determines the optimal portfolio combinations of work to be resourced and performed, so that value is optimized for the available level of resources within the electric and gas businesses.

Q. What protocols are followed to ensure that PSE&G's expenditures are reasonable and cost effective?

A. The policies and procedures that PSE&G has in place to ensure effective cost control for our capital projects are set forth in the Pegasus Annual Report included with Schedule PANEL-4(a) R-1. The Company undertakes a comprehensive approach applying cost control measures to all phases of its major capital projects, including Project Initiation, Design, Scheduling, Contracting, Material Procurement, and Construction. For example, during the Project Initiation phase, projects undergo a rigorous process of funding requests and project review and are subject to estimating procedures that utilize four cost estimating phases through which, as a project moves towards certainty, the tighter the cost estimate needs to become. Numerous procedures are also applied during the Design, Scheduling, Contracting, Material Procurement, and Construction phases to facilitate cost control, including project scope and invoice management, competitive bidding, and strict construction oversight. The Company's policies and procedures are extensive, well documented and afford the Company the opportunity to discern and mitigate potential project cost overruns and ensure that the Company's expenditures are reasonable and cost effective.

Q. Please describe some of the specific practices the Company uses to control costs associated with electric and gas distribution capital expenditures.

A. The Company utilizes various methods to cost-effectively manage its electric and gas distribution capital program including, where possible, undertaking planned rather than reactive capital work and coordinating capital programs between electric and gas operations, as well as with third parties. PSE&G also benchmarks costs to help track and manage capital expenditures. For example, the Company tracks cost per mile and cost per foot information, allowing monitoring of capital expenditures in relation to original budgets and to make appropriate changes where possible.

The Company's gas distribution business has established a group dedicated to project management and implemented new software for managing project and construction activities. PSE&G has also partnered with critical material providers to strategically source construction supplies, helping to obtain bulk pricing and receive direct deliveries to job sites to help facilitate cost control and minimize risk of construction work delays.

B. Electric Capital Expenditures

Q. Please describe PSE&G's electric capital spending since its last base rate case.

A. The Company's electric distribution rates were last reset in a base rate case approved by the Board in 2018. Since that time, PSE&G has invested a substantial amount of capital -- approximately $3.3 billion, of which $2.4 billion was placed in service, net of retirements -- in new electric distribution plant and services equipment through May 31, 2023. The majority of these investments were for various projects focused on maintaining and improving reliability. As reflected on Schedule PANEL-2(a) R-1, the Company projects that during the period June 1, 2023 through November 30, 2024, it will complete investments in electric distribution plant totaling $2.0 billion. This level of investment was and is required to maintain and further enhance safe and reliable service to customers, support a continuation of the Company's infrastructure hardening and modernization efforts, and facilitate PSE&G's ongoing commitment to provide excellent service to customers.

Q. Please summarize the Company's test year and post-test year electric capital expenditures set forth on Schedule PANEL-2(a) R-1.

A. As reflected on Schedule PANEL-2(a) R-1, the Company expects to incur electric capital expenditures of approximately $1.4 billion during the test year and approximately $0.6 billion in the post-test year period in various spending categories that are described further below. In service test year investments amount to $1.4 billion and post-test year investments total $0.4 billion. The test year and known and measurable post-test year expenditures that will be placed in-service by November 30, 2024 are reflected in Mr. McFadden's Schedule MPM-7 R-1.

Q. What are the test year pre- and post-test year electric capital expenditure categories reflected on Schedule PANEL-2(a) R-1?

A. The test year, pre- and post-test year expenditure categories reflected on Schedule PANEL-2(a) R-1 include the major categories of electric investment described below:

1. Facilities Replacements

Q. Please explain the electric Facilities Replacements expenditures reflected on Schedule PANEL-2(a) R-1 for the test year, pre- and post-test year periods.

A. Test year, pre- and post-test year expenditures in this category involve the replacement of defective or aging equipment and facilities to maintain the integrity of the electric infrastructure and to replace large equipment failures that may occur. The expenditures also include ongoing work to replace specific types of electric equipment, such as capacitors, street lights, poles, transformers, breakers, and replacement meters; underground facilities such as cables; and inside plant and substation facilities.

2. System Reinforcements

Q. Please explain the electric System Reinforcement expenditures reflected on Schedule PANEL-2(a) R-1 for the test year and post-test year periods.

A. System Reinforcements involve expenditures associated with increasing electric system capacity to accommodate customers' peak demand and capacity requirements and enhance the system's ability to provide high levels of reliable service under adverse conditions, ensuring that the Company continues to meet its reliability goals and design criteria. These expenditures predominantly include investments in electric facilities such as new substations and work done to improve the poorest performing circuits. These circuits are defined as the 4kV and 13kV circuits in each division with the poorest combined performance in terms of number of outages and total customer hours of interruption. Other expected system reinforcement funding areas include pole reinforcements, animal guards, and other reliability improvement programs.

New Business Category

Q. Please explain the types and amounts of costs associated with the electric New Business category reflected on Schedule PANEL-2(a) R-1 for the test year/post-test year periods.

A. The New Business category includes the costs of connecting new electric customers or upgrading existing services. This includes costs for meters, street and private area lighting, and the service connections for electric residential and smaller business customers, as well as the specific connection costs for large electric customer projects. Capital expenditures for new business are driven primarily by the number and type of new customers that PSE&G is required to serve. Test year and post-test year expenditures on Schedule PANEL-2(a) R-1 include the costs to serve new customers in the test year/post-test year period. Historically, large contributors to the capital plan include data centers, retail business expansions, as well as high-rise apartments and condominiums throughout the state. To illustrate the size and impact of data centers, in the past 10 years, PSE&G has invested $30 million in infrastructure to support data centers through 2022, with an additional ~$40 million for projects in the pipeline. Also, PSE&G has seen an increase in applications for electric vehicles in all customer categories, though for residential customers the requests are categorized as upgrades to existing service rather than new service. Businesses, on the other hand, often require new service as the requirements are large and may not be located near the existing service (e.g., electric vehicle charging station in far end of supermarket parking lot). Lastly, PSE&G has been monitoring other expected impacts to electric new business, including electrification of ports, transportation, fleets, and other large customer categories.

3. Environmental/Regulatory Category

Q. Please explain the costs reflected in the electric Environmental/Regulatory category for the test year/post-test year periods.

A. Expenditures in this category include the costs associated with non-discretionary relocation of facilities and miscellaneous projects needed to meet environmental or regulatory obligations. The greatest driver of the test year/post-test year expenditures within this category is the costs to relocate facilities to facilitate municipal construction projects. Other test year/post-test year expenditures within this category include the costs related to compliance with the Environmental Protection Agency's Spill Prevention, Control, and Countermeasure Program.

4. Facilities Support

Q. Please discuss the costs reflected in the electric Facilities Support category for the test year/post-test year periods.

A. Major expenditures included in this category on Schedule PANEL-2(a) R-1 are associated with support facilities such as buildings, vehicles, and similar miscellaneous expenditures. This category includes costs related to the replacement of the Company's vehicle fleet used to support electric distribution operations. The vehicles being replaced are at the end of their life cycle and cannot be cost effectively maintained. This category also reflects expenditures associated with the replacement of electric distribution radio equipment, which similarly has reached the end of its life cycle.

5. Energy Strong II (Electric)

Q. Please describe the Energy Strong II Electric Program.

A. The costs in this category are expenditures associated with Energy Strong II Program electric investments that will be placed in service during the test year and post-test year. In the Energy Strong II Order, the BPU authorized a second phase of PSE&G's Energy Strong Program to make further investments aimed at improving the reliability and resiliency of the Company's electric and gas systems by rebuilding and raising critical electrical equipment, installing stronger poles and wires, deploying advanced technology, building backup pipes, modernizing critical gas equipment, and improving customer service. The Energy Strong II Program has a four-year term, commencing on October 1, 2019, with work expected to conclude by December 31, 2023, subject to certain exceptions in the Board's Order. Under the Energy Strong II Program, PSE&G is authorized to make $641 million in electric capital investments, spread among the following sub-programs:

- $389 million for Electric Station Flood Mitigation, to mitigate storm risks at 16 identified electric stations;
- $145 million for Contingency Reconfiguration, to harden its electric distribution system and increase system resiliency by implementing contingency reconfiguration strategies;
- $72 million for Grid Modernization, Communications, which includes installation of a private wireless communications network and eliminate the use of dedicated phone lines for remote communication for both PSE&G and customer equipment; and
- $35 million for Grid Modernization, to replace the existing Outage Management System with an Advanced Distribution Management System ("ADMS") that will incorporate data from Geographic Information System and SCADA, intelligent fault indicators, Smart Meters, and other advanced metering infrastructure.

In addition, $100 million was also designated for stipulated base, which includes outside plant higher design and construction standards and/or electric life cycle subprogram project.

Q. Please describe the Energy Strong II Program electric investments in service and projected through the end of the Program.

A. For Energy Strong II the cost placed into service are shown in the table below:

Program Summary	Total Cost Placed in Service ($M)	
Electric Stations Flood Mitigation	$	336.1
Contingency Reconfiguration	$	145.5
Grid Modernization, Communication	$	63.6
Grid Modernization, ADMS	$	17.4
Stipulated Base	$	77.7
Total	**$**	**640.3**

Stipulated Base	Total Spending Through Program	
Total	$	100.0

Q. Have any of these Energy Strong II capital investments been placed into rates?

A. The Energy Strong II Program approval Order permits the Company to file for rate adjustments to include Energy Strong II electric investments in the Company's rates.

Since the Company's previous base rate case, the Board has authorized four rate adjustments for Energy Strong II electric investments, which included capital investments of $447.1 million, or $456.9 million inclusive of allowance for funds used during construction. These investments were authorized by the Board to be included in base rates on a provisional basis subject to review in this rate case.[5]

The reasonableness and effectiveness of the costs underlying the rates implemented pursuant to these adjustments, as well as the success of the Energy Strong II Program, is supported by the findings contained in the Reports of the Energy Strong Independent Monitor that are attached as Schedule PANEL-4(a) R-1. In addition, the Company provides quarterly

[5] On November 1, 2023, PSE&G filed a fifth rate adjustment request under Docket No. ER23110784.

reports to Board Staff and Rate Counsel pursuant to the Energy Strong II Order that contains detailed information about Energy Strong II Program costs, ongoing reliability performance, and satisfaction of program goals. A copy of the most recent Energy Strong II quarterly report is attached as Schedule PANEL-4(b) R-1.

Q. Turning now to Energy Strong II Program expenditures that will be incurred during the test year, are these expenditures reflected on Schedule PANEL-2(a) R-1?

A. Yes. Schedule PANEL-2(a) R-1 reflects Energy Strong II electric investments that will be undertaken during the test year. As explained by Company witness Mr. McFadden, PSE&G's filing in this case reflects certain ratemaking adjustments to ensure the Company does not double count the revenues associated with Energy Strong II investments that are expected to be captured in the rate adjustments expected to occur during the test year.

6. Infrastructure Advancement Program

Q. Please describe the Infrastructure Advancement Electric Program ("IAP").

A. The costs in this category are expenditures associated with IAP electric investments that will be placed in service during the test year and post-test year. The IAP was authorized by Board Order dated June 29, 2022, in BPU Docket Nos. EO21111211 and GO21111212 ("IAP Order"). The IAP Order authorizes the Company to invest up to $281.2 million in electric system upgrades to improve last mile reliability while supporting the electrification of the transportation sector and increased use of Distributed Energy Resources. The authorized IAP electric investments are split into two sub-programs:

- $91 million for the Electric Outside Plant Subprogram, including the Spacer Cable Conversion Project, the Lashed Cable Replacement Project, Electric Station Flood Mitigation, the Spacer Upgrade Project, the Conventional Underground Cable Replacement Project, and the Voltage Optimization Project; and

- $190.2 million for the Substation Modernization Program, which includes the 26kV Station Upgrade Project and the 4kV Substation Modernization Project to upgrade equipment at 5 stations. The IAP Order also requires the Company to spend a Stipulated Base of $160 million on certain capital projects to be recovered through base rates, $142.6 million of which shall be spent on electric system investments in specified categories.

Q. Have any IAP electric expenditures been reflected in rates?

A. There are currently no IAP electric expenditures included in the Company's rates. The Company filed for its first IAP rate adjustment on November 1, 2023 in BPU Docket No. ER23110783.

Q. Are any electric expenditures related to the IAP included in the test year or post-test year, as shown on Schedule PANEL-2(a) R-1?

A. Schedule PANEL-2(a) R-1 reflects IAP electric investments that will be undertaken during the test year. As explained by Company witness Mr. McFadden, PSE&G's filing in this case reflects certain ratemaking adjustments to ensure the Company does not double count the revenues associated with IAP investments that are expected to be captured in the rate adjustments expected to occur during the test year and post-test year periods.

7. NJ Transit Mason Substation Replacement

Q. Please describe the Company's NJ Transit Mason Substation Replacement Project.

A. By Order dated November 21, 2017, the Board approved a plan to demolish facilities known as the Mason Substation, comprising a number of facilities and electric plant that at the time was owned by New Jersey Transit Corporation ("NJ Transit"), and to rebuild and modernize the facilities under PSE&G ownership. The substation, which is a crucial facility for both NJ Transit and northern New Jersey, suffered severe damage during Superstorm Sandy.

The cost of the rebuilt facility is shared between NJ Transit and PSE&G. The Board authorized PSE&G to recover its prudently incurred investment of up to $100 million plus an Allowance For Funds Used During Construction in a later base rate case. To date, $60 million of investment in the Mason Substation has been placed in-service, and the remaining $40 million will be placed in-service by November 30, 2024. PSE&G's final cost to complete the project will be $100 million. This cost was prudently incurred to enable PSE&G to continue to provide safe and reliable electric service in the northern New Jersey portion of its service territory. There is no question that the Mason Substation is necessary to support the electricity requirements of both NJ Transit and PSE&G and its other customers. Moreover, in proceeding with this Board-approved project PSE&G followed all of the practices and procedures I have described previously that ensure that PSE&G's share of the cost of this essential facility remained reasonable.

Q. What costs for the NJ Transit Mason Substation Replacement Project are being included in rates?

A. The Company has included in rates $100 million of costs prudently incurred to rebuild the structure. That figure includes costs that will be incurred in the post-test year period.

C. Gas Capital Expenditures

Q. Please describe PSE&G's gas capital spending since its last base rate case.

A. Since the Company's last gas distribution rate case it has invested a substantial amount of capital -- approximately $4.3 billion -- in new gas distribution plant through May 31, 2023. The majority of these investments were for the replacement of aging infrastructure and the hardening of the gas distribution system. As reflected on Schedule PANEL-2(b) R-1, the

Company projects that during the period June 1, 2023 through November 30, 2024, PSE&G will complete investments in new gas distribution plant totaling almost $1.8 billion. As with electric distribution, this level of gas distribution investment was and is required to maintain and enhance safe and reliable service to customers, support a continuation of our infrastructure investment efforts, and facilitate our ongoing commitment to provide excellent service to our customers.

Q. Please summarize the Company's test year and post-test year gas distribution capital expenditures set forth on Schedule PANEL-2(b) R-1.

A. As reflected on Schedule PANEL-2(b) R-1, the Company expects to incur gas system capital expenditures of approximately $1.2 billion during the test-year and approximately $0.6 billion in the post-test year in various spending categories that are described further below. In service test year investments amount to $1.1 billion and post-test year investments total $0.6 billion. The test year and known and measurable post-test year expenditures that will be placed in-service by November 30, 2024 are set forth in Mr. McFadden's testimony at Schedule MPM-7 R-1.

Q. What are the test year and post-test year gas capital expenditure categories reflected on Schedule PANEL-2(b) R-1?

A. The test year/post-test year expenditure categories reflected on Schedule PANEL-2(b) R-1 include the major categories of gas investment described below:

1. Facilities Replacements

Q. Please describe the Facilities Replacements gas expenditures reflected on Schedule PANEL-2(b) R-1 for the test year and post-test year periods.

A. The Facilities Replacements category reflects expenditures associated with replacing defective or aging gas facilities. Test year and post-test year gas expenditures in this category include the replacement of approximately 265 miles of cast iron and unprotected steel mains, 18,150 services, 53 regulators, 223,000 gas meters and 15,000 house regulators. Mains and services replacements are prioritized in accordance with PSE&G's federally-mandated Distribution Integrity Management Program ("DIMP"), with the objective of enhancing safety by identifying and reducing gas distribution pipeline integrity risks. A pipeline integrity risk assessment is conducted as part of the DIMP and considers risk factors such as leak and break history, consequence of pipeline or pipeline component failure, operating and maintenance experience, and regulatory requirements. Expenditures in this category also include the replacement of certain metering and regulating equipment, and the replacement of certain pounds-to-pounds regulating station equipment. Notable projects in this category include the reconstruction of the Glen Rock pounds-to-pounds regulating station with a total projected cost of $19.5 million and replacement of a section of the Harrison lateral transmission line crossing multiple railroads with a total projected cost of $28.0 million.

2. System Reinforcements

Q. Please explain the System Reinforcement expenditures reflected on Schedule PANEL-2(b) R-1 for the test year and post-test year periods.

A. System Reinforcement expenditures are costs associated with increasing gas system capability to accommodate customers' peak demand and capacity requirements and for enhancing the system's ability to provide high levels of reliable service under adverse conditions. Test year and post-test year gas expenditures in this category include the encapsulation of approximately 5,459 cast iron bell joints of various sizes, the installation of 23.7 miles of new gas mains and two new pounds-to-pounds regulating stations to reinforce system pressures, and the installation of cathodic protection devices, including testing stations, anodes and insulators on existing protected steel mains. Two major projects in this category are the Chatham System Reinforcement Project ("Chatham Project"), with a total projected cost of $19.7 million and the Haddon Township System Reinforcement Project ("Haddon Project") with a total projected cost of $15.7 million. The Chatham Project involves the conversion of the existing M&R station from a 15 PSI outlet pressure station to a 120 PSI outlet pressure station, the installation of approximately two miles of reinforcement main, and the installation of a new 120 PSI to 15 PSI pounds-to-pounds regulating station. This project enables the Company's Northern 15 PSI system to maintain adequate pressures at system low points in Springfield under design day demand conditions. The Haddon Project involves the installation of approximately two miles of reinforcement main and the installation of a new 60 PSI to 15 PSI pounds-to-pounds regulating station. This project enables the Company's Brooklawn-Camden 15 PSI system to maintain adequate pressures at system low points Haddon Heights, Barrington and Haddonfield under design day demand conditions.

3. New Business

Q. Please describe the gas New Business expenditures reflected on Schedule PANEL-2(b) R-1 for the test year and post-test year periods.

A. New Business expenditures are costs incurred to connect new gas customers or upgrade existing services. Capital expenditures for gas new business depend largely on the number and type of new gas customers that PSE&G is required to serve. The expenditures reflected on

Schedule PANEL-2(b) R-1 reflect the costs associated with service connections for new residential, commercial and industrial customers in the test year/post-test year period.

4. Environmental/Regulatory

Q. Please describe the Environmental/Regulatory gas expenditures reflected on Schedule PANEL-2(b) R-1 for the test year and post-test year periods.

A. Environmental/Regulatory expenditures are costs associated with projects needed to meet mandated environmental or regulatory obligations. Test year and post-test year gas expenditures in this category include various items related to environmental/regulatory compliance. Major test year expenditures in this category include the costs associated with service-cut-offs, as well as the costs related to unprotected steel service replacements as required by the *N.J.A.C.* 14:7-1.20, and main and service relocations due to municipal requirements. Test year/post-test year expenditures also include work involving pipeline replacement and construction to support ongoing integrity assessments in conformance with PSE&G's Gas Transmission Integrity Management Plan (or "TIMP") required under 49 CFR Part 192. Major projects within this category include multiple pipeline modifications to allow for integrity assessments utilizing robotic technology, to ensure compliance with 49 CFR Part 192.

5. Facilities Support

Q. Please describe the Facilities Support gas expenditures reflected on Schedule PANEL-2(b) R-1 through the end of the test year and post-test year periods.

A. Facilities Support expenditures are costs associated with support facilities such as buildings, vehicles, and similar miscellaneous expenditures. The projects included in the Facilities Support expenditures during this period include the relocation of the Oradell Gas District Headquarters due to ongoing flooding issues at the current location. This category also includes necessary building improvements at the Company's twelve (12) Gas District Headquarters, the replacement of gas distribution fleet and radio equipment and security upgrades associated with Transportation Security Administration ("TSA") critical facility requirements. These security upgrades will take place, for example, at certain gas M&R stations and at transmission valve sites, where upgrades may include electronic access controls, security cameras, motion detectors, upgraded fencing and locking devices with patent keys.

6. Energy Strong II (Gas)

Q. Please describe the Energy Strong II Gas Program.

A. The Energy Strong II Order authorized the Company to make $50.5 million in gas system investments as part of the M&R Station Upgrades sub-program to rebuild/modernize M&R stations on the Company's gas system.

The Gas M&R Station Upgrade subprogram involved the modernization of the design of six (6) M&R stations to reduce the likelihood and consequence of equipment failure. The existing stations in the subprogram had an outdated design with upstream relief valves and single regulation runs. This arrangement can lead to a methane emission release through the relief valves in the event of a single regulator failure. The new design greatly reduces the likelihood of methane release. Additionally, the upgrades replaced aging facilities and hardened facilities located in the flood zones against severe flooding events. Two stations in the subprogram (Camden and East Rutherford) are in FEMA flood zones.

The project work under the Gas Metering & Regulating Upgrades subprogram commenced in the beginning of October 2019, with all the project works to be completed before the end of the test year. Under the Energy Strong II Accelerated Recovery Rate

Mechanism, up to $50.5 million was invested by the Company to rebuild and modernize the following M&R stations:

- Camden
- Central
- East Rutherford
- Mount Laurel
- Paramus
- Westampton

Any prudently incurred costs for work on the six M&R stations that exceeded $50.5 million has been credited toward the Company's stipulated base requirement, as authorized by the Energy Strong II Order.

Q. Please describe the Energy Strong II Program gas investments and projects placed in service through May 31, 2023, prior to the commencement of the test year.

A The Camden, East Rutherford and Westampton M&R station upgrade projects were placed into service prior to the test year. The upgrade work associated with these M&R stations included removal of existing PSE&G regulation and Remote Terminal Unit ("RTU") buildings and foundation, existing pipeline company regulators, and downstream piping. This work also included the installation of new buildings to house pressure regulation equipment, RTU functions, and, at Camden, a new boiler gas heating system. The Company also installed new yard piping from the point of ownership change to the new regulator and new RTU and associated equipment at the three sites. Series regulator runs designed as a working regulator and a standby monitor regulator for on-site systems were installed at the three stations, along with downstream piping with new relief valves as a second line of overpressure protection. The scrubber, blowdown tank and associated piping connections, backup generator, and Monoethylene Glycol unit and associated piping connections at each facility were replaced, and the Company made upgrades to electrical and lighting systems and installed new security measures (*e.g.*, cameras, access control, door alarms). At the Camden and East Rutherford stations, PSE&G also elevated all buildings and sensitive equipment to a minimum of the FEMA 100-year flood elevation plus one foot (+ 1 ft) as part of the station upgrade. The Company also replaced existing water bath gas heaters at the Camden and East Rutherford stations.

Q. Have any of these Energy Strong capital investments been rolled into rates?

A. The Board has authorized two rate adjustments for Energy Strong II gas investments, which included capital investments of $50.5 million, or $51.9 million inclusive of allowance for funds used during construction, for Energy Strong II gas projects placed in service prior to the commencement of the test year. These investments were authorized by the Board to be included in base rates on a provisional basis subject to review and finalization in this rate case.

Like the Energy Strong electric distribution expenditures, the reasonableness and cost effectiveness of the gas distribution costs underlying the rates approved by the Rate Adjustment Orders, as well as the success of the Energy Strong Program, is supported by the findings in the Pegasus Reports attached as Schedule PANEL-4(a) R-1. As noted above, the Company also provides annual and quarterly reports to Board Staff and Rate Counsel pursuant to the Energy Strong Order that contains detailed information about Energy Strong program costs, ongoing reliability performance, and satisfaction of program goals. A copy of the most recent Energy Strong quarterly report is attached as Schedule PANEL-4(b) R-1.

Q. Turning to the test year, does Schedule PANEL-2(b) R-1 reflect Energy Strong expenditures for this period?

A. Yes. The gas Energy Strong expenditures on Schedule PANEL-2(b) R-1 represent Energy Strong Program investments that the Company expects to undertake during the test year from June 1, 2023 to May 31, 2024.

7. GSMP I

Q. Please describe the Gas System Modernization Program I ("GSMP I").

A. GSMP is an accelerated infrastructure replacement program that was approved by a Board Order dated November 16, 2015 ("GSMP I Order"). The GSMP I Order authorized the Company to invest up to $905 million over three years to:

i. replace up to 510 miles of utilization pressure cast iron main ("UPCI") and unprotected steel main and services;

ii. uprate the UPCI system to higher pressure;

iii. install excess flow valves;

iv. abandon district regulators;

v. replace high pressure cast iron mains ("HPCI"); and

vi. recover the incremental cost of relocating inside meter sets outside.

Of the $905 million approved for GSMP, the Company was authorized to invest up to $650 million to be recovered by the Alternative Rate Mechanism. The GSMP Order required that PSE&G make base capital investments, referred to in the GSMP Order as "Stipulated Base," that are subject to two minimum investment criteria. The first criterion is that PSE&G

must spend a minimum of $85 million per calendar year from 2016 through 2018 on the types of plant specified to be part of Stipulated Base. The second requirement is that during the three years 2016 – 2018, PSE&G must install and place in service no less than a total of 110 miles of main to replace cast iron and unprotected steel mains and associated services under the Stipulated Base ("Stipulated Base Mileage and Stipulated Base Services").

Q. Please describe the Gas System Modernization Program II ("GSMP II").

A. GSMP II is the second phase of the Company's GSMP Program, which was approved by the Board in an order dated May 22, 2018 in BPU Docket No. GR17070776 ("GSMP II Order"). The GSMP II Order authorized the Company to invest up to $1.575 billion million over five years to: (a) replace UPCI mains and associated services and Unprotected Steel mains and associated services; (b) uprate the UPCI systems (including the uprating of associated protected steel and plastic mains and associated services) to higher pressures; and (c) install excess flow valves and eliminate district regulators, where applicable.

Under GSMP II PSE&G is required to make base capital investments, also referred to as a Stipulated Base. The Company must spend $300 million on certain capital projects during the five-year GSMP II, with no less than $20 million expended in each calendar year from 2019 through 2023, which shall be recovered through base rates.

Q. Has the Company met its Stipulated Base requirements under the GSMP I and II Orders?

A. Yes. In GSMP I the Company spent more than the stipulated requirement of $85M per year in each year with a total expenditure of $288.6 million. The Company has spent more than $20 million on stipulated base investments in each year of the GSMP II program with a total expenditure of $305.5 million.

Q. Are any of the GSMP I and GSMP II investments currently reflected in rates?

A. In the Company's previous base rate case, the Board found that PSE&G's GSMP I investments placed in service through September 30, 2017, were prudent and should be included in base rates. These investments were approved as prudent by the Board in the Company's 2018 rate case.

Since the last base rate case, the Board has approved two additional rate adjustment filings for GSMP I investments, consisting of $311.5 million in capital investments, and eight rate adjustment filings for GSMP II investments, consisting of $1.575 billion in capital investments. Pursuant to the Board's orders approving these filings, the revenue requirements associated with these investments have been included in the Company's rates on a provisional basis, subject to a prudency review in this proceeding.

Q. Can you summarize the Company's total GSMP I and II investments and Stipulated Base since the inception of the GSMP Program but prior to the commencement of the test year in this case?

A. The summary of the GSMP I&II Program and Stipulated Base investments are shown in the table below:

	2016	2017	2018	2019	2020	2021	2022	2023*
GSMP Investment ($M)	$159	$245	$201	$336	$407	$495	$353	$40
GSMP Miles Replaced	118	104	86	212	318	281	112	23
GSMP Services Replaced	6,808	9,858	9,963	14,655	18,222	27,324	20,462	1,331
Stipulated Base Investment ($M)	$95	$100	$94	$60	$46	$42	$128	$30
Stipulated Base Miles Replaced	71	29	42	23	22	26	63	12
Stipulated Base Services Replaced	3,180	2,494	3,241	1,393	1,107	932	4,678	1,092

* GSMP II was completed in Feb. 2023

Q. Turning to the test year expenditures, does Schedule PANEL-2(b) R-1 include Investments and Stipulated Base expenditures for the GSMP I and II?

A. Schedule PANEL-2(b) R-1 includes Investments and Stipulated Base expenditures for GSMP I and II.

Q. Are the costs underlying the rates approved by the Board, as well as all GSMP investments to date (including Stipulated Base spending), reasonable?

A. Yes. The GSMP investments were subject to the same PSE&G capital practices and policies described above that were favorably reviewed by Pegasus for the Energy Strong II Program. As we explained earlier, while the requirement to retain the independent monitor derives from the Energy Strong Order, the capital practices and processes reviewed by Pegasus apply uniformly to all capital spending, including GSMP investments. As noted above, the Company also provides monthly and quarterly reports to Board Staff and Rate Counsel in connection with GSMP I and II. Those reports contain information about GSMP costs and satisfaction of program goals, *i.e.*, leak reduction data. A copy of the most recent GSMP monthly report is attached as Schedule PANEL-4(c) R-1.

8. IAP (Gas)

Q. Please describe the Infrastructure Advancement Gas Program.

A The IAP Order authorized the Company to invest $69.8 million in gas system upgrades through the IAP, all of which are directed to the Gas M&R Station Modernization Subprogram. As noted above, the IAP Order requires the Company to invest a stipulated base of $160 million over the term of the program, $17.4 million of which must be used for specified gas investments.

Q. Have any IAP gas expenditures been placed into rates?

A. There are currently no IAP gas expenditures included in the Company's rates.

Q. Are any gas expenditures related to the IAP included in the test year or post-test year, as shown on Schedule PANEL-2(b) R-1?

A. No. The first IAP projects are scheduled to be placed into service in December 2024, after the conclusion of the post-test year period in this proceeding.

IV. OPERATION AND MAINTENANCE EXPENSE

Q. Please provide an overview of your testimony regarding distribution-related O&M expense.

A My testimony addresses the level of electric and gas distribution-related O&M expense that PSE&G expects to incur in the test year, major expenses associated with operating the Company's electric and gas distribution systems, and the efforts taken by the Company to control distribution-related O&M expenses.

Q. What is the level of electric and gas distribution-related O&M expense that PSE&G expects to incur during the test year?

A. Total test year electric and gas distribution-related O&M expense is approximately $360 million. Of that amount, approximately $208 million is related to electric distribution operating costs and approximately $152 million is related to gas distribution operating costs. Electric and gas distribution O&M amounts are shown on Schedules PANEL-5(a) R-1 and PANEL-5(b) R-1, respectively.

A. Electric Distribution O&M

Q. Please discuss the types of expenses that comprise electric distribution O&M.

A. Electric distribution O&M expenses include the day-to-day activities of running the electric system that are critical to meeting the needs of our customers and maintaining the overall safety and reliability of the Company's electric distribution system. Electric distribution O&M work encompasses all of the extensive inspection and maintenance programs that are described in detail in PSE&G's Annual System Performance Report provided to the BPU. Major O&M activities include vegetation management (tree trimming); load checks on all underground transformers; storm restoration (which is discussed in more detail below); routine repairs, troubleshooting, and mark-outs of underground facilities; various inspections, including inspections of overhead lines, network protectors, critical plant inside substations, and various others types of facilities and equipment; meter and streetlight repairs; connecting and disconnecting active and inactive customers, shut-offs and restorations of customers; responding to police/fire emergency calls and customer complaints; maintaining customer accounts, billing and metering; and accounting, employee benefit management, and information technology. Also included in O&M are the costs of training the Company's workforce, which is a very critical area today given the turnover being experienced due to the retirement of experienced skilled workers and the significant hiring of new employees, many of whom are in apprenticeship classifications. For many job assignments or categories, it takes up to two years of training and work experience before an apprentice or new employee is ready to be a fully qualified contributor.

Q. What are the key drivers of electric distribution O&M?

A. The major drivers of the test year electric distribution O&M budget are expenditures associated with (i) vegetation management, (ii) corrective maintenance, (iii) buildings and grounds, (iv) inspections, and (v) measurement cost. Test year expenditures for these major categories are set forth on Schedule PANEL-5(a) R-1. I discuss these major cost categories further below.

Q. Please discuss vegetation management costs.

A. Vegetation management costs have increased since the last rate case driven by significant labor inflation for this service. Vegetation management is performed when circuits are inspected and require maintenance per regulations discussed further below.

Q. What do the vegetation management regulations require?

A. In general, the regulations require that all circuits be inspected and, if necessary, that trees be trimmed at least once every four years. Consistent with the Board's regulations, all vegetation clearing work is performed in compliance with American National Standards Institute (ANSI) Z133.1 standard, which addresses arboriculture safety requirements for pruning, repairing, maintaining and removing trees and for using equipment in such operations; and with the A-300 standard, which addresses pruning and trimming operations, as well as all applicable OSHA requirements. Work related to vegetation management is performed by outside contractors with a small number of internal crews.

Q. Please discuss corrective maintenance costs.

A. Corrective maintenance is performed when facilities and/or equipment malfunction or otherwise do not perform at an optimal level. Maintenance intervention is required to return facilities and equipment to an operational, safe and reliable state.

Q. Please describe the costs associated with buildings and grounds.

A. Buildings and grounds costs involve the different activities associated with various structures (*e.g.,* office buildings, substation control houses) and associated property operated and maintained by the Company. Some typical costs include snow removal, weed control, repairs, janitorial services, utility bills and fire and building inspections.

Q. Please address inspections costs.

A. Inspection costs include inspections and related activities associated with PSE&G utility poles, underground lines, inside plant such as transformers breakers and relays, and other utility facilities. These activities are critical to help maintain the safety and reliability of the electric energy delivery system by identifying and eliminating defective facilities before failures can cause injury, damage, or unscheduled outages.

Q. Please address measurement costs.

A. Measurement costs involve expenditures for the many meter-related functions associated with 2.3 million electric meters located in PSE&G's service territory. These functions include activating and deactivating meters; reading meters; disconnecting and reconnecting meters; repairing and maintaining meter sets; and flood investigations at the meter. Please see testimony of Company witness David Johnson for additional details regarding the Company's Advanced Meter Infrastructure ("AMI") deployment.

B. Gas Distribution O&M

Q. Please discuss the types of activities within the gas distribution O&M budget.

A. PSE&G conducts extensive gas O&M activities, including finding and repairing gas leaks on mains, services and customer premises; responding to emergency leak situations; responding to gas pressure problems; conducting leak surveys; performing construction inspections and meter inspections; maintaining, monitoring and controlling gas pressures on the system; and maintaining customer accounts, billing, metering, and appliance safety for all customers. Most field operation activities are mandated by the U.S. Department of Transportation, including activities associated with pipeline integrity requirements for maintaining our gas transmission lines. Other activities, such as research and development participation, training and continuing education, accounting, employee benefit management, information technology, standards development, and participation in industry operations forums are in direct support of safe and effective gas distribution system operation.

Q. What are the key drivers of gas distribution O&M?

A. The biggest drivers of the gas distribution O&M budget are the costs associated with (i) safety, (ii) measurement, (iii) gas mark-outs, (iv) inspections and surveys, and (v) mains and services maintenance. Test year expenditures for these categories are shown on Schedule PANEL-5(b) R-1. I will address them in turn.

Q. Please address safety costs.

A. The safety category includes the costs associated with the first response to inside and outside gas leaks, meter and heater inspections, and initial appliance repair diagnostic work.

The costs associated with these activities are largely dependent on weather conditions and tend to be higher in periods where the temperature is colder than normal.

Q. Please address measurement costs.

A. Measurement costs involve expenditures for the many meter-related functions associated with almost 1.9 million gas meters located in PSE&G's service territory. These functions include activating and deactivating meters; reading meters; disconnecting and reconnecting meters; meter inspections, repairing and maintaining meter sets; and flood investigations at the meter.

Q. Please address gas mark-outs.

A. The State of New Jersey requires that the location of underground utility installations be identified and marked out prior to work that involves any digging operation. Activities covered by this requirement include excavations or trenching, blasting, installation of tents, sign posts, or fence posts, and removing or planting of trees. Expenditures in this category have been trending upward since PSE&G's last base rate case largely because of an increase in the number of mark-outs, as well as an increase in costs of 2.8% per year (2019 – 2022) due to wage increases. For example, in 2023 mark-out costs were approximately $19.2 million compared to costs of approximately $17 million in 2019 and projected test year expenditures of over $12.2 million.

Q. Please discuss inspections and surveys costs.

A. Expenditures in this category relate to the wide variety of surveys and inspections conducted on over 35,600 miles of gas mains and services and almost 1.9 million gas meters in PSE&G's service territory. Expenditures here include the costs associated with patrols, inspections, and surveys to check and maintain the safety, reliability, and operational soundness of the Company's facilities, including mains, services, and inside and outside meters.

Q. Please address mains and services maintenance costs.

A. These costs include all maintenance of and repairs to mains, services, regulators, and cathodic protection of protected steel mains. Ongoing maintenance and repairs are needed to maintain the safety and reliability of the gas distribution system.

C. <u>Electric and Gas Distribution O&M Cost Control Efforts</u>

Q. Please describe some of the efforts taken by the Company to manage electric and gas distribution O&M costs.

A. Since the Company's last electric and gas base rate cases, various steps have been taken to help manage the Company's electric and gas distribution operating costs. While these costs relate to essential functions that are required to operate and maintain the electric and gas distribution systems, the Company continues to look for ways to maximize efficiencies and control operating costs.

As mentioned previously, the Company is aggressively replacing cast iron and unprotected steel gas main and services through its GSMP program. One of the many benefits of the GSMP accelerated replacement is the reduction in the number of leaks associated with leak prone pipes, which supports the control of O&M costs associated with leak response and management. Since the last rate case, the Company has experienced a downward trend in open leaks, cast iron main breaks, leak repairs, and leak repairs per mile.

The Company continually focuses on identification and implementation of efficient processes and technological improvements to control O&M costs.

For example, the Company has replaced obsolete paper chart pressure recorders at natural gas district regulator stations with electronic pressure recording devices. Every low pressure distribution system that is supplied by more than one district regulator is required to have at least one pressure recording device. The use of electronic pressure recording devices eliminates the costs associated with paper chart retrieval and maintenance. Electronic pressure recorders also have the added benefit of providing real-time alarms that can be sent to a computer or phone, as well as access to the data by multiple users through a secure online portal.

The Company sought to increase efficiency when conducting required leak detection surveys through the use of new technology solutions. The implementation and use of remote methane leak detectors ("RMLD") effectively reduces the time required for service leak detection surveys, and improves survey efficiency. The Company's Gas Appliance Services also implemented a new software to manage Appliance Service work orders. The software has the capability to automatically dispatch work orders to Appliance Service Field Technicians, significantly improving efficiency by reducing travel time and costs to customers' premises.

Additionally, in an effort to reduce costs associated with training entry level apprentices and employees, the Company effectively negotiated with the unions to modify time-in position lock-in periods. Various entry-level Bargaining Unit positions now have a five-year lock-in period, ensuring that personnel do not transfer to another position within the Company in the first five years of employment. This new lock-in requirement has reduced the amount of training required for these positions, thus reducing the associated training costs.

Other savings initiatives that the Company has implemented include:

- Increased supplier pool and multi-year contracts for vegetation management;
- Optimized vehicle maintenance schedules;
- Enhanced training opportunities including e-learning curriculum;
- Reevaluation and optimization of Administrative staff;
- Minimized travel expenses for only essential/critical business meetings;
- Reevaluated and adjusted shift timing to reduce overtime;
- Instituted our Tech talk program reducing travel time and costs associated with appliance repair; and
- Re-evaluated facilities' needs to reduce unnecessary maintenance costs.

D. <u>Storm Restoration Costs</u>

Q. You mentioned earlier that costs associated with storm restoration are among the major O&M costs incurred by the Company; could you briefly explain what types of costs are included as "storm restoration costs"?

A. Storm restoration costs are the incremental labor, material, outside contractor, and other costs incurred by the Company to safely and efficiently restore customer's electric and gas service as quickly as possible after an interruption due to a Major Event, including but not limited to costs associated with extraordinary internal labor deployment, mutual aid contractors, tree trimming contractors, staging areas, pole fixtures, meals and lodging for restoration personnel, and communications with customers, emergency personnel and local authorities.

Q. How does the Company currently recover storm restoration costs in rates?

A. The prior rate case included a new regulatory asset consisting of the deferred incremental O&M storm costs incurred prior to and during the test year. These prior incurred storm costs are currently being recovered in rates. The Company is not recovering any deferred incremental storm costs incurred since the prior base rate case. The capital storm costs are included in net plant from the prior rate case.

Q. How does the Company ensure that its storm restoration costs are reasonable?

A. During the storm preparation phase, an analysis of the storm severity level and required staffing requirements is completed, and the optimized restoration resources are procured. Additionally, the restoration effort is closely monitored by senior leadership through multiple daily conference calls and real time operations data. These calls, coupled with real time restoration data, enable the efficient deployment of both internal and external resources to ensure that customers are restored in the safest, quickest and most cost effective manner possible.

Q. Do the Company's books and records contain a regulatory asset for storm restoration costs incurred since the Company's previous rate case?

A. Yes, the Company's books and records contain $106.6 million for electric and $3.7 million for gas in a regulatory asset for incremental O&M costs related to Major Storm Event restoration. From 2019 through February 2024, a total of six storms occurred, two of which were named storms known as Tropical Storm Isaias ($72 million O&M cost for electric) and Hurricane Ida ($8 million O&M cost for electric and gas). The other four storms were the January 2024 Major Storm, February 2021 Snow Storms, the June 2020 Derecho, and the July 2019 Major Storm.

Q. Please explain why you believe that those deferred storm restoration costs were reasonably incurred to provide safe and reliable service to customers.

A. PSE&G has a robust and disciplined approach to storm restoration which enables the Company to restore customers in a safe, efficient and timely manner after unpredictable and widespread severe weather event damage. This storm restoration approach and the Company's spending in support thereof has been reviewed by the Board and found to be prudent in the Board's September 30, 2014 order in BPU Docket Nos. AX13030196 and EO13070607. The incremental O&M costs we are now seeking recovery for was spent in a similar disciplined and efficient manner with the sole purpose of restoring our electric and gas customer's service as safely and quickly as possible.

Q. Is the Company proposing to modify the way it recovers storm restoration costs in the rates established in this proceeding?

A. Yes. As discussed by Company witnesses Mr. McFadden and Mr. Swetz, the use of deferred accounting coupled with an annual surcharge mechanism is the most appropriate means of recovering Major Storm event costs by protecting the Company from significant financial harm from major weather events outside its control as well as ensuring that customers only pay for actual prudently incurred costs.

Q. Why is the Company proposing to change the way it recovers storm restoration costs?

A. Adoption of a Major Storm Events cost recovery mechanism as proposed by the Company would allow for a prudence review of the deferrals and cost recovery within a reasonable time after they are incurred instead of reviewing all Major Storm Events that occur between rate cases at the same time. These interim rate proceedings will help the Company maintain its credit ratings as noted above (which have benefited customers) as well as prevent any rate shock to customers that could arise if the Company were permitted to recover the costs of all post-test year events at the same time. Finally, the use of a surcharge provides a mechanism to stop the amortization when recovery of the deferral is completed. As a result, the Company is proposing that a new clause, "the Storm Recovery Charge" be created to recover the $110 million in deferred storm costs increased since the last rate case as well as any future prudently incurred storm costs. For more details concerning the new clause, please see the testimony of Company witness Stephen Swetz.

Q. Are you proposing any other change to the manner in which costs associated with major storm events are recovered from customers?

A. Yes. Based upon the severity of weather forecasts, the Company sometimes prepares in advance for a storm by procuring and/or mobilizing contractor crews prior to the onset of adverse weather with the intention of deploying those crews to shorten the duration of customer interruptions. If the actual weather does not end up meeting the definition of a "major storm" the Company should nonetheless be provided an opportunity to recover prudently incurred "pre-staging costs" incurred to respond to potential storms. The Company proposes that under the Major Storm Events cost recovery clause that it is proposing it should be permitted to include recovery of pre-staging costs that exceed, in any instance, $250,000. Permitting the deferral and recovery of such pre-staging costs will encourage the Company to prudently prepare for future storms to the benefit of all its customers.

Q. Why does the Company believe that it is reasonable for the Company to recover pre-staging costs through its proposed storm restoration clause?

A. PSE&G's first priority is providing safe, efficient and reliable service to its customers. This commitment is tested during severe weather events, where efforts to ensure timely restoration of service begin well before the first signs of severe weather enter our territory. In an effort to minimize delays in restoration, the Company must secure staging areas, materials, and mutual aid/contractor resources early on in the process, many times prior to any reported outages, depending on the severity of the weather forecast. This preparation is a critical step in the restoration process, and is undertaken in good faith that the reasonable expenses incurred will be recovered in the future.

V. APPLIANCE SERVICE BUSINESS

Q. Please describe PSE&G's Appliance Service Business ("ASB").

A. PSE&G has been providing appliance service since the 1920s, when the Company sold and serviced its own appliances and certified other appliances as safe. These services are currently offered as competitive services for customers in PSE&G's service territory in accordance with a tariff filed with the Board of Public Utilities ("Board"). These services include (a) Appliance Repair Service, (b) Maintenance Services, (c) Replacement Parts Service Contracts, (d) Water Heater replacement Service, and Central Heater and Central Air Conditioning ("HVAC") Replacement. The majority of the existing program work is performed utilizing PSE&G's workforce with the exception of the water heating replacement work, which is performed by contractors retained by the Company.

Q. Does PSE&G's ASB function only provide competitive services?

A. No. The majority of the work performed by the ASB function unit is non-competitive work that is part of PSE&G's regulated gas utility business. The bulk of regulated work performed by the ASB group involves emergency response (*e.g.*, responding to calls from customers about gas leaks and pilot odors) and gas appliance adjustment services. Technicians also perform meter services (e.g., meter installations and replacements and turn on and shutoff services). These non-competitive services are an intrinsic part of PSE&G's traditional utility business of distributing natural gas. There are no charges for customer requested regulated services, except for heating "turn on" charges and off cycle inspections.

Q. What competitive services does PSE&G offer to customers through its Appliance Repair Service and Maintenance Services businesses?

A. The Appliance Repair Service and Maintenance Services, also known as PSE&G's "APSO" product line, are core services for the Company and align with the Company's reputation as a safe, trusted and reliable provider of gas service. The APSO product lines covers, repair and the replacement of defective parts on specified appliances for residential and small industrial and commercial customers. Appliances covered by the APSO line include furnaces and boilers, central air conditioning, ductless mini-split heating and cooling equipment, water heaters, refrigerators, stoves, wall ovens, electric freezers, dishwashers, washers, dryers, pool heaters, gas grills, and gas fireplaces. APSO service work is performed by highly skilled PSE&G service technicians. APSO services are billed separately for each repair to customers utilizing the service based on a predetermined pricing schedule.

Q. Please describe the Replacement Parts Service Contracts product line offered by PSE&G.

A. Appliance-parts contracts, commonly known as WorryFree® Replacement Parts Service Contracts, generally cover the cost of the repair and replacement of specified parts on the appliances, including central house heating equipment, water heaters, electric central air conditioners, kitchen and laundry equipment, gas piping, gas fireplaces, rooftop heating equipment, electric rooftop and central air conditioners. WorryFree® service also includes, where appropriate, the cost of labor, materials, and diagnostic time. PSE&G offers repair contracts and parts replacement through the WorryFree® program but does not sell new appliances at this time.

As with all competitive services, participation in the WorryFree® Replacement Parts Service Contract program is optional. Customers who utilize the WorryFree® Replacement Parts Service Contract program are billed for the service on their PSE&G Utility monthly statements.

Q. Please describe the Water Heater and HVAC Replacement Service product line.

A. The Water Heater and HVAC Replacement Service product line provides customers with reliable, premium replacement services for water heaters, central house heating, electric central air conditioning, and heat pumps. Through this program, PSE&G customers are able to select equipment that matches their requirements and have that equipment installed.

Q. How are the costs and revenues associated with the ASB reflected in the Company's electric and gas rates?

A. ASB net margin revenues are accounted for and allocated in accordance with N.J.A.C. 14:3-3.6(r). Under this regulation, total gas margin from ASB revenues is treated above-the-line for rate-making purposes and is credited to customers. For electric ASB revenues, however, the regulation dictates that 50 percent of the total margins be recorded in competitive service revenue accounts and included above-the-line for ratemaking purposes and credited to customers. The remaining 50 percent of electric ASB margins may be recorded below-the-line and retained by the Company.

The revenues and expenses associated with the appliance service business are included in the income statement for the utility, specifically in the gas business. As a result, the net above-the-line margin (revenue less expenses) from operating the appliance service business is credited to customers in base rates. In this current base rate case proceeding, the Company proposes $47 million in ASB margin to directly offset the Company's revenue requirement to the benefit of customers.

Q. Do any other utility companies in New Jersey maintain ASBs?

A. No. All other utility companies in New Jersey have ceased to provide competitive ASB products and services. As such, PSE&G's ASB, and the associated ASB revenues included in the Company's revenue requirement are a unique benefit that PSE&G provides to its customers.

Q. Is ASB a growing business for the Company?

A. No. Although the Company provides appliance services to a significant number of customers, since 2020, virtually all of the Company's ASB products and services have experienced negative growth in terms of number of customers. In other words, the ASB market is saturated. At the same time, the Company's costs of providing the service have consistently increased due to largely unavoidable increases in cost items such as employee wages, benefits, and increases in material costs.

Q. Is the Company proposing to change the way ASB revenues are treated for ratemaking purposes?

A. Yes. The Company proposes that the Board grant a waiver of *N.J.A.C.* 14:4-3.6(r)(4) such that PSE&G is permitted to retain 50% of the total net margins associated with both gas and electric ASB services.

Q. Why does the Company believe that this change is appropriate?

A. The Company believes this change is appropriate for several reasons. First, the ability to retain a portion of margin revenues related to gas ASB products will provide a strong incentive to continue to provide ASB services, to continue to seek and implement efficiencies in the ASB business, and to seek opportunities for growth of the ASB business in an increasingly challenging marketplace.

Q. How will this change benefit customers?

A. This change will benefit customers because it will allow the Company to continue to its ASB business and, as a result, customers will continue to benefit from ASB margin revenues being reflected in the Company's rates as well as from the Company's continued presence as an ASB provider. As noted above, the inclusion of ASB revenues in rates is a unique benefit in the State for PSE&G customers. PSE&G believes the proposed adjustment will allow the Company to justify remaining in the ASB in an increasingly challenging marketplace.

Q. Please explain the challenges that the Company's ASB is facing.

A. The Company is grappling with external factors that have reshaped the appliance industry, resulting in declining or stagnant performance for ASB program revenues. Manufacturers for many appliances have begun emphasizing replacement of old or underperforming appliances with new equipment, rather than maintenance and repairs of existing appliances. This, in turn, has shifted consumer habits, creating a surge in demand for new appliances from manufacturers while slowing or reducing demand for the Company's ASB services. Warranties for these new appliances, as well as service programs offered by manufacturers, have further impacted PSE&G's ASB revenues.

In addition, cost inflation has negatively impacted ASB contract margin. Cost for replacement parts has increased in recent years, resulting in PSE&G raising contract prices to mitigate negative margin impacts. A strategy of regular price increases can drive higher levels of contract cancellations, eventually leading to declining margins.

Other macroeconomic and regulatory forces have also impacted the Company's ASB revenues. Homeownership in New Jersey has decreased from 69% in 2006 to 64% in 2022, resulting in a reduction of approximately 28,000 homeowners in PSE&G's service territory. This has impacted the number of potential customers for the ASB programs as homeowners are more likely to purchase ASB services. Additionally, the Company has been focused on reducing uncollectible account receivables since 2010 and has determined that it will not provide ASB services to customers with outstanding uncollectable balances in an effort to encourage collections.

The shift in economic factors and consumer habits present significant challenges to PSE&G's ASB business. If unaddressed, these factors pose a notable threat to the continued economic viability of the ASB programs, and the ASB revenues used for the benefit of customers.

Q, Has PSE&G made any effort to address the challenges faced by the ASB programs?

A. Yes. In an effort to maintain the revenue margins for the ASB programs, PSE&G has increased prices for ASB programs. Although these increases have helped to maintain revenue margins from the ASB businesses, this approach is not sustainable because higher prices incentivize customers to opt for new appliance replacements instead of repairs, exacerbating the decline in customer contracts.

Q. Is the Company considering any other modifications to its ASB offerings?

A. Yes. The Company is considering expanding its ASB offerings to include new technologies and services, including but not limited to internal and external home electric system protection plans, home energy audits, home weatherization services, and electric vehicle ("EV") charger installation and servicing. In the event that the Company determines to move forward with any new ASB services, it will comply with all regulatory requirements applicable to such services including, if necessary, filing a petition with the BPU for authority to offer such services. These new products and services may provide the Company the opportunity to generate additional ASB revenues to justify the continued existence of the program.

Q. What is the potential effect of continuing the status quo with respect to the Company's ASB?

A. The current economics of the ASB impose considerable risks on the Company with prospects for limited improvement. Although the Company would like to maintain its ASB services, the Company cannot continue to engage in a line of business that is not economic. The closure of the ASB business would hurt both the Company's customers, through the loss of ASB margin revenues and the availability of ASB services, and the State's economy, through the loss of jobs provided by the ASB business. The Company believes that the changes discussed here will provide the ASB with the additional needed support to continue the business.

VI. TRAFFIC CONTROL REGULATION

Q. Are you aware of any recently adopted regulations that would impact PSE&G's cost of service?

A. Yes. On August 7, 2023, the New Jersey Department of Community Affairs adopted new regulations titled "Managing and accounting for outside employment of off-duty law enforcement officers." These regulations created new requirements related to any entity's utilization of off-duty law enforcement officers for purposes that include security and traffic safety control.

Q. What are the new requirements for an entity that utilizes off-duty law enforcement officers?

A. The new regulations require that the entity utilizing off-duty officers pay for such services in advance of such utilization, based on an estimate provided by the municipality/county employing those officers, and then requires the municipality/county issue a written statement within 30 days of such utilization, based on which that entity must resolve any outstanding balance. The new regulations also provide authority for a municipality/county to require that any entity employing off-duty law enforcement officers on a regular basis "maintain a minimum balance in the trust fund equal to the average amount paid to assigned off-duty law enforcement officers within a specified time period." That regulation permits a municipality/county to cease providing off-duty officers if an outside entity does not maintain a minimum balance in a trust fund.

Q. Does PSE&G rely on off-duty officers for security and traffic control?

A. Yes. PSE&G employs trained and qualified personnel in the form of flaggers and off duty police officers to mitigate safety risks for its crews performing construction activities on or around a roadway. In certain municipalities, it has been stipulated by the town that PSE&G must use off duty police officers for Traffic Control services. Currently, PSE&G has 305 municipalities that provide off duty police officers for Traffic Control Services for work performed in our service territory. The traffic control regulation applies not only to municipalities or counties, but also a third-party entity if they are using them to manage traffic control for them. As shown in the table below, the traffic control spend is significant and continues to increase each year.

TOTAL ACTUALS YEARS 2021-2023

LOB	**2021**	**2022**	**2023**
ELECTRIC DIST.	$ 26,107,888	$ 32,323,891	$ 45,341,413
ELECTRIC TRANS.	$ 14,436,227	$ 15,607,584	$ 12,875,582
GAS	$ 64,613,792	$ 71,946,068	$ 86,901,828
Grand Total	**$ 105,157,907**	**$ 119,877,544**	**$ 145,118,823**

Q. How does this regulation impact the Company's cost of service and this filing?

A. The new regulation will require the Company to maintain "working capital" type balances with municipalities in order for the municipalities to have sufficient pre-funded cash on hand from PSE&G to pay for the costs of the off-duty officers. This will have both a working capital requirement on the Company's cash flow as it will need to create and maintain the required pre-funded municipal trust balances as well as an incremental administrative and managerial costs compared to the test year to monitor the balances with each municipality. Given the annual traffic control spend and the number of municipalities in the Company's service territory, the time and cost to monitor the pre-funded trust balances are expected to be significant.

Q. Is the Company seeking recovery of these incremental costs as a result of the regulation?

A. Not at this time. As discussed in the testimony of Mr. McFadden, the Company is seeking to defer the incremental costs associated with this regulation for recovery of all prudently incurred costs in a future base rate case.

Q. Does this conclude your testimony?

A. Yes, it does.

Test Year / Post Test Year Electric Capital Expenditures

in $000 **Schedule - PANEL-2(a)**

	Test Year Total June 2023 - May 2024	Post Test Year Total June 2024 - Nov 2024
Facilities Replacements	$ 290,931	$ 100,059
System Reinforcements	$ 282,083	$ 142,870
New Business	$ 168,019	$ 73,503
Environmental/Regulatory	$ 13,242	$ 5,540
Facilities Support	$ 135,551	$ 27,088
Energy Strong	$ 151,210	$ 16,603
IAP	$ 127,194	$ 94,823
AMI	$ 245,290	$ 93,700
Total	**$ 1,413,518**	**$ 554,186**

Test Year / Post Test Year Gas Capital Expenditures

in $000

Schedule - PANEL-2(b)

	Test Year Total June 2023 - May 2024	Post Test Year Total June 2024 - Nov 2024
Facilities Replacements	$ 676,760	$ 152,473
System Reinforcements	$ 150,466	$ 36,604
New Business	$ 110,461	$ 54,497
Environmental/Regulatory	$ 23,748	$ 10,608
Facilities Support	$ 131,357	$ 49,879
Energy Strong II	$ 34,039	$ 5,137
IAP	$ 18,475	$ 27,932
GSMP II Extension	$ 27,128	$ 276,559
Total	**$ 1,172,435**	**$ 613,688**

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PSEG
Services Corporation

August 19, 2019

Via Electronic Mail & Regular Mail

James Giuliano, Director
Division of Reliability and Security
New Jersey Board of Public Utilities
225 East State Street - 2nd Floor, Area 2W
Trenton, New Jersey 08625

RE: MAJOR EVENT REPORT
SEVERE WEATHER EVENTS
JULY 17 - 25, 2019

Dear Director Giuliano:

As required by 14:5-8.9, enclosed is a copy of PSE&G's Major Event Report for the severe weather events from July 17 - 25, 2019.

Questions concerning this matter can be directed to me or Donald W. Weyant, Manager - Regulatory Compliance at (973) 430-6730.

Respectfully submitted,

Matthew Weissman

Matthew M. Weissman

Attachments

C (Email Only)
Joseph Fiordaliso, President
Upendra Chivukula, Commissioner
Robert Gordon, Commissioner
Mary-Anna Holden, Commissioner
Dianne Solomon, Commissioner

PSE&G's REPORT TO THE BPU
MAJOR EVENT
SEVERE WEATHER EVENTS
JULY 17 - 25, 2019

EXECUTIVE SUMMARY

During the period of July 17-25, 2019, PSE&G's service territory was affected by three separate weather events. During the afternoon on July 17th, severe thunderstorms affected the entire service territory with Southern Division experiencing the most damage and the most outages. Beginning on July 20th, extreme heat was experienced in all four operating divisions. High temperatures were in the 95–100 degree F range with heat indices of 105–110 degrees F. The extreme heat ended on the afternoon of July 22nd when very severe thunderstorms crossed the entire service territory. Once again, Southern Division was hit the hardest with extensive plant damage and the most outages. Wind gusts of up to 76 MPH were measured in Burlington and Camden Counties.

As discussed with Board staff on July 23rd because of the severity of these weather events, they will be considered as one Major Event. These weather events qualify as a Major Event since 243,406 customers in Southern Division, which is more that 10% of the 579,052 customers in the Division and 352,915 customers Company wide, which is more than 10% of the 2,400, 252 customers served by the Company, were interrupted and each of PSE&G's other three operating divisions supplied line and service repair crews to Southern Division.

SEVERE THUNDERSTORMS - JULY 17–19, 2019

EXECUTIVE SUMMARY

During the afternoon on July 17th, severe thunderstorms affected the entire service territory with Southern Division experiencing the most damage and the most outages. Based upon weather forecasts, during that morning's 0800 hrs. daily operations conference call, a 1300 hrs. conference call was scheduled to review storm preparation plans. During that conference call, line crews, support personnel and tree crews in each of PSE&G's four operating divisions were held over to work the 1500 - 2300 hrs. shift. In addition, these divisions placed line crews, support personnel and tree crews on stand-by.

As a result of the plant damage and outages in Southern Division, a staffing conference call was scheduled for 0630 hrs. on July 18th. During that call, PSE&G assigned 48 line crews and support personnel that morning from the other three divisions, Projects and Construction (P&C) and from a contractor that was on PSE&G's property to Southern Division to assist in service restoration. Central Division also supplied a line crew to Southern Division at 2300 hrs. on July 17th.

Beginning at 0800 hrs. on July 18th, PSE&G held multiple conference calls concerning storm restoration efforts until July 19th. Participants in the conference calls included representatives from Electric Delivery's General Office staff, the four operating divisions, P&C, the Electric System Operations Center (ESOC) along with personnel from other operating and staff departments of the company.

Communications with Board staff concerning this weather event began on July 18th and continued until July 19th.

PSE&G opened its Utility Emergency Operations Center (UEOC) from 0600 - 1700 hrs. on July 18th and from 0700 - 1700 hrs. on July 19th.

OPERATING REPORT

Extended customer interruptions and restoration times for customers during this weather event are as follows:

Division	Customers Interrupted Extendedly	Final Restoration
Central	15,940	July 19th - 0300 hrs.
Metropolitan	2,493	July 18th - 1853 hrs.
Palisades	7,020	July 18th - 2000 hrs.
Southern	51,933	July 19th - 1115 hrs.
Total	77,386	

Attached are the following Customer Restoration Summary Graphs which encompass all three weather events:

Attachment “A” - Company Wide
Attachment “B” - Central Division
Attachment “C” - Metropolitan Division
Attachment “D” - Palisades Division
Attachment “E” - Southern Division

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PERSONNEL DEPLOYMENT

Attached are the following Work Force Graphs which encompass all three weather events:

Attachment "F" - Overhead Line Crews, Service Repair Crews and Troubleshooters - Company
Attachment "G" - Overhead Line Crews, Service Repair Crews and Troubleshooters - Central Division
Attachment "H" - Overhead Line Crews, Service Repair Crews and Troubleshooters - Metropolitan Division
Attachment "I" - Overhead Line Crews, Service Repair Crews and Troubleshooters - Palisades Division
Attachment "J" - Overhead Line Crews, Service Repair Crews and Troubleshooters - Southern Division
Attachment "K" - Contractor Tree FTEs – Company and Contractor Tree FTEs – Outside Contractors Assisting Southern Division.
Attachment "L" - Overhead Line Crews and Service Repair Crews Assisting Central Division
Attachment "M" - Overhead Line Crews, Service Repair Crews and Troubleshooters Assisting Southern Division.
Attachment "N" - PSE&G Contractor Line Crews Assisting Southern Division
Attachment "O" - Mutual Aid FTEs Assisting Southern Division

A liaison was assigned to Southern Division from 0700 hrs. to 1930 hrs. on July 18^{th} and from 0730 hrs. to 1100 hrs. on July 19^{th} to assist in addressing customer inquiries.

All 11 Offices of Emergency Management (IEM) were contacted. Burlington and Camden County Offices opened but did not require a PSE&G representative on site. The PSE&G representatives provided remote support.

TROUBLE LOCATIONS AND CLASSIFICATIONS

Outside plant damage locations are listed below:

69 & 26-kV	- 16
13 & 4-kV	- 210
Transformers	- 38
Secondaries	- 30
Services	- 90
Poles	- 32
Trees	- 136
Total	- 552

INCIDENTS

The Ewing Community Center, 999 Lower Ferry Road, Ewing became a gathering point for residents who had their electric service interrupted by the storm. On July 18th, PSE&G supplied water, ice and customer services to the Center. The customer services included providing ETR updates to customers and issuing service orders if needed.

COMMUNICATIONS

Communications with Board staff concerning this weather event began on July 18th and continued until July 19th.

PSE&G's Corporate Communications Department issued internal communications, press releases and handled multiple newspaper, television and radio information requests during this period. In addition, social media posts to particularly hard hit communities provided support information including the location of cooling stations.

HEAT STORM – JULY 20-22, 2019

EXECUTIVE SUMMARY

Immediately following the July 17th severe thunderstorms weather event, PSE&G's entire service territory was subjected to a heat storm beginning on July 20th. High temperatures were in the 95-100 degree F range with heat indices of 105-110 degrees F. The heat storm ended on the afternoon of July 22nd when very severe thunderstorms crossed the entire service territory.

On July 18th in anticipation of the heat storm, Board staff requested that the EDC's, "report any outages affecting multi-unit-at-risk population buildings (hospitals, nursing homes, assisted living centers, senior living complexes, etc.) to the BPU as soon as you become aware of the outage." PSE&G made arrangements that day to adhere to that request.

Beginning at 1100 hrs. on July 20th, PSE&G held multiple conference calls concerning the heat storm until July 22nd. Participants in the conference calls included representatives from Electric Delivery's General Office staff, the four operating divisions, P&C and ESOC along with personnel from other operating and staff departments of the company.

Communications with Board staff concerning this weather event began on July 18th and continued until July 22nd.

PSE&G did not have to open its UEOC for this weather event.

OPERATING REPORT

Extended customer interruptions and restoration times for customers during this weather event are as follows:

Division	Customers Interrupted Extendedly	Final Restoration
Central	26,288	July 23rd – 0500 hrs.
Metropolitan	7,199	July 22nd – 1811 hrs.
Palisades	7,800	July 22nd – 1615 hrs.
Southern	15,015	July 22nd – 1655 hrs.
Total	56,302	

Attached are the following Customer Restoration Summary Graphs which encompass all three weather events:

Attachment "A" - Company Wide
Attachment "B" - Central Division
Attachment "C" - Metropolitan Division
Attachment "D" - Palisades Division
Attachment "E" - Southern Division

Immediately following the July 17th severe thunderstorms weather event, PSE&G's entire service territory was subjected to a heat storm beginning on July 20th. High temperatures were in the 95-100 degree F range with heat indices of 105-110 degrees F. The heat storm ended on the afternoon of July 22nd when very severe thunderstorms crossed the entire service territory.

On July 18th in anticipation of the heat storm, Board staff requested that the EDC's, "report any outages affecting multi-unit-at-risk population buildings (hospitals, nursing homes, assisted living centers, senior living complexes, etc.) to the BPU as soon as you become aware of the outage." PSE&G made arrangements that day to adhere to that request.

Beginning at 1100 hrs. on July 20th, PSE&G held multiple conference calls concerning the heat storm until July 22nd. Participants in the conference calls included representatives from Electric Delivery's General Office staff, the four operating divisions, P&C and ESOC along with personnel from other operating and staff departments of the company.

On July 21st, PSEG had a new Sunday system peak of 9,540 MW.

PERSONNEL DEPLOYMENT

Attached are the following Work Force Graphs which encompass all three weather events:

Attachment “F” - Overhead Line Crews, Service Repair Crews and Troubleshooters - Company
Attachment “G” - Overhead Line Crews, Service Repair Crews and Troubleshooters - Central Division
Attachment “H” - Overhead Line Crews, Service Repair Crews and Troubleshooters - Metropolitan Division
Attachment “I” - Overhead Line Crews, Service Repair Crews and Troubleshooters - Palisades Division
Attachment “J” - Overhead Line Crews, Service Repair Crews and Troubleshooters - Southern Division
Attachment “K” - Contractor Tree FTEs – Company and Contractor Tree FTEs – Outside Contractors Assisting Southern Division
Attachment “L” - Overhead Line Crews and Service Repair Crews Assisting Central Division
Attachment “M” - Overhead Line Crews, Service Repair Crews and Troubleshooters Assisting Southern Division
Attachment “N” - PSE&G Contractor Line Crews Assisting Southern Division
Attachment “O” - Mutual Aid FTEs Assisting Southern Division

It was not necessary for PSE&G to assign liasions to the operating divisions or to the Inquiry Centers during this weather event. It was also not necessary to contact any of the 11 County Offices of Emergency Management.

TROUBLE LOCATIONS AND CLASSIFICATIONS

Outside plant damage locations are listed below:

69 & 26-kV	-	11
13 & 4-kV	-	137
Transformers	-	155
Secondaries	-	8
Services	-	30
Poles	-	20
Trees	-	32
Total	-	393

COMMUNICATIONS

Communications with Board staff concerning this weather event began on July 18th and continued until July 22nd.

PSE&G’s Corporate Communications Department responded to several television and radio information requests during this period. In addition, social media posts were monitored.

VERY SEVERE THUNDERSTORMS – JULY 22-25, 2019

EXECUTIVE SUMMARY

The heat storm ended on the afternoon of July 22nd when very severe thunderstorms crossed the entire service territory. Once again, Southern Division was the hardest hit with extensive plant damage and the most outages.

During the 0800 hrs. operations conference call on July 22nd, Central Division reported that they still had over 1,300 customers out of service from the thunderstorms that hit their service area during the early evening on July 21st. As a result, Southern Division sent five line crews, two service repair crews and support personnel to Central Division that morning. In addition, P&C sent seven line crews and support personnel to Central Division that morning. As a result, of a weather bulletin from PSE&G's weather service warning of severe thunderstorms later that afternoon and evening, a conference call was scheduled for 1300 hrs. to discuss staffing needs.

During the 1300 hrs. conference call, PSE&G's weather service predicted that thunderstorms with possible 60 MPH winds, along with isolated tornadoes, would hit the service area that afternoon. Storm restoration plans were reviewed and line force and support personnel coverage for the 1500-2300 and 2300-0700 shifts were made. In addition, tree crew coverage was scheduled.

PSE&G began to feel the effects of these severe thunderstorms during the afternoon on July 22nd with the most plant damage and outages occurring in Southern Division. Wind gusts of up to 76 MPH were measured in Burlington and Camden Counties. PSE&G began to attempt to obtain contractor line FTEs from contractors at 1830 hrs. However, most were in Michigan which was struck by severe thunderstorms several days earlier. PSE&G then requested a North American Mutual Assistance Group (NAMAG) conference call at 2100 hrs. During that call, PSE&G requested 500 line FTEs. PSE&G also made arrangements to move any available line and service crews from other divisions to Southern Division at 2300 hrs. that evening.

Beginning at 0800 hrs. on July 22nd, PSE&G held multiple conference calls concerning storm restoration efforts until July 25th. Participants in the conference calls included representatives from Electric Delivery's General Office staff, the four operating divisions, P&C and ESOC along with personnel from other operating and staff departments of the company. After the 0800 hrs. conference call on July 23rd, PSE&G requested an additional 500 line FTEs from PSEG-LI.

Communications with Board staff concerning this weather event began on July 22nd and continued until July 26th.

PSE&G opened its UEOC from 0600–2100 hrs. on July 23rd and July 24th and from 0600-2000 hrs. on July 25th.

These weather events qualify as a Major Event since 243,406 customers in Southern Division, which is more than 10% of the 579,052 customers in the Division and 352,915 customers Company wide, which is more than 10% of the 2,400, 252 customers served by the Company were interrupted and each of PSE&G's other three operating divisions supplied line and service repair crews to Southern Division.

OPERATING REPORT

Extended customer interruptions and restoration times for customers during this weather event are as follows:

Division	Customers Interrupted Extendedly	Final Restoration
Central	31,717	July 24th - `1207 hrs.
Metropolitan	4,369	July 23rd – 1204 hrs
Palisades	6,683	July 23rd – 1720 hrs.
Southern	176,458	July 25th – 1542 hrs.
Total	219,227	

Attached are the following Customer Restoration Summary Graphs which encompass all three weather events:

Attachment “A” - Company Wide
Attachment “B” - Central Division
Attachment “C” - Metropolitan Division
Attachment “D” - Palisades Division
Attachment “E” - Southern Division

During the 0800 hrs. operations conference call on July 22nd, Central Division reported that they still had over 1,300 customers out of service from the thunderstorms that hit their service area during the early evening on July 21st. As a result, Southern Division sent five line crews, two service repair crews and support personnel to Central Division that morning. In addition, P&C sent seven line crews and support personnel to Central Division that morning. As a result, of a weather bulletin from PSE&G’s weather service warning of severe thunderstorms later that afternoon and evening, a conference call was scheduled for 1300 hrs. to discuss staffing needs.

During the 1300 hrs. conference call, PSE&G’s weather service predicted that thunderstorms with possible 60 MPH winds, along with isolated tornadoes, would hit the service area that afternoon. Storm restoration plans were reviewed and line force and support personnel coverage for the 1500-2300 and 2300-0700 shifts were made. In addition, tree crew coverage was scheduled.

PSE&G began to feel the effects of these severe thunderstorms during the afternoon on July 22nd with the most plant damage and outages occurring in Southern Division. Wind gusts of up to 76 MPH were measured in Burlington and Camden Counties. PSE&G began to attempt to obtain contractor line FTEs from contractors at 1830 hrs. However, most were in Michigan which was struck by severe thunderstorms several days earlier. PSE&G then requested a North American Mutual Assistance Group (NAMAG) conference call at 2100 hrs. During that call, PSE&G requested 500 line FTEs. PSE&G also made arrangements to move line and service repair crews from other divisions to Southern Division at 2300 hrs. that evening.

Beginning at 0800 hrs. on July 22nd, PSE&G held multiple conference calls concerning storm restoration efforts until July 25th. Participants in the conference calls included representatives from Electric Delivery’s General Office staff, the four operating divisions, P&C and ESOC along with personnel from other operating and staff departments of the company. After the 0800 hrs. conference call on July 23rd, PSE&G requested an additional 500 line FTEs from PSEG-LI.

PERSONNEL DEPLOYMENT

In the early evening on July 22nd, PSE&G began to attempt to obtain contractor line FTEs. However, most were in Michigan which was struck by severe thunderstorms several days earlier. PSE&G then requested a NAMAG conference call at 2100 hrs. During that call, PSE&G requested 500 line FTEs. On July 23rd, PSE&G requested 500 line FTEs from PSEG-LI. The results of these requests follow:

Date Requested	Mutual Aid and Line Construction Contractors	Location	No. of FTEs	Date Arrived	Date Released
7/22	Holland Power	Canada	245	7/23	7/25
7/22	Tri-Wire Line	Canada	84	7/23	7/25
7/22	National Grid	New York	37	7/23	7/25
7/22	On-Target	Maine	18	7/23	7/25
7/22	Sargent	Maine	20	7/23	7/25
7/22	Northline	Maine	19	7/23	7/25
7/22	Green Mountain Power	Vermont	43	7/23	7/25
7/22	Riggs Distler	New Jersey	12	7/23	7/25
7/23	Harlan	New York	25	7/23	7/25
7/23	Furguson	New York	35	7/24	7/25
7/23	D&D	New York	48	7/24	7/25
7/23	O'Connell Electric	New York	26	7/24	7/25
7/23	Asplundh	New York	10	7/24	7/25
7/23	Riggs Distler	New York	31	7/24	7/25
7/23	Elecnor-Hawkeye	New York	36	7/24	7/25
7/23	Northline Utilities	New York	16	7/24	7/25
7/23	Northern Line	Maine	13	7/24	7/25
7/23	Asplundh	New York	150	7/24	7/25
7/23	Haugland	New York	72	7/24	7/25
7/23	Henkels & McCoy	Maryland	24	7/24	7/25
Total			964		

An issue developed with paperwork required to allow the crews from Canada to cross the border into the United States. Board staffer James Bruncati was instrumental in resolving the issue.

In addition, PSE&G assigned 69 contractor line FTEs (23 crews) already on the property to Southern Division from July 23-25th.

PSE&G utilized one staging area, at the Burlington County Mall, for the foreign crews where poles, transformers, conductors and other material was stored. The crews received their work assignments and safety briefings at this site.

PSE&G contacted tree trimming contractors on July 23rd for assistance and succeeded in obtaining 203 FTEs to supplement PSE&G's tree trimming FTEs already working on the property. The majority of the additional FTEs arrived on July 23rd and came from Virginia, West Virginia, Massachusetts, New York and New Jersey. They were released on July 25th.

Beginning in the evening of July 22nd, PSE&G began assigning line crews, service repair crews and look-up personnel from the other three operating divisions, and P&C, to Southern Division to assist in service restoration. Look-up personnel from PSE&G's General Office were also assigned to Southern Division beginning on July 23rd. PSE&G utilized personnel from its Gas Delivery Department to stand by wires down in Southern Division beginning late in the evening on July 22nd.

Attached are the following Work Force Graphs which encompass all three weather events:

- Attachment "F" - Overhead Line Crews, Service Repair Crews and Troubleshooters - Company
- Attachment "G" - Overhead Line Crews, Service Repair Crews and Troubleshooters - Central Division
- Attachment "H" - Overhead Line Crews, Service Repair Crews and Troubleshooters - Metropolitan Division
- Attachment "I" - Overhead Line Crews, Service Repair Crews and Troubleshooters - Palisades Division
- Attachment "J" - Overhead Line Crews, Service Repair Crews and Troubleshooters - Southern Division
- Attachment "K" - Contractor Tree FTEs – Company and Contractor Tree FTEs – Outside Contractors Assisting Southern Division
- Attachment "L" - Overhead Line Crews and Service Repair Crews Assisting Central Division
- Attachment "M" - Overhead Line Crews, Service Repair Crews and Troubleshooters Assisting Southern Division
- Attachment "N" - PSE&G Contractor Line Crews Assisting Southern Division
- Attachment "O" - Mutual Aid FTEs Assisting Southern Division

Liaisons were assigned to Southern Division from 2300 hrs. on July 22nd until 1640 hrs. on July 25th, and at PSE&G's Inquiry Center from 0800 hrs. on July 23rd until 1640 hrs. on July 25th, to assist in addressing customer service inquiries.

PSE&G contacted the Somerset, Burlington, Camden, Gloucester, Mercer and Monmouth County Offices of Emergency Management (OEMs) with remote support provided the Somerset, Burlington and Camden Offices on the overnight on July 22-23rd. A PSE&G representative was assigned to the Burlington Office on the 0800-1600 hrs. shift on July 23rd. That office, plus those in Camden, Gloucester, Mercer and Monmouth Counties were supported remotely until the afternoon on July 25th.

TROUBLE LOCATIONS AND CLASSIFICATIONS

Outside plant damage locations are listed below:

69 & 26-kV	-	32
13 & 4-kV	-	759
Transformers	-	116
Secondaries	-	90
Services	-	1,051
Poles	-	159
Trees	-	537
Total	-	2,744

COMMUNICATIONS

Communications with Board staff concerning this weather event began on July 22nd and continued until July 26th.

PSE&G's Corporate Communications Department issued internal communications, press releases and handled multiple newspaper, television and radio information requests during this period. In addition, social media activity was followed and used by PSE&G in targeted messages to the areas in Southern Division that were hardest hit.

A message concerning the very severe thunderstorms and proper storm preparation procedures was sent to PSE&G's Priority 4 (special needs) customers on July 22nd. PSE&G contacted these customers in the affected areas in Southern Division from July 23rd–25th.

PSE&G conducted conference calls with Mayors and other Municipal Officials on July 23rd, 24th and 25th to discuss and review the storm restoration efforts. Members of the Regional Public Affairs Department organized and participated on the calls as did division personnel.

PSE&G's Business Customer Solutions (BCS) Department contacted impacted large customers in Southern Division during this event to communicate storm restoration efforts. The Department utilized liaisons in Southern Division and roving liaisons in heavily impacted areas to aid in this effort.

Water, Ice and Customer Service Centers were established at the following sites:

- 34 Municipal Drive, Lumberton and 1 Municipal Drive, Bordentown on July 23rd and July 24th
- 429 John F. Kennedy Way, Willingboro and 1750 Kresson Road, Cherry Hill on July 24th and 25th

In addition, a Mobile Customer Service Center provided water and ice to:

- A senior home at 429 John F. Kennedy Way, Willingboro on July 23rd
- The County OEM site at 295 Bordentown Chesterfield Road, Chesterfield on July 24th
- The Camden Cooling Community Center, 1200 Merrimac Road, Camden on July 24th

The Customer Service Centers provided ETR updates for customers and were able to issue service orders if required.

Over two million text messages were exchanged with customers during this weather event.

PSE&G's Regional Public Affairs Managers kept in constant contact with municipal and state officials in the areas in Southern Division hardest hit by these very severe thunderstorms. In person meetings, telephone calls, text messages and press releases were all utilized in this communication process. The municipalities of Collingswood and Willingboro were especially hard hit. In addition to the Regional Public Affairs Managers communicating with officials in those two municipalities, PSE&G officers were also in contact with those officials.

INCIDENTS

Bordentown and Collingswood Substations experienced extended outages during this weather event.

Bordentown Substation was shutdown from 1755 hrs. on July 22nd to 1543 hrs. on July 23rd when 1,597 customers were restored. 973 customers were restored at 1646 hrs. Tree damage caused the three 26-kV supply lines to the station to lock out.

Collingswood Substation was shutdown from 1740 hrs. on July 22nd to 2343 hrs. on July 24th affecting 157 customers, all in the business district of the municipality. Tree damage caused the two 26-kV supply lines to the station to lock out. Complicating repairs was the location of the two lines along a railroad right-of-way on opposite sides of the railroad tracks.

SUMMARY

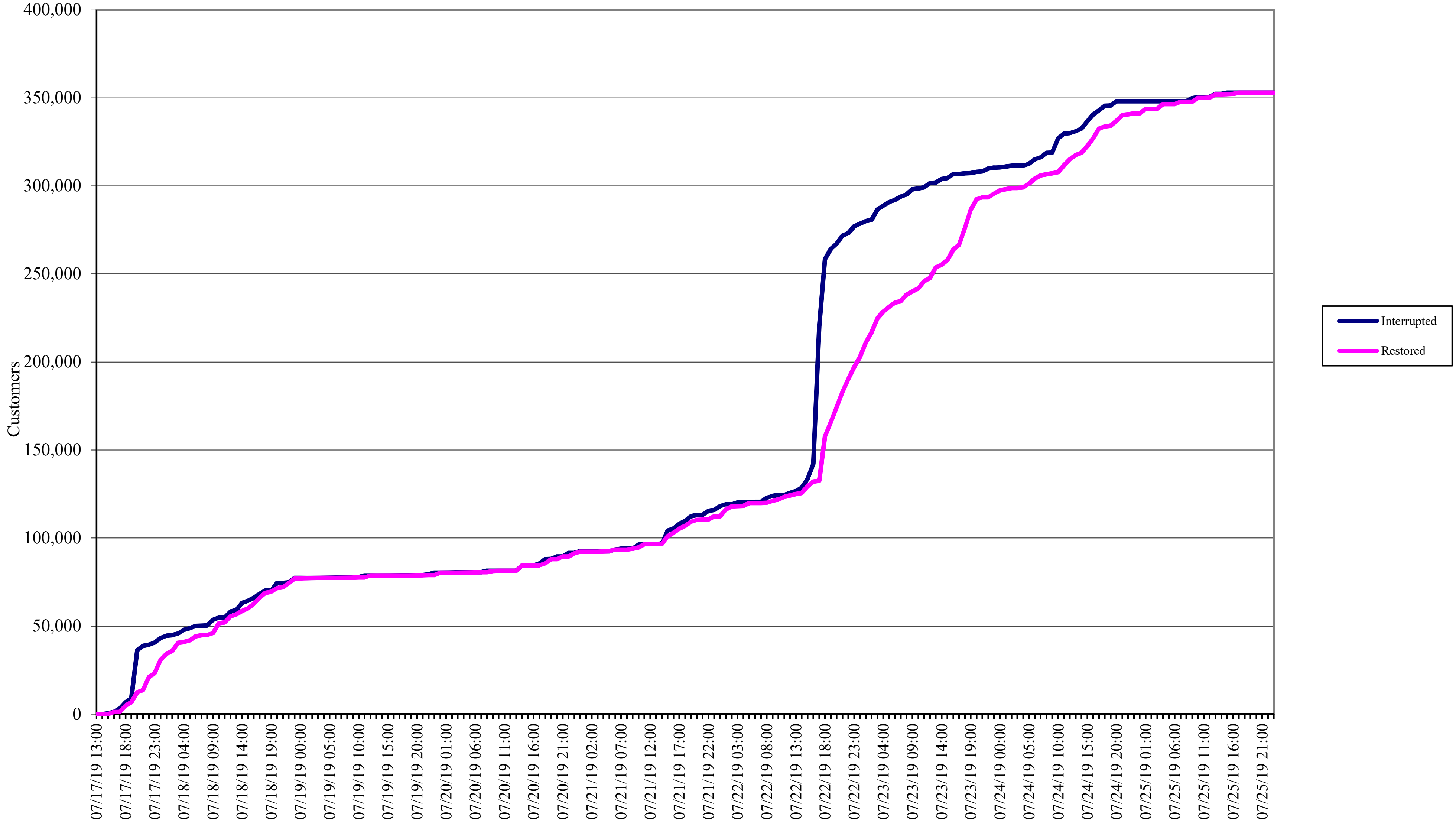
These weather events qualify as a Major Event since 243,406 customers in Southern Division, which is more than 10% of the 579,052 customers in the Division and 352,915 customers Company wide, which is more than 10% of the 2,400, 252 customers served by the Company, were interrupted and each of PSE&G's other three operating divisions supplied line and service restoration crews to Southern Division.

PSE&G's excellent relationship with its unions was beneficial during these events.

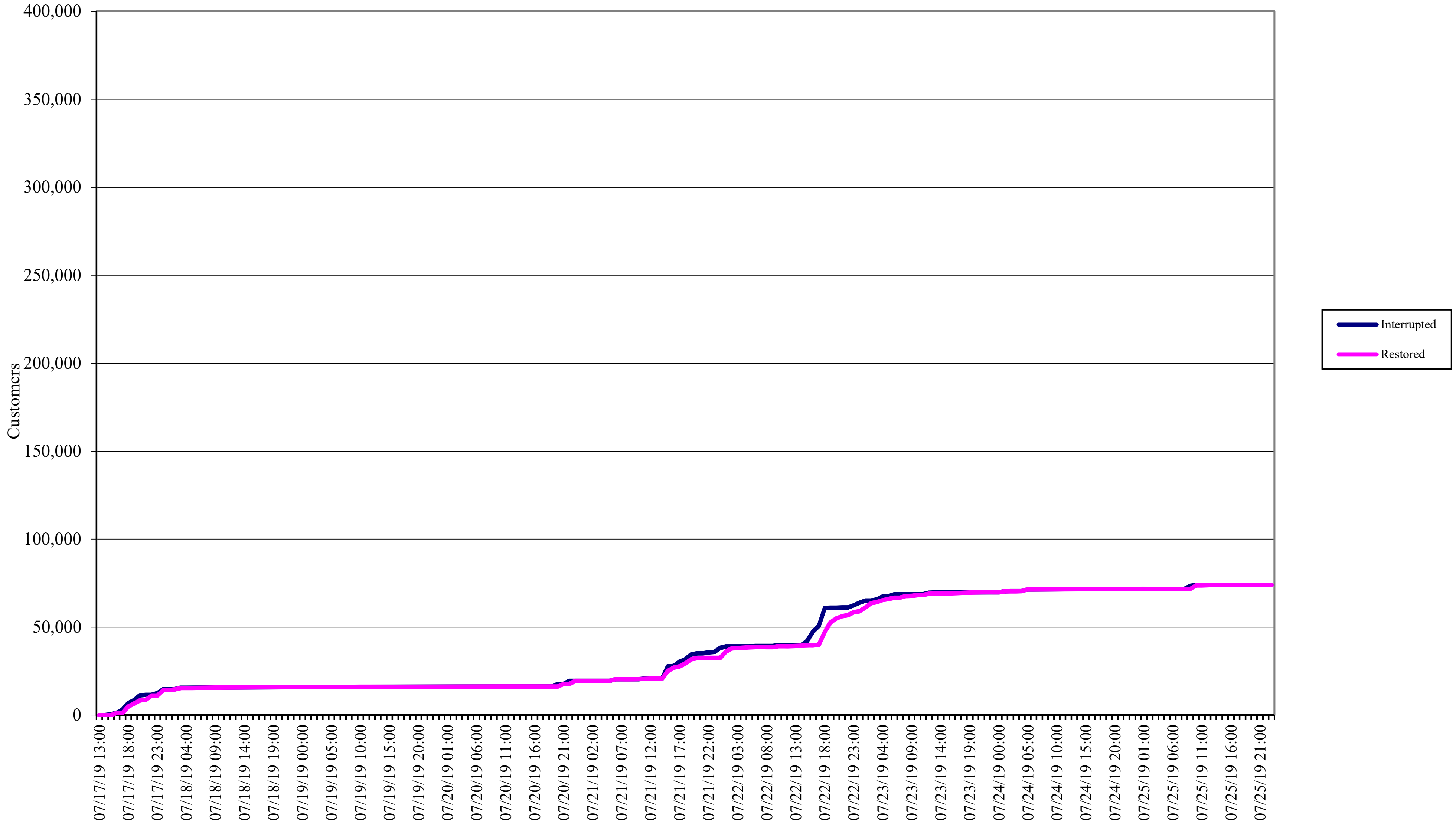
There were no issues involving equipment or material during these events.

DWW: af
8/16/19

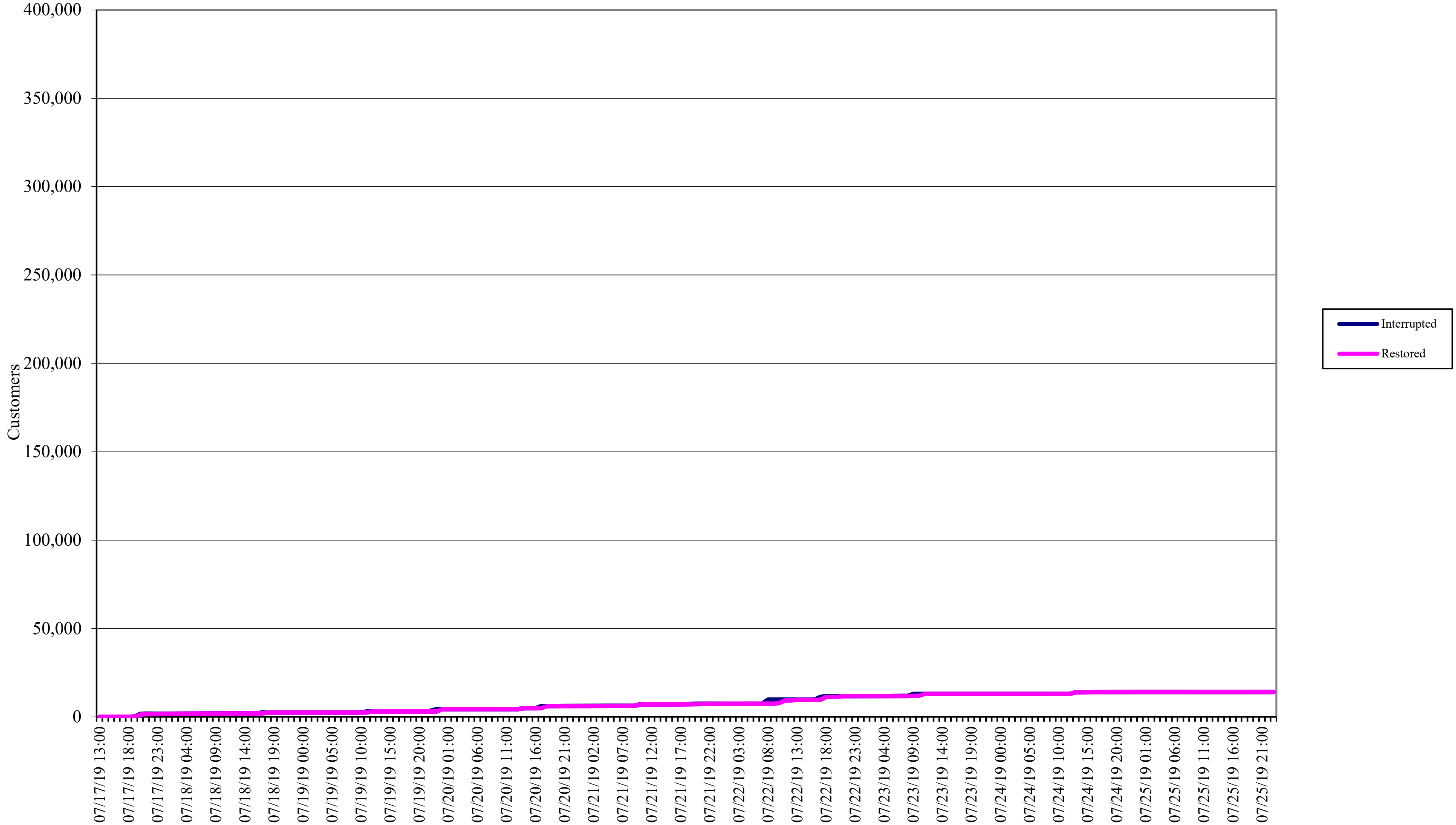
Attachment "A"
PSE&G
Customer Restoration Summary
Severe Weather Events - July 17-25, 2019
Company Wide



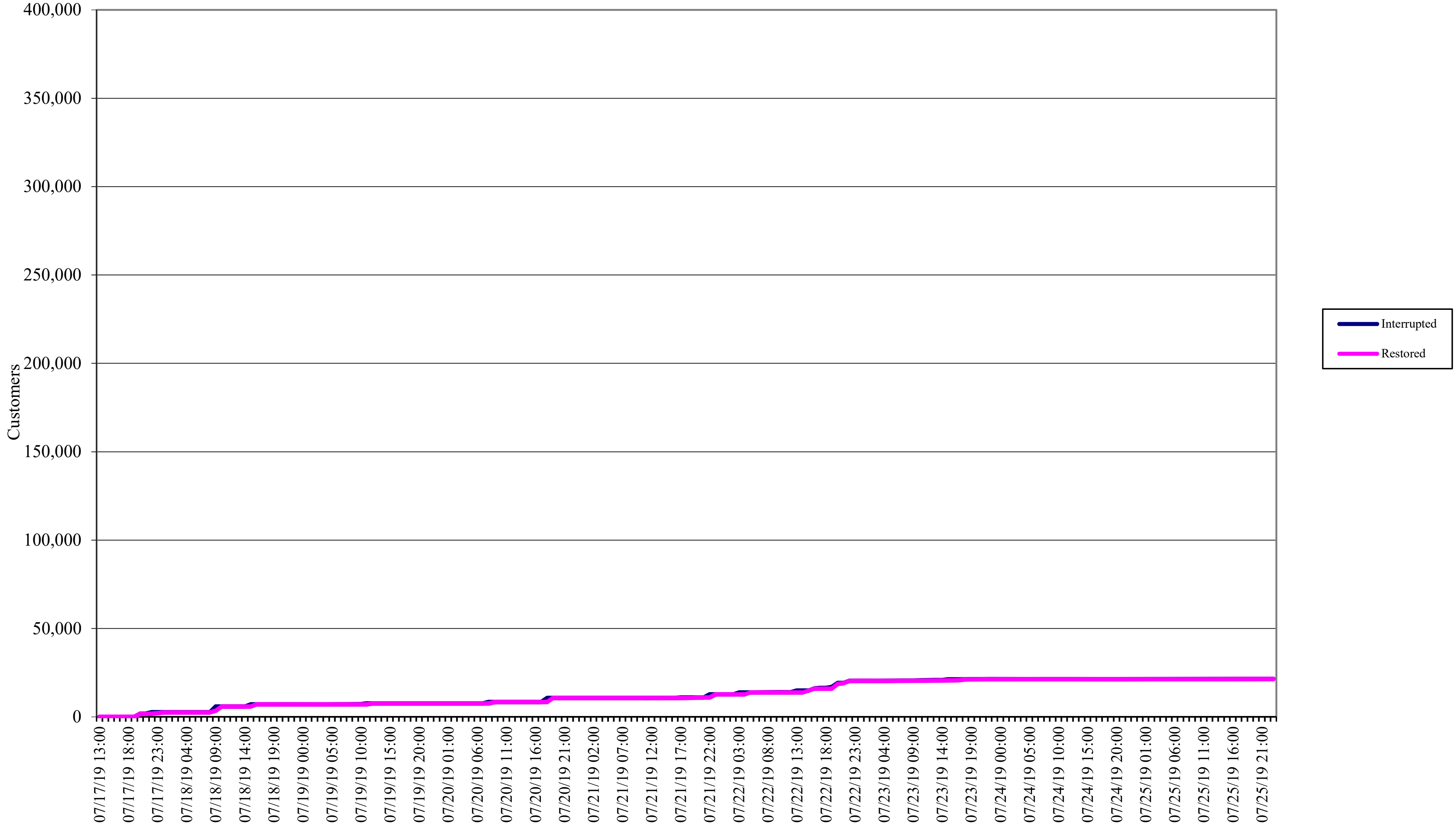
Attachment "B"
PSE&G
Customer Restoration Summary
Severe Weather Events - July 17-25, 2019
Central Division



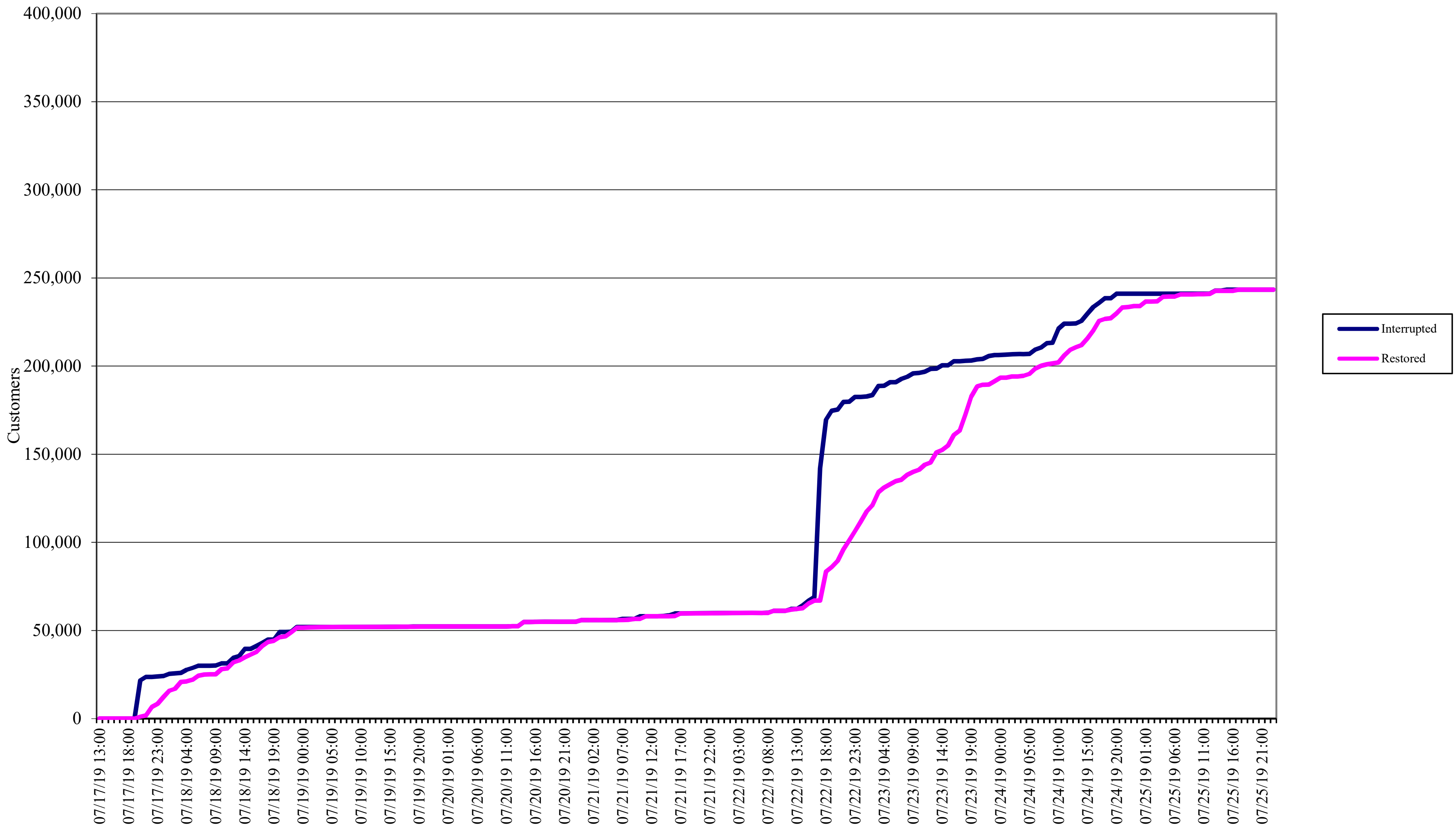
Attachment "C"
PSE&G
Customer Restoration Summary
Severe Weather Events - July 17-25, 2019
Metropolitan Division



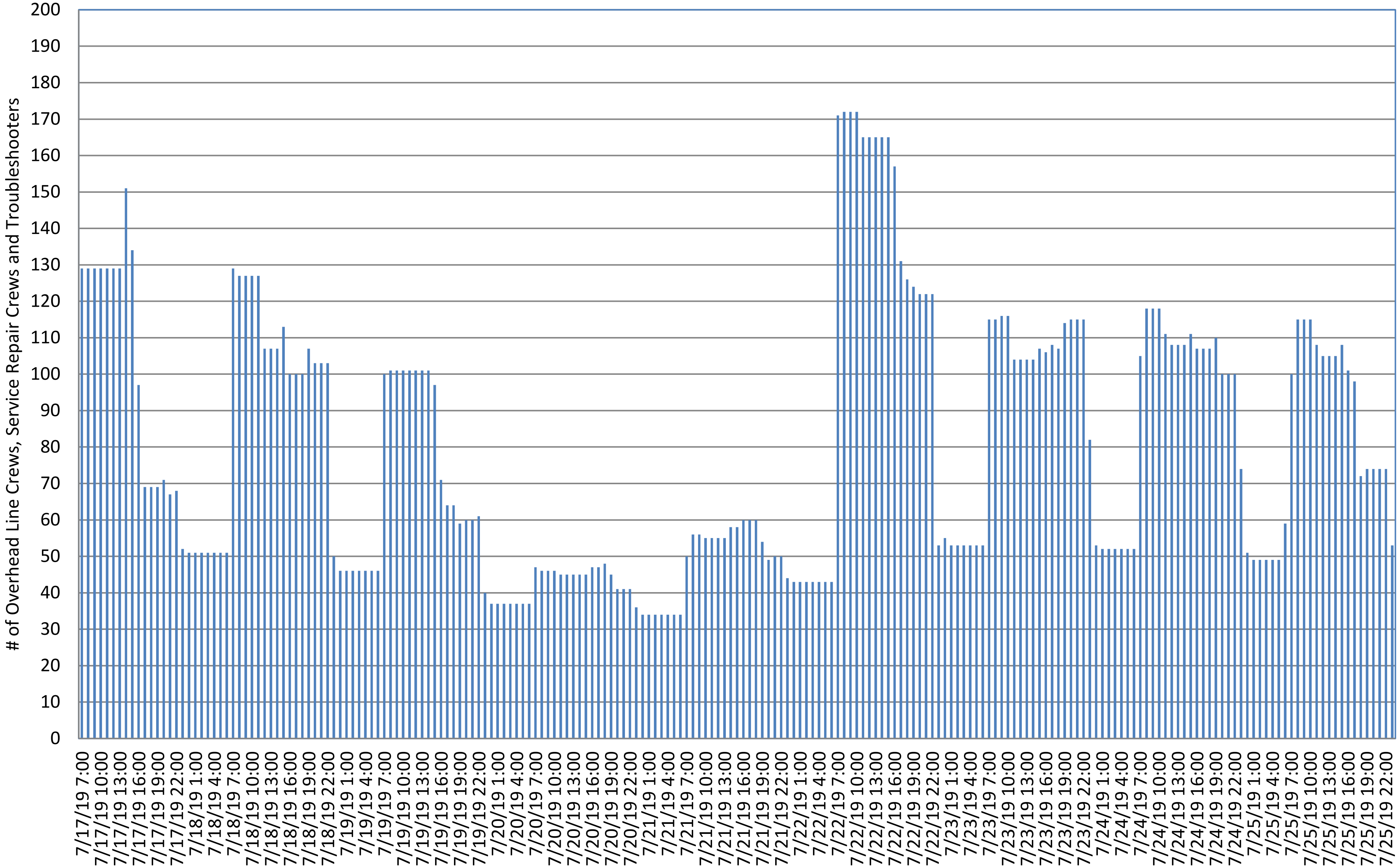
Attachment "D"
PSE&G
Customer Restoration Summary
Severe Weather Events - July 17-25, 2019
Palisades Division



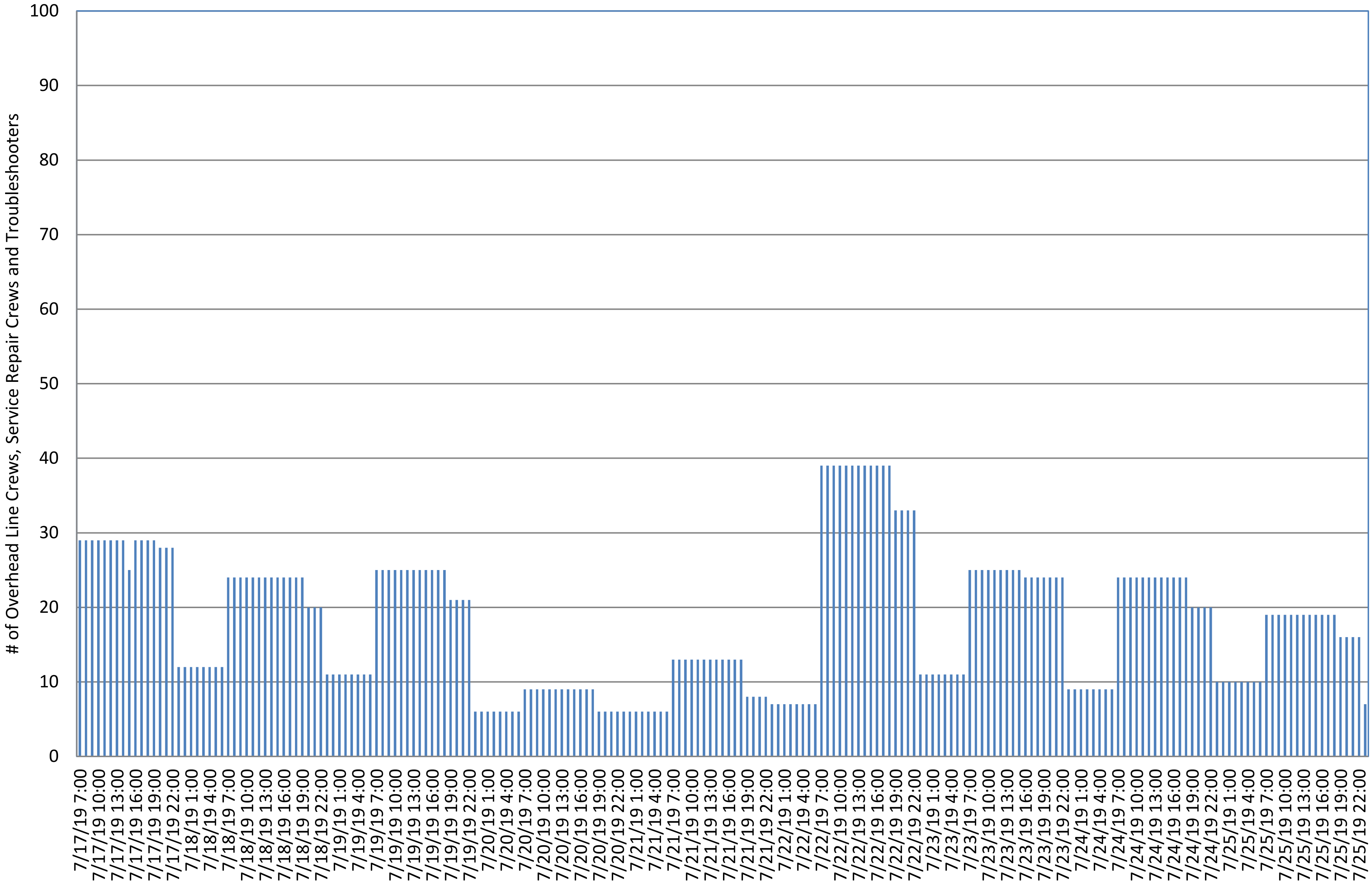
Attachment "E"
PSE&G
Customer Restoration Summary
Severe Weather Events - July 17-25, 2019
Southern Division



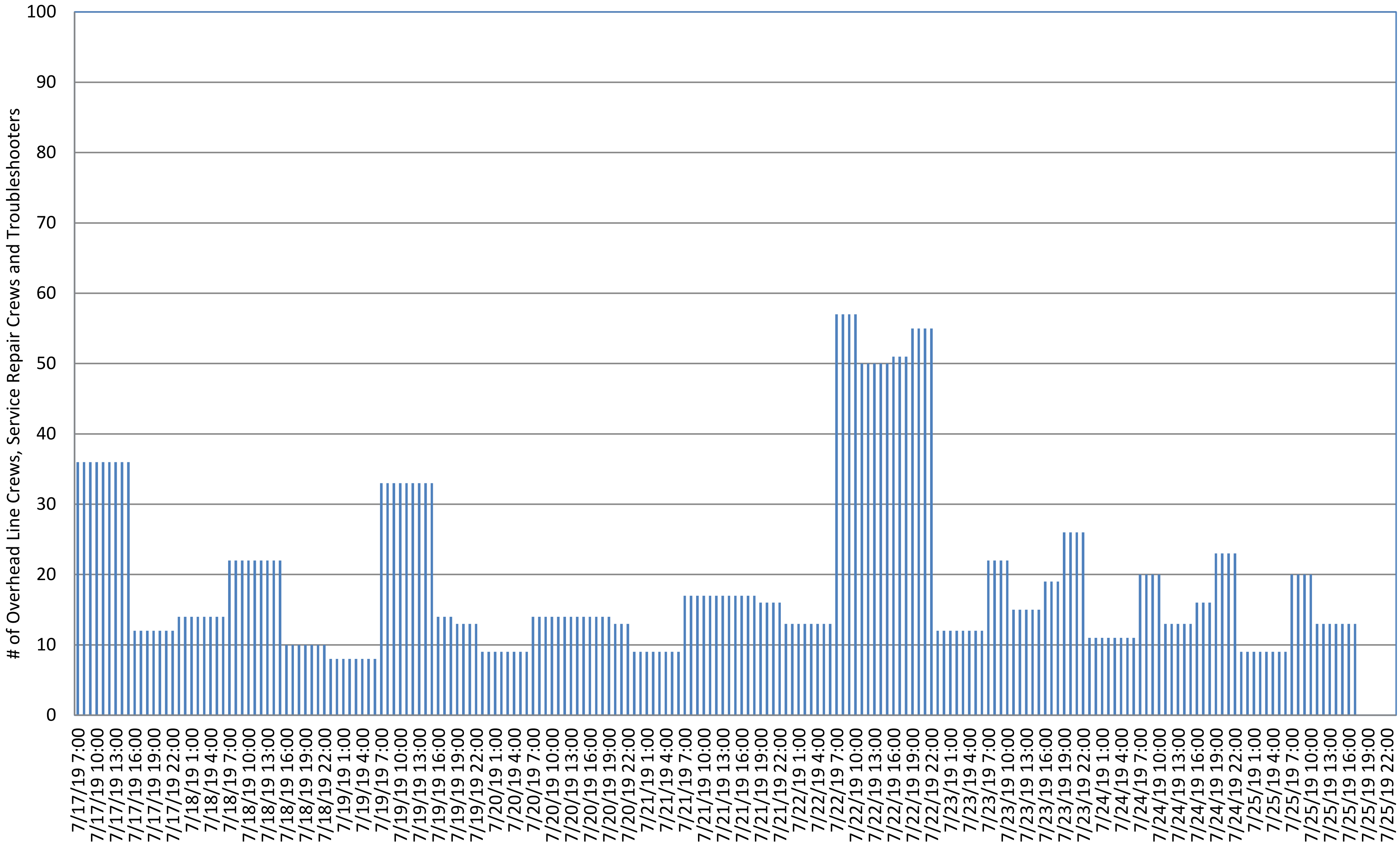
Attachment "F"
PSE&G
Overhead Line Crews, Service Repair Crews and Troubleshooters - Company
Severe Weather Events - July 17-25,2019



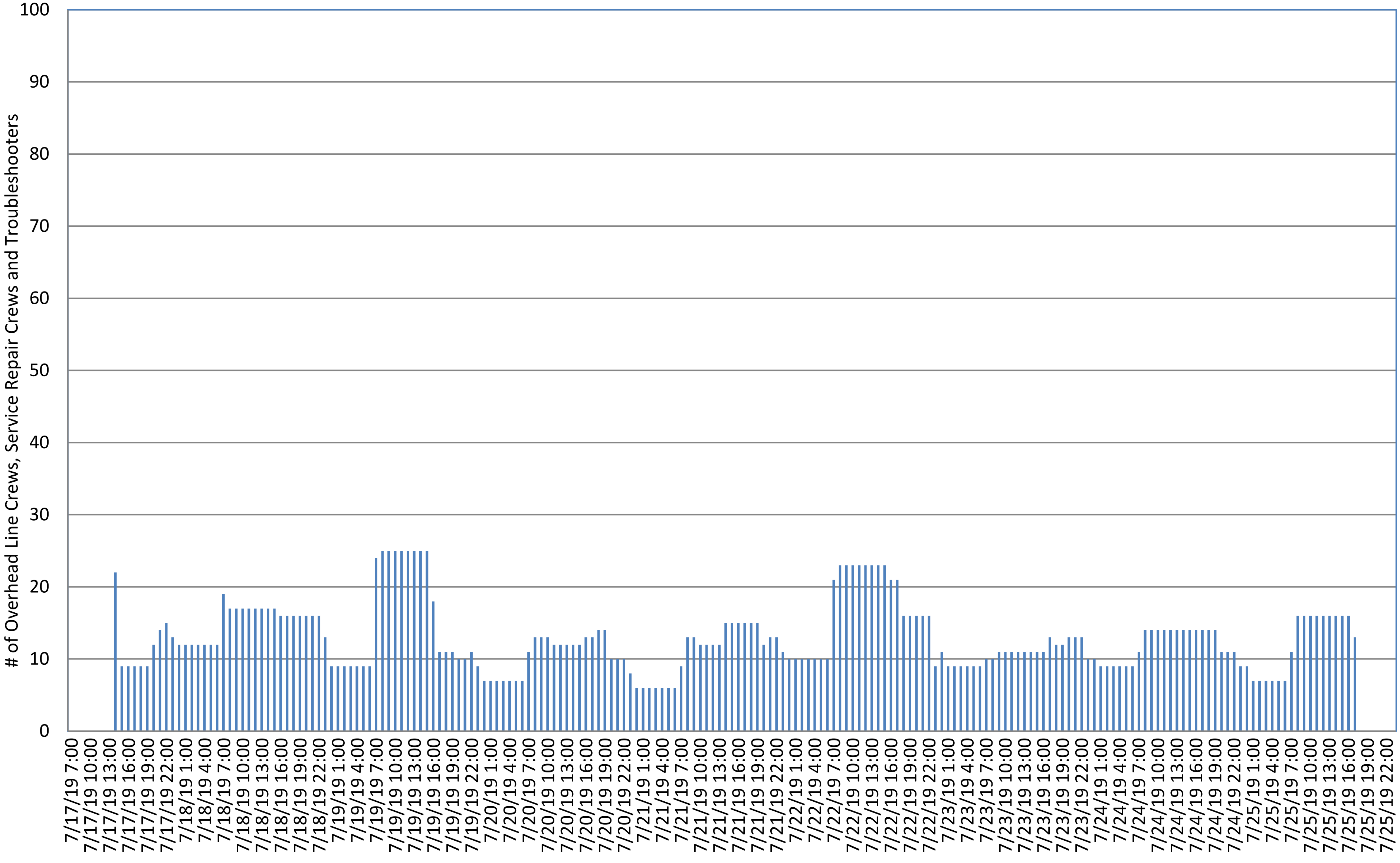
Attachment "G"
PSE&G
Overhead Line Crews, Service Repair Crews and Troubleshooters - Central Division
Severe Weather Events - July 17-25,2019



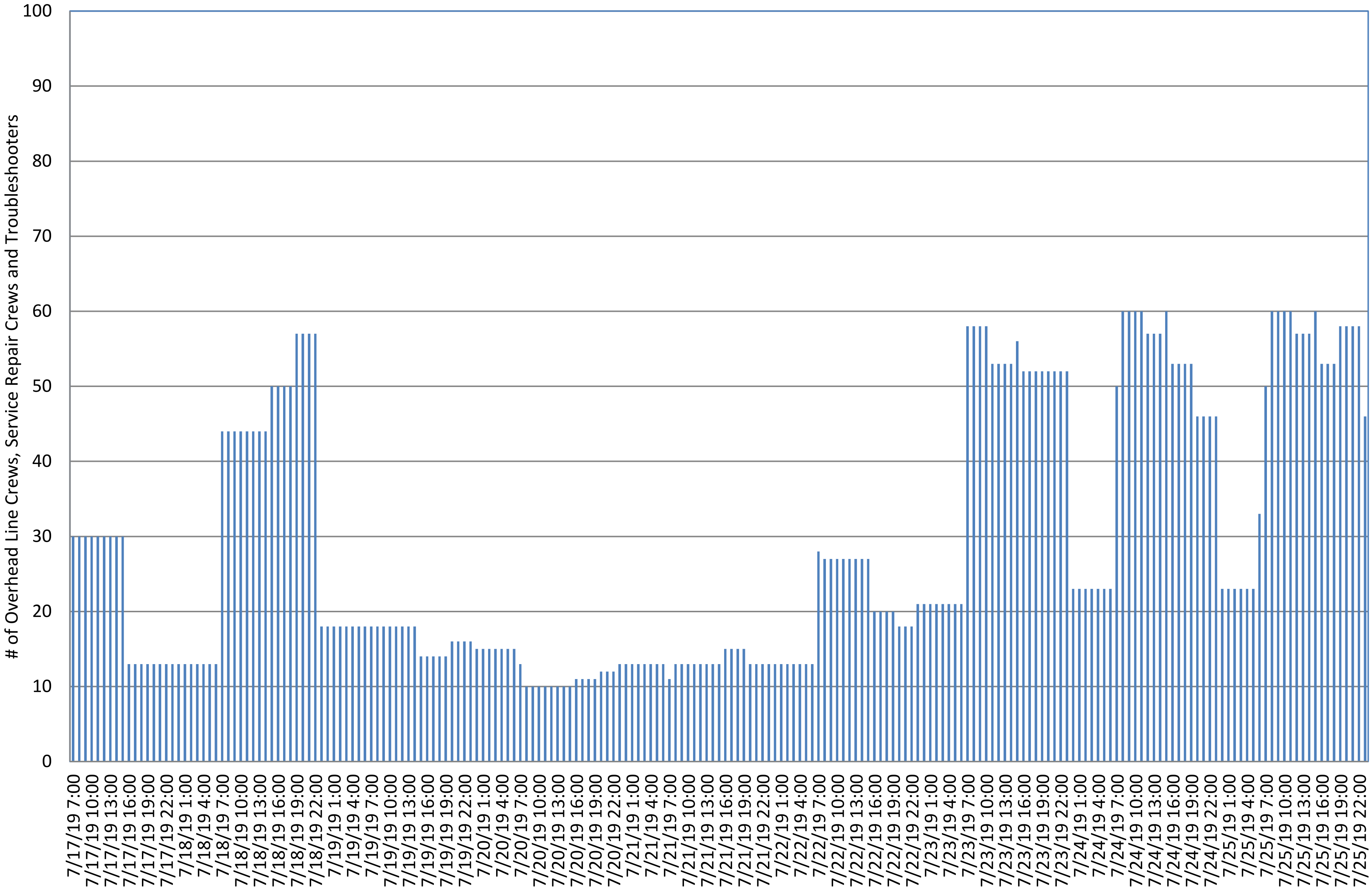
Attachment "H"
PSE&G
Overhead Line Crews, Service Repair Crews and Troubleshooters - Metropolitan Division
Severe Weather Events - July 17-25, 2019



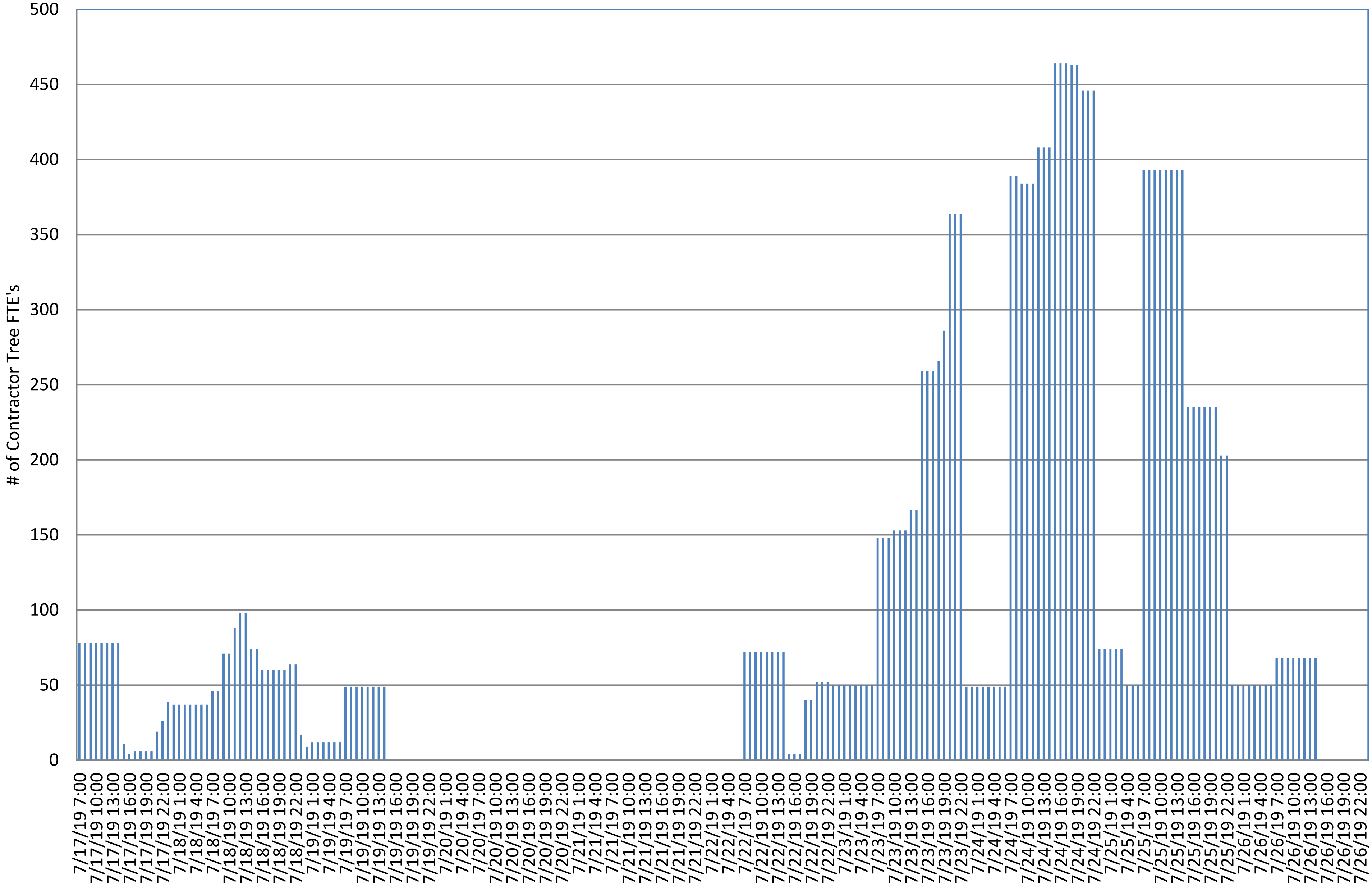
Attachment "I"
PSE&G
Overhead Line Crews, Service Repair Crews and Troubleshooters - Palisades Division
Severe Weather Events - July 17-25, 2019



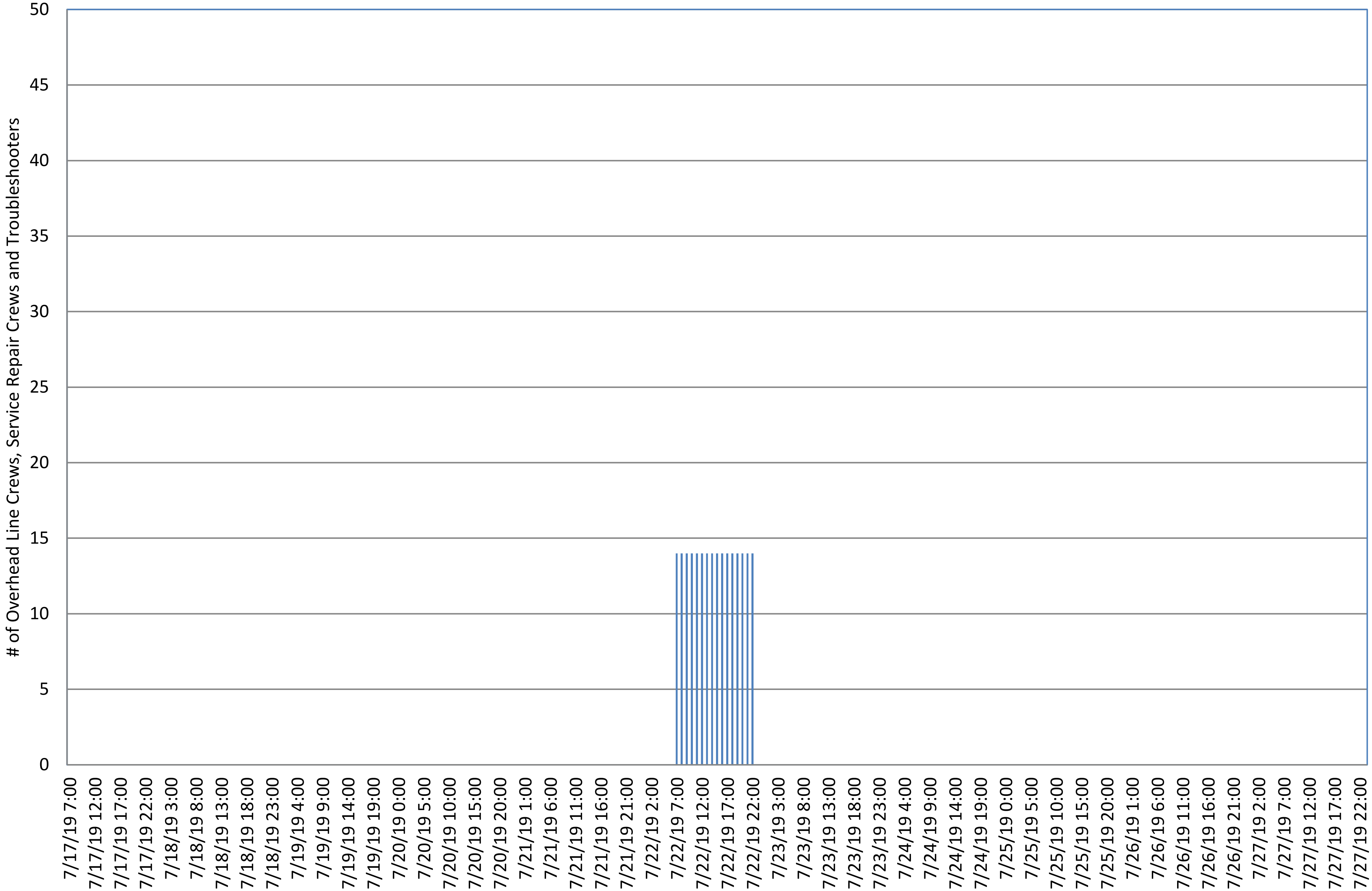
Attachment "J"
PSE&G
Overhead Line Crews, Service Repair Crews and Troubleshooters - Southern Division
Severe Weather Events - July 17-25, 2019



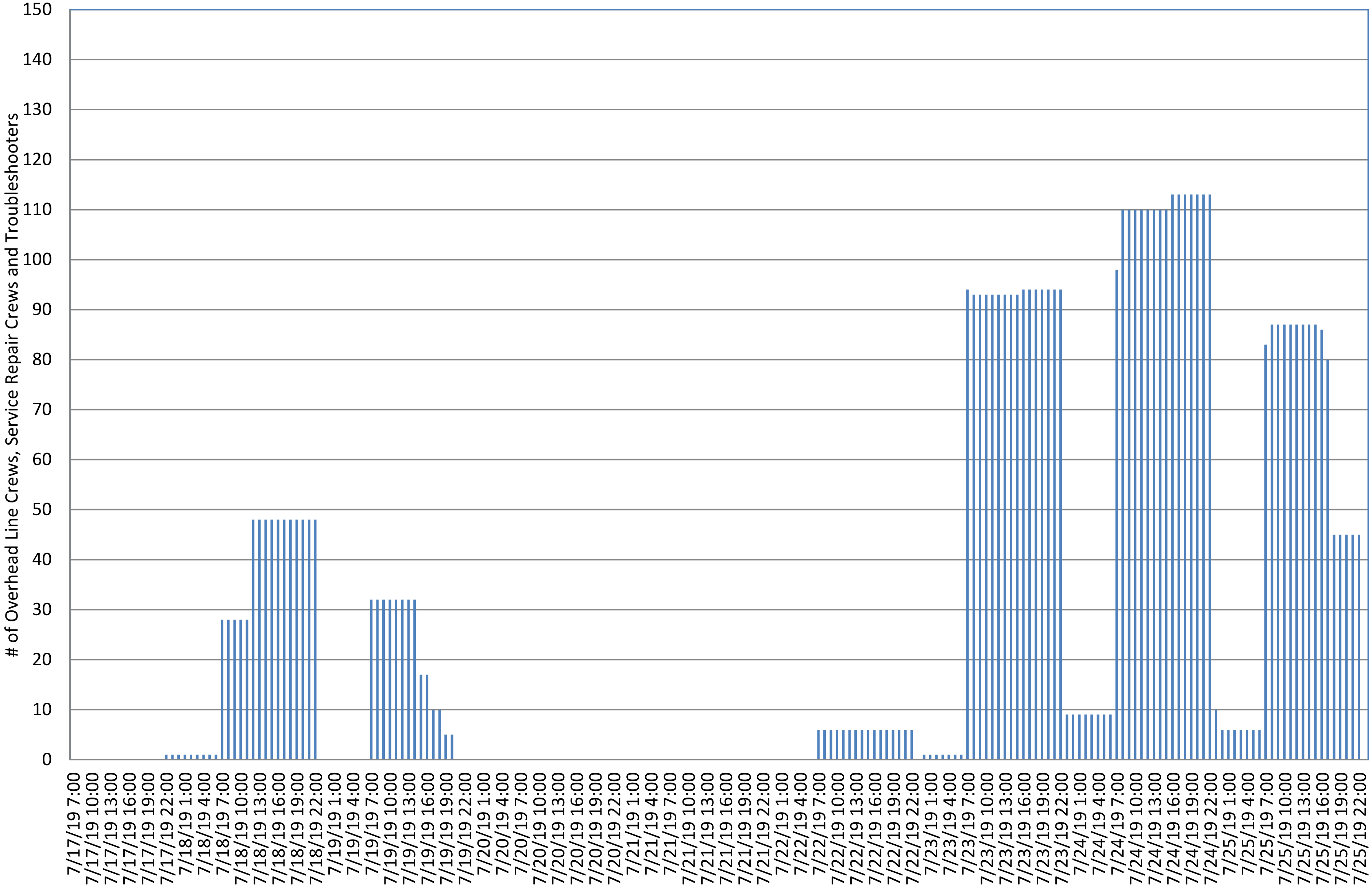
Attachment "K"
PSE&G
Contractor Tree FTE's - Company and Contractor Tree FTE's - Outside Contractors Assisting Southern Division
Severe Weather Events - July 17-25, 2019



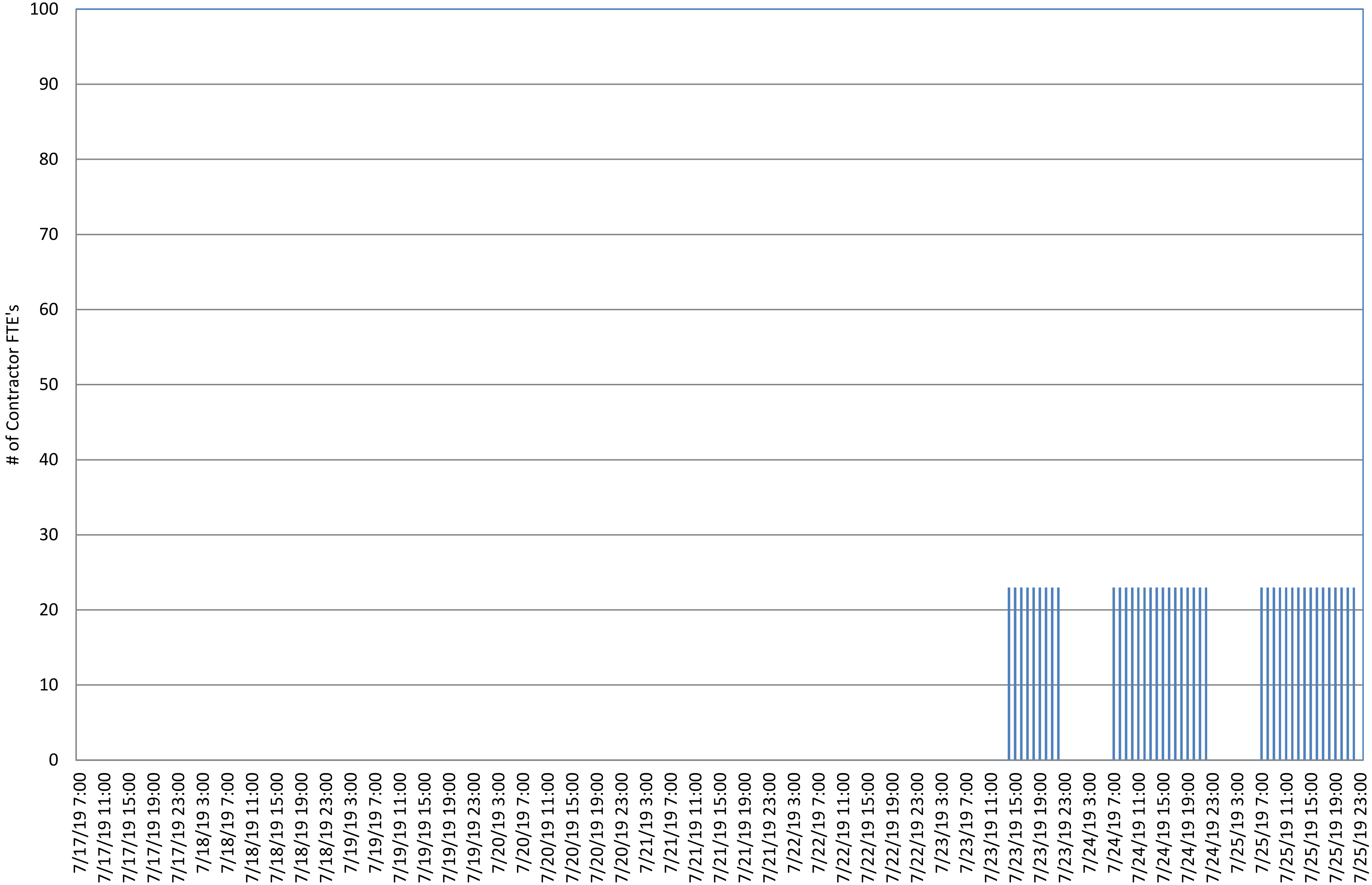
Attachment "L"
PSE&G
Overhead Line Crews, Service Repair Crews and Troubleshooters Assisting Central Division
Severe Weather Events - July 17-25,2019



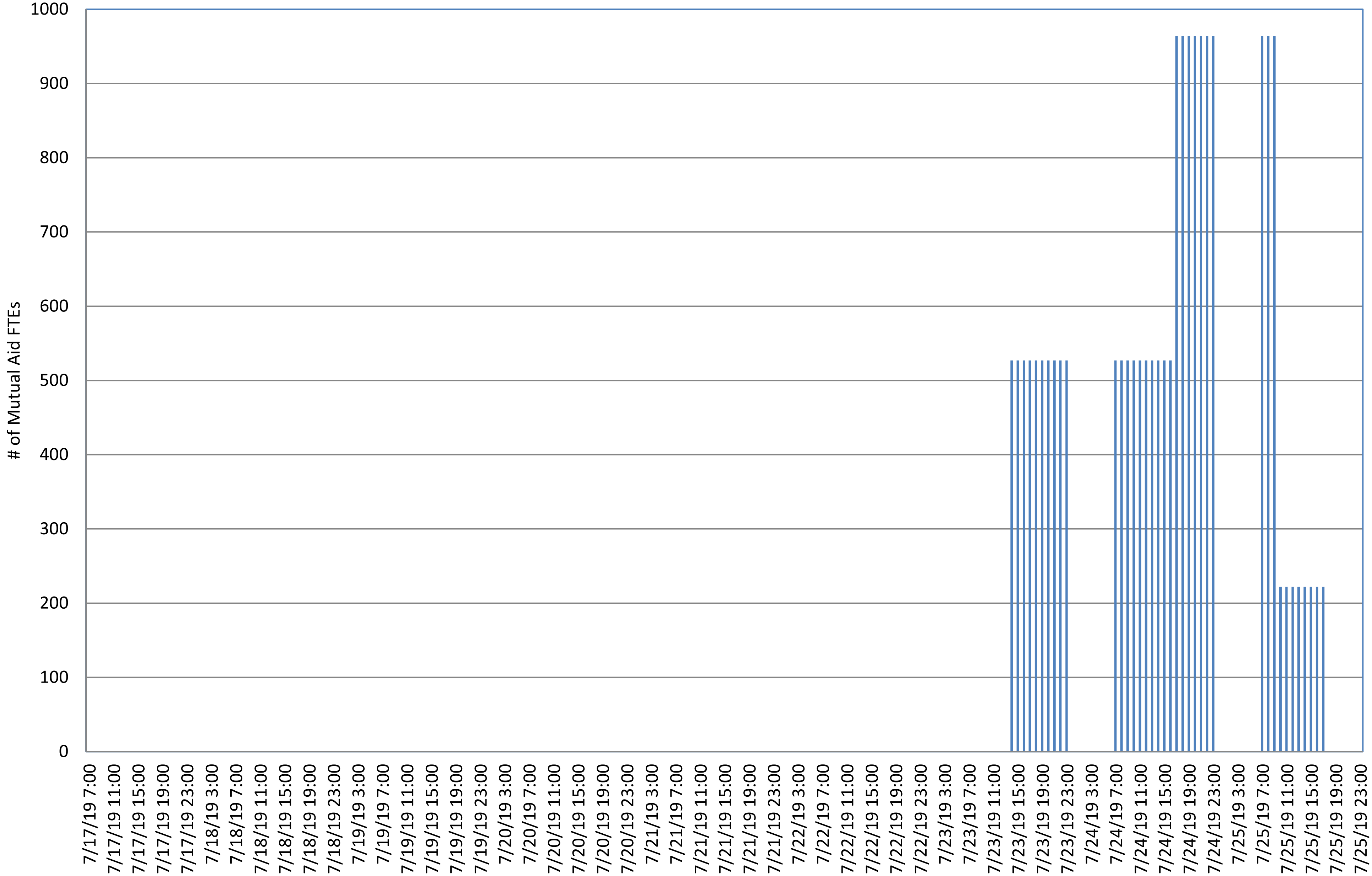
Attachment "M"
PSE&G
Overhead Line Crews, Service Repair Crews and Troubleshooters Assisting Southern Division
Severe Weather Events - July 17-25,2019



Attachment "N"
PSE&G
PSE&G Contractor Line Crews Assisting Southern Division
Severe Weather Events - July 17-25,2019



Attachment "O"
PSE&G
Mutual Aid FTEs Assisting Southern Division
Severe Weather Events - July 17-25, 2019



		7/22 Storm Electric Delivery Capital Expenditures (CapEx)	O&M Expenses	CapEx + O&M Expenses	Incremental O&M Expenses
1	Total Labor	**1,816,649**	**6,339,603**	**8,156,251**	**2,010,595**
2	Contractor/Mutual Aid	2,997,010	7,834,946	10,831,956	7,834,946
3	Tree Removal	467,772	1,746,306	2,214,078	1,746,306
4	Buses	-	-	-	-
5	Other Contractor	292,597	108,490	401,087	108,490
	Total Contractor	**3,757,379**	**9,689,742**	**13,447,121**	**9,689,742**
6	Material	**530,150**	**498,203**	**1,028,353**	**215,760**
7	Food	7,644	38,658	46,301	38,658
8	Lodging	9,494	37,230	46,724	37,230
9	Security	-	-	-	-
10	Water and Ice	-	167,314	167,314	167,314
11	Other	70,996	217,948	288,943	6,991
	Total Other	**88,134**	**461,149**	**549,283**	**250,192**
	Total Incurred	**6,192,311**	**16,988,698**	**23,181,009**	**12,166,290**
12	O&M Base Rate Storm Costs	-	-	-	-
	Total	**6,192,311**	**16,988,698**	**23,181,009**	**12,166,290**

June 26, 2020

Via Electronic Mail & Regular Mail

James Giuliano, Director
Division of Reliability and Security
New Jersey Board of Public Utilities
225 East State Street – 2nd Floor, Area 2W
Trenton, New Jersey 08625

RE: MAJOR EVENT REPORT
DERECHO AND SEVERE THUNDERSTORMS
JUNE 3-7, 2020

Dear Director Giuliano:

As required by 14:5-8.8 Major Event Report, enclosed is a copy of PSE&G's Major Event Report for the derecho and severe thunderstorms that affected PSE&G's Southern Division from June 3-7, 2020.

Questions concerning this matter can be directed to me or Donald W. Weyant, Manager - Regulatory Compliance at (973) 430-6730.

Respectfully submitted,

Matthew M. Weissman

Attachments

C (Email Only)
Joseph Fiordalisio, President
Upendra Chivukula, Commissioner
Robert Gordon, Commissioner
Mary-Anna Holden, Commissioner
Dianne Solomon, Commissioner
Stacy Peterson, Director

PSE&G's REPORT TO THE BPU
MAJOR EVENT
DERECHO AND SEVERE THUNDERSTORMS
JUNE 3 - 7, 2020

EXECUTIVE SUMMARY

During the period of June 3 - 7, 2020, a derecho and severe thunderstorms affected PSE&G's Southern Division. Shortly after noon on June 3, a derecho swept across the division causing extensive plant damage and significant tree damage. Wind gusts of 73 and 72 mph were measured at Moorestown and Delran respectively. The National Weather Service stated that the derecho was moving at 80 mph. Later that evening, a severe thunderstorm struck the division. On June 4 severe thunderstorms struck the division in the afternoon and late evening. These three storms inflicted additional plant damage and caused more tree damage.

As discussed with Board staff, because of the severity of the weather events on June 3 and 4, they will be considered as one Major Event. These weather events quality as a Major Event since 246,075 customers in Southern Division, which is more than 10% of the 585,381 customers in the Division, and 257,209 customers Company wide, which is more than 10% of the 2,430,197 customers served by the Company, were interrupted. Also, each of PSE&G's other three operating divisions supplied line and service restoration crews to Southern Division.

During PSE&G's daily 0800 hrs. operations conference call on June 3, PSE&G's weather service predicted strong storms for the entire service territory after 1200 hrs. The storms were predicted to contain straight line wind gusts. PSE&G's storm preparation plans began to be developed and staffing assignments for the 1500 - 2300 hrs. and 2300 - 0700 hrs. shifts were to be scheduled and presented at a 1300 hrs. operations conference call.

At the 1300 hrs. conference call, PSE&G's weather service indicated that the severe thunderstorms, which had already began to hit Southern Division, would be through the division by 1400 hrs. A second line of storms with straight line wind gusts of 70-80 mph and possible tornadoes was predicted to hit the division between 1700 - 2200 hrs. Participants in this conference call, and in the multiple conference calls concerning storm restoration efforts that continued until June 7, included representatives from Electric Delivery's General Office staff, the four operating divisions, Projects and Construction (P&C), the Electric System Operations Center (ESOC) along with personnel from other operating and staff departments of the Company.

During the call, Southern Division personnel reported multiple sub-transmission and distribution circuit lock-outs, indicating extensive plant damage. Arrangements were made to immediately send line crews, service repair crews and support personnel to Southern Division from the other three operating divisions and P&C to assist Southern Division's personnel in storm restoration. Additional tree trimming crews were also re-directed to Southern Division.

Two subsequent conference calls that afternoon focused on analyzing the outages and preparing for the other three divisions to send crews to Southern Division at 2300 hrs. At the same time, PSE&G was able to secure approximately 75 contractor line FTEs and approximately 200 line FTEs from PSEG-LI. In addition, PSE&G requested a North Atlantic Mutual Assistance Group (NAMAG) conference call at 1715 hrs. during which PSE&G requested 500 Mutual Aid Line FTEs and received a commitment for 436 FTEs.

During the 1900 hrs. operations conference call that evening, PSE&G's weather service predicted a severe thunderstorm would strike Southern Division between 2000 - 2200 hrs. with 55 - 60 mph winds and lightning. Staffing plans for the 2300 - 0700 shift were confirmed. It was announced that two material staging areas were being established at Rowan College sites in Mount Laurel and Pemberton. Also, three comfort stations for the distribution of water and ice would open on June 4 in Audubon, Lumberton and Willingboro. In addition, a Mayor's conference call to inform municipal officials of storm restoration efforts was scheduled for June 4 at 1100 hrs.

During the 0800 hrs. operations conference call on June 4, PSE&G's weather service predicted another round of severe thunderstorms would strike Southern Division later that afternoon, some of which could contain 50 - 60 mph winds. Southern Division personnel reported that storms struck their service territory during the evening on June 3 causing additional plant damage and more tree damage.

During the late afternoon and late evening on June 4, additional storms struck Southern Division resulting in even more plant damage.

PSE&G scheduled another NAMAG conference call for 2100 hrs. during which PSE&G requested 300 additional Line FTEs and received a commitment for 50 FTEs. In addition on June 4, PSE&G was able to secure 194 tree trimming FTEs from other utilities.

Another Mayors' conference call was scheduled for June 5 at 1100 hrs.

It must be pointed out that the restoration efforts were impacted by the need to observe COVID-19 protocols and work practices.

Communications with Board staff concerning these weather events began on June 3 and continued until June 7.

PSE&G opened a "virtual" Emergency Operations Center (EOC) from 1300 hrs. on June 3 to 1700 hrs. on June 7.

The restoration efforts went extremely well with 45% of the customers interrupted in Southern Division restored to service within one day, 81% within two days, 97% within three days and complete restoration in a little over four days.

<u>OPERATING REPORT</u>

Extended customer interruptions and restoration times for customers during this Mutual Aid assignment are as follows:

Division	Customers Interrupted Extendedly	Final Restoration
Central	3,400	1402 hrs. – 6/7*
Metropolitan	502	1332 hrs. – 6/7*
Palisades	7,232	1600 hrs. – 6/7*
Southern	246,075	1650 hrs. – 6/7
Total	257,209	

*Outages occurred on 6/7

Attached are the following Customer Restoration Summary Graphs for this weather event:

Attachment “A” - Company Wide
Attachment “B” - Central Division
Attachment “C” - Metropolitan Division
Attachment “D” - Palisades Division
Attachment “E” - Southern Division

During the period of June 3 - 7, 2020, a derecho and severe thunderstorms affected PSE&G’s Southern Division. Shortly after noon on June 3 a derecho swept across the division causing extensive plant damage and significant tree damage. Wind gusts of 73 and 72 mph were measured at Moorestown and Delran respectively. The National Weather Service stated that the derecho was moving at 80 mph. Later that evening, a severe thunderstorm struck the division. On June 4 severe thunderstorms struck the division in the afternoon and late evening. These three storms inflicted additional plant damage and caused more tree damage.

During PSE&G’s daily 0800 hrs. operations conference call on June 3rd, PSE&G’s weather service predicted strong storms for the entire service territory after 1200 hrs. The storms were predicted to contain straight line wind gusts. PSE&G’s storm preparation plans began to be developed and staffing assignments for the 1500 - 2300 hrs. and 2300 - 0700 hrs. shifts were to be scheduled and presented at a 1300 hrs. operations conference call.

At the 1300 hrs. conference call, PSE&G’s weather service indicated that the severe thunderstorms, which had already began to hit Southern Division, would be through the division by 1400 hrs. A second line of storms with straight line wind gusts of 70-80 mph and possible tornadoes was predicted to hit the division between 1700 - 2200 hrs. Participants in this conference call, and in the multiple conference calls concerning storm restoration efforts that continued until June 7, included representatives from Electric Delivery’s General Office staff, the four operating divisions, Projects and Construction (P&C), the Electric System Operations Center (ESOC) along with personnel from other operating and staff departments of the Company.

During the call, Southern Division personnel reported multiple sub-transmission and distribution circuit lock-outs, indicating extensive plant damage. Arrangements were made to immediately send line crews, service repair crews and support personnel to Southern Division from the other three operating divisions and P&C to assist Southern Division’s personnel in storm restoration. Additional tree trimming crews were also re-directed to Southern Division.

Two subsequent conference calls that afternoon focused on analyzing the outages and preparing for the other three divisions to send crews to Southern Division at 2300 hrs. At the same time, PSE&G was able to secure approximately 75 contractor Line FTEs and approximately 200 Line FTEs from PSEG-LI. In addition, PSE&G’s requested a North Atlantic Mutual Assistance Group (NAMAG) at 1715 hrs. during which PSE&G requested 500 Mutual Aid Line FTEs and received a commitment for 436 FTEs.

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During the late afternoon and late evening on June 4, additional storms struck Southern Division resulting in even more plant damage.

PSE&G scheduled another NAMAG conference call at 2100 hrs. during which PSE&G requested 300 additional Line FTEs and received a commitment for 50 FTEs. In addition, on June 4, PSE&G was able to secure 194 tree trimming FTEs from other utilities.

Another Mayors' conference call was scheduled for June 5 at 1100 hrs.

It must be pointed out that the restoration efforts were impacted by the need to observe COVID-19 protocols and work practices.

PERSONNEL DEPLOYMENT

Attached are the following Work Force Graphs for this weather event:

Attachment "F" - Overhead Line Crews, Service Repair Crews and Troubleshooters - Company
Attachment "G" - Overhead Line Crews, Service Repair Crews and Troubleshooters - Central Division
Attachment "H" - Overhead Line Crews, Service Repair Crews and Troubleshooters - Metropolitan Division
Attachment "I" - Overhead Line Crews, Service Repair Crews and Troubleshooters - Palisades Division
Attachment "J" - Overhead Line Crews, Service Repair Crews and Troubleshooters - Southern Division
Attachment "K" - Contractor Tree Crews - Company
Attachment "L" - Overhead Line Crews, Service Repair Crews, Troubleshooters, Service Dispatchers and Substation Operators Assisting Southern Division
Attachment "M" - Mutual Aid Line FTEs Assisting Southern Division

Listed below is the "Mutual Aid Crews List" for this weather event:

Mutual Aid Crews List					
Company name	Home Location	FTEs	Arrival Status	Acquired VIA	Release Status
PSEG-LI Internal Crews	Long Island, NY	16	Arrived 6/5/20 - 3pm	Outside NAMAG 6/4/2020	Released as of 06.06.20 @ 0700
PSEG-LI Asplundh	Long Island, NY	93	Arrived 6/4/2020 - 1pm	Outside NAMAG 6/3/2020	Released as of 06.07.20 @ 1700
PSEG-LI Asplundh	Long Island, NY	40	Arrived 6/4/2020 - 1pm	Outside NAMAG 6/3/2020	Released as of 06.07.20 @ 1700
PSEG-LI Haugland	Long Island, NY	55	Arrived 6/4/2020 - 1pm	Outside NAMAG 6/3/2020	Released as of 06.07.20 @ 1700
PSEG-LI Haugland	Long Island, NY	7	Arrived 6/4/2020 - 1pm	Outside NAMAG 6/3/2020	Released as of 06.07.20 @ 1700
Danella	NJ/PA	34	Arrived 6/3/2020 - 8pm	Outside NAMAG 6/3/2020	Released as of 06.06.20 @ 0700
PSEG-LI Elecnor Hawkeye	Long Island, NY	50	Arrived 6/4/2020 - 1pm	Outside NAMAG 6/3/2020	Released as of 06.07.20 @ 1700
PSEG-LI Elecnor Hawkeye	Long Island, NY	4	Arrived 6/4/2020 - 1pm	Outside NAMAG 6/3/2020	Released as of 06.07.20 @ 1700
Mc Phee Electric	NJ/PA	11	Already On Property 6/3/20	P&C Contractors	Released as of 06.06.20 @ 0700
Riggs-Distler	NJ/PA	21	Arrived on property 6/3/2020 - 8pm	Outside NAMAG 6/3/2020	Released as of 06.06.20 @ 0700
Henkels - Aberdeen	Maryland	14	Already On Property 6/3/20	P&C Contractors	Released as of 06.07.20 @ 1700
Michael's Power	Wisconsin	9	Arrived On Property 6/4/2020 3pm-5pm	From NAMAG Request 6/3/20	Released as of 06.06.20 @ 0700
D&D Power Team #1, Central Hudson Crews	New York	30	Arrived On Property 6/4/2020 3pm-5pm	From NAMAG Request 6/3/20	Released as of 06.06.20 @ 0700
D&D Power Team #2, National Grid Crews	New York	25	Arrived On Property 6/4/2020 3pm-5pm	From NAMAG Request 6/3/20	Released as of 06.06.20 @ 0700
O'Connell Electric AvanGrid Crews Team #1	Plattsburg NY	15	Arrived On Property 6/4/2020 3pm-5pm	From NAMAG Request 6/3/20	Released as of 06.06.20 @ 0700
O'Connell Electric Avagrid Crews Team #2	Plattsburg NY	16	Arrived On Property 6/4/2020 3pm-5pm	From NAMAG Request 6/3/20	Released as of 06.06.20 @ 0700
MTV Line Eversource Crews Construction	Massachussetts	11	Arrived On Property 6/4/2020 3pm-5pm	From NAMAG Request 6/3/20	Released as of 06.06.20 @ 0700
EJ Electric Central Hudson Crews	New York	30	Arrived On Property 6/4/2020 3pm-5pm	From NAMAG Request 6/3/20	Released as of 06.06.20 @ 0700
AvanGrid NY - RGE, Comprised of Various Contractors	New York	75	Arrived On Property 6/4/2020 3pm-5pm	From NAMAG Request 6/3/20	Released as of 06.06.20 @ 0700
Hauglaund Energy-Central Hudson Crews	New York	7	Arrived On Property 6/4/2020 3pm-5pm	From NAMAG Request 6/3/20	Released as of 06.06.20 @ 0700
Riggs Distsler - United Illuminating Crews,	Connecticut	54	Arrived On Property 6/4/2020 3pm-5pm	From NAMAG Request 6/3/20	Released as of 06.06.20 @ 0700

Asplundh Eversource Crews	New York	74	Arrived On Property 6/4/2020 3pm-5pm	From NAMAG Request 6/3/20	Released as of 06.06.20 @ 0700
Gratten Line Eversource Crews	New York	14	Arrived On Property 6/4/2020 3pm-5pm	From NAMAG Request 6/3/20	Released as of 06.06.20 @ 0700
Asplundh Eversource MASSACHUSSETTS	Massachussetts	36	Arrived On Property 6/4/2020 3pm-5pm	From NAMAG Request 6/3/20	Released as of 06.06.20 @ 0700
United Illuminating Company	Connecticut	41	Arrived On Property 6/4/2020 3pm-5pm	From NAMAG Request 6/3/20	Released as of 06.06.20 @ 0700
Cianbro Electric Eversource Crews	New Hampshire	14	Arrived On Property 6/4/2020 3pm-5pm	From NAMAG Request 6/3/20	Released as of 06.06.20 @ 0700
Con Edison	New York	49	Arrived On Property 6/4/2020 3pm-5pm	From NAMAG Request 6/3/20	Released as of 06.06.20 @ 0700
Harlan Electric - National Grid	New York	26	Arrived On Property 6/4/2020 3pm-5pm	From NAMAG Request 6/3/20	Released as of 06.06.20 @ 0700
Northline	New York	37	Arrived On Property 6/4/2020 3pm-5pm	From NAMAG Request 6/3/20	Released as of 06.06.20 @ 0700
CMP Internal	Maine	50	Arrive on property 6/5/2020 - 5pm	From NAMAG Request 6/4/20	Released as of 06.06.20 @ 0700
Valiant	NJ/PA	22	Arrived On Property 6/5/2020 - 9am-11am	Outside NAMAG 6/4/2020	Released as of 06.07.20 @ 1700
PSEG LI - Internal Service Crews	Long Island, NY	24	Arrived On Property 6/5/2020 - 11am	Outside NAMAG 6/4/2020	Released as of 06.06.20 @ 0700
	Total	1004			

On June 4, PSE&G was able to secure 194 contractor tree trimming FTEs as listed below:

Off-System Crew Log									
Vendor	Requested	Utility	State	Arrived		Departed		Crew #	FTE #
				Date	Time	Date	Time		
Asplundh	6/4/2020	UGI	PA	6.5.20	7:30am	6.6.20	7:00am	5	11
Asplundh	6/4/2020	Con Ed	NY	6.4.20	11:00pm	6.6.20	7:00am	10	22
Asplundh	6/4/2020	PSEG LI	NY	6.5.20	11:30am	6.6.20	3:30pm	2	48
ARS	6/4/2020	HG&E	MA	6.5.20	4:00am	6.6.20	7:00am	6	13
ARS	6/4/2020	PSEG LI	NY	6.5.20	2:00am	6.6.20	8:00pm	13	28
NG Gilbert	6/4/2020	Potomac Ed	MD	6.5.20	11:00am	6.6.20	7:00am	10	24
NG Gilbert	6/4/2020	NYSEG	NY	6.5.20	9:30am	6.6.20	7:00am	8	18
NG Gilbert	6/4/2020	First Energy	NJ	6.5.20	10:00am	6.6.20	8:00pm	13	30

Look-up personnel from the other three operating divisions, P&C and Asset Management & Centralized Services (AMSC) supported the storm restoration process in Southern Division from June 3 – June 7. In addition, Gas Delivery personnel were utilized in Southern Division from June 3-June 5 to stand by downed wires.

Liaisons were assigned to Southern Division from June 3 to June 7 to assist in addressing customer inquiries. Remote liaisons were also assigned to the Inquiry Center from June 3 to June 6 to assist in addressing customer inquiries.

The Burlington, Camden, Gloucester and Mercer County Offices of Emergency Management (OEMs) were contacted on June 3. Only the Camden office opened and was remotely supported by liaisons from June 3 to June 6.

TROUBLE LOCATIONS AND CLASSIFICATIONS

Outside plant damage locations are listed below:

69 & 26-kV	-	40
13 & 4-kV	-	668
Transformers	-	221
Secondaries	-	135
Services	-	347
Poles	-	255
Trees	-	724
Total	-	2,390

INCIDENTS

Bordentown Substation was shut down at 1240 hrs. on June 3 affecting 2,663 customers when both 26-kV supply lines were interrupted. It was restored at 1758 hrs. on June 3 when the L-428 was energized.

Ewing Substation was shut down at 1240 hrs. on June 3 affecting 4,690 customers when both 69-kV supply lines were interrupted. It was restored at 1737 hrs. on June 3 when the V-724 was energized.

Collingswood Substation was shut down at 1633 hrs. on June 3 affecting 157 customers when both 26-kV supply lines were interrupted. It was restored at 2030 hrs. on June 3 when the I-373 was energized.

Woodlynne Substation was shut down at 1943 hrs. on June 3 affecting 11,319 customers when both 26-kV supply lines were interrupted. It was restored at 2235 hrs. on June 3 via the W-387, an emergency tie line installed under Energy Strong I.

COMMUNICATIONS

Communications with Board staff concerning this weather event began on June 3 and continued until June 7.

PSE&G's Corporate Communications Department issued internal communications, press releases and handled multiple newspaper, television and radio information requests during this period. In addition, social media posts to particularly hard hit communicates provided support information including the location of the three comfort stations.

Over 1.2 million emails were sent to customers regarding storm preparedness.

A notification to PSE&G's critical needs (P-4) customers about the storm was issued in the early afternoon on June 3 and notifications were also included in the outbound calls made with Estimated Times of Restoration (ETR).

Conference calls with mayors and other municipal officials concerning storm restoration efforts were held at 1100 hrs. on June 4 and June 5. Members of the Regional Public Affairs Department organized the calls and participated on the calls as did Southern Division personnel.

PSE&G's Regional Public Affairs Managers kept in constant contact with municipal and state officials in the areas in Southern Division hardest hit by these very severe thunderstorms. In person meetings, telephone calls, text messages and press releases were utilized in this communication process. In addition to the Regional Public Affairs Managers communicating with municipal officials in the hardest hit municipalities, PSE&G officers were also in contact with those officials.

SUMMARY

As discussed with Board staff, because of the severity of the weather events on June 3 and 4, they will be considered as one Major Event. These weather events quality as a Major Event since 246,075 customers in Southern Division, which is more than 10% of the 585,381 customers in the Division, and 257,209 customers Company wide, which is more than 10% of the 2,430,197 customers served by the Company were interrupted. Also, each of PSE&G's other three operating divisions supplied line and service restoration crews to Southern Division.

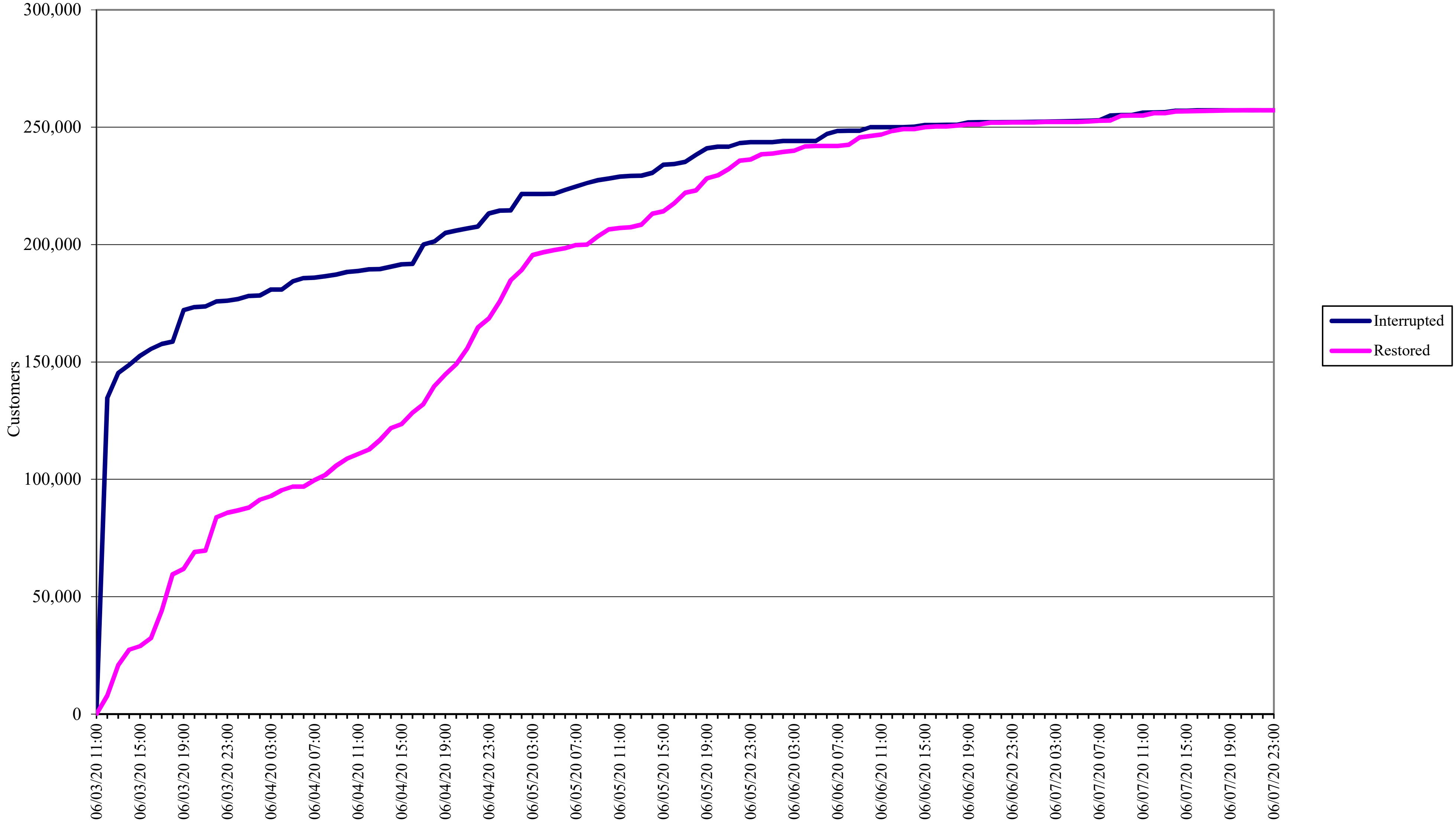
The restoration efforts went extremely well with 45% of the customers interrupted in Southern Division restored to service within one day, 81% within two days, 97% within three days and complete restoration in a little over four days.

PSE&G's excellent relationship with its unions was beneficial during this event.

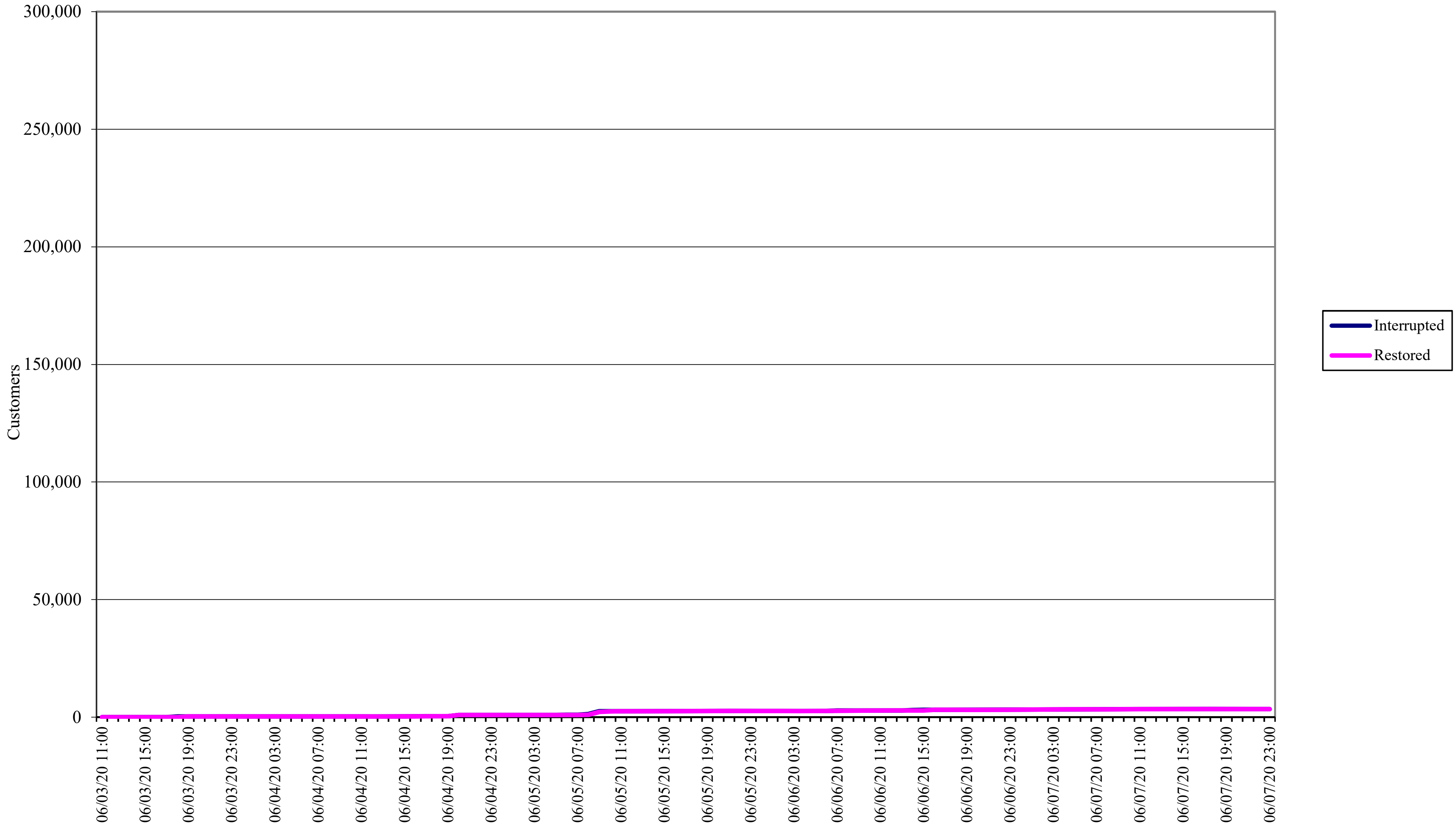
These were no issues involving equipment or material during this event.

DWW:bmc
6/24/20

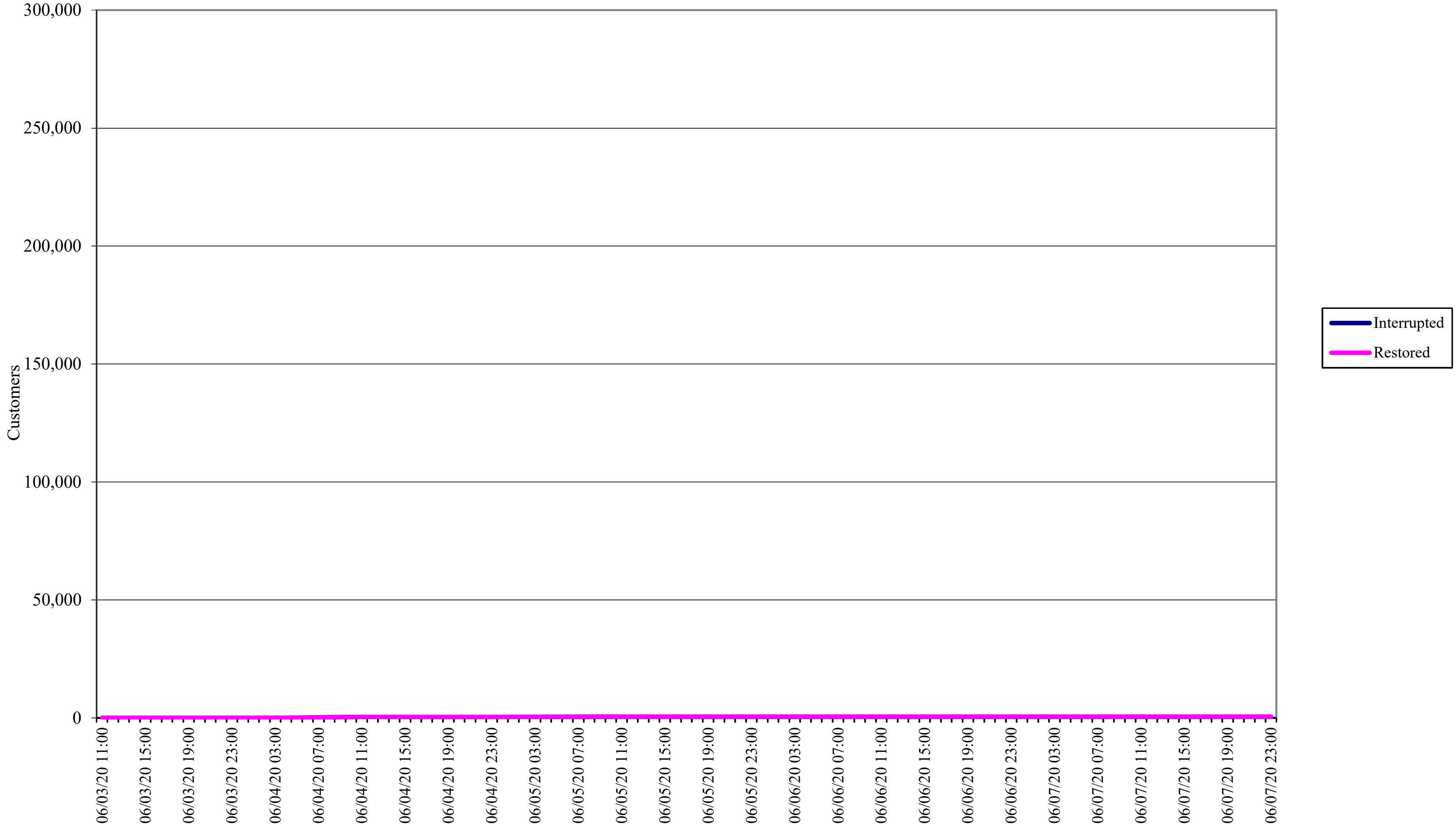
Attachment "A"
PSE&G
Customer Restoration Summary
Derecho and Severe Thunderstorms – June 3-7, 2020
Company Wide



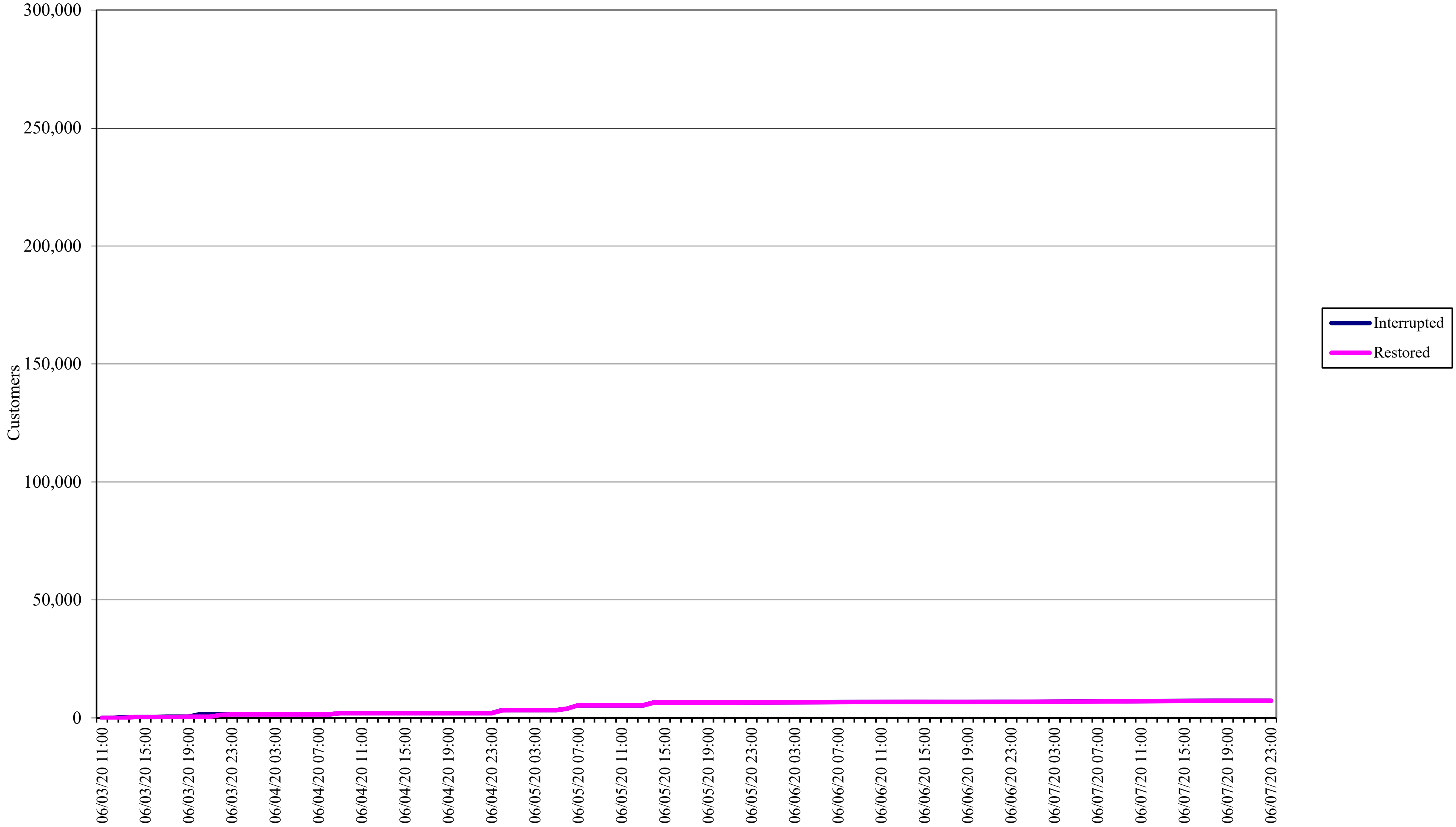
Attachment "B"
PSE&G
Customer Restoration Summary
Derecho and Severe Thunderstorms – June 3-7, 2020
Central Division



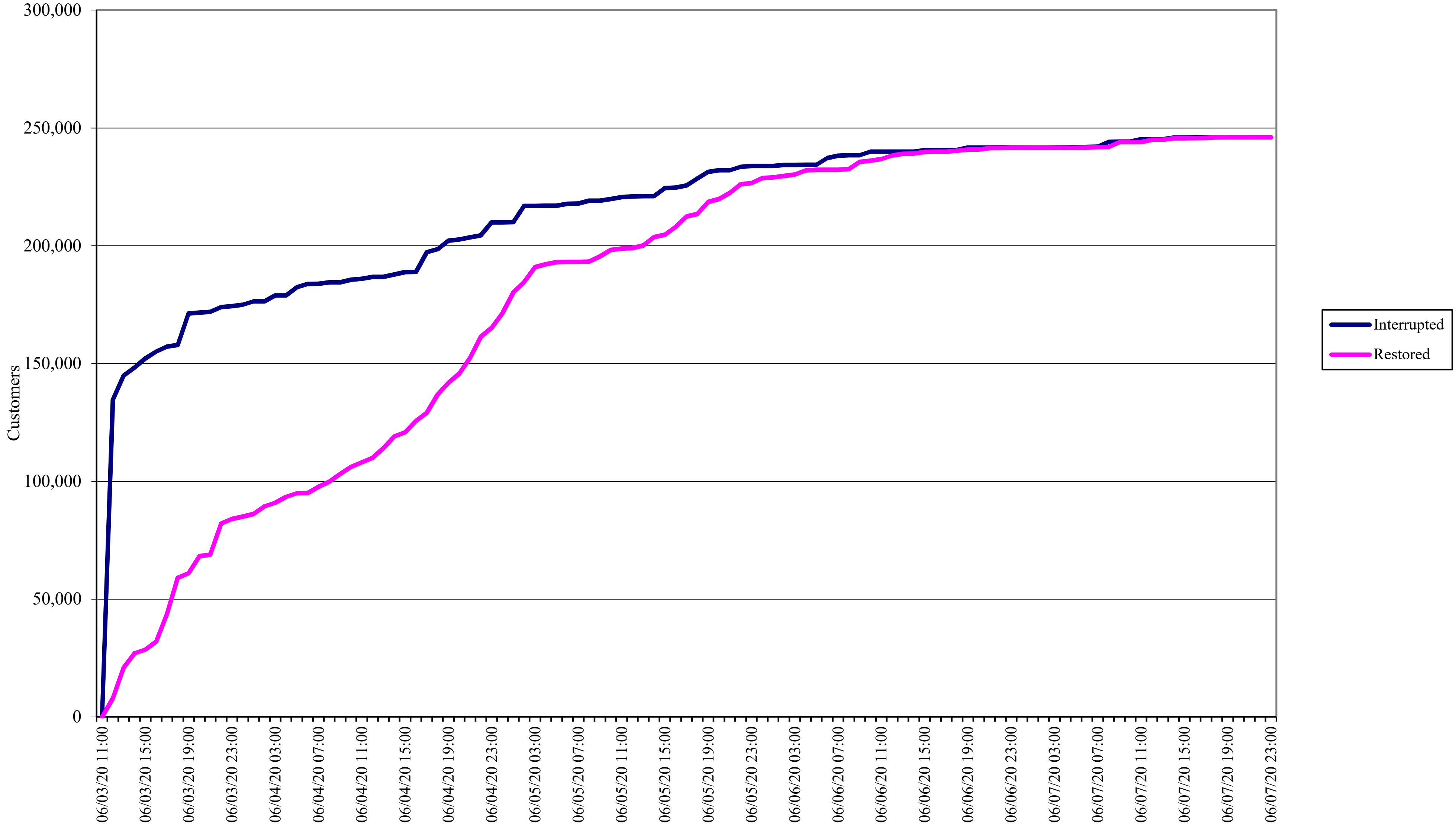
Attachment "C"
PSE&G
Customer Restoration Summary
Derecho and Severe Thunderstorms – June 3-7, 2020
Metropolitan Division



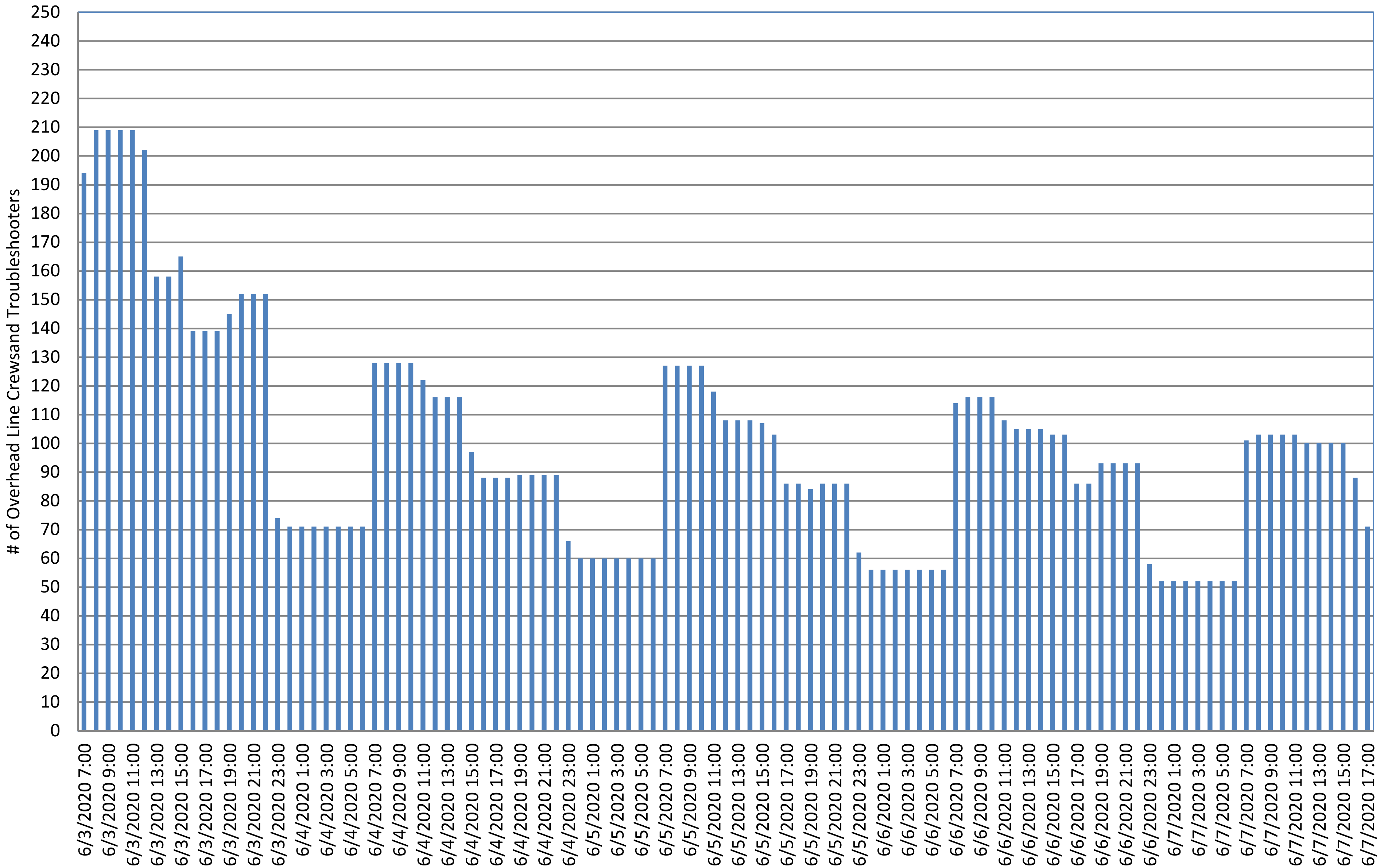
Attachment "D"
PSE&G
Customer Restoration Summary
Derecho and Severe Thunderstorms – June 3-7, 2020
Palisades Division



Attachment "E"
PSE&G
Customer Restoration Summary
Derecho and Severe Thunderstorms – June 3-7, 2020
Southern Division

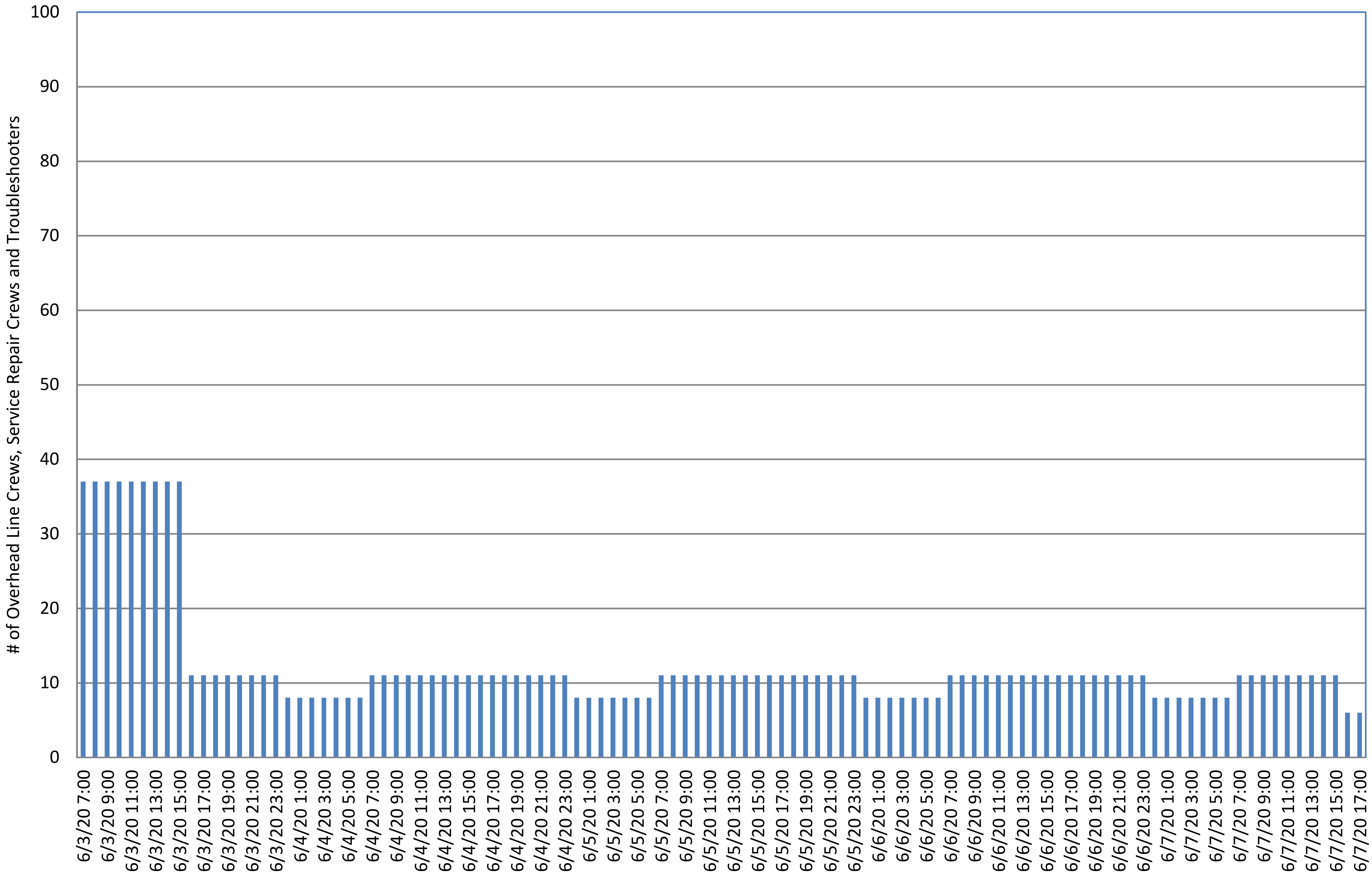


Attachment "F"
PSE&G
Overhead Line Crews, Service Repair Crews, and Troubleshooters on PSE&G Property - Company
Derecho and Severe Thunderstorms - June 3-7, 2020

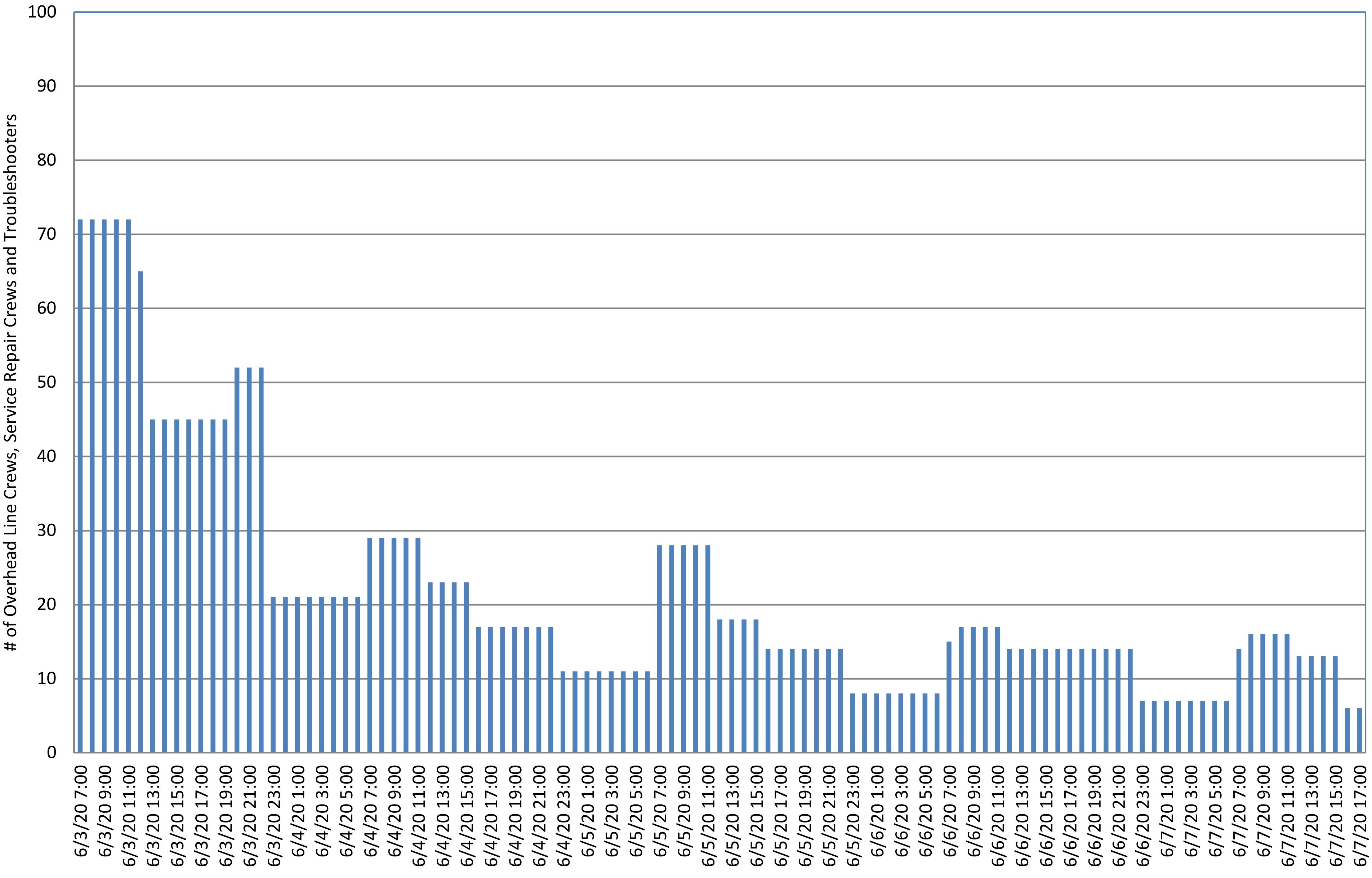


*These values include P&C Workforce Numbers

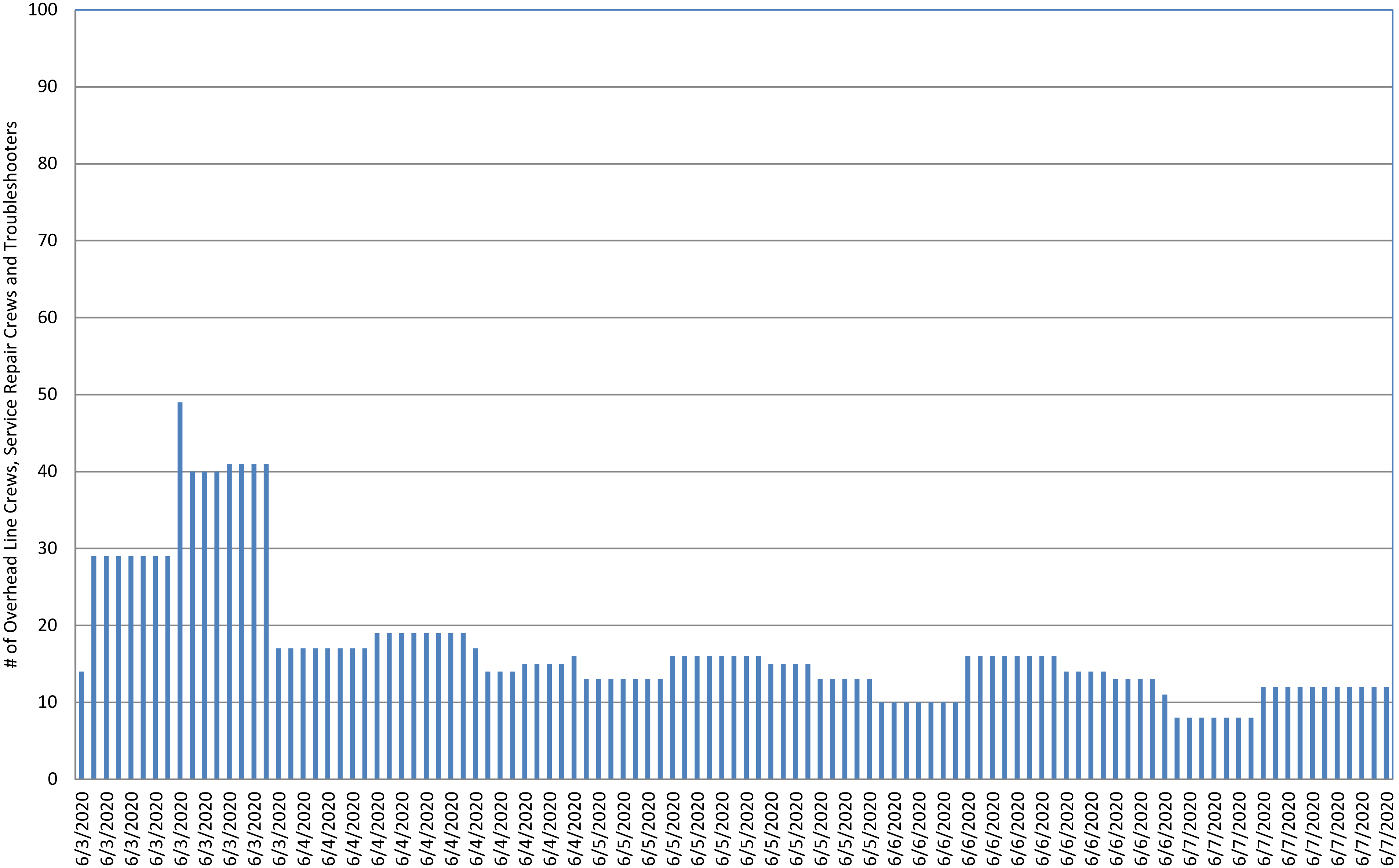
Attachment "G"
PSE&G
Overhead Line Crews, Service Repair Crews and Troubleshooters on PSE&G Property - Central Division
Derecho and Severe Thunderstorms - June 3-7, 2020



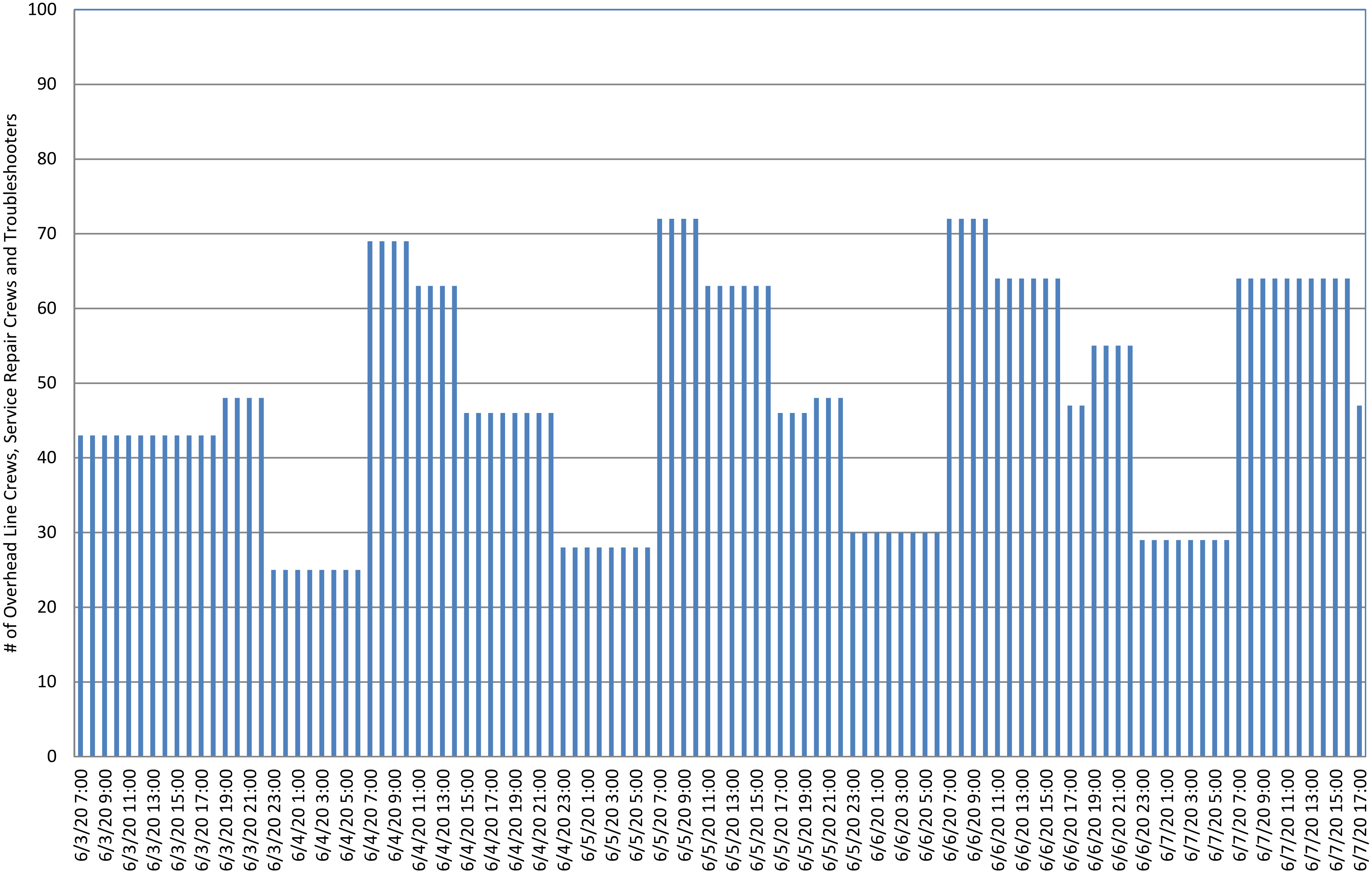
Attachment "H"
PSE&G
Overhead Line Crews, Service Repair Crews and Troubleshooters on PSE&G Property - Metropolitan Division
Derecho and Severe Thunderstorms - June 3-7, 2020



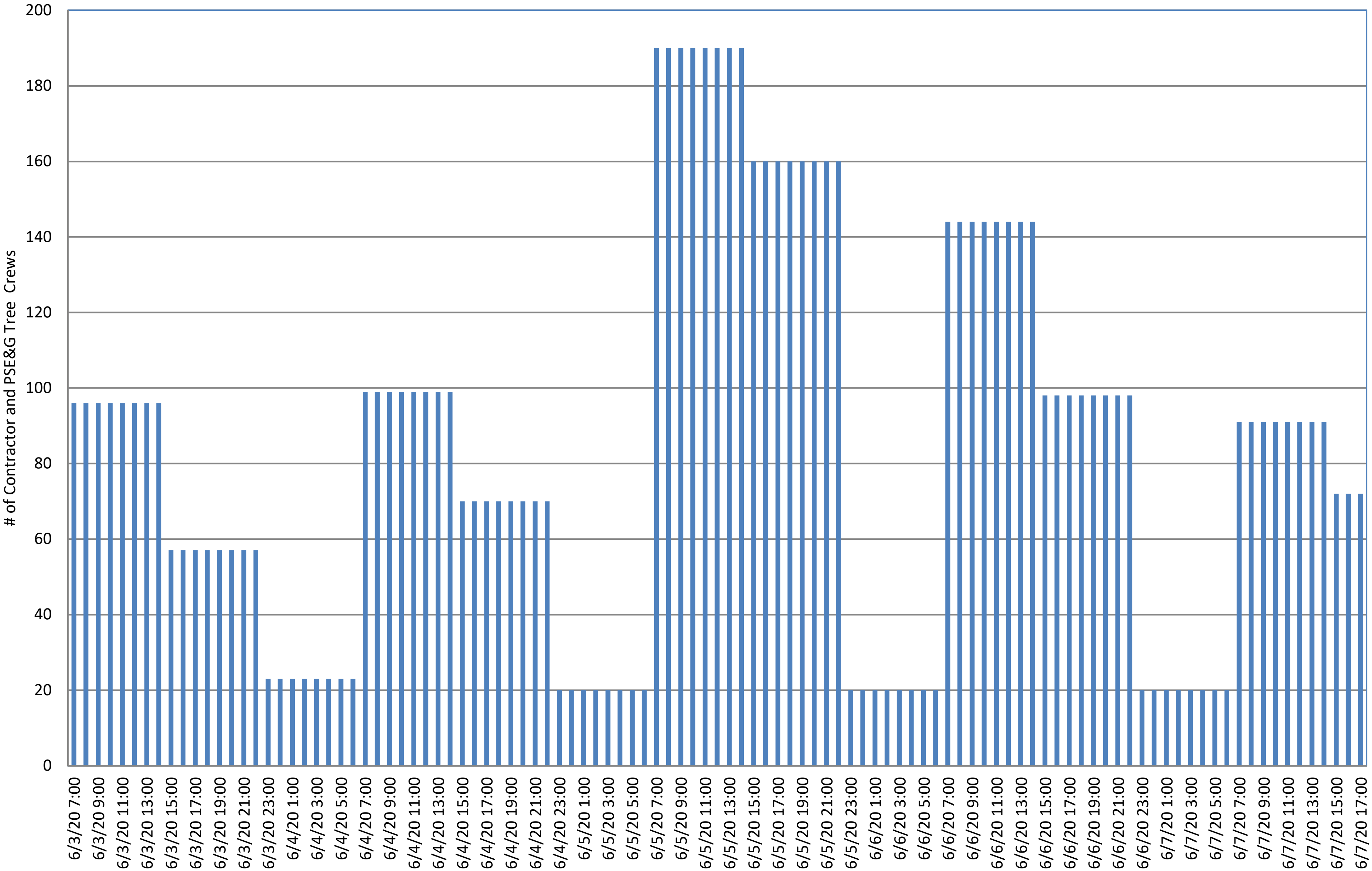
Attachment "I"
PSE&G
Overhead Line Crews, Service Repair Crews and Troubleshooters on PSE&G Property - Palisades Division
Derecho and Severe Thunderstorms - June 3-7, 2020



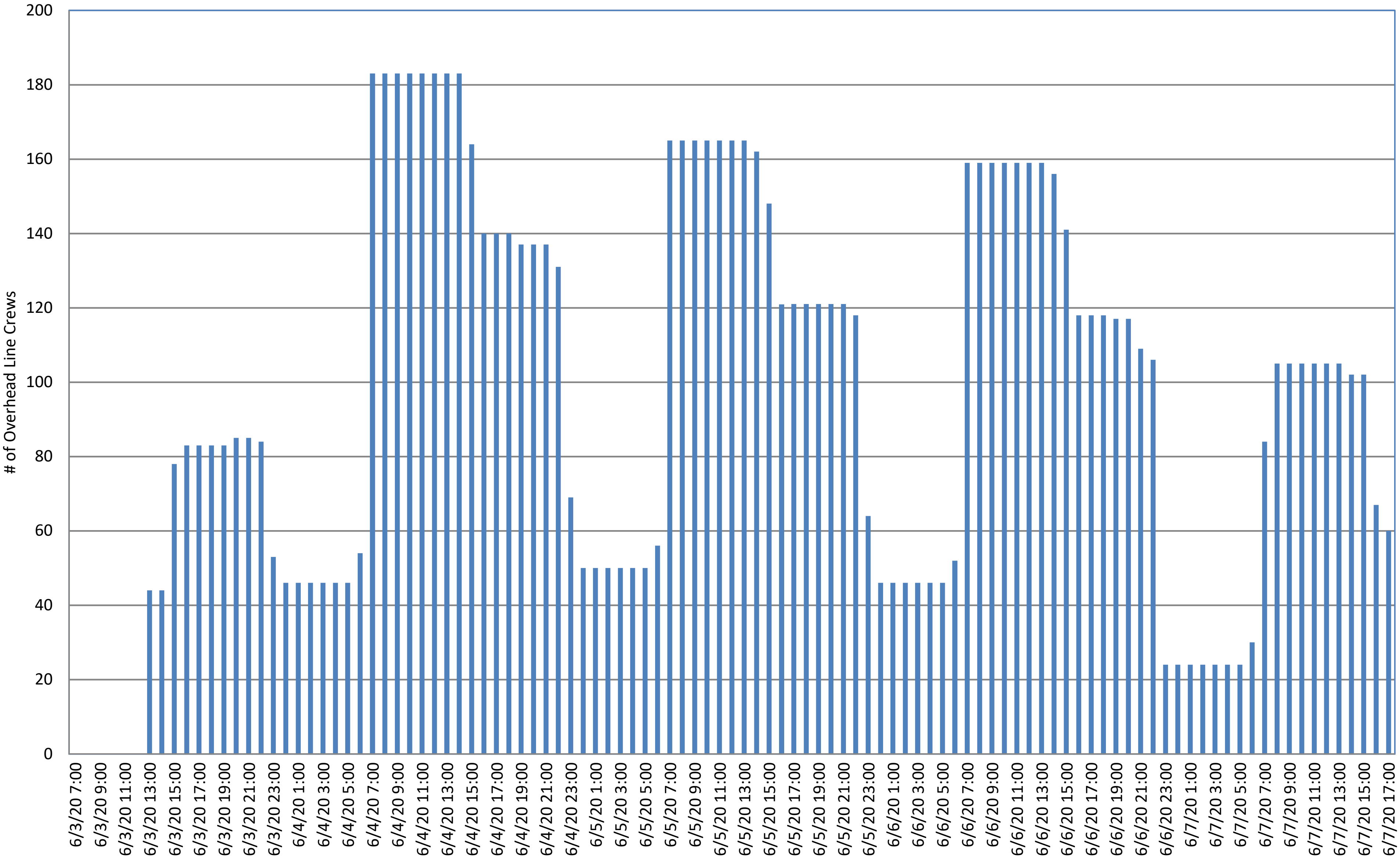
Attachment "J"
PSE&G
Overhead Line Crews, Service Repair Crews and Troubleshooters on PSE&G Property - Southern Division
Derecho and Severe Thunderstorms - June 3-7, 2020



Attachment "K"
PSE&G
Contractor Tree Crews on PSE&G Property - Company
Derecho and Severe Thunderstorms - June 3-7, 2020

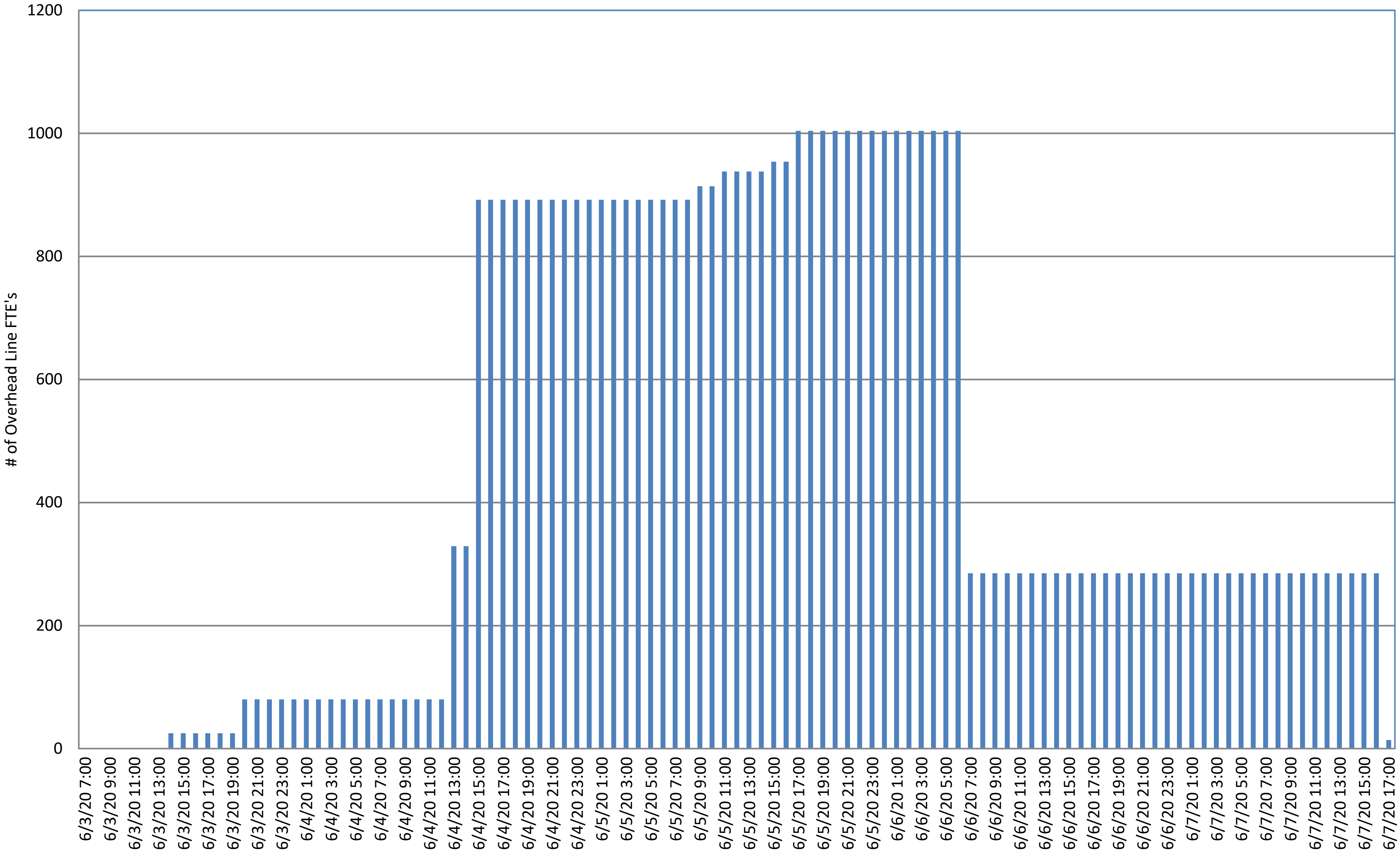


Attachment "L"
PSE&G
Overhead Line Crews, Service Repair Crews, Troubleshooters, Service Dispatchers and Substation Operators Assisting Southern Division
Derecho and Severe Thunderstorms - June 3-7, 2020



*These values include P&C Workforce Numbers

Attachment "M"
PSE&G
Mutual Aid Line FTE's Assisting Southern Division
Derecho and Severe Thunderstorms - June 3-7, 2020



6/3 Storm
Electric Delivery

		Capital Expenditures (CapEx)	O&M Expenses	CapEx + O&M Expenses	Incremental O&M Expenses
1	Total Labor	**2,255,814**	**7,010,862**	**9,266,675**	**3,385,023**
2	Contractor/Mutual Aid	4,891,523	8,387,837	13,279,360	8,387,837
3	Tree Removal	600,928	1,728,426	2,329,354	1,728,426
4	Buses	-	-	-	-
5	Other Contractor	719,956	218,548	938,504	218,548
	Total Contractor	**6,212,408**	**10,334,811**	**16,547,218**	**10,334,811**
6	Material	**672,258**	**110,167**	**782,425**	**103,785**
7	Food	35,520	103,471	138,991	103,471
8	Lodging	245,142	693,380	938,522	693,380
9	Security	-	1,411	1,411	1,411
10	Water and Ice	-	159,895	159,895	159,895
14	Email Alerts	-	6,935	6,935	6,935
11	Other	64,529	185,943	250,473	4,318
	Total Other	**345,191**	**1,151,036**	**1,496,227**	**969,411**
	Total Incurred	**9,485,671**	**18,606,875**	**28,092,545**	**14,793,029**
12	O&M Base Rate Storm Costs	-	-	-	-
	Total	**9,485,671**	**18,606,875**	**28,092,545**	**14,793,029**

March 16, 2021

<u>Via Electronic Mail Only</u>

Robert Brabston, Acting Director
Division of Reliability and Security
New Jersey Board of Public Utilities
225 East State Street - 2nd Floor, Area 2W
Trenton, New Jersey 08625

**RE: MAJOR EVENT REPORT
STATE OF EMERGENCY - WINTER STORMS
JANUARY 31 - FEBRUARY 23, 2021**

Dear Director Brabston:

As required by 14:5-8.8 Major Event Report, enclosed is a copy of PSE&G's Major Event Report for the State of Emergency - Winter Storms that affected PSE&G's entire service territory from January 31 - February 23, 2021.

Questions concerning this matter can be directed to me or Donald W. Weyant, Manager - Regulatory Compliance at (973) 430-6730.

Respectfully submitted,

Matthew M. Weissman

Attachments

C (Email Only)
Joseph Fiordaliso, President
Upendra Chivukula, Commissioner
Robert Gordon, Commissioner
Mary-Anna Holden, Commissioner
Dianne Solomon, Commissioner
Stacy Peterson, Director

PSE&G'S REPORT TO THE BPU
MAJOR EVENT
STATE OF EMERGENCY - WINTER STORMS
JANUARY 31 - FEBRUARY 23, 2021

EXECUTIVE SUMMARY

PSE&G's entire service territory was affected by a series of winter storms from January 31 to February 23, 2021. These winter storms began with a heavy snowstorm on February 1 - 2, which deposited up to 24" of snow in portions of the service territory. Subsequent storms during this period caused snow, sleet and freezing rain to fall over the entire service territory. Governor Phil Murphy declared a State of Emergency (SOE) on January 31 at 1900 hrs. The SOE was lifted on February 23 at 1700 hrs. There were 104,932 customers that experienced extended interruptions during these weather events.

PSE&G began preparing for the predicted heavy February 1 - 2 snowstorm on January 29 on its 0800 hrs. operations conference call. Extra line crews and support personnel were scheduled throughout the weekend and the 72/48/24 hour storm preparation checklists were scheduled to be reviewed. Representatives from Electric Delivery's General Office staff, the four operating divisions, Projects & Construction (P&C), the Electric System Operations Center (ESOC), along with personnel from other operating and staff departments of the Company were involved on this call as well as subsequent calls of this nature.

On January 29, PSE&G contacted contractors for the availability of Line FTEs. Commitments for 68 Line FTEs were obtained with the individuals scheduled to leave for PSE&G at 0700 hrs. on February 1. They arrived later that day. Their services were not required and they were released at 0800 hrs. on February 3. In addition, 40 contractor Line FTEs that were already on PSE&G's property were also available for storm restoration work.

On February 13, PSE&G was able to secure 29 contractor Line FTEs that arrived on February 14. Their services were not required and they were released on February 16. In addition, 35 contractor Line FTEs that were already on PSE&G's property were also available for storm restoration work.

A remote reporting site for the foreign crews was established at PSE&G's Hadley Road location in South Plainfield.

PSE&G opened its Emergency Operations Center (EOC) on February 1 at 0830 hrs. It remained open in a virtual mode until 0830 hrs. on February 2. This was the only time during this series of winter storms that it had to be activated.

Communications with 12 County Offices of Emergency Management (OEM) and the City of Newark's Emergency Management Center began on February 1. Liaison support provided was remote and continued until the OEMs closed.

Conference calls with mayors and other municipal and elected officials were held on February 1 and February 18 concerning storm restoration efforts. Members of the Regional Public Affairs (RPA) Department organized the calls and participated in them as did the Senior Directors and other personnel from each of the four operating divisions.

Communications with Board staff began on January 29 and continued until February 23.

OPERATING REPORT

There were 104,932 customers that experienced extended interruptions during these weather events as listed below:

Division	# Customers Interrupted	Final Restoration
Central	21,822	2/22 - 1628 hrs.
Metropolitan	26,508	2/23 - 1430 hrs.
Palisades	27,213	2/23 - 1427 hrs.
Southern	29,289	2/23 - 1017 hrs.
Total	104,932	

Attached are the following Customer Restoration Summary Graphs for these weather events:

Attachment “A” - Company Wide
Attachment “B” - Central Division
Attachment “C” - Metropolitan Division
Attachment “D” - Palisades Division
Attachment “E” - Southern Division

PSE&G’s entire service territory was affected by a series of winter storms from January 31 to February 23, 2021. These winter storms began with a heavy snowstorm on February 1 - 2, which deposited up to 24” of snow in portions of the service territory. Subsequent storms during this period caused snow, sleet and freezing rain to fall over the entire service territory. Governor Phil Murphy declared a State of Emergency (SOE) on January 31 at 1900 hrs. The SOE was lifted on February 23 at 1700 hrs. There were 104,932 customers that experienced extended interruptions during these weather events.

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On January 29, PSE&G contacted contractors for the availability of Line FTEs. Commitments for 68 Line FTEs were obtained with the individuals scheduled to leave for PSE&G at 0700 hrs. on February 1, they arrived later that day. Their services were not required and they were released at 0800 hrs. on February 3. In addition, 40 contractor Line FTEs that were already on PSE&G’s property were also available for storm restoration work.

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A remote reporting site for the foreign crews was established at PSE&G’s Hadley Road location in South Plainfield.

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Conference calls with mayors and other municipal and elected officials were held on February 1 and February 18 concerning storm restoration efforts. Members of the Regional Public Affairs (RPA) Department organized the calls and participated in them as did the Senior Directors and other personnel from each of the four operating divisions.

Communications with Board staff began on January 29 and continued until February 23.

PERSONNEL DEPLOYMENT

Attached are the following Work Force Graphs for these weather events:

Attachment "F" - Overhead Line Crews, Service Repair Crews and Troubleshooters - Company
Attachment "G" - Overhead Line Crews, Service Repair Crews and Troubleshooters - Central Division
Attachment "H" - Overhead Line Crews, Service Repair Crews and Troubleshooters - Metropolitan Division
Attachment "I" - Overhead Line Crews, Service Repair Crews and Troubleshooters - Palisades Division
Attachment "J" - Overhead Line Crews, Service Repair Crews and Troubleshooters - Southern Division
Attachment "K" - Contractor Tree Crews - Company
Attachment "L" - Mutual Aid Contractor Line FTEs

As is standard operating procedure in system emergencies, liaison support to each of the four operating divisions was provided beginning on February 1. This remote support continued until February 23. Remote liaison support was provided to the two Inquiry Centers during these weather events. These liaisons assisted on addressing customer inquiries.

TROUBLE LOCATIONS AND CLASSIFICATIONS

Outside plant damage locations are listed below:

69 & 26-kV	-	41
13 & 4-kV	-	419
Transformers	-	50
Secondaries	-	5
Services	-	26
Poles	-	73
Trees	-	20
Total	-	634

COMMUNICATIONS

Communications with Board staff began on January 29 and continued until February 23.

PSEG's Corporate Communications Department issued internal communication press releases and handled newspapers, television and radio information requests during these weather events.

PSE&G proactively utilized Social Media (Facebook, Twitter and LinkedIn) to communicate storm restoration information to customers during these weather events releasing 65 different messages. In addition, 5.3 Million emails were sent to customers during this weather event informing them of storm restoration progress.

As required in Recommendation 3 from the Tropical Storm Isaias Board Order, the following standardized Call Center information is provided:

Date	Number of calls Offered (NCO)	Number of calls Handled (NCH)	Number of call Abandoned (NCA)	Call abandonment rate (CA %)	Average speed of answer (ASA)
1/31/2021	7994	7921	73	0.9%	9.0
2/1/2021	22413	22258	155	0.7%	2.5
2/2/2021	17831	17715	116	0.7%	1.3
2/3/2021	22134	21710	424	1.9%	27.4
2/4/2021	21411	20818	593	2.8%	48.8
2/5/2021	23545	22341	1204	5.1%	102.2
2/6/2021	11355	11160	195	1.7%	13.9
2/7/2021	6158	6106	52	0.8%	2.2
2/8/2021	26646	25347	1299	4.9%	104.9
2/9/2021	22665	21691	974	4.3%	88.9
2/10/2021	21282	20717	565	2.7%	42.7
2/11/2021	22508	20622	1886	8.4%	82.7
2/12/2021	19509	19120	389	2.0%	33.1
2/13/2021	10697	10545	152	1.4%	5.0
2/14/2021	5785	5745	40	0.7%	1.7
2/15/2021	18619	18308	311	1.7%	12.9
2/16/2021	28101	26008	2093	7.4%	176.2
2/17/2021	22721	21493	1228	5.4%	113.3
2/18/2021	20398	19938	460	2.3%	32.9
2/19/2021	20545	20356	189	0.9%	2.6
2/20/2021	10541	10416	125	1.2%	1.9
2/21/2021	6213	6157	56	0.9%	1.5
2/22/2021	26979	25602	1377	5.1%	99.2
2/23/2021	22072	21011	1061	4.8%	91.9

Notifications to PSE&G's critical needs (P-4) customers were issued on January 31, February 13, 15 and 17 informing them of the impending storms and recommending precautions they should take. This information was also included in outbound calls made with Estimated Times of Restoration (ETRs).

Conference calls with mayors and other municipal and elected officials were held on February 1 and February 18 concerning storm restoration efforts. Members of the Regional Public Affairs (RPA) Department organized the calls and participated in them as did the Senior Directors and other personnel from each of the four operating divisions.

A North Atlantic Mutual Assistance Group (NAMAG) conference call was held on February 1 at 1300 hrs. On the call, utilities in New England requested assistance. Another conference call was held on February 14 at 1800 hrs. where again utilities in New England requested assistance. PSE&G did not offer any assistance on either call.

INCIDENTS

Service to Ellis Island was interrupted on February 1 at 1510 hrs. and was restored on February 3 at 0033 hrs. The interruption was caused by snow entering the customer's switchgear. PSE&G personnel worked with Ellis Island personnel in resolving the problem.

On February 19 at 1233 hrs., 345-kV circuit F-3432 locked out. Investigation revealed that falling ice from an "A" frame at Bayway Switching Station contacted equipment on a portion of the station's 345-kV bus. The 345-kV bus was cleaned and the circuit was restored to service on February 21 at 2050 hrs.

On February 20 at 0955 hrs., 345-kV circuit S-3419 locked out. Investigation revealed flash marks on a 345-kV lightning arrester at the circuit's North Avenue Substation terminal. The lightning arrester was found to be ice covered and contaminated with road sand, apparently from snow plowing activities on nearby North Avenue. The lightning arrester was cleaned and the circuit was restored to service on February 21 at 1113 hrs.

SUMMARY

Restoration effects during these weather events went extremely well. PSE&G was well prepared to address the outages caused by the winter weather. There were 104,932 customers that experienced extended interruptions during these weather events.

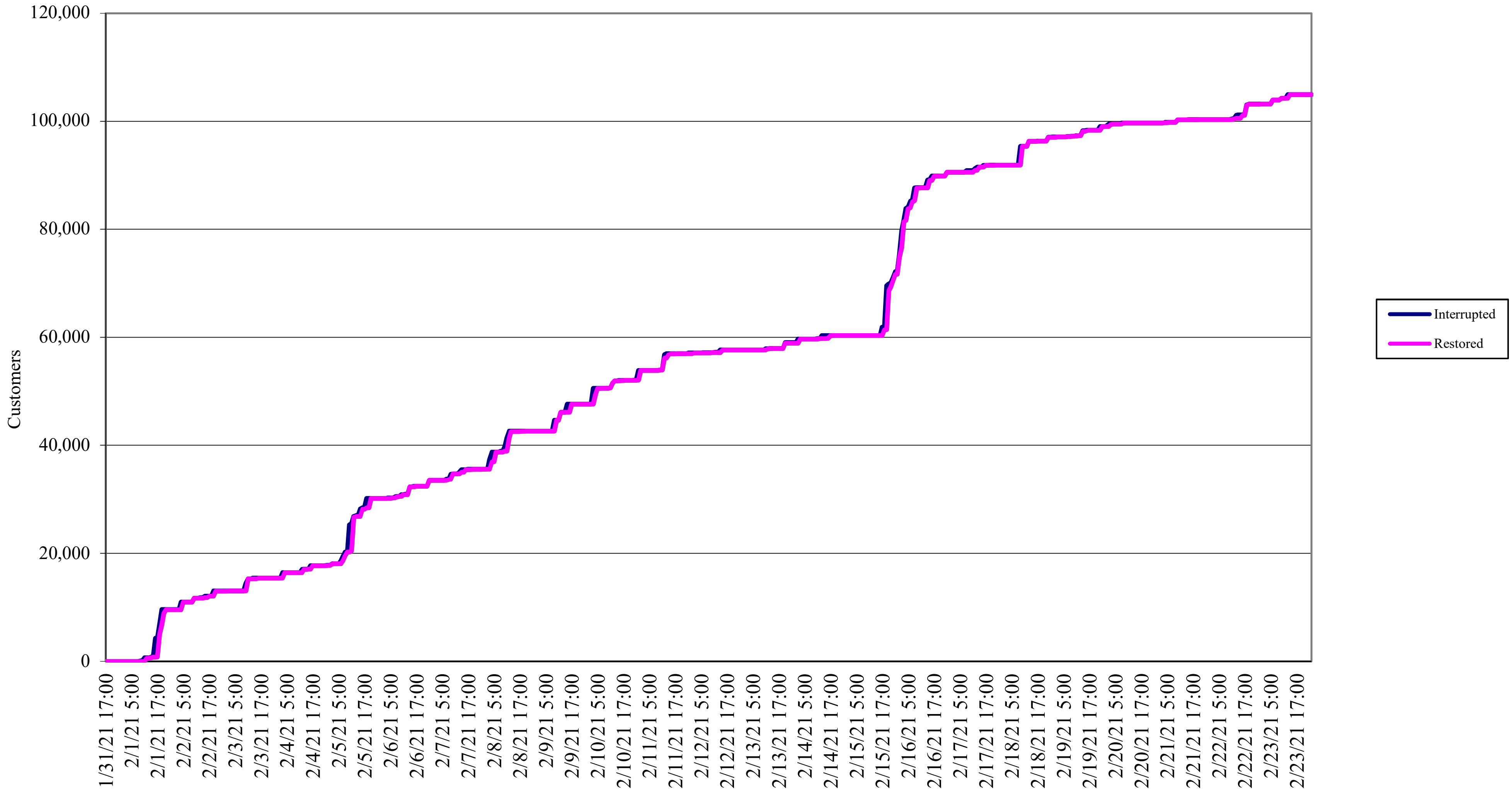
PSE&G excellent relationships with its unions were beneficial during these weather events.

There were no issues involving equipment or material during these weather events.

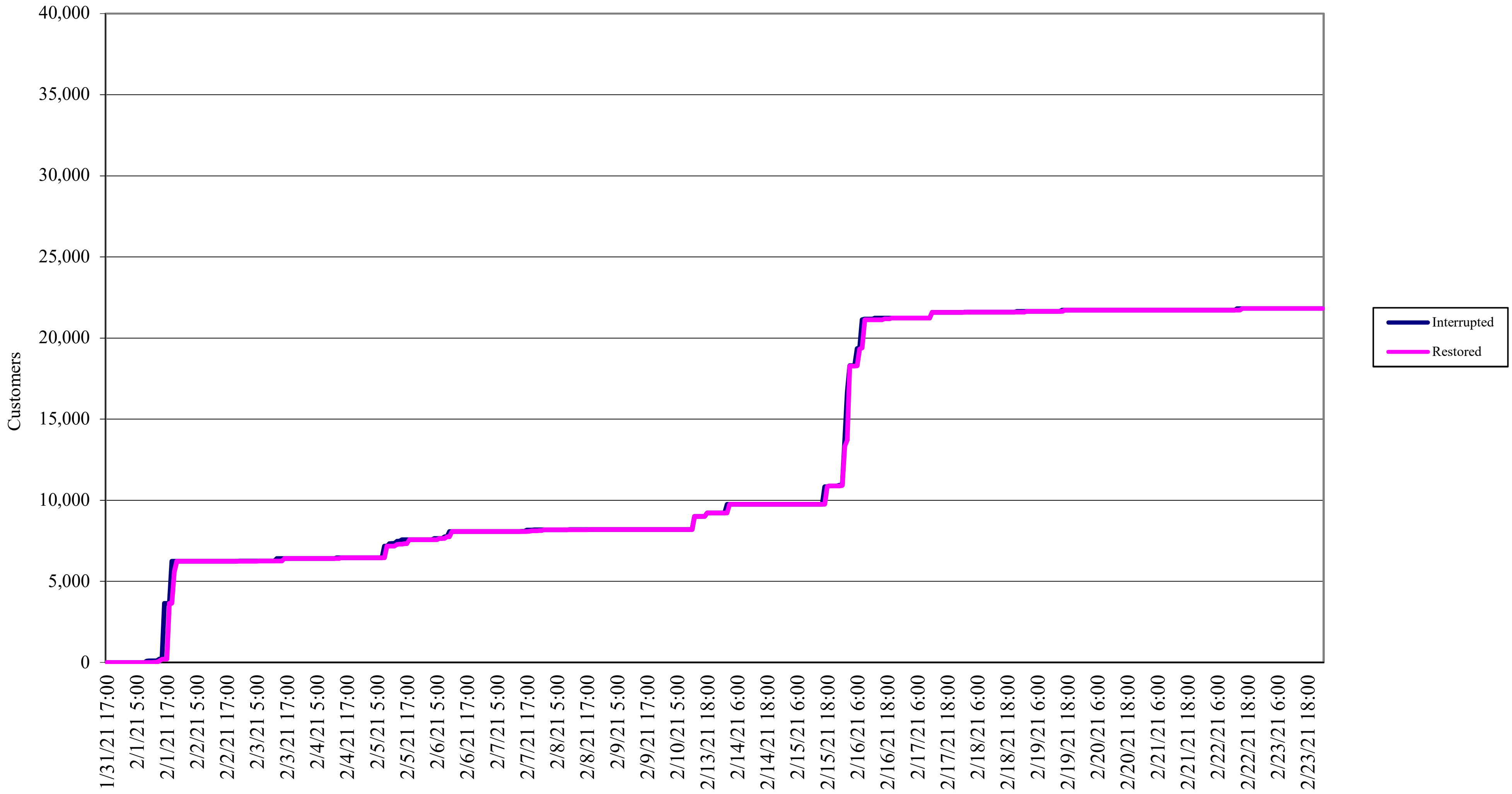
As required in Recommendation 11 from the Tropical Storm Isaias Board Order, a review of past storms revealed that these weather events were somewhat similar to winter weather events that affected PSE&G's service territory during the period February 3 - 14, 2014 when 139,249 customers experienced extended interruptions. The resiliency projects completed in PSE&G's Energy Strong I program and those that are currently underway in PSE&G's Energy Strong II program all contribute to improved reliability both during blue sky days and during Major Events. Comprehensive, comparison resiliency data involving Major Events is reported quarterly by PSE&G to the Independent Monitor as part of PSE&G's Energy Strong II Program, as it was during the Energy Strong I Program. The data referencing the weather events during the period January 31-February 23, 2021 will be submitted in PSE&G's First Quarter 2021 Energy Strong II Program Report.

DWW: bmc
3/10/21

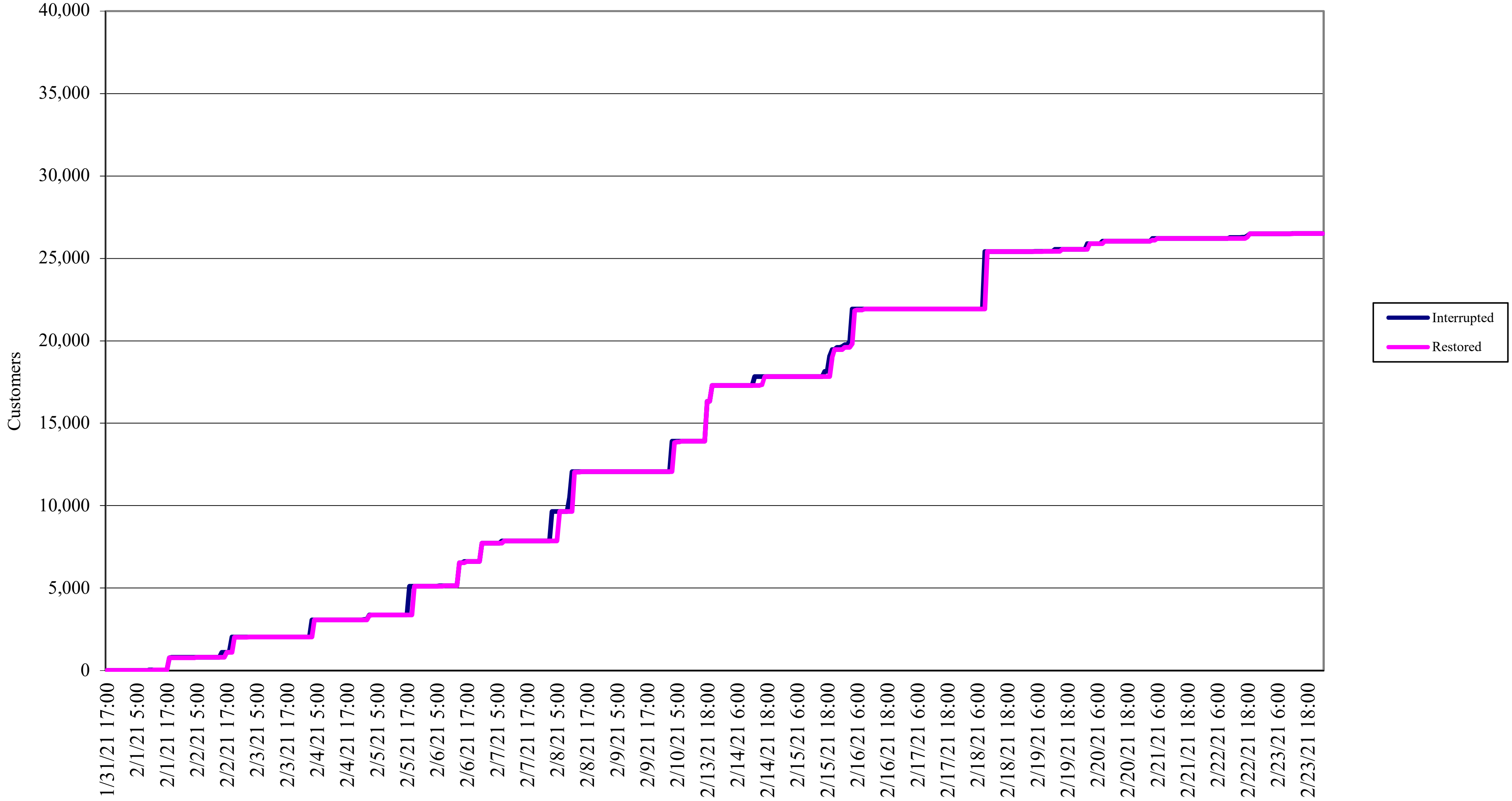
Attachment "A"
PSE&G
Customer Restoration Summary
State of Emergency - Winter Storms - January 31 - Febraury 23, 2021
Company Wide



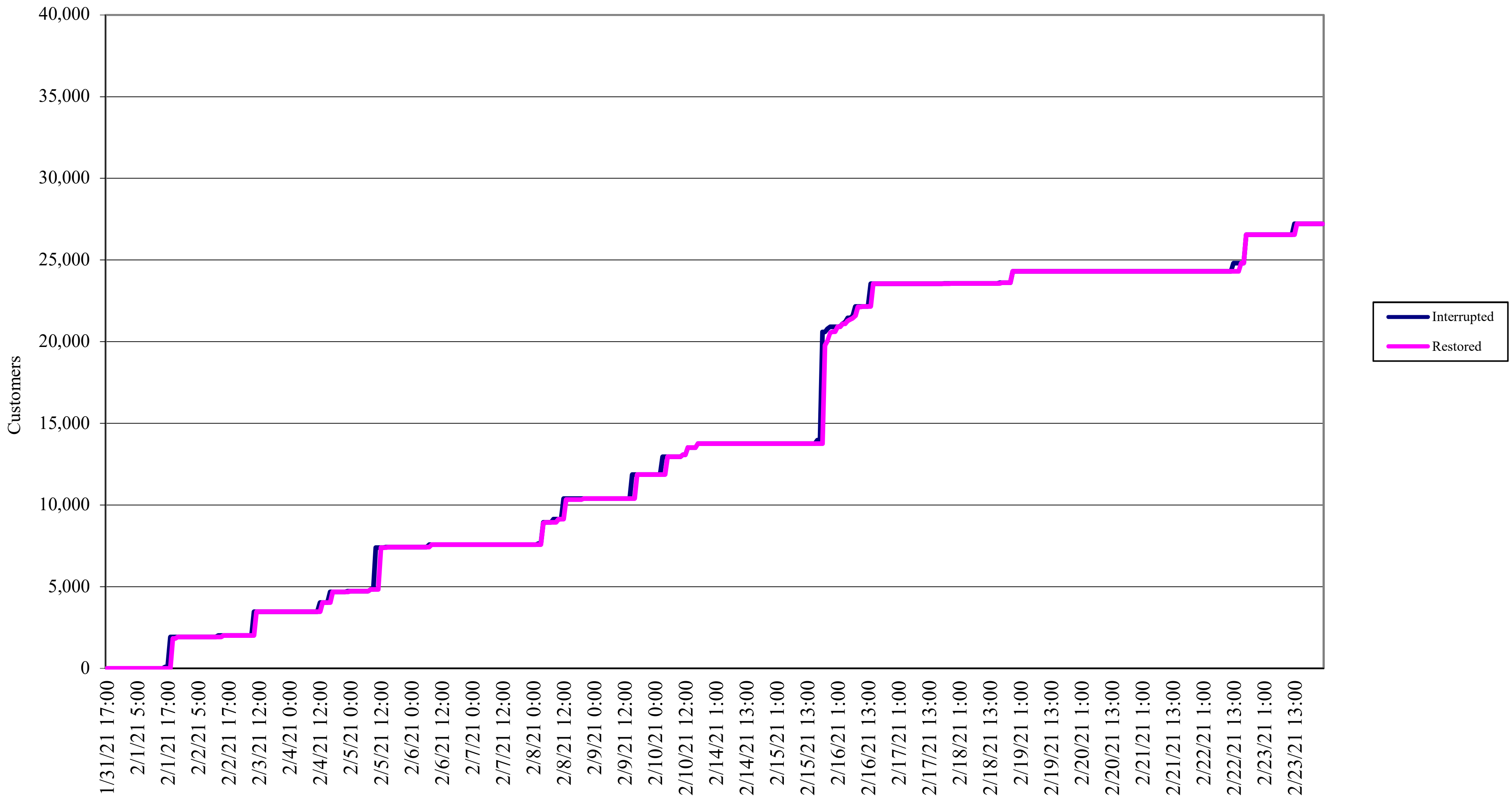
Attachment "B"
PSE&G
Customer Restoration Summary
State of Emergency - Winter Storms - January 31 - Febraury 23, 2021
Central Division



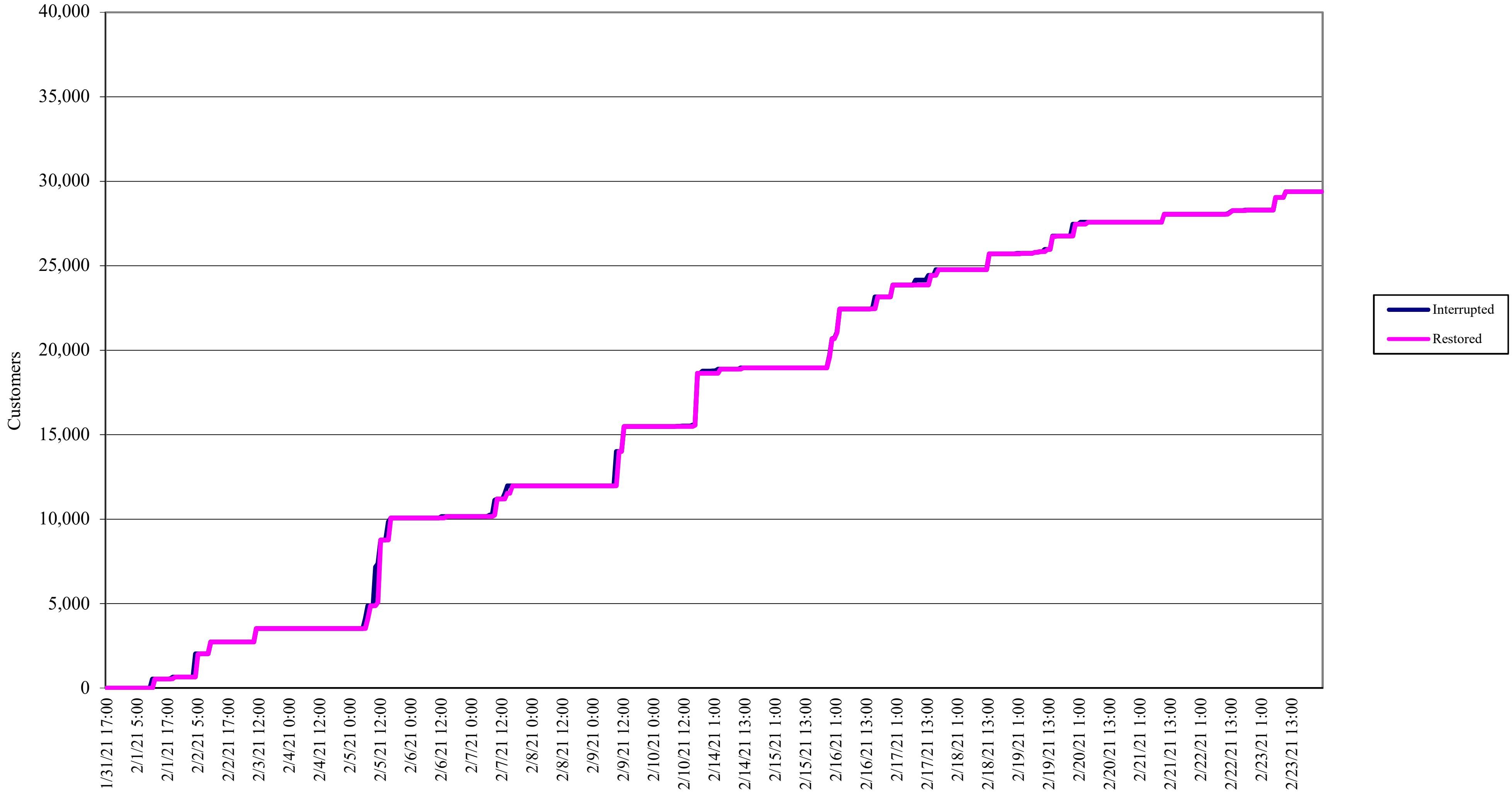
Attachment "C"
PSE&G
Customer Restoration Summary
State of Emergency - Winter Storms - January 31 - Febraury 23, 2021
Metropolitan Division



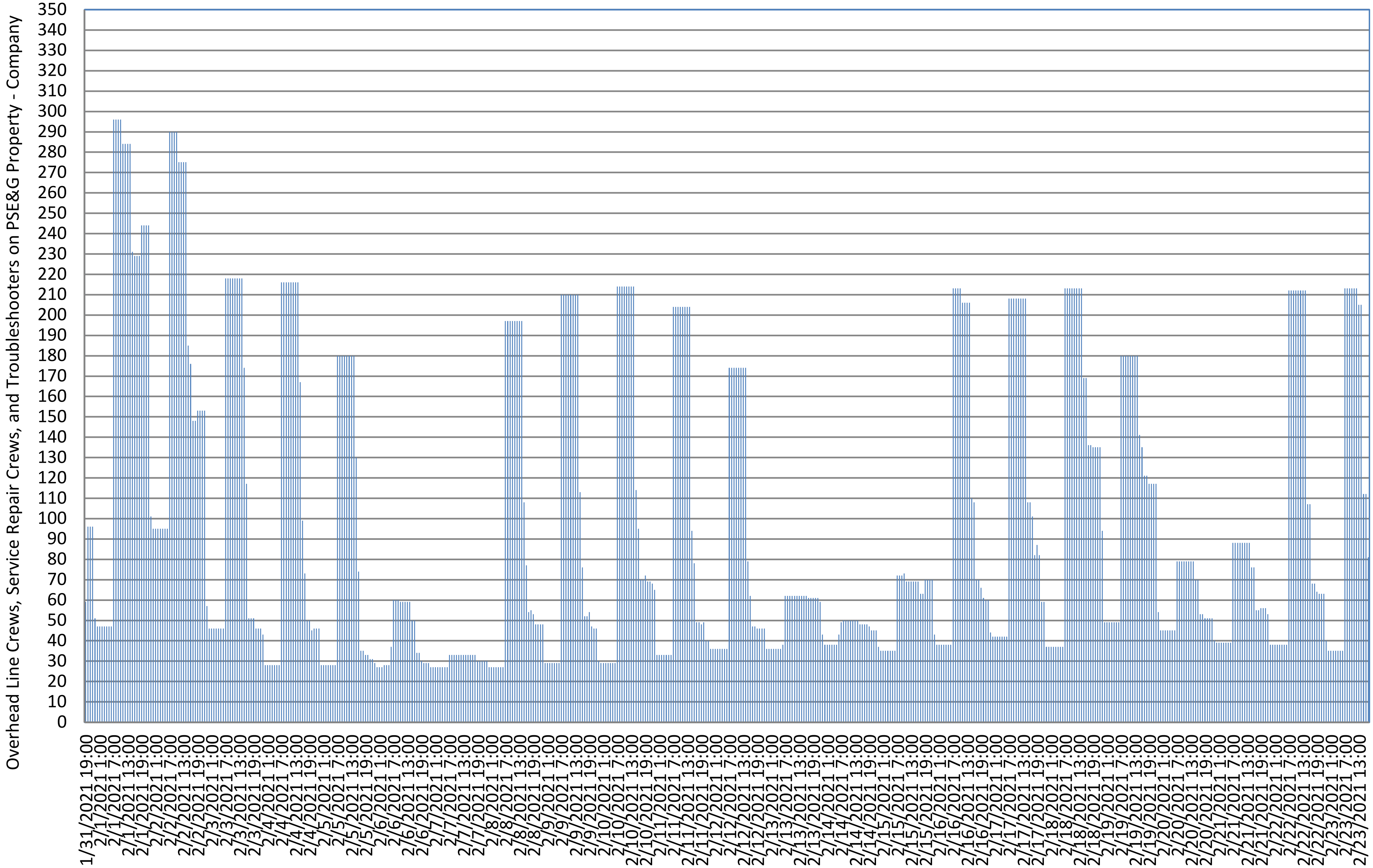
Attachment "D"
PSE&G
Customer Restoration Summary
State of Emergency - Winter Storms - January 31 - Febraury 23, 2021
Palisades Division



Attachment "E"
PSE&G
Customer Restoration Summary
State of Emergency - Winter Storms - January 31 - Febraury 23, 2021
Southern Division

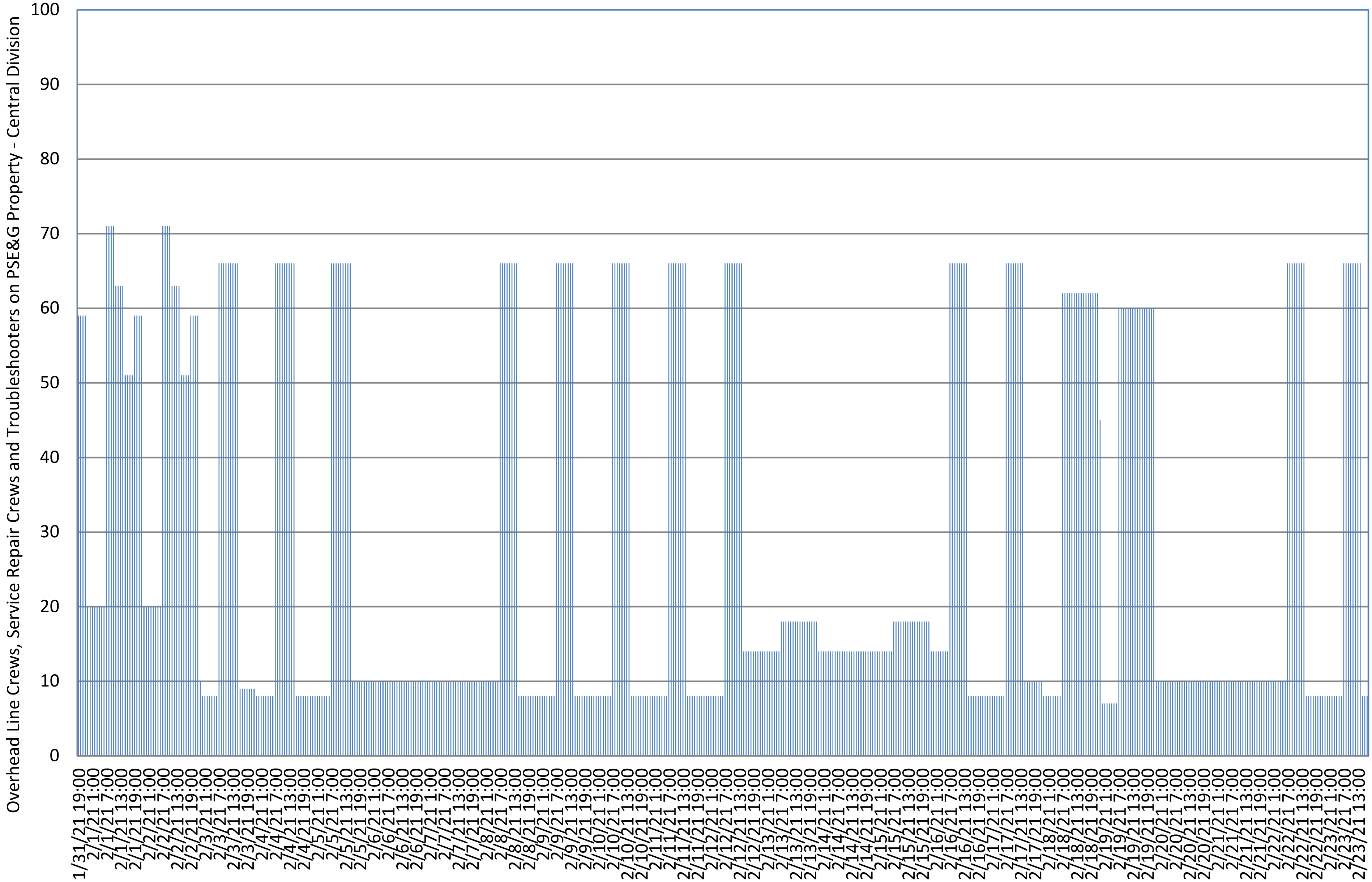


Attachment "F"
PSE&G
Overhead Line Crews, Service Repair Crews, and Troubleshooters on PSE&G Property - Company
State of Emergency - Winter Storms - January 31 - Febraury 23, 2021

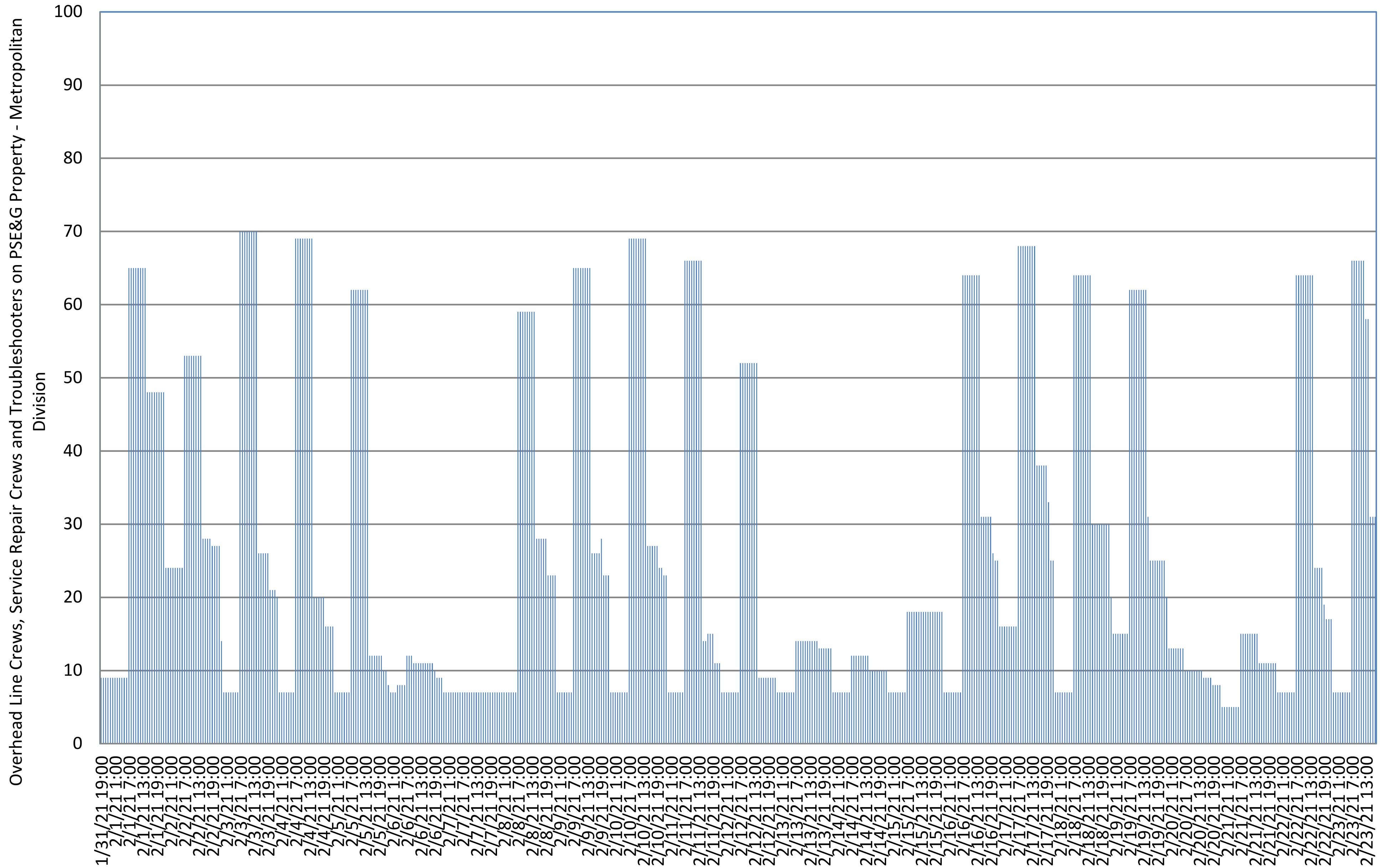


*These values include P&C Workforce Numbers

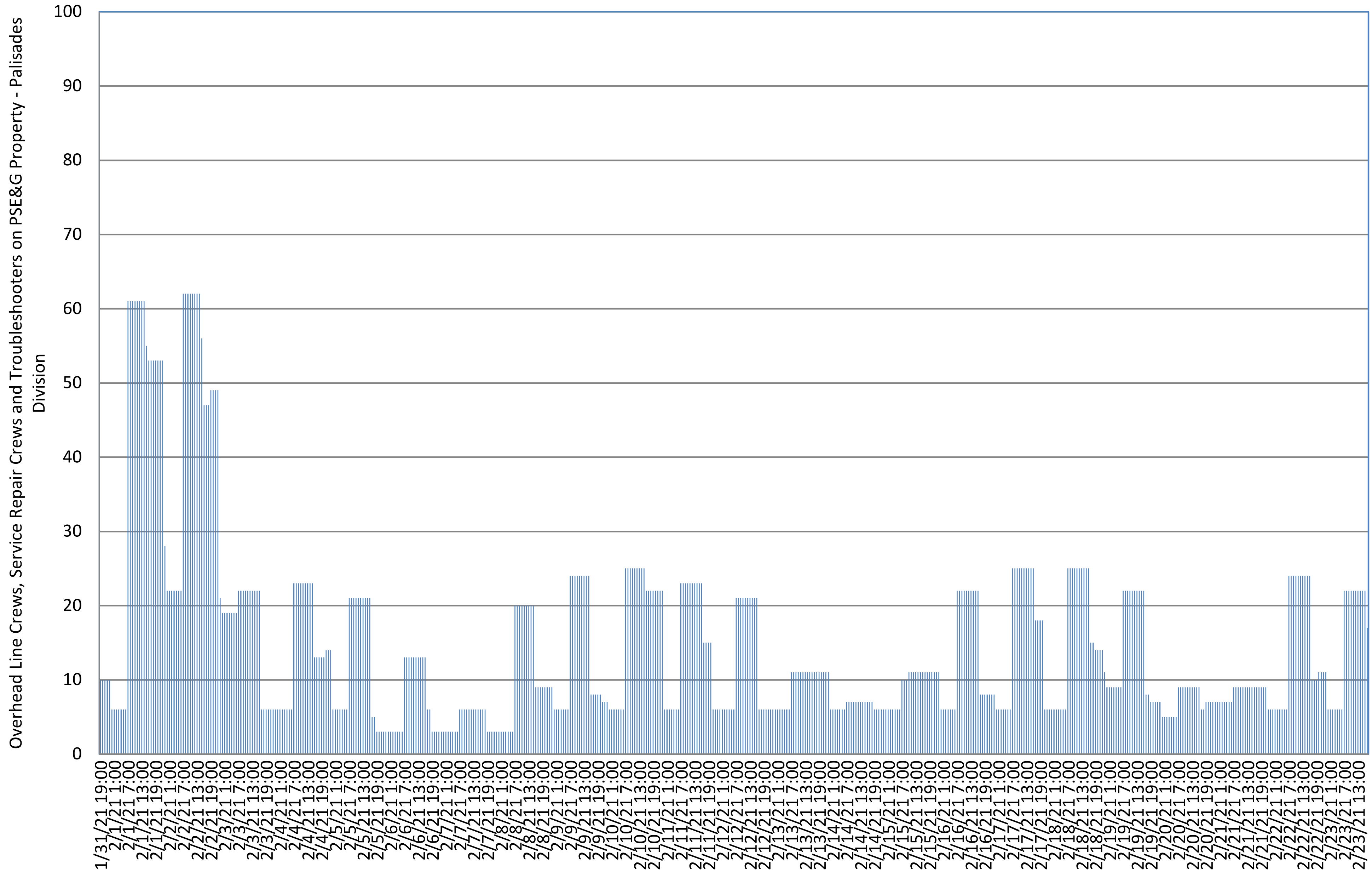
Attachment "G"
PSE&G
Overhead Line Crews, Service Repair Crews and Troubleshooters on PSE&G Property - Central Division
State of Emergency - Winter Storms - January 31 - Febraury 23, 2021



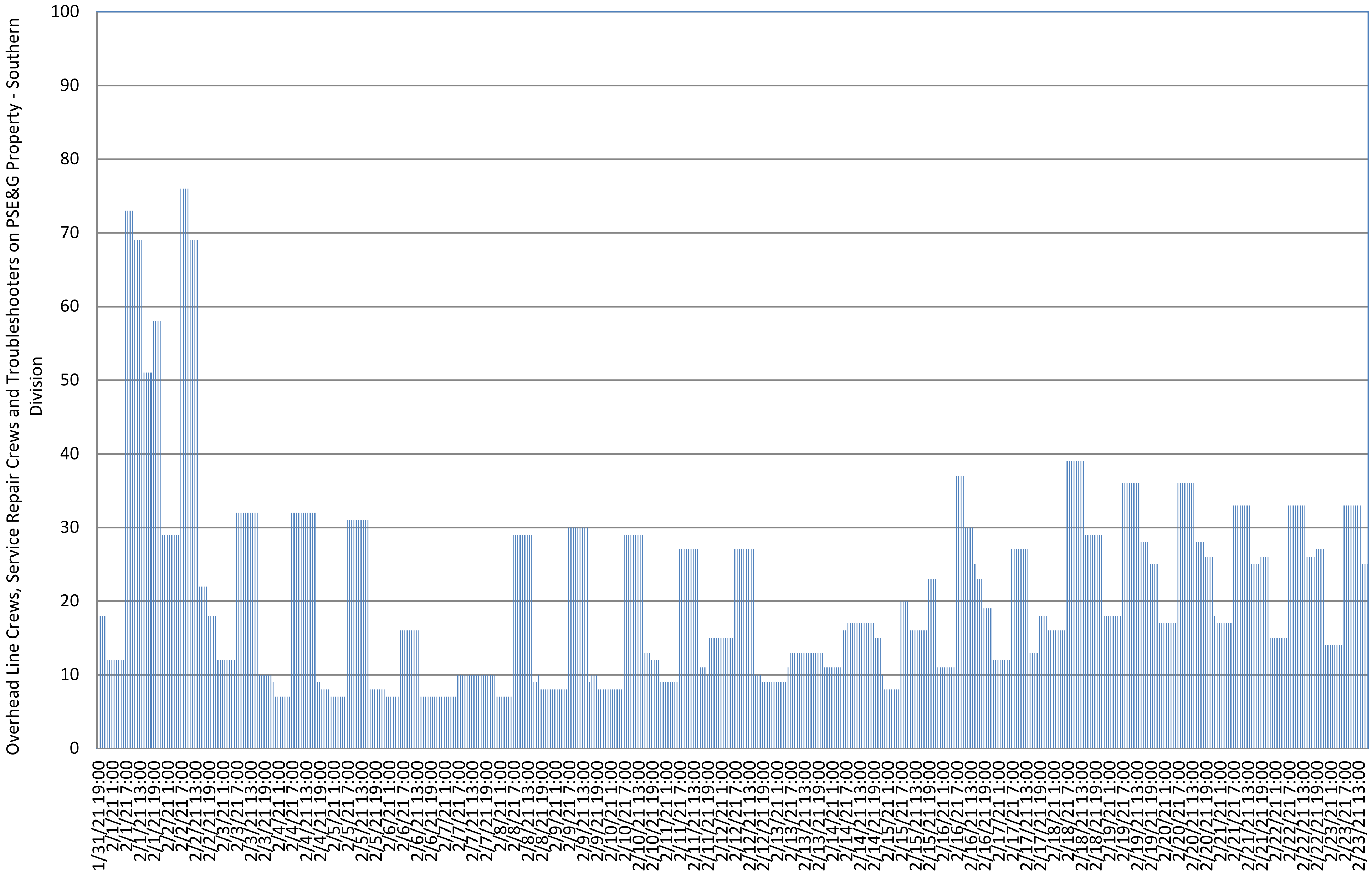
Attachment "H"
PSE&G
Overhead Line Crews, Service Repair Crews and Troubleshooters on PSE&G Property - Metropolitan Division
State of Emergency - Winter Storms - January 31 - Febraury 23, 2021



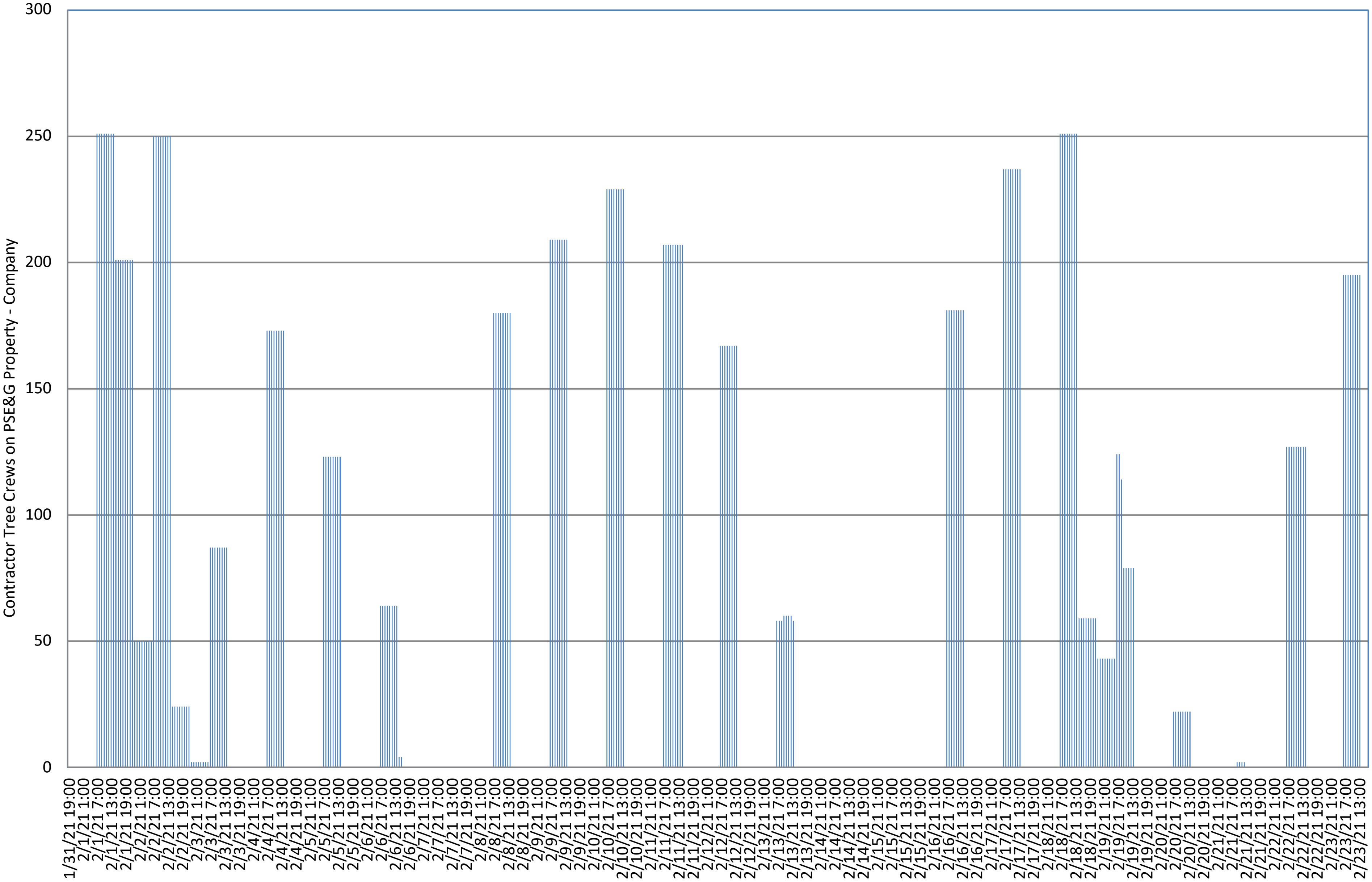
Attachment "I"
PSE&G
Overhead Line Crews, Service Repair Crews and Troubleshooters on PSE&G Property - Palisades Division
State of Emergency - Winter Storms - January 31 - Febraury 23, 2021



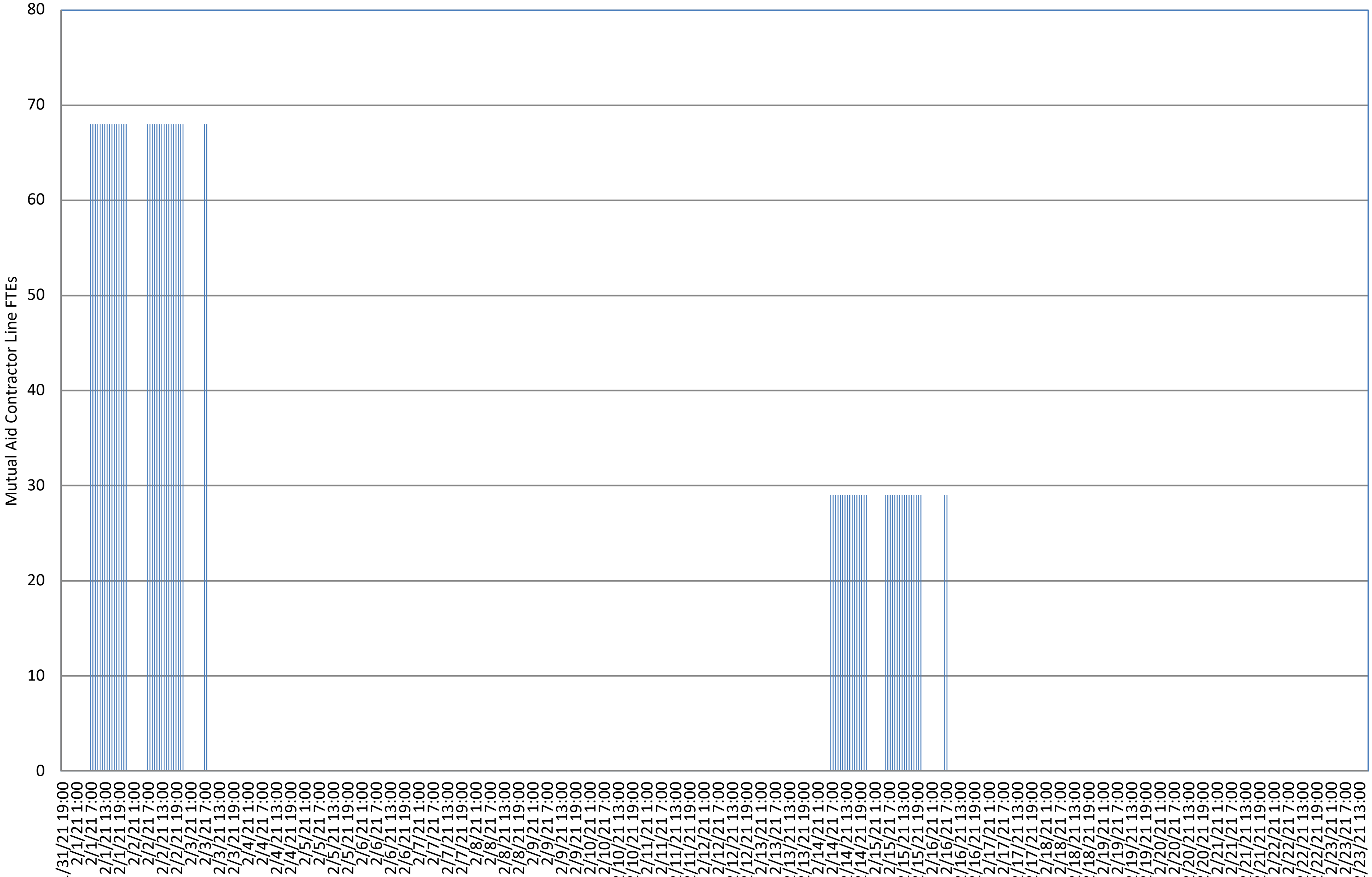
Attachment "J"
PSE&G
Overhead Line Crews, Service Repair Crews and Troubleshooters on PSE&G Property - Southern Division
State of Emergency - Winter Storms - January 31 - Febraury 23, 2021



Attachment "K"
PSE&G
Contractor Tree Crews on PSE&G Property - Company
State of Emergency - Winter Storms - January 31 - Febraury 23, 2021



Attachment "L"
PSE&G
Mutual Aid Contractor Line FTEs
State of Emergency - Winter Storms - January 31 - Febraury 23, 2021



		Feb Storm Electric Delivery Capital Expenditures (CapEx)	O&M Expenses	CapEx + O&M Expenses	Incremental O&M Expenses
1	Total Labor	-	-	-	-
2	Contractor/Mutual Aid	-	1,084,647	**1,084,647**	1,084,647
3	Tree Removal	-	876,950	**876,950**	876,950
4	Buses	-	-	-	-
5	Other Contractor	-	18,037	18,037	18,037
	Total Contractor		**1,979,634**	**1,979,634**	**1,979,634**
				-	
6	Material	-	-	-	-
				-	
7	Food	-	-	-	-
8	Lodging	-	-	-	-
9	Security	-	-	-	-
10	Water and Ice	-	-	-	-
14	Email Alerts	-	-	-	-
11	Other	-	-	-	-
	Total Other		-	-	-
				-	
	Total Incurred		**1,979,634**	**1,979,634**	**1,979,634**
12	O&M Base Rate Storm Costs	-	-	-	-
	Total	-	**1,979,634**	**1,979,634**	**1,979,634**

September 4, 2020

<u>Via Electronic Mail and Overnight Mail</u>

James Giuliano, Director
Division of Reliability and Security
New Jersey Board of Public Utilities
225 East State Street - 2nd Floor, Area 2W
Trenton, New Jersey 08625

RE: MAJOR EVENT REPORT
TROPICAL STORM ISAIAS, MUTUAL AID TO PSEG-LI
AND STATE OF EMERGENCY
AUGUST 4-13, 2020

Dear Director Giuliano:

As required by 14:5-8.8 Major Event Report, enclosed is a copy of PSE&G's Major Event Report for Tropical Storm Isaias that affected PSE&G's entire service territory, during the State of Emergency from August 4-13, 2020.

Questions concerning this matter can be directed to me or Donald W. Weyant, Manager - Regulatory Compliance at (973) 430-6730.

Respectfully submitted,

Matthew Weissman

Matthew M. Weissman

Attachments

C (Email Only)
Joseph Fiordalisio, President
Upendra Chivukula, Commissioner
Robert Gordon, Commissioner
Mary-Anna Holden, Commissioner
Dianne Solomon, Commissioner
Stacy Peterson, Director

PSE&G'S INITIAL REPORT TO THE BPU
MAJOR EVENT
TROPICAL STORM ISAIAS, MUTUAL AID TO PSEG-LI AND STATE OF EMERGENCY
AUGUST 4 - 13, 2020

EXECUTIVE SUMMARY

Tropical Storm Isaias affected PSE&G's entire service territory with the initial effects of the storm's impact being felt shortly after midnight on August 4, 2020. Wind gusts of 55 - 65 MPH and rainfall amounts of 2" - 6" were predicted. Governor Phil Murphy declared a State of Emergency at 0500 hrs. that morning. This weather event will rank as one of the worst storms in PSE&G's history in terms of the number of customers interrupted, with a preliminary estimate indicating that 575,000 customers experienced an extended interruption. Due to the severity of the weather event and the plant damage that was experienced, exact data involving the number of customers interrupted and the number of plant damage locations is not available at this time. PSE&G will provide Board staff with a final Major Event Report after a thorough review of all storm related data has been completed.

PSE&G began storm response planning for Tropical Storm Isaias on July 30 with reviews of PSE&G's 72/48/24 hour checklists beginning on July 31. A 1300 hrs. conference call was held on July 31, to discuss storm preparations and Mutual Aid needs. Representatives from Electric Delivery's General Office staff, the four operating divisions, Projects & Construction (P&C), the Electric System Operations Center (ESOC), along with personnel from other operating and staff departments of the Company were involved on the call as well as subsequent calls of this nature beginning on August 2.

PSE&G began securing Mutual Aid Line FTEs on July 31, when 220 contractor Line FTEs were obtained. 70 of these FTEs came from Nova Scotia. PSE&G appreciates the assistance that Board staffer James Bruncati provided in helping with the border crossing. PSE&G requested a 1500 hrs. NAMAG conference call. On that call, PSE&G requested 300 Line FTEs but did not receive any commitments. PSE&G continued to secure contractor Line FTEs and on August 1 had secured commitments for 420 Line FTEs. During a 1500 hrs. NAMAG conference call on August 2, PSE&G requested 1,300 Line FTEs but did not receive any commitments.

After the 1500 hrs. NAMAG call on August 2, NAMAG leadership contacted the Southeast Electric Exchange (SEE) Mutual Assistant Group for resources. During a 2100 hrs. NAMAG call that evening, SEE provided a list of contractor companies that FP&L was going to release. On August 3 at 0700 hrs., PSE&G was able to secure 700 Line FTEs from FP&L. Also at that time, PSE&G was able to secure an additional 275 Line FTEs outside of NAMAG. It was extremely important and beneficial to PSE&G's storm restoration efforts to have secured these Mutual Aid Line FTEs prior to the arrival of Tropical Storm Isaias.

Another NAMAG call was held on August 4 at 0800 hrs. during which PSE&G requested 300 Line FTEs and was able to secure 75 from FP&L. At the end of the day on August 4, PSE&G had secured 1,050 Line FTEs, via NAMAG and 384 Line FTEs via other means for a total of 1,434 Line FTEs.

During a NAMAG call on August 5 at 0800 hrs. PSE&G requested 1,000 Line FTEs and secured 287 Line FTEs.

Another NAMAG call was held on August 6, at 0800 hrs. At that time, PSE&G had secured 1,929 Line FTEs. During the call, PSE&G requested 500 Line FTEs and was able to secure 80 Line FTEs. At the end of the day, PSE&G had secured 1,998 Line FTEs.

During a NAMAG call on August 7 at 0900 hrs., PSE&G requested 250 Line FTEs but did not receive any commitments. At the end of the day, PSE&G had secured 2,004 Line FTEs.

Another NAMAG call was held on August 8 at 1400 hrs. PSE&G did not request any assistance during the call. The final number of Line FTEs secured by PSE&G was 2,019.

PSE&G received Mutual Aid crews from the following states:

Indiana	Maryland	Iowa	Oklahoma	Illinois	Pennsylvania
Missouri	Florida	New Jersey	Alabama	Louisiana	Kentucky
Wisconsin					

And the Province of Nova Scotia.

PSE&G was also successful in obtaining additional tree-trimming FTEs. Efforts to obtain them began on July 31. By August 2, 132 were secured, by August 3, 226, by August 4, 383, by August 6, for a total of 722. At the same time, PSE&G utilized 270 contractor tree trimmers already on the property, for a total of 992.

The tree-trimming crews came from the following states:

West Virginia	Tennessee	Indiana	Missouri	Arkansas	Ohio
Florida	Pennsylvania	Michigan	Mississippi	Virginia	Alabama
North Carolina	Wisconsin	South Carolina			

On August 7, PSE&G was able to move approximately 190 Mutual Aid Line FTEs from Central Division to Palisades Division. On August 8 and 9, PSE&G was able to move all the Mutual Aid Line FTEs from Central Division to Metropolitan and Palisades Divisions.

On August 8, PSE&G was able to move approximately 400 Mutual Aid Line FTEs from Southern Division to Palisades Division. On August 9, PSE&G was able to move all the Mutual Aid Line FTEs from Southern Division to Palisades Division. Southern Division was also able to move line and service restoration crews to Central and Metropolitan Divisions on August 8 and 9 respectively.

On the morning of August 9, PSE&G began to release Tree Trimming FTEs and on the morning of August 10, PSE&G began to release Mutual Aid Line FTEs. On the morning of August 12, the remaining Mutual Aid Line FTEs and Tree Trimming FTEs were released.

That morning, PSE&G sent 62 Line FTEs to PSEG-LI for a one day, 16 hour, Mutual Aid Storm Restoration assignment as follows:

Central Division	- 9
Metropolitan Division	- 7
Palisades Division	- 19
Southern Division	- 11
P&C	- 16
Total	- 62

PSE&G, along with the other EDCs, participated in three conference calls with Board staff between August 5 and August 13. Communications with Board staff involving this weather event began on July 30 and continued until August 17.

PSE&G opened its Emergency Operations Center (EOC) on August 4 at 0700 hrs. It remained open in a virtual mode, until August 13 at 0700 hrs.

Communications with 12 County Offices of Emergency Management (OEM) and the City of Newark's Emergency Management Center began on August 4. The liaison support provided was remote and continued until the OEMs closed.

Conference calls with mayors and other municipal and elected officials concerning storm restoration efforts were held daily beginning on August 3 through August 9. Members of the Regional Public Affairs (RPA) Department organized the calls and participated on them, as did the Senior Directors and other personnel from each of the four operating divisions.

PSE&G monitored possible flooding of substations prior to the event using the Stevens Institute of Technology's Flood Model. The Model indicated possible flooding of Marshall Street Substation in Hoboken. Protective barriers were in place around the station's 4-kV equipment and pumps were in place inside of the substation. Fortunately, flooding did not occur.

PSE&G opened six water and ice comfort stations at locations throughout the service territory on August 5.

OPERATING REPORT

The preliminary number of customer interruptions and the final restoration times for customers as of 1100 hrs. on September 2 are as follows:

Division	Preliminary Number of Customers Interrupted	Restoration Entire Circuits	Restoration Areas / Services	Restoration End of SOE
Central	169,173	August 8 - 0810 hrs.	August 11 – 1230 hrs.	August 13* - 1401 hrs.
Metropolitan	170,677	August 7 - 1112 hrs.	August 11 - 1209 hrs.	August 13* 1729 hrs.
Palisades	211,280	August 7 - 0639 hrs.	August 10 - 1347 hrs.	August 13* - 1523 hrs.
Southern	251,717	August 7 - 0400 hrs.	August 10 - 1229 hrs.	August 13* - 1920 hrs.
Total	802,847			

*Outages occurred on August 13.

A preliminary estimate indicated that 575,000 customers experienced and extended interruption. The number and percentage of customers restored were based on that amount. The number and percentage of customers restored for data as of 1100 hrs. on September 2 is also listed below.

Date / Time	Preliminary Number of Customers Restored	Preliminary Percentage of Customers Restored	Updated Number of Customers Restored	Updated Percentage of Customers Restored
August 5 - 0900 hrs.	276,000	48%	347,995	43%
August 6 - 0900 hrs.	430,000	75%	547,603	68%
August 7 - 0900 hrs.	517,000	90%	655,392	82%
August 8 - 0900 hrs.	552,000	96%	722,625	90%
August 9 - 0900 hrs.	569,000	99%	750,650	94%
August 10 - 0900 hrs.			757,397	94%
August 11 - 0900 hrs.			766,512	96%

Attached are the following preliminary Customer Restoration Summary Graphs for this weather event:

Attachment “A” - Company Wide
Attachment “B” - Central Division
Attachment “C” - Metropolitan Division
Attachment “D” - Palisades Division
Attachment “E” - Southern Division

Tropical Storm Isaias affected PSE&G’s entire service territory with the initial effects of the storm’s impact being felt shortly after midnight on August 4, 2020. Wind gusts of 55 - 65 MPH and rainfall amounts of 2” - 6” were predicted. Governor Phil Murphy declared a State of Emergency at 0500 hrs. that morning. This weather event will rank as one of the worst storms in PSE&G’s history in terms of the number of customers interrupted, with a preliminary estimate indicating that 575,000 customers experienced an extended interruption. Due to the severity of the weather event and the plant damage that was experienced, exact data involving the number of customers interrupted and the number of plant damage locations is not available at this time. PSE&G will provide Board staff with a final Major Event Report after a thorough review of all storm related data has been completed.

PSE&G began storm response planning for Tropical Storm Isaias on July 30, with reviews of PSE&G’s 72/48/24 hour checklists beginning on July 31. A 1300 hrs. conference call was held on July 31 to discuss storm preparations and Mutual Aid needs. Representatives from Electric Delivery’s General Office staff, the four operating divisions, Projects & Construction (P&C), the Electric System Operations Center (ESOC), along with personnel from other operating and staff departments of the Company were involved on the call as well as subsequent calls of this nature beginning on August 2.

PSE&G began securing Mutual Aid Line FTEs on July 31, when 220 contractor Line FTEs were obtained. 70 of these FTEs came from Nova Scotia. PSE&G appreciates the assistance that Board staffer James Bruncati provided in helping with the border crossing. PSE&G requested a 1500 hrs. NAMAG conference call. On that call, PSE&G requested 300 Line FTEs but did not receive any commitments. PSE&G continued to secure contractor Line FTEs and on August 1 had secured commitments for 420 Line FTEs. During a 1500 hrs. NAMAG conference call on August 2, PSE&G requested 1,300 Line FTEs but did not receive any commitments.

After the 1500 hrs. NAMAG call on August 2, NAMAG leadership contacted the Southeast Electric Exchange (SEE) Mutual Assistant Group for resources. During a 2100 hrs. NAMAG call that evening, SEE provided a list of contractor companies that FP&L was going to release. On August 3, at 0700 hrs., PSE&G was able to secure 700 Line FTEs from FP&L. Also at that time, PSE&G was able to secure an additional 275 Line FTEs outside of NAMAG. It was important extremely important and beneficial to PSE&G's storm restoration efforts to have secured these Mutual Aid Line FTEs prior to the arrival of Tropical Storm Isaias.

Another NAMAG call was held on August 4 at 0800 hrs. during which PSE&G requested 300 Line FTEs and was able to secure 75 from FP&L. At the end of the day on August 4, PSE&G had secured 1,050 Line FTEs, via NAMAG and 384 Line FTEs via other means for a total of 1,434 Line FTEs.

During a NAMAG call on August 5 at 0800 hrs., PSE&G requested 1,000 Line FTEs and secured 287 Line FTEs.

Another NAMAG call was held on August 6, at 0800 hrs. At that time, PSE&G had secured 1,929 Line FTEs. During the call, PSE&G requested 500 Line FTEs and was able to secure 80 Line FTEs. At the end of the day, PSE&G had secured 1,998 Line FTEs.

During a NAMAG call on August 7 at 0900 hrs. PSE&G requested 250 Line FTEs but did not receive any commitments. At the end of the day, PSE&G had secured 2,004 Line FTEs.

Another NAMAG call was held on August 8 at 1400 hrs. PSE&G did not request any assistance during the call. The final number of Line FTEs secured by PSE&G was 2,019.

PSE&G received Mutual Aid crews from the following states:

Indiana	Maryland	Iowa	Oklahoma	Illinois	Pennsylvania
Missouri	Florida	New Jersey	Alabama	Louisiana	Kentucky
Wisconsin					

and the Province of Nova Scotia.

PSE&G was also successful in obtaining additional tree trimming FTEs. Efforts to obtain them began on July 31. By August 2, 132 were secured, by August 3, 226 by August 4, 383, by August 6, the final total of 722 at the same time, PSE&G utilized 270 contractor tree trimmers already on the property, for a total of 992.

The tree-trimming crews came from the following states:

West Virginia	Tennessee	Indiana	Missouri	Arkansas	Ohio
Florida	Pennsylvania	Michigan	Mississippi	Virginia	Alabama
North Carolina	Wisconsin	South Carolina			

On August 7, PSE&G was able to move approximately 200 Mutual Aid Line FTEs from Central Division to Palisades Division. On August 8 and 9, PSE&G was able to move all the Mutual Aid Line FTEs from Central Division to Metropolitan and Palisades Divisions.

On August 8, PSE&G was able to move approximately 400 Mutual Aid Line FTEs from Southern Division to Palisades Division. On August 9, PSE&G was able to move all the Mutual Aid Line FTEs from Southern Division to Palisades Division. Southern Division was also able to move line and service restoration crews to Central and Metropolitan Divisions on August 8 and 9 respectively.

On the morning of August 9, PSE&G began to release tree-trimming FTEs and on the morning of August 10, PSE&G began to release Mutual Aid Line FTEs. On the morning of August 12, the remaining Mutual Aid Line FTEs and tree-trimming FTEs were released.

That morning, PSE&G sent 62 Line FTEs to PSEG-LI for a one day, 16 hour, Mutual Aid Storm Restoration assignment as follows:

Central Division	- 9
Metropolitan Division	- 7
Palisades Division	- 19
Southern Division	- 11
P&C	- 16
Total	- 62

PSE&G, along with the other EDCs, participated in three conference calls with Board staff between August 5 and August 13. Communications with Board staff involving this weather event began on July 30 and continued until August 17.

PSE&G opened its Emergency Operations Center (EOC) on August 4 at 0700 hrs. It remained open in a virtual mode, until August 13 at 0700 hrs.

Communications with 12 County Offices of Emergency Management (OEM) and the City of Newark's Emergency Management Center began on August 4. The liaison support provided was remote and continued until the OEMs closed.

Conference calls with mayors and other municipal and elected officials concerning storm restoration efforts were held daily beginning on August 3 through August 9. Members of the RPA Department organized the calls and participated on them, as did the Senior Directors and other personnel from each of the four operating divisions.

PSE&G monitored possible flooding of substations prior to the event using the Stevens Institute of Technology's Flood Model. The Model indicated possible flooding of Marshall Street Substation in Hoboken. Protective barriers were in place around the station's 4-kV equipment and pumps were in place inside of the substation. Fortunately, flooding did not occur.

The peak wind gust measured in PSE&G's service territory on August 4 was 68 MPH. There were six hours of sustained winds of 30 MPH with gusts of over 50 MPH.

PSE&G opened six water and ice comfort stations at locations throughout the service territory on August 5.

PERSONNEL DEPLOYMENT

Attached are the following Work Force Graphs for this weather event:

Attachment "F" - Overhead Line Crews, Service Repair Crews and Troubleshooters - Company
Attachment "G" - Overhead Line Crews, Service Repair Crews and Troubleshooters - Central Division
Attachment "H" - Overhead Line Crews, Service Repair Crews and Troubleshooters - Metropolitan Division
Attachment "I" - Overhead Line Crews, Service Repair Crews and Troubleshooters - Palisades Division
Attachment "J" - Overhead Line Crews, Service Repair Crews and Troubleshooters - Southern Division
Attachment "K" - Contractor Tree Crews - Company
Attachment "L" - Mutual Aid Contractor Tree Trimming FTEs
Attachment "M" - Mutual Aid Contractor Line FTEs Assisting Central Division
Attachment "N" - Mutual Aid Contractor Line FTEs Assisting Metropolitan Division
Attachment "O" - Mutual Aid Contractor Line FTEs Assisting Palisades Division

Attachment "P" - Mutual Aid Contractor Line FTEs Assisting Southern Division
Attachment "Q" - Southern Division Overhead Line and Service Repair Crews Assisting Central Division.
Attachment "R" - Southern Division Overhead Line and Service Repair Crews Assisting Metropolitan Division
Attachment "S" - Mutual Aid to PSEG - LI

The following is a listing of the Mutual Aid Contractors' Line FTEs that PSE&G secured:

FTEs Requested	FTEs Secured	Comments	Staging	Released Day/time
50	50	Inside contractors Henkel's & McPhee (NJ/PA)	Southern	HOLD ON PSE&G-NJ Thru 8/11
75	75	Henkel's & McCoy (Wisconsin/Illinois/Michigan)	Southern	HOLD ON PSE&G-NJ Thru 8/10
35	35	Henkel's & McCoy - (Maryland)	Southern	HOLD ON PSE&G-NJ Thru 8/11
50	50	AEP Swepco Internal Crews (Louisiana)	Southern	Released 8/10/2020 7am
52	52	AEP Swepco Contractors - Non-Union Crews (Louisiana),	Southern	Released 8/10/2020 7am
82	82	Centerphase Energy -Non Union Contractors (Oklahoma)	Southern	Released 8/10/2020 7am
22	22	2nd Wave Centerphase Energy -Non Union Contractors (Oklahoma)	Southern	Released 8/10/2020 7am
21	21	3rd Wave Centerphase Energy -Non Union Contractors (Oklahoma)	Southern	Released 8/10/2020 7am
53	53	Mid-Con Energy - NonUnion Contactors (Oklahoma)	Southern	Released 8/10/2020 7am
42	42	Pike Electric (Oklahoma)	Southern	Released 8/10/2020 7am
Total	**482**			
50	50	Riggs-Distler (NJ/PA)	Central - Hadley Rd	HOLD ON PSE&G-NJ Thru 8/10
120	120	Onpower - (Florida)	Central - Hadley Rd	HOLD ON PSE&G-NJ Thru 8/11
58	34	2nd Wave - Onpower - (Florida)	Central - Hadley Rd	HOLD ON PSE&G-NJ Thru 8/11
192	192	OneSource - Non Union Contractors (Florida)	Central - Hadley Rd	Released 8/10/2020 7am
95	95	2nd Wave OneSource - Non Union Contractors (Florida)	Central - Hadley Rd	Released 8/10/2020 7am
28	28	Alliant - Michels Power - (IOWA)	Central - Hadley Rd	Released 8/10/2020 7am
34	58	United Electric - (Kentucky)	Central - Hadley Rd	Released 8/10/2020 7am
Total	**577**			

FTEs Requested	FTEs Secured	Comments	Staging	Released Day/time
70	70	East Coast Power - (Nova Scotia)	Northern - Wayne Staging	Released to PSEG-LI 8/10/2020
50	50	3rd Wave MP Systems/Onpower - (Florida)	Northern - Wayne Staging	Released 8/11/2020 7am
45	45	CC Power - (Michigan)	Northern - Wayne Staging	Released to PSEG-LI 8/10/2020
104	104	Lee Electric (North Carolina)	Northern - Wayne Staging	Released to PSEG-LI 8/10/2020
77	77	Ameren Contractors - (Missouri)	Northern - Wayne Staging	Released to PSEG-LI VIA NAMAG 8/10/2020
56	56	Mid-Con Energy - Non Contractors (Oklahoma)	Northern - Wayne Staging	Released to PSEG-LI 8/10/2020
8	8	Valiant - (PA)	Northern - Wayne Staging	Released 8/10/2020 7am
Sub Total	**410**			
80	80	Henkel's & McCoy (PA)	Northern - Bergen Comm. College	HOLD ON PSE&G-NJ Thru 8/10
214	214	Collective Storm Services - (Alabama)	Northern - Bergen Comm. College	Released to PSEG-LI VIA NAMAG 8/10/2020
21	21	2nd Wave Collective Storm Services - (Alabama)	Northern - Bergen Comm. College	Released to PSEG-LI VIA NAMAG 8/10/2020
15	15	3rd Wave Collective Storm Services - (Alabama)	Northern - Bergen Comm. College	Released to PSEG-LI VIA NAMAG 8/10/2020
32	32	Mohawk Electric - (Missouri)	Northern - Bergen Comm. College	Released to PSEG-LI VIA NAMAG 8/10/2020
20	20	Mohawk Electric - (Missouri)	Northern - Bergen Comm. College	Released to PSEG-LI VIA NAMAG 8/10/2020
117	117	Heart Utilities - (Florida)	Northern - Bergen Comm. College	HOLD ON PSE&G-NJ Thru 8/10

FTEs Requested	FTEs Secured	Comments	Staging	Released Day/time
20	20	Henkel's & McCoy (NJ)	Northern - Bergen Comm. College	HOLD ON PSE&G-NJ Thru 8/11
31	31	Heart Utilities - (Florida)	Northern - Bergen Comm. College	HOLD ON PSE&G-NJ Thru 8/10
Sub Total	**550**			
Total	**2,019**			

The following is a listing of the tree-trimming contractors' FTEs that PSE&|G secured:

Contractor	Crew Count	FTE	Actual Date of Arrival	Actual Time of Arrival	Release Date	Release Time	Origin Utility	City & State of Origin
Nelson	4	16	8/3/2020	7:20 PM	8/9/2020	7:00 PM	AEP-WV	Huntington, WV
Nelson	5	15	8/3/2020	7:20 PM	8/9/2020	7:00 PM	AEP-WV	Beckley, WV
Nelson	0	1	8/5/2020	11:00 PM	8/9/2020	7:00 PM	AEP OH	Canton, OH
Nelson	5	11	8/6/2020	5:00 PM	8/9/2020	7:00 PM	AEP OH	Canton, OH
Nelson	5	11	8/6/2020	5:00 PM	8/9/2020	7:00 PM	AEP OH	Canton, OH
Asplundh	7	18	8/3/2020	11:30 PM	8/10/2020	9:00 AM	Detroit Edison Wave 1	Howell, MI
Asplundh	10	21	8/3/2020	11:30 PM	8/10/2020	9:00 AM	Detroit Edison Wave 1	Howell, MI
Asplundh	10	23	8/3/2020	11:30 PM	8/10/2020	9:00 AM	Detroit Edison Wave 1	Howell, MI
Asplundh	5	13	8/6/2020	11:00 PM	8/12/2020	7:00 AM	Detroit Edison Wave 2	Howell, MI
Asplundh	7	18	8/6/2020	11:00 PM	8/12/2020	7:00 AM	Detroit Edison Wave 2	Howell, MI
Asplundh	6	13	8/6/2020	11:00 PM	8/10/2020	9:00 AM	Detroit Edison Wave 2	Howell, MI
Asplundh	5	11	8/7/2020	8:00 AM	8/10/2020	9:00 AM	Consumers Energy	Jackson, MI
Asplundh	5	12	8/7/2020	8:00 AM	8/10/2020	9:00 AM	Consumers Energy	Mt Pleasant, MI
Asplundh	5	11	8/6/2020	10:00 PM	8/12/2020	7:00 AM	We-Energies, Richland Energies, Oakdale Electric & Rock Energies	Waukesha, WI, Richland Center, WI, Oakdale, WI & Beloit, WI
Asplundh	6	19	8/6/2020	10:00 PM	8/10/2020	9:00 AM	Petit Jean Elect Coop, Memphis Gas Water Light, Jonesboro CWL	Clinton, AR, Memphis, TN, Jonesboro, AR

Contractor	Crew Count	FTE	Actual Date of Arrival	Actual Time of Arrival	Release Date	Release Time	Origin Utility	City & State of Origin
Asplundh	3	8	8/7/2020	9:00 AM	8/10/2020	9:00 AM	4 County	West Point, MS
Asplundh	4	9	8/7/2020	9:00 AM	8/10/2020	9:00 AM	Central Electric	Kosciusko, MS
Asplundh	3	10	8/7/2020	9:00 AM	8/10/2020	9:00 AM	Central Electric	Kosciusko, MS
Asplundh	7	16	8/6/2020	11:00 PM	8/10/2020	9:00 AM	Dothan Utility	Dothan, AL
Asplundh	3	11	8/6/2020	11:00 PM	8/10/2020	9:00 AM	Pioneer	Greenville, AL
Asplundh	5	11	8/6/2020	11:00 PM	8/10/2020	9:00 AM	Joe Wheeler	Moultan, AL
Asplundh	3	9	8/6/2020	11:00 PM	8/10/2020	9:00 AM	Bessemer	Bessemer, AL
Asplundh	5	11	8/4/2020	6:00 PM	8/10/2020	9:00 AM	AEP OH Wave 1	Canton, OH
Asplundh	5	11	8/4/2020	6:00 PM	8/10/2020	9:00 AM	AEP OH Wave 1	Chillicothe, OH
Asplundh	5	11	8/4/2020	6:00 PM	8/10/2020	9:00 AM	AEP OH Wave 1	Canton, OH
Asplundh	5	11	8/4/2020	10:30PM	8/10/2020	9:00 AM	AEP OH Wave 1	Wooster, OH
Asplundh	0	1	8/4/2020	7:00 PM	8/10/2020	9:00 AM	AEP OH Wave 1	Millersport, OH
Asplundh	0	1	8/4/2020	7:00 PM	8/10/2020	9:00 AM	AEP OH Wave 1	Millersport, OH
Asplundh	5	11	8/4/2020	6:00 PM	8/10/2020	9:00 AM	AEP OH Wave 1	Crooksville, OH
Asplundh	5	11	8/4/2020	10:30PM	8/10/2020	9:00 AM	AEP OH Wave 1	Pomeroy, OH
Asplundh	5	11	8/4/2020	6:00 PM	8/10/2020	9:00 AM	AEP OH Wave 1	McConnelsville, OH
Asplundh	5	11	8/4/2020	10:30PM	8/10/2020	9:00 AM	AEP OH Wave 1	Athens, OH
Asplundh	5	11	8/4/2020	6:00 PM	8/10/2020	9:00 AM	AEP OH Wave 1	Chillicothe, OH
Asplundh	5	11	8/4/2020	6:00 PM	8/10/2020	9:00 AM	AEP OH Wave 1	Crooksville, OH
Asplundh	6	13	8/6/2020	3:00 PM	8/10/2020	9:00 AM	AEP OH Wave 2	Columbus, OH
Asplundh	6	13	8/6/2020	6:00 PM	8/10/2020	9:00 AM	AEP OH Wave 2	Portsmouth, OH
Asplundh	5	12	8/6/2020	3:00 PM	8/10/2020	9:00 AM	AEP OH Wave 2	Coshocton, OH
ARS	12	38	8/3/2020	11:45 PM	8/9/2020	4:00 PM	Clay Electric	Jacksonville, FL
NG Gilbert / Townsend	8	18	8/4/2020	2:00 AM	8/11/2020	3:00 PM	Clark Rem / Meade Rec	Bradenburg, KY / Sellersburg, IN
NG Gilbert / Townsend	6	14	8/3/2020	11:00 PM	8/9/2020	4:00 PM	SEIREMC	Osgood, IN
NG Gilbert / Townsend	6	20	8/3/2020	7:00 PM	8/10/2020	9:00 AM	APCO	Fayetteville, WV
NG Gilbert / Townsend	5	11	8/3/2020	10:00 PM	8/9/2020	4:00 PM	APCO	Kingsport, TN
NG Gilbert / Townsend	0	1	8/3/2020	10:00 PM	8/11/2020	3:00 PM	APCO	Kingsport, TN
NG Gilbert / Townsend	5	11	8/3/2020	9:00 PM	8/9/2020	4:00 PM	APCO	Kingsport, TN
NG Gilbert / Townsend	6	14	8/5/2020	6:30 AM	8/9/2020	4:00 PM	Duke Energy	Martinsville, IN
NG Gilbert / Townsend	4	9	8/5/2020	3:00 AM	8/10/2020	9:00 AM	APCO	Pt Pleasant, WV
NG Gilbert / Townsend	6	19	8/5/2020	12:00 AM	8/10/2020	9:00 AM	APCO	Princeton, WV

Contractor	Crew Count	FTE	Actual Date of Arrival	Actual Time of Arrival	Release Date	Release Time	Origin Utility	City & State of Origin
NG Gilbert / Townsend	5	13	8/5/2020	12:00 AM	8/10/2020	9:00 AM	PEMC & APCO	Burlington, NC & Princeton, WV
NG Gilbert / Townsend	5	11	8/5 & 8/6	3PM & 5:30 AM	8/9/2020	4:00 PM	Duke Energy & SEIREMC	Brookville, IN & Osgood, IN
NG Gilbert / Townsend	5	11	8/7/2020	12:00 PM	8/9/2020	4:00 PM	SEMO Electric	Sikeston, MO
NG Gilbert / Townsend	5	12	8/7/2020	11:00 AM	8/9/2020	4:00 PM	HBPW, SEMO Electric, City of Jackson, City of Sikeston & Black River Electric	Hannibal, MO, Sikeston, MO, Jackson, MO, Fredericktown, MO
NG Gilbert / Townsend	5	12	8/7/2020	11:00 AM	8/9/2020	4:00 PM	Black River Electric	Fredericktown, MO
Valiant	2	7	8/4/2020	12:00 PM	8/11/2020	11:00 AM	N/A	Allentown, PA
Lewis	3	8	8/6/2020	10:00 PM	8/9/2020	4:00 PM	AEP OH	Columbus, OH
Lewis	6	15	8/6/2020	10:00 PM	8/9/2020	4:00 PM	AEP OH	Mansfield, OH
Lewis	4	9	8/6/2020	8:00 PM	8/9/2020	4:00 PM	AEP OH	Cadiz, OH
Lewis	3	6	8/6/2020	8:00 PM	8/9/2020	4:00 PM	AEP OH	Cadiz, OH
Lewis	0	1	8/6/2020	9:30 PM	8/9/2020	4:00 PM	AEP / I&M	Muncie, IN
Lewis	0	1	8/5/2020	6:30 PM	8/9/2020	4:00 PM	Dominion	Chesterfield, VA
Lewis	0	1	8/5/2020	10:30 PM	8/9/2020	4:00 PM	AEP	Winchester, IN
Lewis	0	1	8/7/2020	10:00 PM	8/9/2020	4:00 PM	Duke Energy	Tampa, FL
Lewis	5	11	8/7/2020	12:00 AM	8/9/2020	4:00 PM	Santee Cooper	Conway, SC
Lewis	5	11	8/7/2020	12:00 AM	8/9/2020	4:00 PM	Berkeley Electric	Goose Creek, SC
Total	**291**	**722**						

Arrangements were made to secure four staging areas to support the Mutual Aid crews. These areas became material storage areas for poles, transformers conductors and other material. They were also the locations where these crews received their work assignments and safety briefings.

As is standard operating procedure in system emergencies, liaison support to each of the four operating divisions was provided beginning at noon on August 4. It continued until 2100 hrs. on August 10. Liaison support was also provided to the two Inquiry Centers during this weather event. These liaisons assisted on addressing customer inquiries.

Conference calls with mayors and other elected officials concerning storm restoration efforts were held daily beginning on August 3 through August 9. Members of the RPA Department organized the calls and the Senior Directors and other personnel of the four operating divisions participated on the calls.

There were a maximum of 155 Gas Delivery associates used for standing by downed wires between August 4 and August 11.

PSE&G also secured a contractor to assist in the damage assessment process. The contractor was utilized on August 8 and 9 and consisted of 107 - 2- person teams.

INITIAL TROUBLE LOCATIONS AND CLASSIFICATIONS

Outside plant damage locations are listed below:

69 & 26-kV	-	120
13 & 4-kV	-	1,856
Transformers	-	663
Secondaries	-	577
Services	-	2,203
Poles	-	988
Trees	-	6,000+
Total	-	12,407+

INCIDENTS

The following PSE&G Substations were shut down during this weather event:

Substation	Date	Time off	Time on	Number of Customers
Avenel	August 4	1215	1800 (August 5)	3,833
Clark	August 13	0930	1040 (August 13)	2,360
Harts Lane	August 4	1242	1534	14,179
Hudson Terrace	August 4	1316	1944	1,049
Hudson Terrace	August 10	1404	2220 (August 10)	1,049
Bordentown	August 4	1151	1750	2,667
Medford	August 4	1253	1743	13,413
Montgomery	August 4	1214	1815	3,978
Mount Holly	August 4	1043	2045	4,205
Princeton	August 4	1228	1548	3,363
Southampton	August 4	1034	1439	5,018

The following Hospitals were interrupted during this weather event:

Hospital	Municipality	Date	Time off	Time on
Englewood	Englewood	August 4	1347	1543
Holy Name	Teaneck	August 4	1221	1309
Pascack Valley	Westwood	August 4	1208	1602*
Valley	Ridgewood	August 4	1307	2021
Lourdes Virtua	Willingboro	August 4	1356	1829
Children's Specialized Hospital	Mountainside	August 4	1223	1756

*Delay due to the customer not being able to transfer their switchgear to the back-up circuit.

COMMUNICATIONS

PSE&G participated in eight NAMAG conference calls between July 31 and August 8.

Communications with 12 County Offices of Emergency Management (OEMs) and the City of Newark's Emergency Management Center and began on August 4. The liaison support provided was remote and continued until the OEMs closed.

Conference calls with mayors and other municipal and elected officials concerning storm restoration efforts were held daily beginning on August 3 through August 9. Members of the RPA Department organized the calls and participated on them, as did the Senior Directors and other personnel from each of the four operating divisions.

PSE&G along with the other EDCs participated in three conference calls with Board staff between August 5 and August 13. Communications with Board staff involving this weather event began on July 30 and continued until August 17.

PSE&G's RPA Managers kept in constant contact with municipal and state officials in the areas hardest hit by Isaias. In person meetings, telephone calls, text messages and press releases were used in the communication process. In addition, PSE&G officers were also in contact with those officials.

PSE&G's Corporate Communications Department issued internal communications, press releases and handled multiple newspapers, television and radio information request during the period including interviews with PSE&G executives. Social media was monitored for customer messages and PSE&G utilized social media to communicate with customers.

The initial notification to PSE&G's critical needs (P-4) customers was issued on August 3. Personalized calls were made to affected P-4 customers during this weather event.

SUMMARY

This weather event qualifies as a Major Event Since more than 10% of PSE&G's 2,430,197 customers were interrupted. In addition, PSE&G supplied Mutual Aid to PSEG-LI on August 12 and Governor Phil Murphy declared a State of Emergency, which extended from 0500 hrs. on August 4 to 1500 hrs. on August 13.

It was extremely important and beneficial to PSE&G's storm restoration efforts that PSE&G started to secure Mutual Aid Line FTEs on July 31 and by August 3 had secured commitments for approximately 1,400 Mutual Aid Line FTEs.

The restoration efforts went extremely well. Initial data indicates that 48% of the customers interrupted were restored to service in one day; 75% in two days; 90% in three days; 96% in four days and 99% in five days.

PSE&G's excellent relationship with its unions was beneficial during this event.

There were no issues involving equipment or material during this event.

Board staff, during a conference call with EDCs on August 13, asked that additional information called "Touch Points" be included in their Major Event Reports. These "Touch Points" were summarized in Board staffer Jody Raines' August 14 email. PSE&G's responses to the majority of the information requests are contained in President David Daly's Hearing Statement made before a Joint Meeting of the New Jersey Assembly

Telecommunications and Utilities and Assembly Homeland Security and State Preparedness Committees on August 19. A copy of PSE&G's Hearing Statement is attached. PSE&G's responses to the "Touch Points" are as follows:

Measuring the value of hardening/resiliency efforts and expenditures:

Please refer to President Daly's comments under "Restoration Performance - Benefits of Prior Infrastructure Hardening"

Tree Trimming

An overwhelming majority of the outages can be associated with trees.

Fallen trees prolong service restoration as they block roads and access points to plant damage. The removal of fallen trees in many cases is a time consuming process due to the amount of debris that has to be removed. The larger the fallen tree, the more plant damage that it can cause.

PSE&G looks forward to working with Board staff in addressing the subject of reducing the impact of trees on reliability.

COMMUNICATIONS

Please refer to President Daly's comments under "Communications and OMS"

Preparedness posture/mutual aid actions and effectiveness

Please refer to President Daly's comments under "Storm Preparedness – Mutual Aid and COVID Protocol" Also, the subject of Mutual Aid is addressed in detail in the Major Event Report.

Road Opening Process

The stand by wires down process was utilized for police and fire calls when a cut clear responder was not available.

Troubleshooters at the request of various entities performed road clearing.

Priorities were communicated from County OEMs, the mayors' calls and requests to RPA Managers. There was no backlog.

Issues involving lists received from the NJDOT have been reviewed with Board staff.

AMI

Please refer to President Daly's comments under "Communications and OMS"

PSE&G held a "Lessons Learned" meeting concerning Isaias on August 20. Action Items from the meeting are being developed.

Another conference call with the EDCs and Board staff was held on August 25 to discuss the additional storm related information contained in Jodi Raines' August 21 email. PSE&G's responses follow:

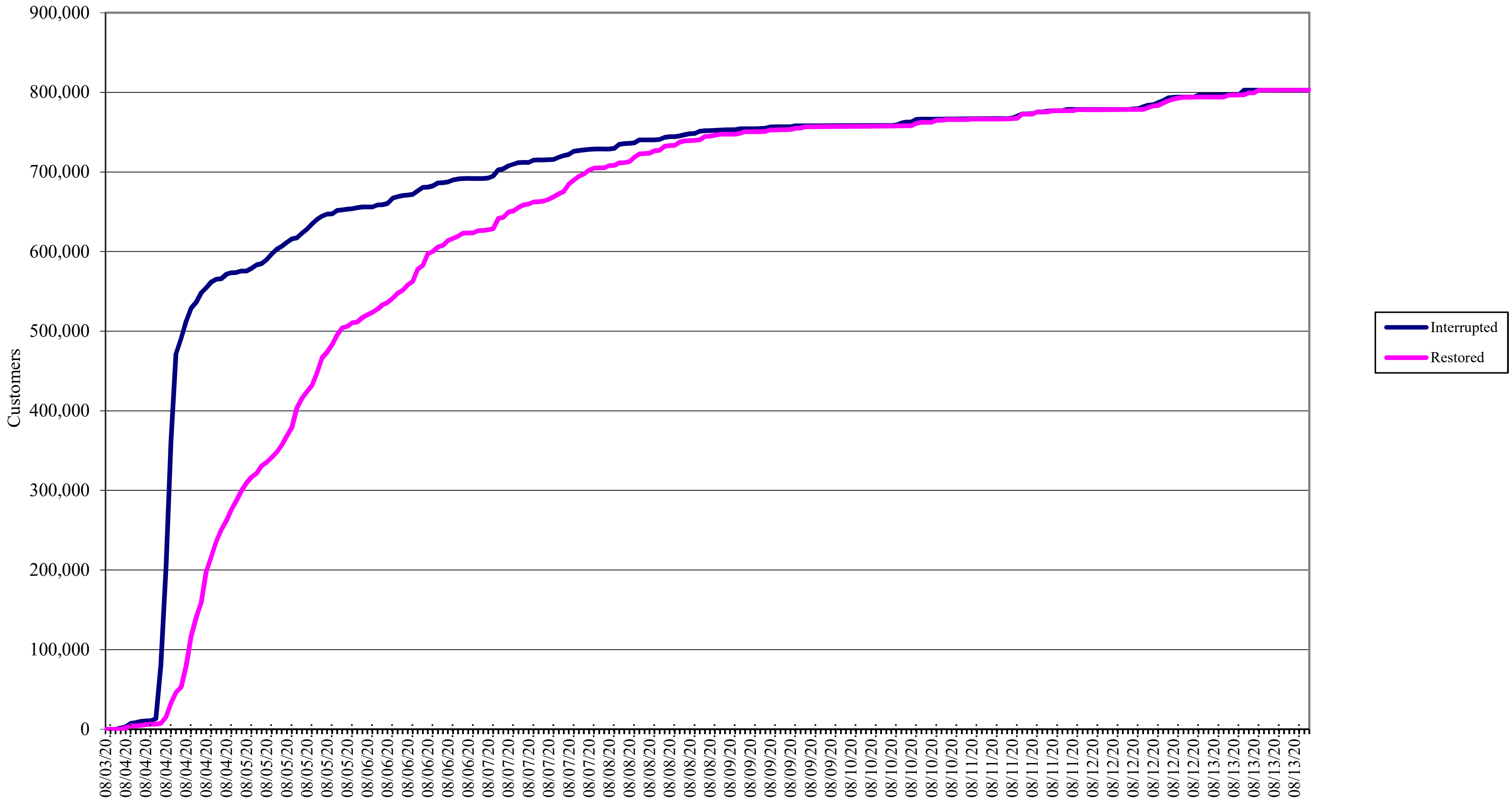
Lists of substations and hospitals interrupted during this event are contained in the Major Event Report, as is a list of Trouble Locations and Classifications.

An overwhelming majority of the primary facility plant damage was caused by total tree failures of seemingly healthy trees, whose removal would have been outside of the trimming scope. Branch failures also caused primary facility plant damage. Falling branches from privately owned non-maintained trees caused the majority of damage to house services.

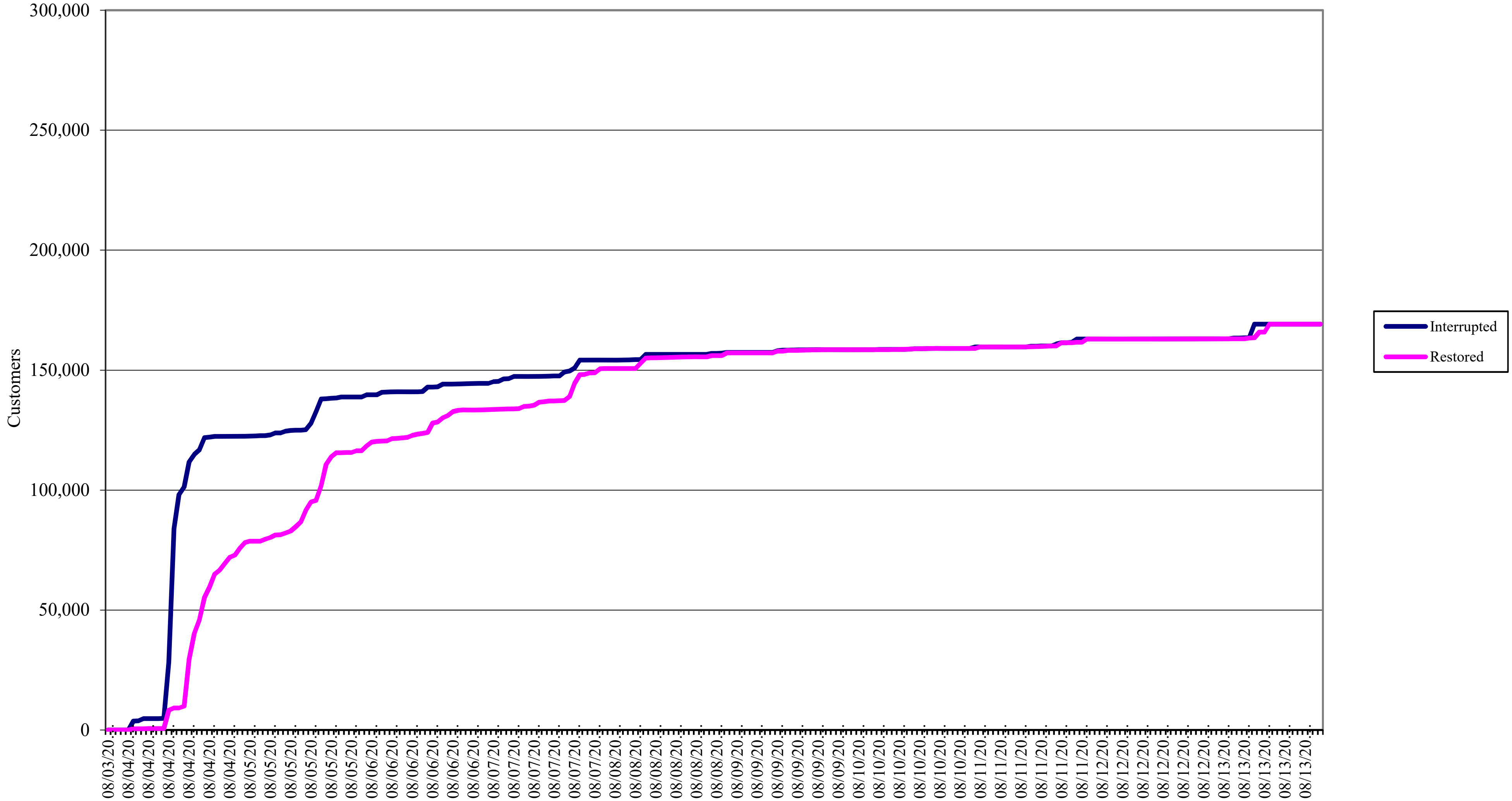
From an initial review of pole damage, fallen trees caused the majority of pole damage. The extreme winds were also the cause of some pole damage.

DWW:bmc
9/2/20

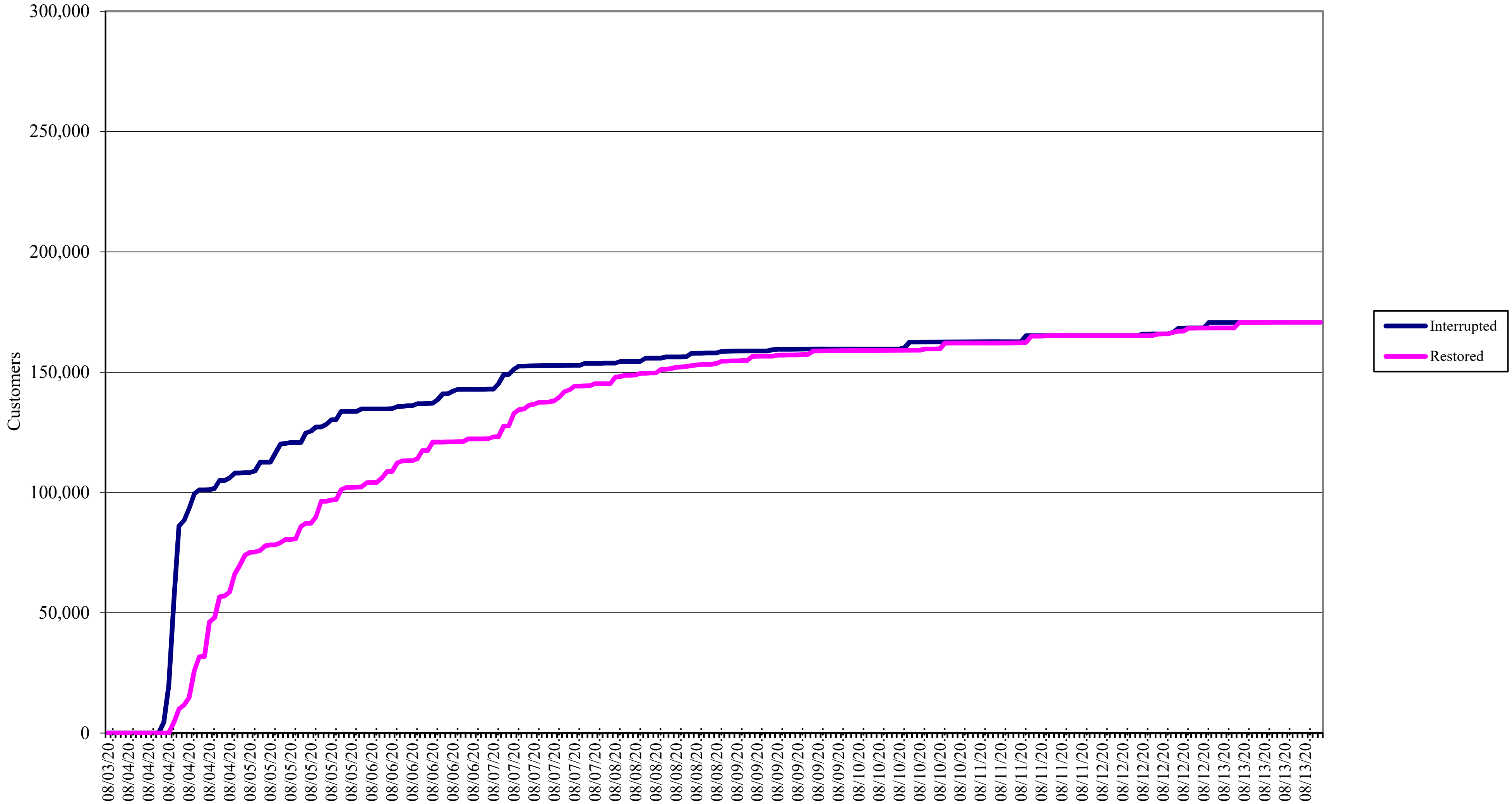
Attachment "A"
PSE&G
Customer Restoration Summary
Tropical Storm Isaias, Mutual Aid to PSEG-LI and State of Emergency - August 4-13, 2020
Company Wide



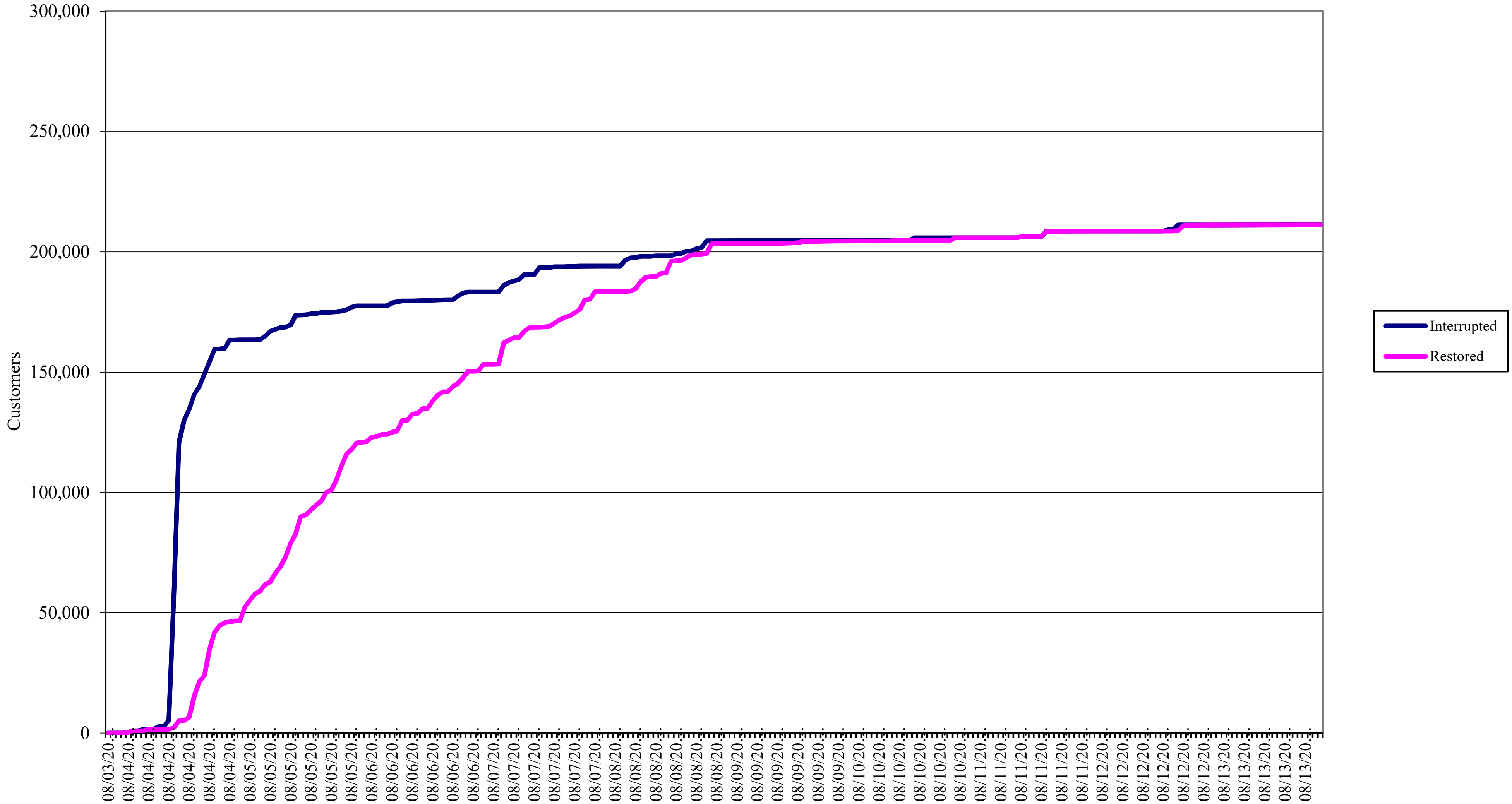
Attachment "B"
PSE&G
Customer Restoration Summary
Tropical Storm Isaias, Mutual Aid to PSEG-LI and State of Emergency - August 4-13, 2020
Central Division



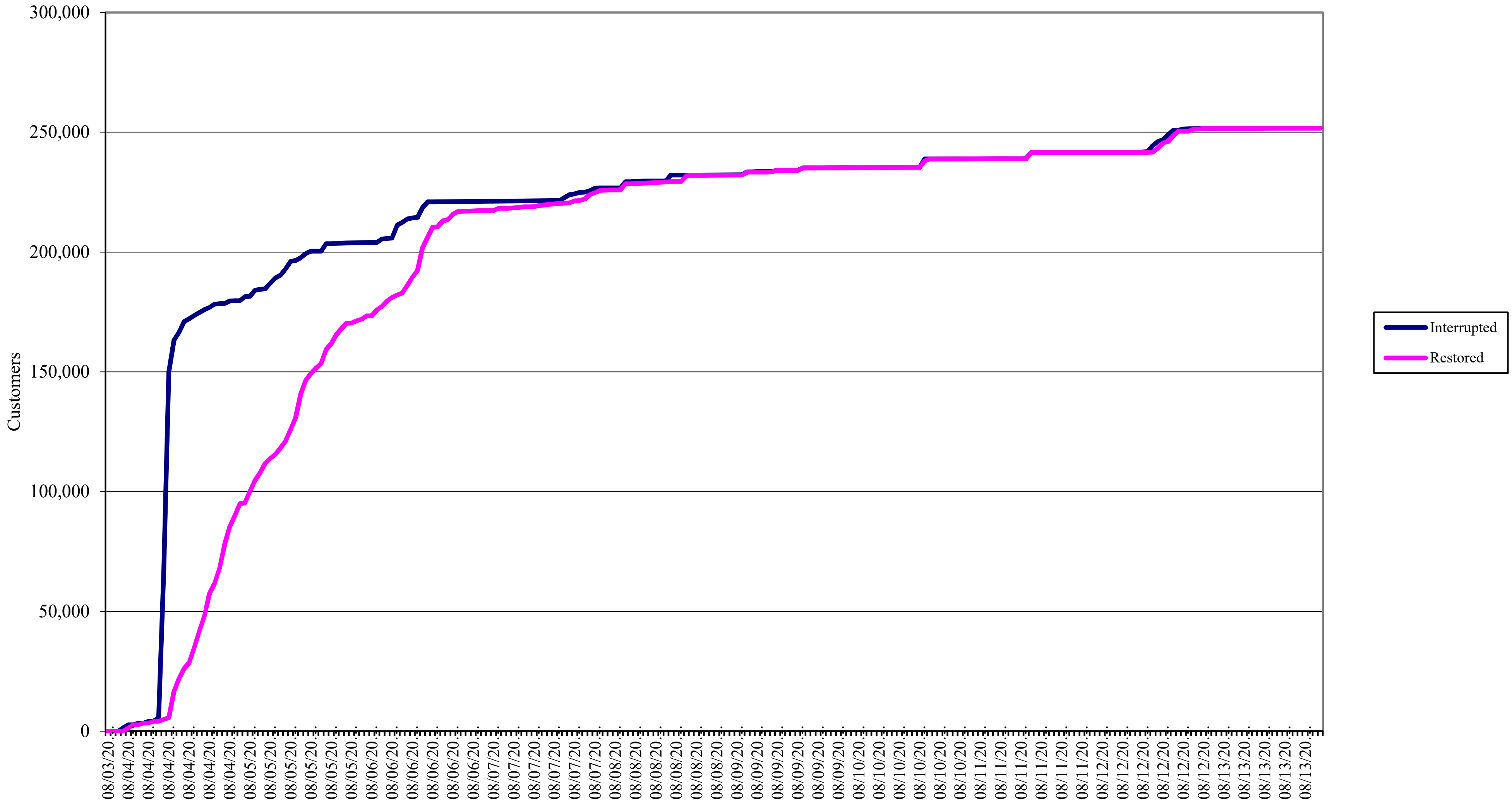
Attachment "C"
PSE&G
Customer Restoration Summary
Tropical Storm Isaias, Mutual Aid to PSEG-LI and State of Emergency - August 4-13, 2020
Metropolitan Division



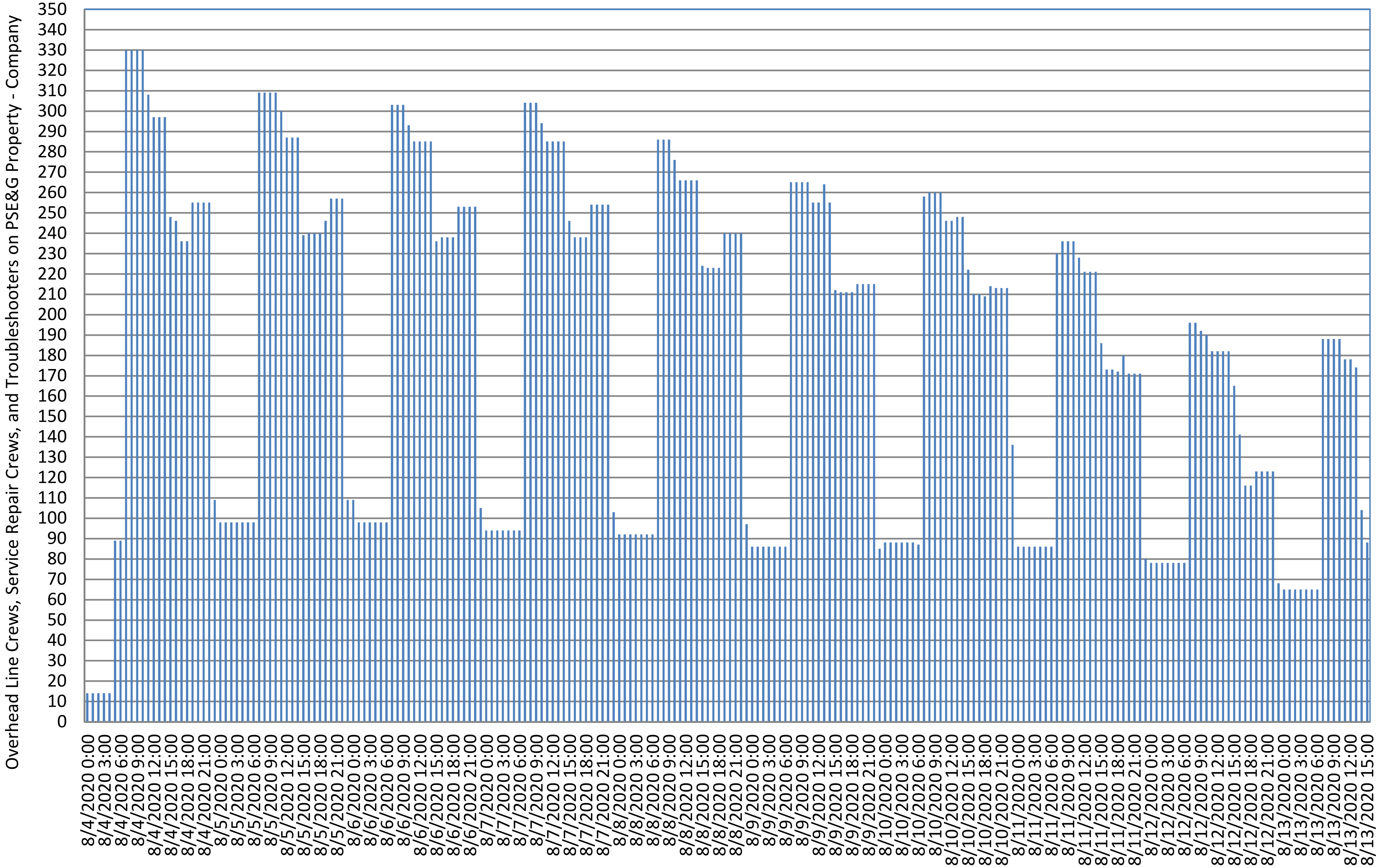
Attachment "D"
PSE&G
Customer Restoration Summary
Tropical Storm Isaias, Mutual Aid to PSEG-LI and State of Emergency - August 4-13, 2020
Palisades Division



Attachment "E"
PSE&G
Customer Restoration Summary
Tropical Storm Isaias, Mutual Aid to PSEG-LI and State of Emergency - August 4-13, 2020
Southern Division

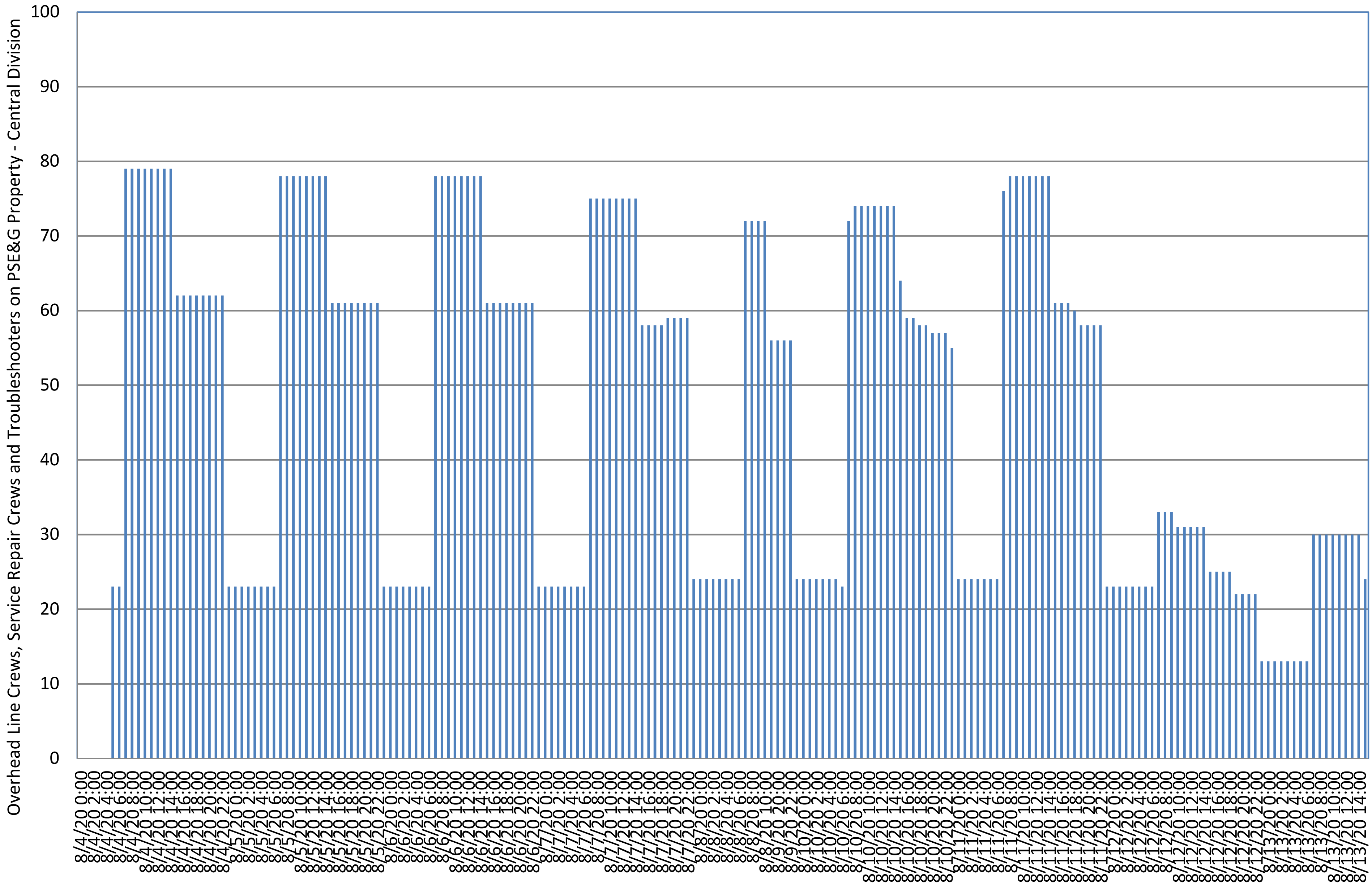


Attachment "F"
PSE&G
Overhead Line Crews, Service Repair Crews, and Troubleshooters on PSE&G Property - Company
Tropical Storm Isaias, Mutual Aid to PSEG-LI and State of Emergency - August 4-13, 2020

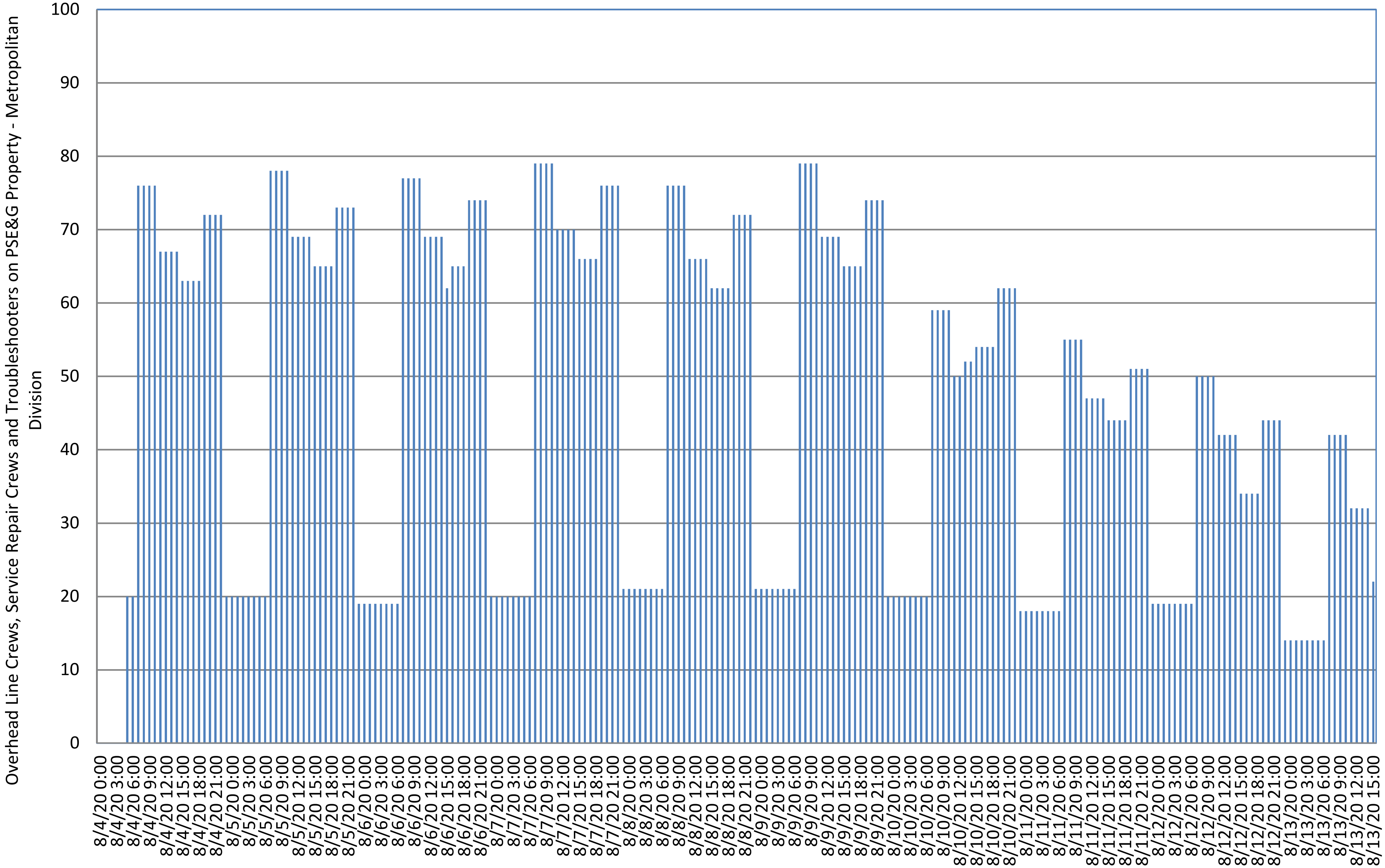


*These values include P&C Workforce Numbers

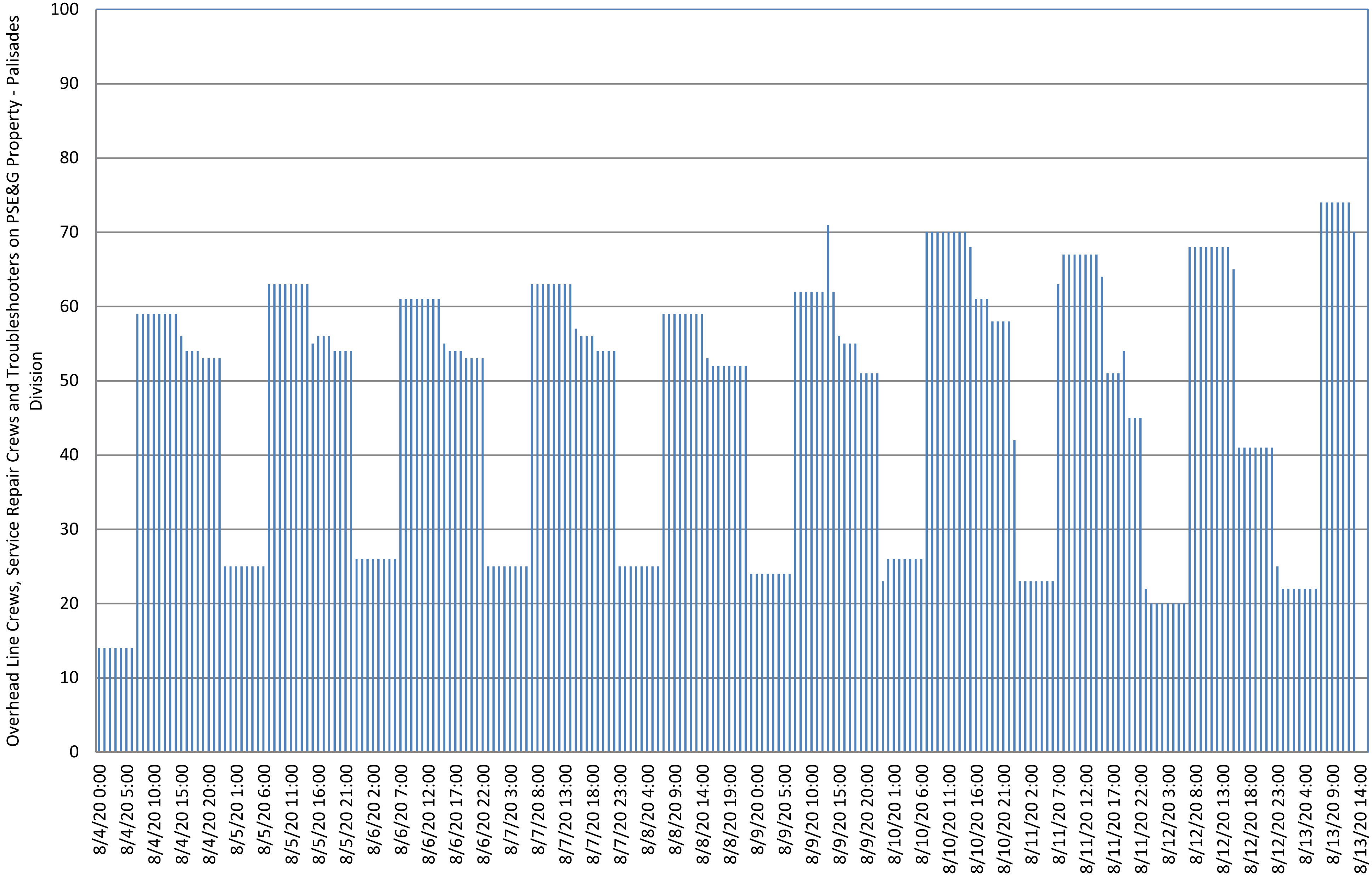
Attachment "G"
PSE&G
Overhead Line Crews, Service Repair Crews and Troubleshooters on PSE&G Property - Central Division
Tropical Storm Isaias, Mutual Aid to PSEG-LI and State of Emergency - August 4-13, 2020



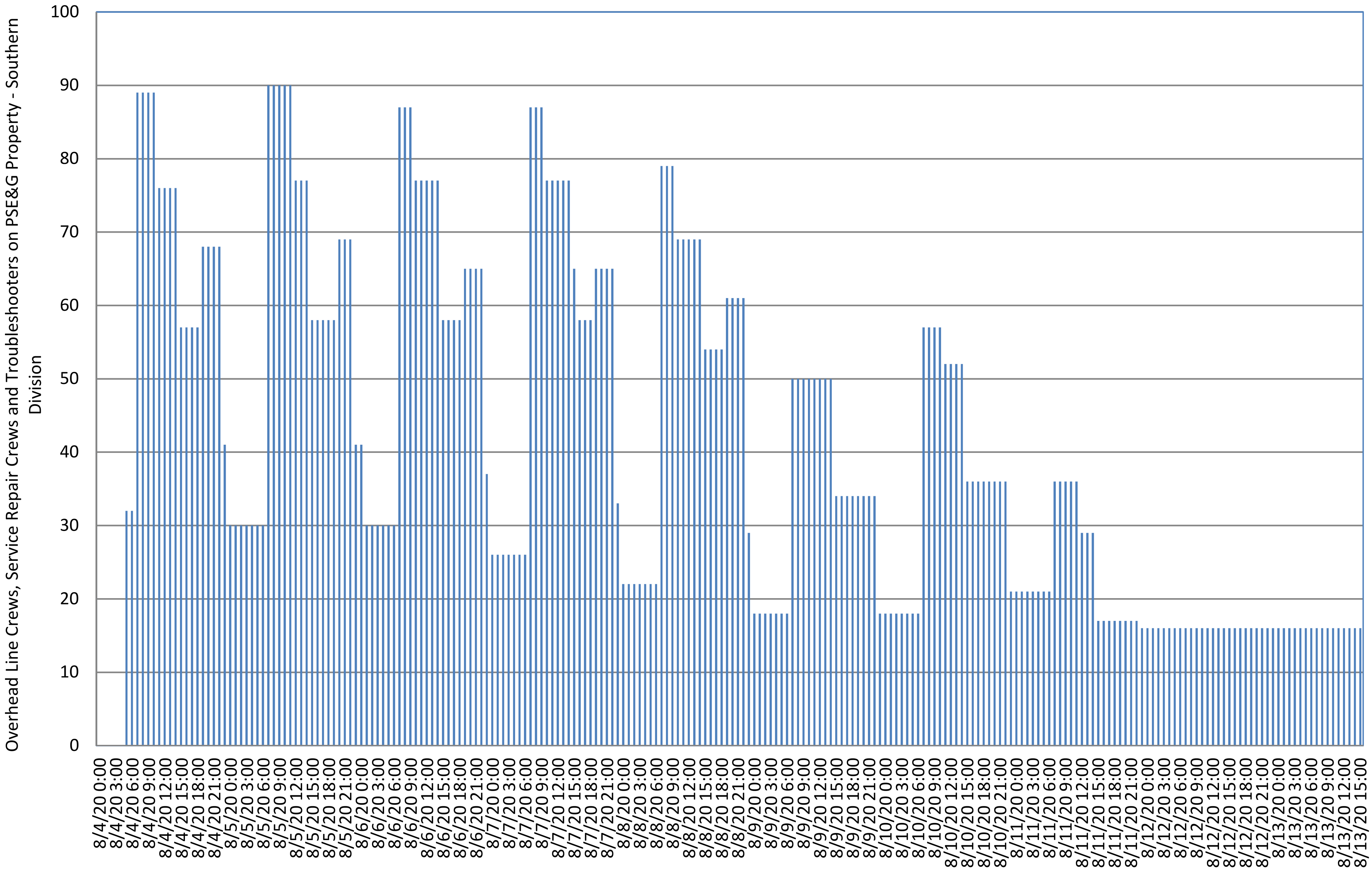
Attachment "H"
PSE&G
Overhead Line Crews, Service Repair Crews and Troubleshooters on PSE&G Property - Metropolitan Division
Tropical Storm Isaias, Mutual Aid to PSEG-LI and State of Emergency - August 4-13, 2020



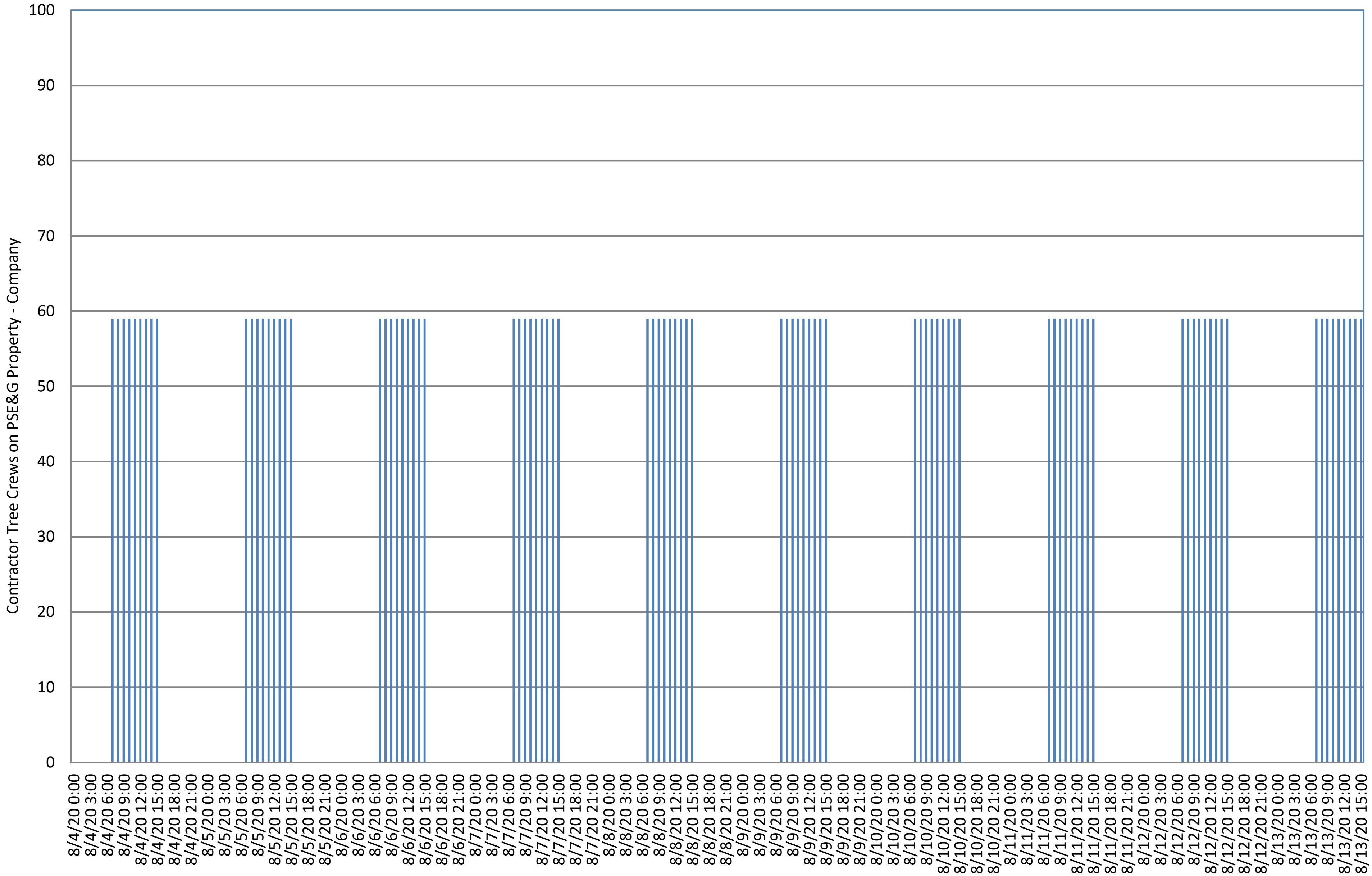
Attachment "I"
PSE&G
Overhead Line Crews, Service Repair Crews and Troubleshooters on PSE&G Property - Palisades Division
Tropical Storm Isaias, Mutual Aid to PSEG-LI and State of Emergency - August 4-13, 2020



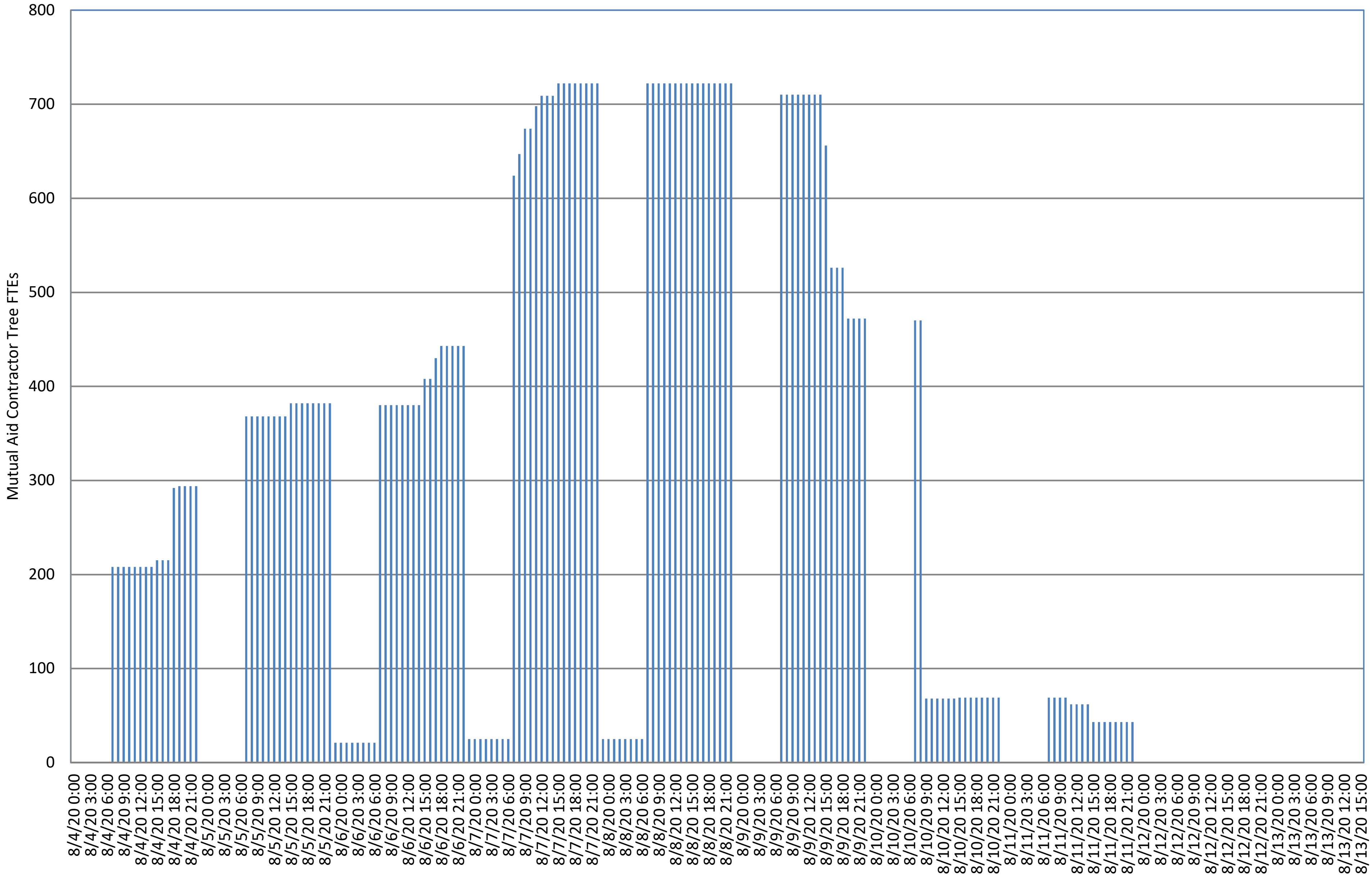
Attachment "J"
PSE&G
Overhead Line Crews, Service Repair Crews and Troubleshooters on PSE&G Property - Southern Division
Tropical Storm Isaias, Mutual Aid to PSEG-LI and State of Emergency - August 4-13, 2020



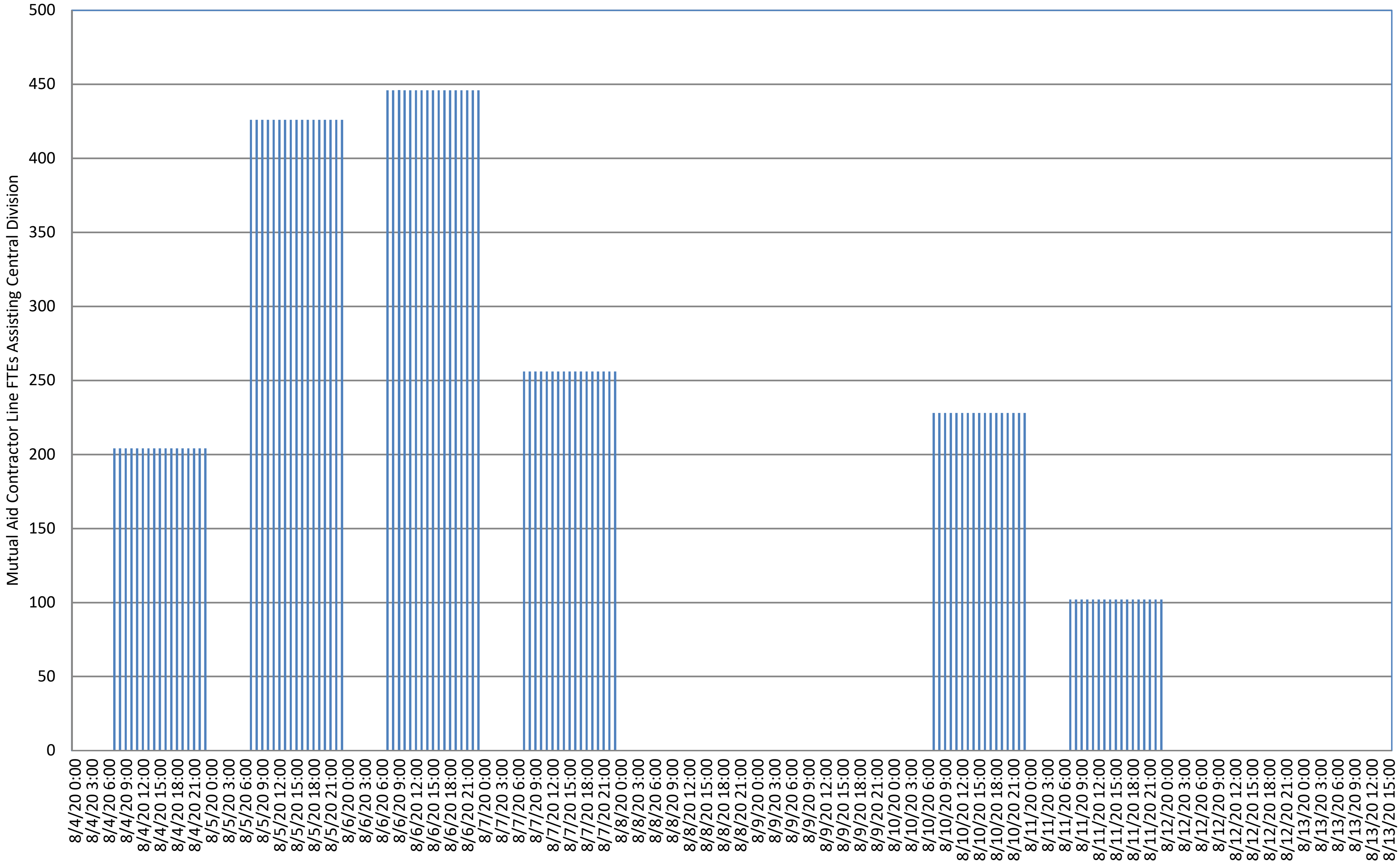
Attachment "K"
PSE&G
Contractor Tree Crews on PSE&G Property - Company
Tropical Storm Isaias, Mutual Aid to PSEG-LI and State of Emergency - August 4-13, 2020



Attachment "L"
PSE&G
Mutual Aid Contractor Tree FTEs
Tropical Storm Isaias, Mutual Aid to PSEG-LI and State of Emergency - August 4-13, 2020

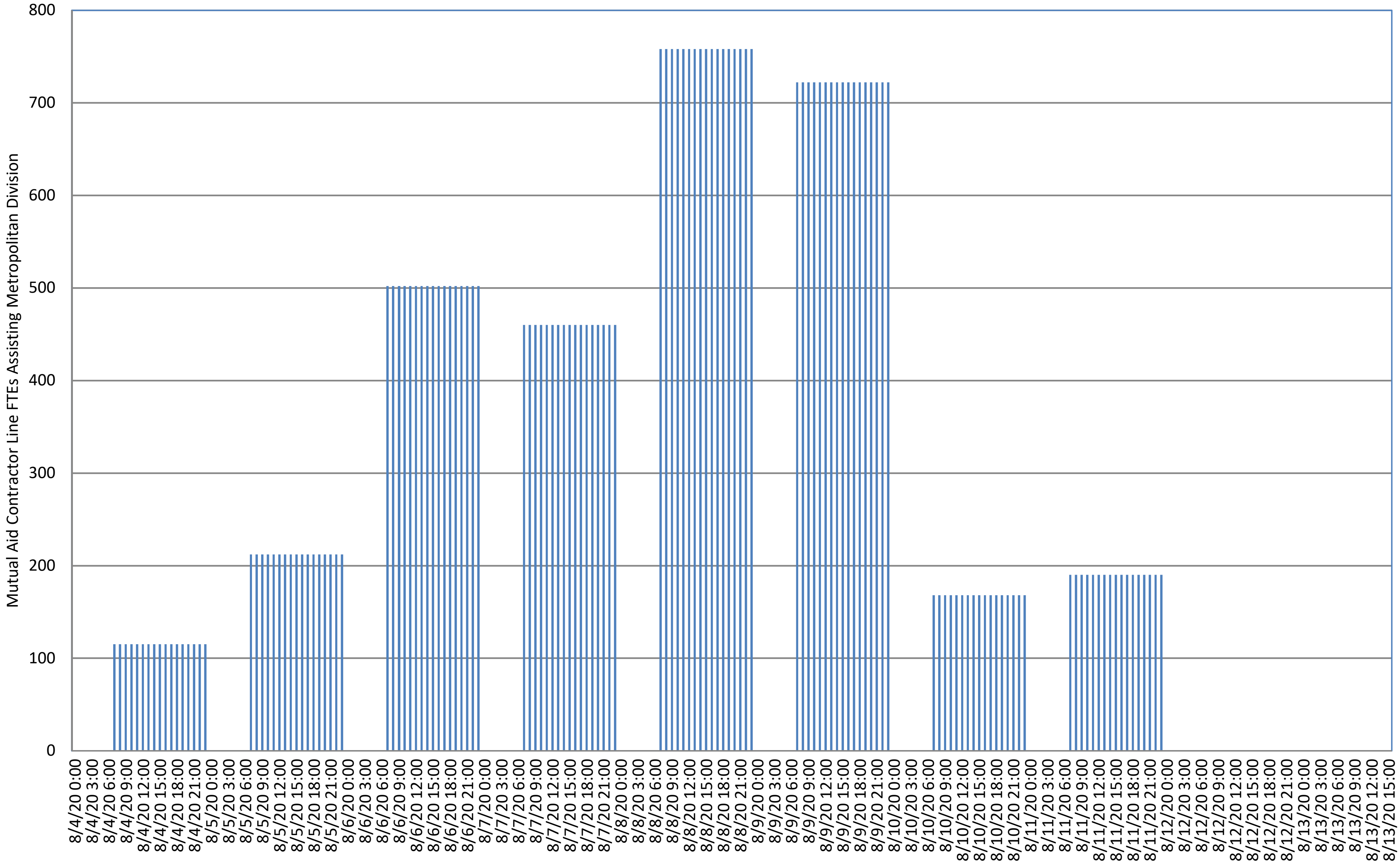


Attachment "M"
PSE&G
Mutual Aid Contractor Line FTEs Assisting Central Division
Tropical StormIsaias, Mutual Aid to PSEG-LI, and State of Emergency - August 4-13,2020



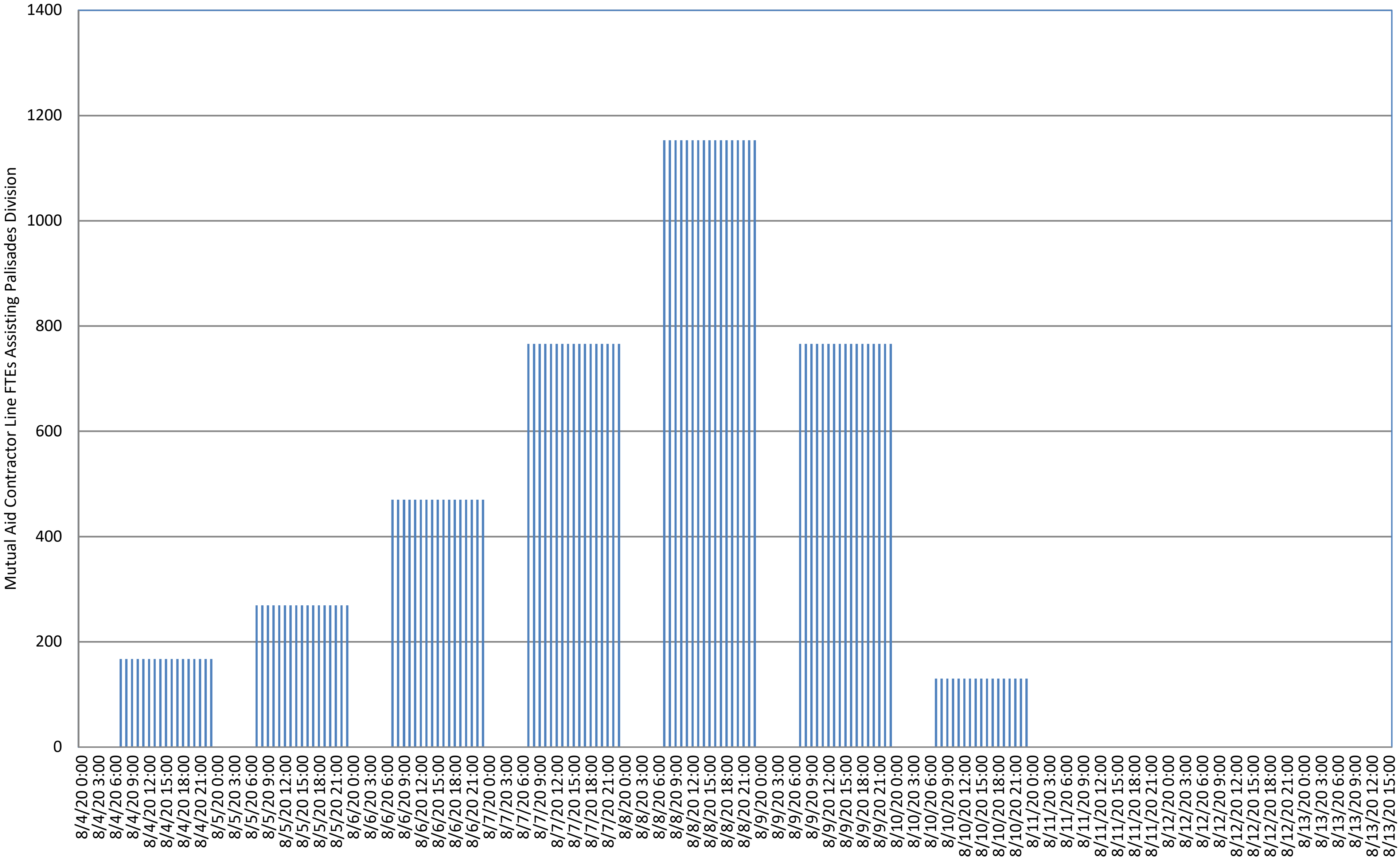
*These values include P&C Workforce Numbers

Attachment "N"
PSE&G
Mutual Aid Contractor Line FTEs Assisting Metropolitan Division
Tropical Storm Isaias, Mutual Aid to PSEG-LI and State of Emergency - August 4-13, 2020



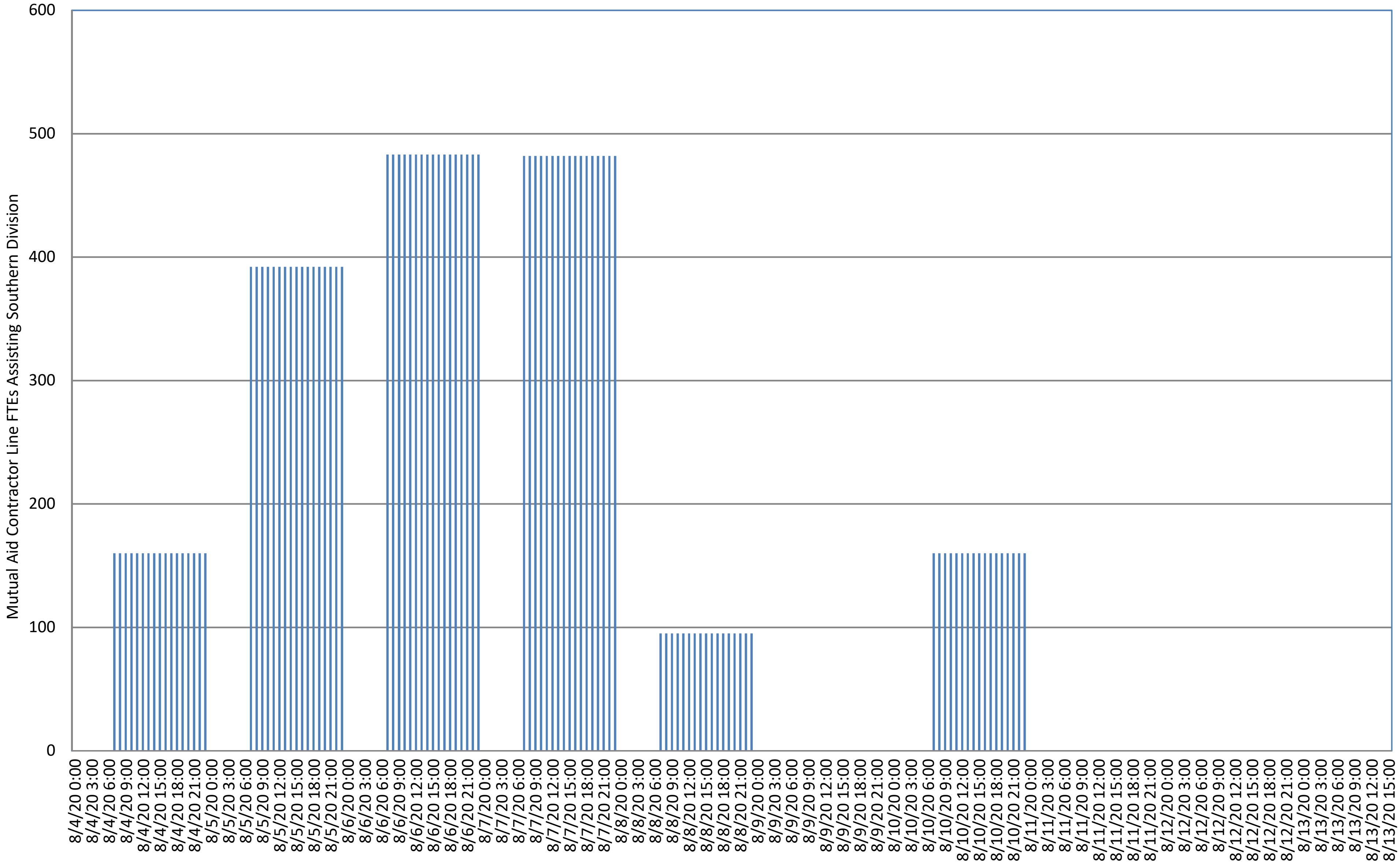
*These values include P&C Workforce Numbers

Attachment "O"
PSE&G
Mutual Aid Contractor Line FTEs Assisting Palisades Division
Tropical Storm Isaias, Mutual Aid to PSEG-LI and State of Emergency - August 4-13, 2020



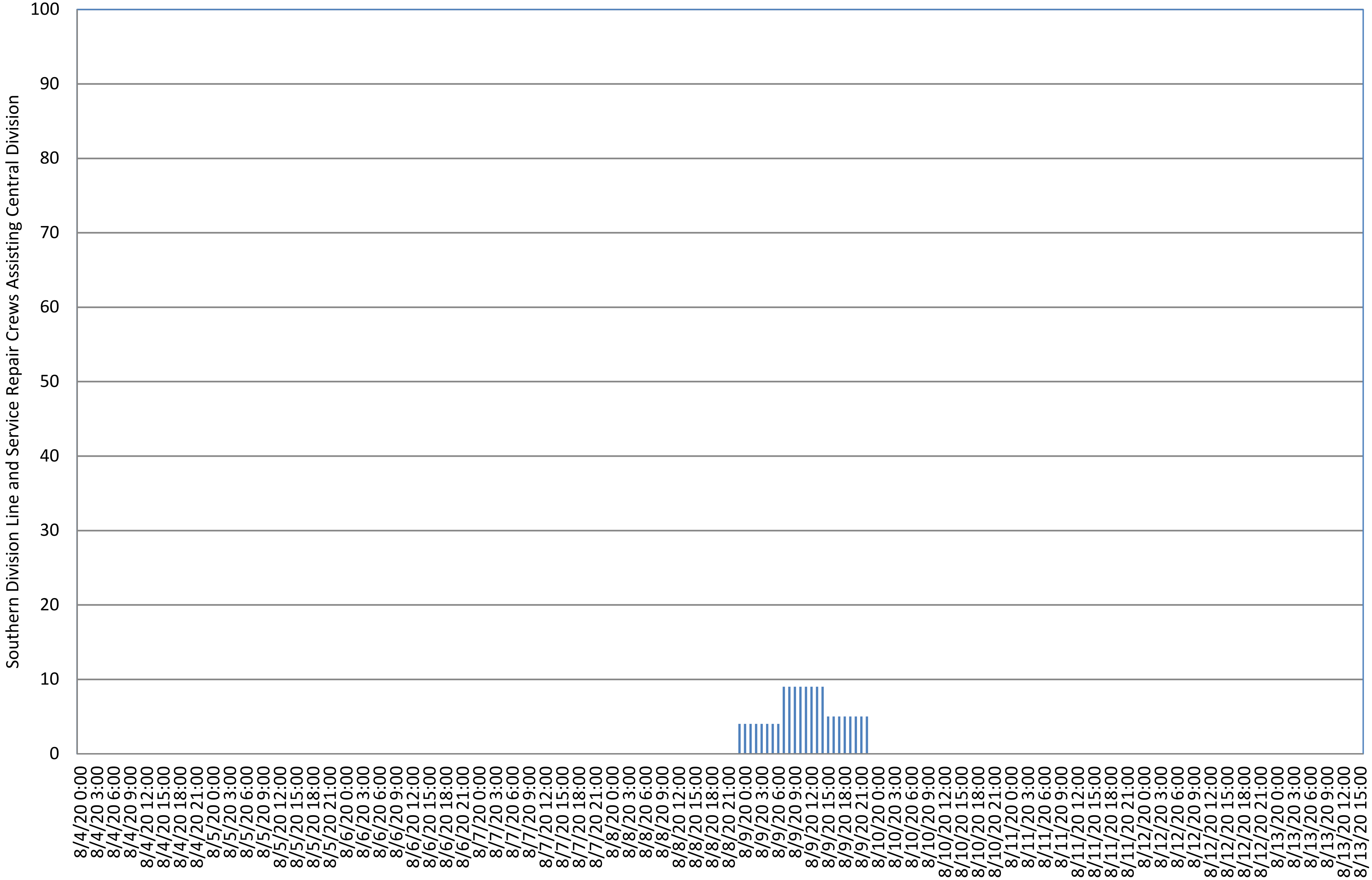
*These values include P&C Workforce Numbers

Attachment "P"
PSE&G
Mutual Aid Contractor Line FTEs Assisting Southern Division
Tropical Storm Isaias, Mutual Aid to PSEG-LI and State of Emergency - August 4-13, 2020

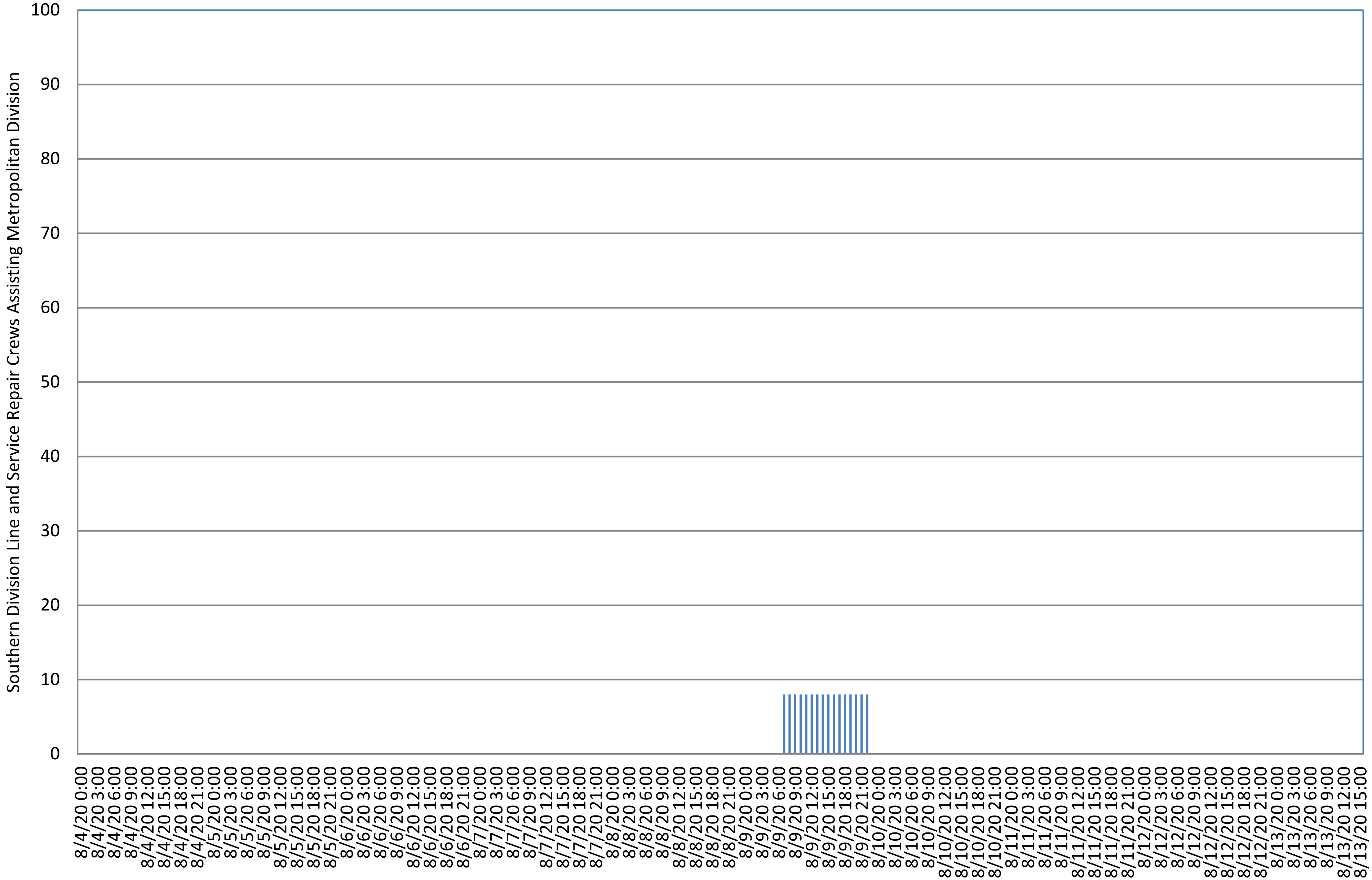


*These values include P&C Workforce Numbers

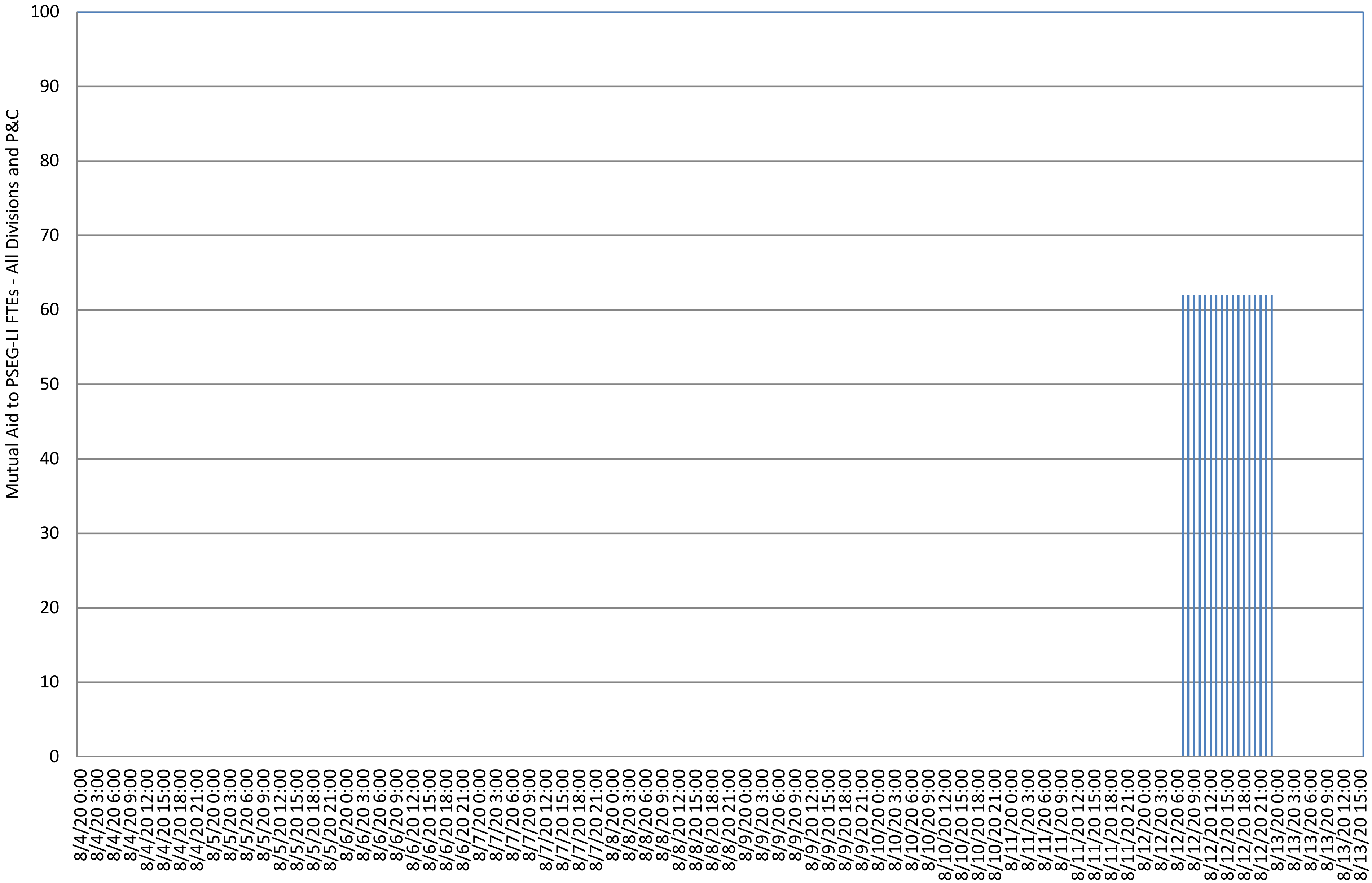
Attachment "Q"
PSE&G
Southern Division Line and Service Repair Crews Assisting Central Division
Tropical Storm Isaias, Mutual Aid to PSEG-LI and State of Emergency - August 4-13, 2020



Attachment "R"
PSE&G
Southern Division Line and Service Repair Crews Assisting Metropolitan Division
Tropical Storm Isaias, Mutual Aid to PSEG-LI and State of Emergency - August 4-13, 2020



Attachment "S"
PSE&G
Mutual Aid to PSEG-LI FTEs - All Divisions and P&C
Tropical Storm Isaias, Mutual Aid to PSEG-LI and State of Emergency - August 4-13, 2020



PSE&G Hearing Statement

Wednesday, August 19, 2020 – 10 am
Zoom Meeting

Joint Meeting of the New Jersey Assembly Telecommunications and Utilities and Assembly Homeland Security and State Preparedness Committees

Good morning Chairpersons Assemblyman DeAngelo and Assemblywoman McKnight, and distinguished committee members. I am David Daly, President and Chief Operating Officer, PSEG Utility & Clean Energy Ventures, on behalf of Public Service Electric and Gas Company (PSE&G). I am joined at this meeting by Kim Hanemann, PSE&G's Senior Vice President and Chief Operating Officer. Thank you for inviting us to speak on behalf of PSE&G at this joint committee meeting regarding our preparation and response to Tropical Storm Isaias.

Introduction

When storms knock out power, it is our job to restore electricity in a timely and safe manner. Thankfully we are not in this alone, and PSE&G appreciates the support we received during the Isaias recovery from government officials, including the Governor's Office, the New Jersey BPU Staff, and the numerous county and municipal officials we work with preparing for and responding to major storm events.

Still, we realize our customers count on PSE&G to respond in storm conditions. We recognize the challenges this storm presented to our customers, and we regret the hardship and inconvenience this event may have caused. Isaias was a particularly destructive tropical storm. As with every storm there is significant work that happens after the last customer is restored, and that work has been on-going since our last customers in New Jersey were restored on August 11, 2020. We have now begun, and over the next several weeks we will complete, an After Action Review (AAR) to evaluate our preparation and restoration performance, and identify strengths as well as areas for improvement. As we have in the past, we will be working closely with the New Jersey Board of Public Utilities to evaluate our storm response, document lessons learned, and continuously improve performance.

In my introductory remarks today I would like to briefly: provide an overview of PSE&G's outage restoration efforts; summarize the preparation and response process, including securing foreign crews in the age of COVID; describe how our transmission and storm hardening distribution system investments fared during Isaias; and acknowledge issues observed with respect to our communications systems.

Tropical Storm Isaias Response Overview

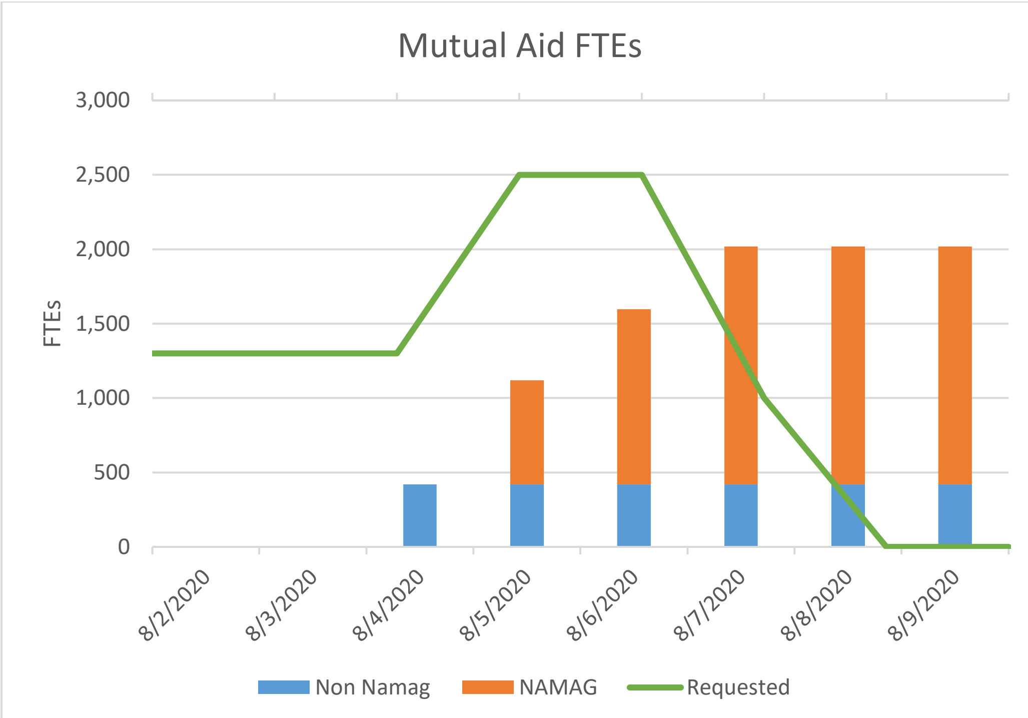
While there are always lessons to be learned, PSE&G believes that the storm preparation and response generally went well. Isaias was an extremely fast-moving tropical storm, and resulted in approximately 575,000 customer outages, with 26,000 jobs to be addressed in PSE&G's service territory. This included work on damaged outside plant facilities such as sub-transmission, primary and secondary conductors, individual services, broken poles and, of course, lots of tree clearing due to the high winds and rain associated with this storm.

The overall numbers are impressive, and reflect the hard work of our dedicated employees, contractors, and other participants in this all-hands-on-deck process. Within 24 hours after the storm hit, 48% of our impacted customers – approximately 276,000 customers -- had been restored. Within 48 hours, the figure was 75%, or approximately 430,000 customers; within 72 hours, 90% of customers who had been out – approximately 517,000 – had been restored. And within 92 hours – just four days – 96% of our affected customers, or approximately 552,000, had been restored.

Storm Preparation – Mutual Aid and COVID Protocols

PSE&G began preparation for Isaias on Thursday, July 30. Since Tropical Storm Isaias was a multi-state event that interrupted more than six million customers across a huge area, there was limited availability of line workers from mutual aid groups, and mutual aid crews were a minimum of 2-3 days travel time away since many of the resources initially secured came from contractors in areas not affected by the hurricane, such as Florida, Nova Scotia and the Midwest. While PSE&G initially requested 300 line workers through the traditional North Atlantic Mutual Assistance Group (NAMAG) process on Friday July 31 and an additional 1,300 FTEs over the weekend, NAMAG resources did not begin to arrive – in smaller numbers than we had requested -- until Tuesday evening, August 2.

Nevertheless, by aggressively reaching out early on to contractors, we were able to obtain 420 FTEs by August 4, allowing work to begin soon after the storm hit. PSE&G continued to secure additional crews throughout the storm and by Saturday August 8, had obtained 2,019 line mutual aid FTEs, and contracted over 200 FTEs for Damage Assessment and 1,000 FTEs for Vegetation Management, with crews arriving from Wisconsin, Louisiana, Maryland, Oklahoma, Indiana, Illinois, Florida, Louisiana, Maryland, Pennsylvania, Iowa, Kentucky, Michigan, Missouri, Alabama, and Nova Scotia. We utilized managers and professionals from across the Enterprise to manage these crucial resources.



A robust multi-dimensional communication and stakeholder engagement plan was planned in advance and implemented for the duration of the storm. In addition to our reoccurring daily media advisory updates designed to keep our customers, elected officials and other critical stakeholders appraised of the ongoing restoration efforts, PSE&G held daily calls with local, state and federal elected officials. Local Offices of Emergency Management were provided with dedicated liaisons as requested. Proactive outreach was initiated to our Life Support (P4) customers. Communications with these customers continued throughout the storm via phone calls regarding updated estimated restoration times.

COVID Impact

Like everything else in our current lives, preparation and response to Isaias was complicated by the continuing pandemic plaguing our nation, particularly in light of the large number of crews from outside of New Jersey required to adequately respond to this event. Well in advance of Isaias, PSE&G had considered this and developed a Storm Pandemic Plan which was implemented for Tropical Storm Isaias, including a set of protocols to be followed by storm crews and a strategy for ensuring those protocols were followed. Independent assessments of the COVID-19 mitigation protocols were conducted at identified field locations on a daily basis by trained observers, who communicated their findings to site leaders and coordinators, and also to PSE&G leadership.

Restoration Performance -- Benefits Of Prior Infrastructure Hardening

PSE&G employs a multi-step process in prioritizing its power restoration efforts. Early in the storm event we establish lists of critical customers (e.g., hospitals, nursing homes, police and fire facilities, customers with life-sustaining equipment) to prioritize those repairs while in parallel prioritizing repairs to transmission lines and substations; our goal is to restore power to the greatest number of customers in the shortest possible time, while prioritizing our most critical customers. For example, we'll make repairs that restore power to 1,000 customers before a repair that would return electricity to 100 customers. Finally, we continue to work 24/7 to restore power to smaller neighborhoods and individual homes or businesses until the power is back for everyone.

On the transmission portion of the system – that is, the higher voltage cables that move power around our service territory -- the news is very good. First, the bulk transmission system (BTS) – including the large "backbone" projects PSE&G has constructed over the past decade, particularly in the years since Superstorm Sandy – held up extremely well. There were only 4 momentary incidents on the BTS which occurred due to flying debris, and there were no transmission-related incidents that resulted in any extended customer outages.

Results were similarly positive for the 69kV portion of the transmission system. In recent years we have been replacing the physically and technologically aging 26kV portion of our system, and upgrading to a modern, networked 69kV system using, generally, larger and stronger poles and stronger circuits. There were very limited problems with the 69kV facilities; only 8,200 customers experienced any type of outage related to our 69kV capital program, and these outages were resolved early in the process, on August 4.

Similarly, the flood mitigation work done beginning in 2014 under the Energy Strong and base capital programs withstood this test. Since this program began we have raised 32 stations, and when storm surge was checked against these stations no precautions were required. This enabled our team to focus on other important preparation activities. The Contingency Reconfiguration program in Energy Strong supported keeping customers in service or reducing outage durations for the 260 critical facilities completed as part of those projects. In addition, the Advanced Technology investments approved by the Board and executed by PSE&G in the Energy Strong effort performed well. Energy Strong upgrades to SCADA and station relaying allowed for remote operation and set-up for work in support of mutual aid, as designed. In other words, this investment enabled PSE&G to remotely operate our system so workers could safely repair and replace damaged infrastructure. Without this investment, we would have had to send workers to substations to operate station breakers to allow workers to work safely. Based on the Energy Strong projects, PSE&G was able to immediately identify issues on over 300 circuits and utilized the remote capabilities to support circuit restoration; during the peak of the restoration effort (August 6 to August 8), PSE&G successfully restored each day more than 1,300 outage incidents, each affecting multiple customers.

Also with regard to infrastructure improvement, I note that the type of outside plant work that PSE&G has unsuccessfully sought approval for in its Energy Strong requests could have, if implemented in a widespread manner, further reduced the damage and outage impacts of Isaias. This includes modern spacer cable configurations and pole upgrades for overhead distribution circuits, that would move the utility away from traditional, more vulnerable, cross-arm construction. This construction is more resistant to tree damage, which is the primary cause of outages in extreme weather events.

Putting aside our improved infrastructure itself, other aspects of the storm response also went well. Critical material such as poles, transformers, cable and wire was available from key suppliers per their contractual requirements. Improved communication between Staging Areas – which are like "mini-headquarters" for the response efforts -- and Mutual Aid Coordinators increased our efficiency. As we have in the past, PSE&G established several comfort stations throughout the service territory to supply ice and water to impacted customers.

Finally, tree outages are typically the leading cause of outages in a major event and this storm was no different. PSE&G has maintained a four year cycle for our vegetation management program in accordance with New Jersey Administrative Code requirements, including the removal of overhanging vegetation in the lock-out zone. To potentially improve our program we are piloting different mapping technologies to find encroachments outside of the program cycle as well. We are open to any discussion the Board may want to consider to enhance its vegetation management regulations intended to reduce outages during extreme weather events.

Communications And OMS

Through our elected official calls we learned that customers felt our automated communications that are generated from the Outage Management System required improvement. Currently, we do not know if an individual customer has power, and must rely on our Outage Management System (OMS) to evaluate individual customer circumstances. The OMS uses a number of criteria to drive messages to our customers. Unfortunately without knowing if the customer has power, the system makes assumptions and sends multiple messages regarding the status of power and estimated time to restore. The current system is not equipped with an advanced two-way information network, including smart meters at customer homes, capable of assessing remotely, and at frequent intervals, whether there is service interruption.

The PSE&G OMS issues experienced during the storm, we believe, led to very heavy call center volume. During normal non-storm conditions, for 2020, our call centers average approximately 260,406 agent handled calls per month. On the first day of the storm, the call center received more than a month's worth of calls -- 351,230 -- and answered 330,696 (308,263 with technology and 22,263 by Agents). Over the course of the storm we handled 635,128 calls (530,557 with technology and 104,571 by Agents).

Customers trying to communicate with us, particularly on the first day of the storm, were very challenged, and PSE&G recognizes that this is an area for follow-up and improvement. Better real-time outage information at a customer premise – which will be easily available after the implementation of AMI throughout our service territory -- would help customer communications drastically and also make the storm restoration process more efficient. Currently, to determine if a single customer has power, we have to physically visit the premise, call the customer, or rely on the customer to call us. In the last two days of a storm, when the majority of our efforts are focused on single service outages, the restoration effort would be much more efficient if the Company knew which customers were off-line. Customer-level outage data made available through AMI would reduce physical site visits and customer phone calls, improve system outage modeling, and reduce the time it takes to restore customers.

Next Steps

We are well aware that we cannot rest upon past successes, and that despite our very best efforts in this storm, there is always room for improvement. As I noted at the outset, we are conducting a thorough internal review to determine what went right, what went wrong, and why.

We also recognize that we're not in this alone -- the findings, observations, and recommendations from various stakeholders across New Jersey provide an opportunity for effecting improvements to benefit customers. Our Senior Leadership Team, and all of our local, caring, and dedicated employees, are committed to cooperating and collaborating with the Legislature , as well as the Board of Public Utilities, and other stakeholders, on implementing recommendations that will improve and enhance our storm response and restoration process.

Thank you very much for your time.

		8/4 Storm Electric Delivery Capital Expenditures (CapEx)	O&M Expenses	CapEx + O&M Expenses	Incremental O&M Expenses
1	Total Labor	**6,161,739**	**20,966,975**	**27,128,713**	**10,221,019**
2	Contractor/Mutual Aid	23,340,682	46,676,688	70,017,370	46,676,688
3	Tree Removal	3,045,794	8,645,999	11,691,794	8,645,999
4	Buses	-	-	-	-
5	Other Contractor	3,325,313	3,824,478	7,149,792	3,824,478
	Total Contractor	**29,711,790**	**59,147,166**	**88,858,955**	**59,147,166**
6	Material	**5,301,618**	**225,030**	**5,526,648**	**198,757**
7	Food	288,643	797,822	1,086,465	797,822
8	Lodging	489,111	1,384,101	1,873,212	1,384,101
9	Security	-	1,463	1,463	1,463
10	Water and Ice	-	566,932	566,932	566,932
14	Email Alerts	-	35,789	35,789	35,789
11	Other	154,611	444,768	599,379	21,948
	Total Other	**932,365**	**3,230,874**	**4,163,238**	**2,808,054**
	Total Incurred	**42,107,511**	**83,570,044**	**125,677,555**	**72,374,996**
12	O&M Base Rate Storm Costs	-	-	-	-
	Total	**42,107,511**	**83,570,044**	**125,677,555**	**72,374,996**

Matthew M. Weissman
Managing Counsel - State Regulatory

Law Department
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email: Matthew.Weissman@pseg.com

PSEG
Services Corporation

October 20, 2021

VIA ELECTRONIC MAIL ONLY

J. B. Cuartas, Director
Division of Reliability and Security
New Jersey Board of Public Utilities
225 East State Street - 2nd Floor, Area 2W
Trenton, New Jersey 08625

RE: MAJOR EVENT REPORT
STATE OF EMERGENCY - REMNANTS OF HURRICANE IDA - FLOODING
LOAD SHEDDING - EAST ORANGE
SEPTEMBER 1 - 28, 2021

Dear Director Cuartas:

As required by 14:5-8.8 Major Event Report, enclosed is a copy of PSE&G's Major Event Report for the State of Emergency – Remnants of Hurricane Ida - Flooding - Load Shedding - East Orange that affected PSE&G's entire service territory from September 1 - 28, 2021.

Questions concerning this matter can be directed to me or Donald W. Weyant, Manager - Regulatory Compliance at (973) 430-6730.

Very truly yours,

Matthew Weissman

Matthew M. Weissman

Attachments

C (Email Only)
Joseph Fiordaliso, President
Upendra Chivukula, Commissioner
Bob Gordon, Commissioner
Mary-Anna Holden, Commissioner
Dianne Solomon, Commissioner
Paul Lupo, Acting Director

PSE&G'S REPORT TO THE BPU
MAJOR EVENT
STATE OF EMERGENCY - REMNANTS OF HURRICANE IDA
FLOODING - LOAD SHEDDING - EAST ORANGE
SEPTEMBER 1 - SEPTEMBER 28, 2021

EXECUTIVE SUMMARY

During the morning of September 1, 2021, PSE&G's entire service territory was affected by the remnants of Hurricane Ida. This weather system brought torrential rain to the state, which caused Governor Phil Murphy to declare a State of Emergency (SOE) at 2100 hrs. that evening. Heavy rains continued to fall over PSE&G's service territory, and the rest of the state, during the following three weeks. On September 28, after reviewing weather forecasts from PSE&G's private weather forecasters for the rest of the week, which did not predict any further heavy rain, PSE&G felt it was prudent to end this Major Event Report at 0800 hrs. on September 28, even though the SOE was still in effect. There were 215,192 customers that experienced extended interruptions during this event with 105,722 being interrupted on September 1 and 2 during the direct impact of the remnants of Hurricane Ida. PSE&G restored 99% of those customers within 48 hours.

PSE&G began preparing for this event on August 29, when a request for resource availability was received from the North Atlantic Mutual Assistance Group (NAMAG). The Southeastern Electric Exchange (SEE) was requesting assistance for southern utilities in anticipation of Hurricane Ida. On August 30, PSE&G decided not to release any PSE&G or contractor line FTES due to the predicted impact on PSE&G's service territory later that week. In addition, PSE&G personnel began to review the 72/48/24 hour storm preparation lists.

During PSE&G's 0800 hrs. daily operations call on September 1, PSE&G's weather forecaster predicted that the full impact of the remnants of Hurricane Ida would affect PSE&G service territory during that afternoon. At that time, PSE&G scheduled additional 1300 hrs. and 1900 hrs. conference calls for later that day and for succeeding days. In addition a 0830 hrs. staffing call was scheduled. Representatives from Electric Delivery's General Office Staff, the four operating divisions, Projects & Construction (P&C), the Electric System Operations Center along with personnel from other operating and staff departments of the Company were involved on this call as well as subsequent calls of this nature.

During the 0830 hrs. staffing call, it was decided to schedule Electric Delivery personnel on a 2 / 3 - 1 / 3 schedule beginning at 1500 hrs. that day. Two thirds of the work force would work the 0700 – 2300 shifts while one third would work the 2300 – 1500 shifts. In addition, arrangements were made to patrol substations that are prone to flooding and to review the Stevens Institute of Technology flood model.

PSE&G was also able to move overhead line crews, underground crews and service repair crews between divisions between September 2 - 7 to address restoration efforts. These crew movements are included on the identified work force graphs. Damage assessors where also assigned to assist other divisions.

PSE&G opened its Emergency Operations Center (EOC) on the afternoon of August 29. It remained open in either virtual or fully activated mode until 1930 hrs. on September 3. This was the only time during these events that it had to be activated.

Communications with 12 County Offices of Emergency Management (OEM) and the City of Newark's Emergency Management Center began on September 1. Liaison support provided was remote and continued until the OEMs closed. However, the Bergen County OEM requested in-person support on September 2 from 1000 - 1730 hrs. which was provided.

Conference calls with mayors and other municipal and elected officials were held on September 1, 2 and 3 concerning storm restoration efforts. Members of the Regional Public Affairs (RPA) Department organized the calls and participated in them, as did the Senior Directors and other personnel from each of the four operating divisions.

Communications with Board staff began on August 31 and continued until September 28.

OPERATING REPORT

There were 215,192 customers that experienced extended interruptions during these events as listed below:

Division	# Customers Interrupted 9/1 - 9/2	Restoration	# Customers Interrupted 9/3 - 9/28	Final Restoration
Central	14,781	2225 - 9/3	17,113	0535 - 9/28
Metropolitan	55,780	1510 - 9/4	27,955	0718 - 9/28
Palisades	11,036	0751 - 9/4	28,567	0741 - 9/28
Southern	24,125	1407 - 9/4	35,835	0800 - 9/28
	105,722		109,470	
Grand Total	215,192			

Attached are the following Customer Restoration Summary Graphs for these events:

Attachment “A” - Company Wide
Attachment “B” - Central Division
Attachment “C” - Metropolitan Division
Attachment “D” - Palisades Division
Attachment “E” - Southern Division

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Communications with Board staff began on August 31 and continued until September 28.

PERSONNEL DEPLOYMENT

Attached are the following Work Force Graphs for these events:

Attachment "F" - Overhead Line Crews, Service Repair Crews and Troubleshooters - Company
Attachment "G" - Overhead Line Crews, Service Repair Crews and Troubleshooters - Central Division
Attachment "H" - Overhead Line Crews, Underground Crews, Service Repair Crews and Troubleshooters – Metropolitan Division
Attachment "I" - Overhead Line Crews, Service Repair Crews and Troubleshooters - Palisades Division
Attachment "J" - Overhead Line Crews, Service Repair Crews and Troubleshooters - Southern Division
Attachment "K" - Contractor Tree Crews - Company
Attachment "L" - Central Division Underground Crews Assisting Metropolitan Division
Attachment "M" - Palisades Division Underground Crews Assisting Metropolitan Division
Attachment "N" - Southern Division Overhead Line, Underground Crews and Service Repairs Crews Assisting Central Division.
Attachment "O" - Southern Division Overhead Line, Underground Crews and Service Repair Crews Assisting Metropolitan Division
Attachment "P" - Mutual Aid Contractor Line FTEs Assisting Palisades Division
Attachment "Q" - Mutual Aid Contractor Line FTEs Assisting Metropolitan Division

A staging area for the Mutual Aid crews was established at the former Toys R Us site in Wayne.

As is standard operating procedure in system emergencies, liaison support to each of the four operating divisions was provided beginning on September 1. This remote support continued until September 3. Remote liaison support was provided to the two Inquiry Centers. These liaisons assisted in addressing customer inquiries.

Communications with 12 County Officers of Emergency Management (OEM) and the City of Newark's Emergency Management Center began on September 1. Liaison Support provided was remote and continued until the OEMs closed. However, the Bergen County OEM requested in-person support on September 2, from 1000 - 1730 hrs. which was provided.

TROUBLE LOCATIONS AND CLASSIFICATIONS

Outside plant damage locations are listed below:

69 & 26-kV	- 37
13 & 4-kV	- 596
Transformers	- 155
Secondaries	- 62
Services	- 247
Poles	- 197
Trees	- 234
Total	1,528

COMMUNICATIONS

Communications with Board staff began on August 31 and continued until September 28.

PSE&G's Corporate Communications Department issued internal communication press releases and handled newspaper, television and radio information requests during these events.

PSE&G proactively utilized Social Media (Facebook, Twitter and LinkedIn) to communicate storm restoration information to customers during this event releasing 44 different messages. In addition, more than 1.6 million emails were sent to customers during this event informing them of storm restoration progress.

As required in Recommendation 3 from the Tropical Storm Isaias Board Order, the following standardized Call Center information is provided:

Date	Number of calls Offered (NCO)	Number of calls Handled (NCH)	Number of calls Abandoned (NCA)	Call Abandonment Rate (CA%)	Average Speed of Answer (ASA)
9/1/2021	33742	31487	2255	6.7%	56
9/2/2021	39762	36807	2955	7.4%	121
9/3/2021	33670	30191	3479	10.3%	230
9/4/2021	14997	14182	815	5.4%	88
9/5/2021	8911	8573	338	3.8%	47
9/6/2021	12250	11697	553	4.5%	92
9/7/2021	39076	35684	3392	8.7%	231
9/8/2021	26759	25172	1587	5.9%	114
9/9/2021	26116	25518	598	2.3%	27
9/10/2021	22742	22375	367	1.6%	16
9/11/2021	8863	8614	249	2.8%	46
9/12/2021	5472	5418	54	1.0%	5
9/13/2021	33477	30859	2618	7.8%	222
9/14/2021	24670	24128	542	2.2%	39
9/15/2021	25075	24086	989	3.9%	91
9/16/2021	21894	21110	784	3.6%	74
9/17/2021	20572	20092	480	2.3%	38
9/18/2021	8102	8020	82	1.0%	11
9/19/2021	4798	4759	39	0.8%	5
9/20/2021	26680	25120	1560	5.8%	156
9/21/2021	20394	19903	491	2.4%	40
9/22/2021	19439	19092	347	1.8%	32
9/23/2021	21445	21180	265	1.2%	10
9/24/2021	19257	18970	287	1.5%	17
9/25/2021	7162	7049	113	1.6%	18
9/26/2021	4911	4876	35	0.7%	6
9/27/2021	24935	23955	980	3.9%	107
9/28/2021	19404	19122	282	1.5%	23

A notification to PSE&G's critical needs (P-4) customers was issued on August 31 informing them of the impending storm and recommending precautions they should take. This information was also included in outbound calls made with Estimated Times of Restoration (ETRs).

Conference calls with mayors and other municipal and elected officials were held on September 1, 2 and 3 concerning storm restoration efforts. Members of the Regional Public Affairs (RPA) Department organized the calls and participated in them as did the Senior Directors and other personnel from each of the four operating divisions.

A North Atlantic Mutual Assistance Group (NAMAG) conference call was held on September 2 at 1030 hrs. PSE&G requested 100 FTEs but none were secured.

On September 3, PSE&G was able to secure 73 Contractor Line FTEs. They arrived at various times on September 3 and were released at 0700 hrs. on September 4. In addition, PSE&G utilized 41 Contractor Line FTEs already on the property.

INCIDENTS

Robert Wood Johnson University Hospital, Rahway

The hospital's service was interrupted on September 1 at 2051 hrs. The hospital does not have a back-up feed and transferred to their emergency generation. Investigation revealed that the outage was caused by a problem in the customer's electrical system. Once repairs were made by the customer, service was restored at 0930 hrs. on September 2.

NJ American Water - Island Farm, Bridgewater

This customer's 26-kV substation was interrupted on September 2, at 0910 hrs. when the main feed to the station, the K-89 locked out. The station did not transfer to the station's backup feed, the J-114. The K-89 was patrolled and no trouble was found. There was no access to the station due to flooding. Finally on September 3, the station was accessible and it was found that the K-89's motor operated disconnects failed to open due to a wiring problem, which is the customer's responsibility to repair. At 0700 hrs. that day, service was restored to the station by way of the J-114.

ROIC, Ewing

At 1653 hrs. on September 1, lightning burned down "B" phase on the ROIC's main supply circuit, LCE 8003, causing a part power condition at the facility. ROIC officials did not want to transfer to their back-up circuit, FEN 8041. They decided instead to remain on their emergency generation until LCE 8003 could be restored. PSE&G made repairs to LCE 8003 and the circuit was restored at 2251 hrs. that day.

Flooding

As a result of the flooding caused by the torrential rains associated with the remnants of Hurricane Ida, PSE&G had to disconnect electric service to customers in each of its four operating divisions as follows:

Central Division	-	1,325
Metropolitan Division	-	12
Palisades Division	-	69
Southern Division	-	14
Total	-	1,420

Services either have been reconnected or will be re-connected pending the appropriate municipal approvals.

As a result of its Energy Strong 1 Program, PSE&G raised or rebuilt facilities at 26 switching stations and substations that were impacted by Super Storm Sandy. Although water did enter eight of these substations, none of the 26 switching stations or substations where facilities were raised or rebuilt where interrupted by the floodwaters associated with the remnants of Hurricane Ida. In addition, seven substations affected by Super Storm Sandy have been eliminated.

Deptford / Woodbury Heights - Severe Wind Damage

During the early evening on September 1, severe winds struck seven areas of Deptford and Woodbury Heights causing extensive damage to PSE&G's overhead facilities. While the National Oceanic and Atmospheric Administration (NOAA) determined that the damage was not caused by a tornado, three tornadoes were verified in this general area. The most extensive damage occurred on Tanyard Road, Barlow Avenue, Willis Avenue and Logan Avenue in Deptford and on Glassboro Road, Lake Avenue and Walnut Avenue in Woodbury Heights.

Approximately 1,300 customers were interrupted at 1831 hrs. when the two circuits serving these areas, Deptford 8041 and Thorofare 8023, locked out. Over the next three days, a total of five line crews and approximately 25 tree crews worked in these areas restoring service. Approximately 4,500' of primary conductors, 20 poles, 20 pole top transformers and multiple house services were replaced. The final customer was restored on September 4 at 1407 hrs.

Central Avenue and Fifteenth Street Substations

At 2018 hrs. on September 1, Central Avenue and Fifteenth Street Substations in Newark were shut down interrupting 21,481 customers extendedly. Investigation revealed that water leaked through the roof of Central Avenue Substation on to the station's 26-kV bus causing a fault which shut the station down including the 26-kV feed to Fifteenth Street Substation.

After clearing the faulted equipment, Central Avenue Substation and Fifteenth Street Substation were restored to service at 2146 hrs.

Temporary repairs were made to the roof of Central Avenue Substation and a roofing contractor will make permanent repairs.

LOAD SHEDDING - EAST ORANGE - SEPTEMBER 1 - 2, 2021

EXECUTIVE SUMMARY

On September 1 at 2305 hrs., PSE&G had to manually shed load in a portion of East Orange by intentionally cutting out 4-kV circuit East Orange (EAO) 4020, interrupting 3,849 customers. That circuit is part of a three circuit network which also includes EAO 4004 and EAO 4025.

At 2023 hrs. on September 1, EAO 4004 locked out and at 2237 hrs., EAO 4025 locked out. PSE&G immediately began to monitor the load on EAO 4020. At 2305 hrs., PSE&G cut the circuit out before it exceeded its Summer Emergency Rating.

PSE&G immediately began to fault locate the underground failures on EAO 4004, EAO 4025 and EAO 4020. Three oil filled cutouts on EAO 4004 failed in a manhole in front of 256 Halstead Street, East Orange. An underground transformer failed on EAO 4025 in front of 50 South Munn Avenue, East Orange. An underground transformer failed on EAO 4020 on Halstead Street n/o Elmwood Avenue, East Orange.

After repairs were made to the failed equipment, EAO 4004 and EAO 4025 were energized at 2215 hrs. on September 2, restoring all 3,849 customers in the network to service. EAO 4020 was energized at 2231 hrs. restoring all three circuits in the network and putting the network back in normal operation.

Board staff was notified of this event on the morning of September 2 and notifications continued until September 3.

OPERATING REPORT

Extended customer interruptions and restoration times during this load shedding event are as follows:

Circuit	Time Out	Time Restored
EAO 4004	2023 - 9/1	2215 - 9/2
EAO 4025	2237 - 9/1	2315 - 9/2
EAO 4020*	2305 - 9/1	2231 - 9/2

*All 3,849 customers were interrupted when EAO 4020 was cut out at 2305 hrs. on September 1. All the customers were restored when EAO 4020 and EAO 4025 were cut in at 2215 hrs. on September 2. The customers are included in the Company and Metropolitan Division Customer Restoration Graphs.

PERSONNEL DEPLOYMENT

Personnel from various Metropolitan Division Departments were involved in this load shedding event and are included in the Company and Metropolitan Division work force graphs.

TROUBLE LOCATIONS

Underground oil filled cutouts - 1
Underground Transformers - 2

COMMUNICATIONS

A Regional Public Affairs Manager contacted the East Orange Chief of Staff on September 1 and this contact was maintained during this event.

PSE&G opened a customer care water and ice station for East Orange residents on September 3 at the East Orange City Hall.

SUMMARY

PSE&G promptly responded to this load shedding event. Once the second circuit in the network failed, the load on EAO 4020 was monitored and the circuit was cut out before it reached its Summer Emergency Rating.

There were no issues involving material or equipment during this load shedding event.

This load shedding event qualifies as a Major Event since this was action taken to maintain the adequacy on security of the electric system, including emergency load control and emergency switching.

UNDERGROUND CIRCUIT FAILURES - METROPOLITAN DIVISION

The severe flooding in Metropolitan Division associated with the remnants of Hurricane Ida caused an extraordinary amount of conventional underground circuit failures. There were 37 separate circuit failures that occurred during this event. Underground crews from Central, Palisades and Southern Divisions and underground crews from P&C were able to assist Metropolitan Division with fault locating and repair work. These forces are included in the respective work force graphs.

SUMMARY

Restoration efforts during these events went extremely well. PSE&G was well prepared to address the outages caused by the remnants of Hurricane Ida. During the direct impact of the remnants of Hurricane Ida on September 1 and 2, 105,722 customers experienced extended interruptions. PSE&G was able to restore service to 99% of these customers within 48 hours. There were 215,192 customers that experienced extended interruptions during these events, which ended on September 28.

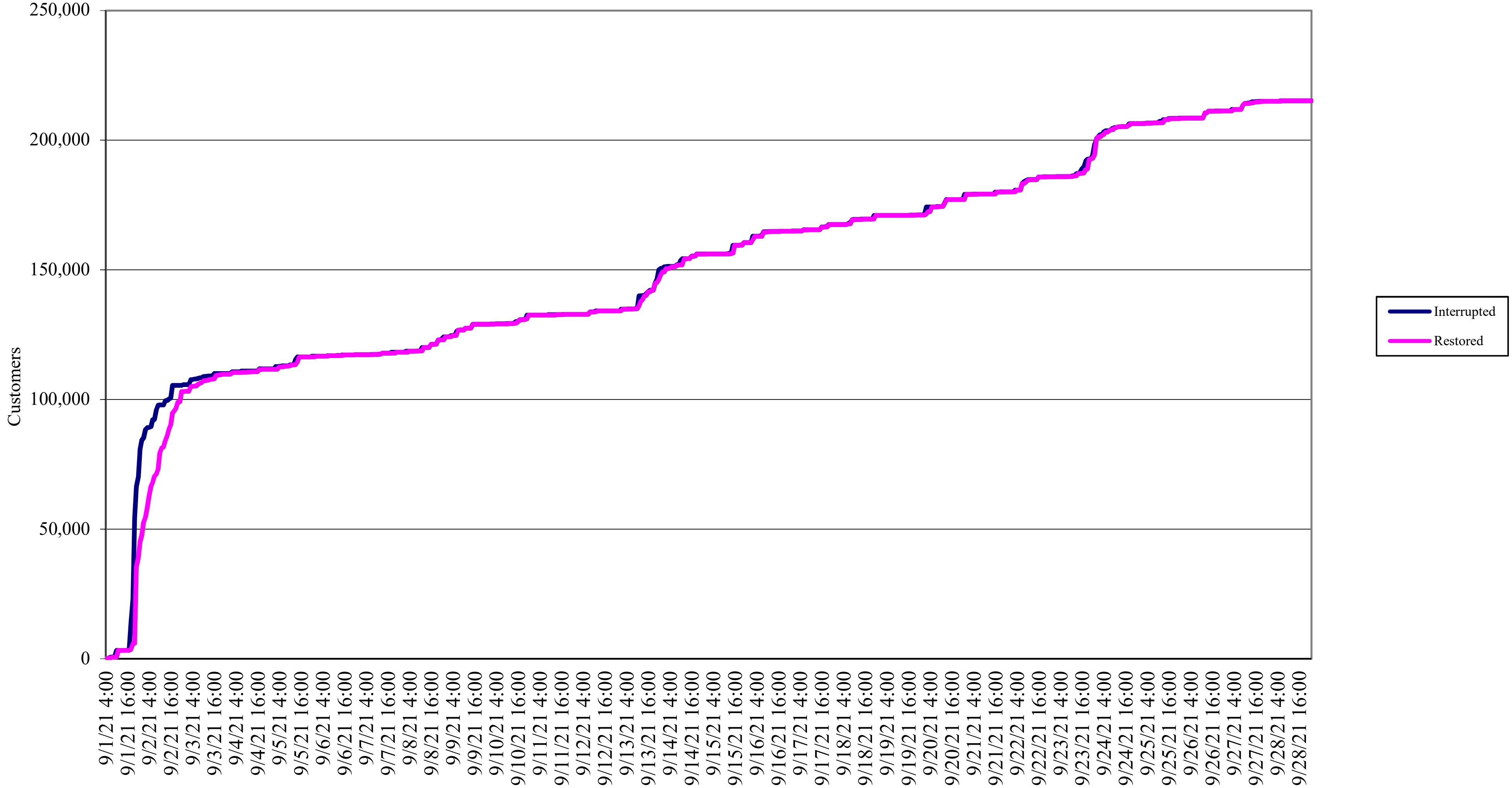
PSE&G's excellent relationships with its unions were beneficial during these events.

There were no issues involving equipment or material during these events.

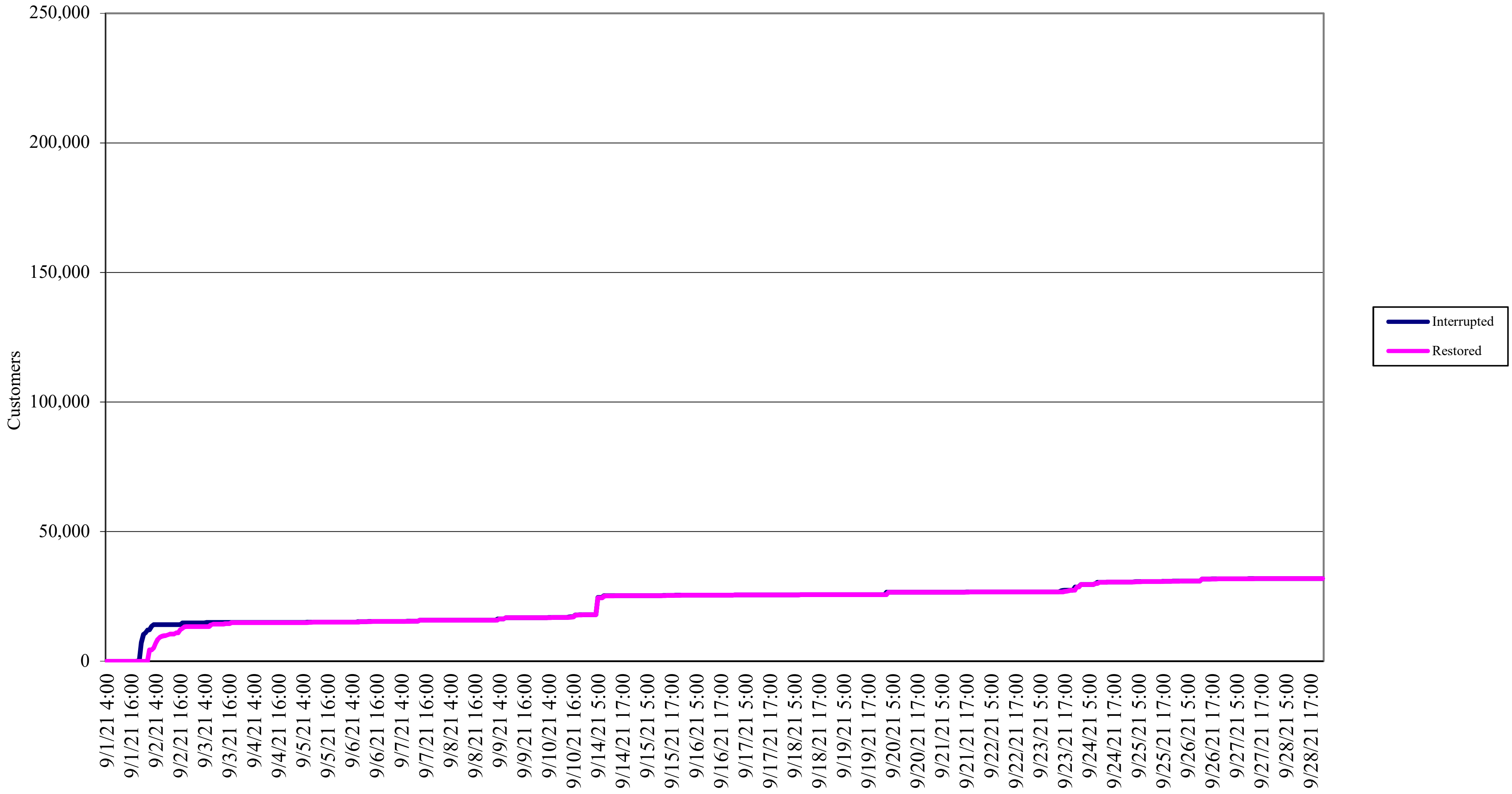
As required in Recommendation 11 from the Tropical Storm Isaias Board Order, a review of past storms revealed that this event was somewhat similar to the remnants of Tropical Storm Lee that affected PSE&G's service territory during the period September 4 - 12, 2021 when 100,022 customers experienced extended interruptions. The resiliency projects completed in PSE&G's Energy Strong I program and those that are currently underway in PSE&G's Energy Strong II program all contribute to improved reliability both during blue sky days and during Major Events. Comprehensive, comparison resiliency data involving Major Events is reported quarterly by PSE&G to the Independent Monitor as part of PSE&G's Energy Strong II Program, as it was during the Energy Strong I Program. The data referencing this event during the period September 1 - 28, 2021 will be submitted in PSE&G's Third Quarter 2021 Energy Strong II Program Report.

DWW: bmc
10/14/21

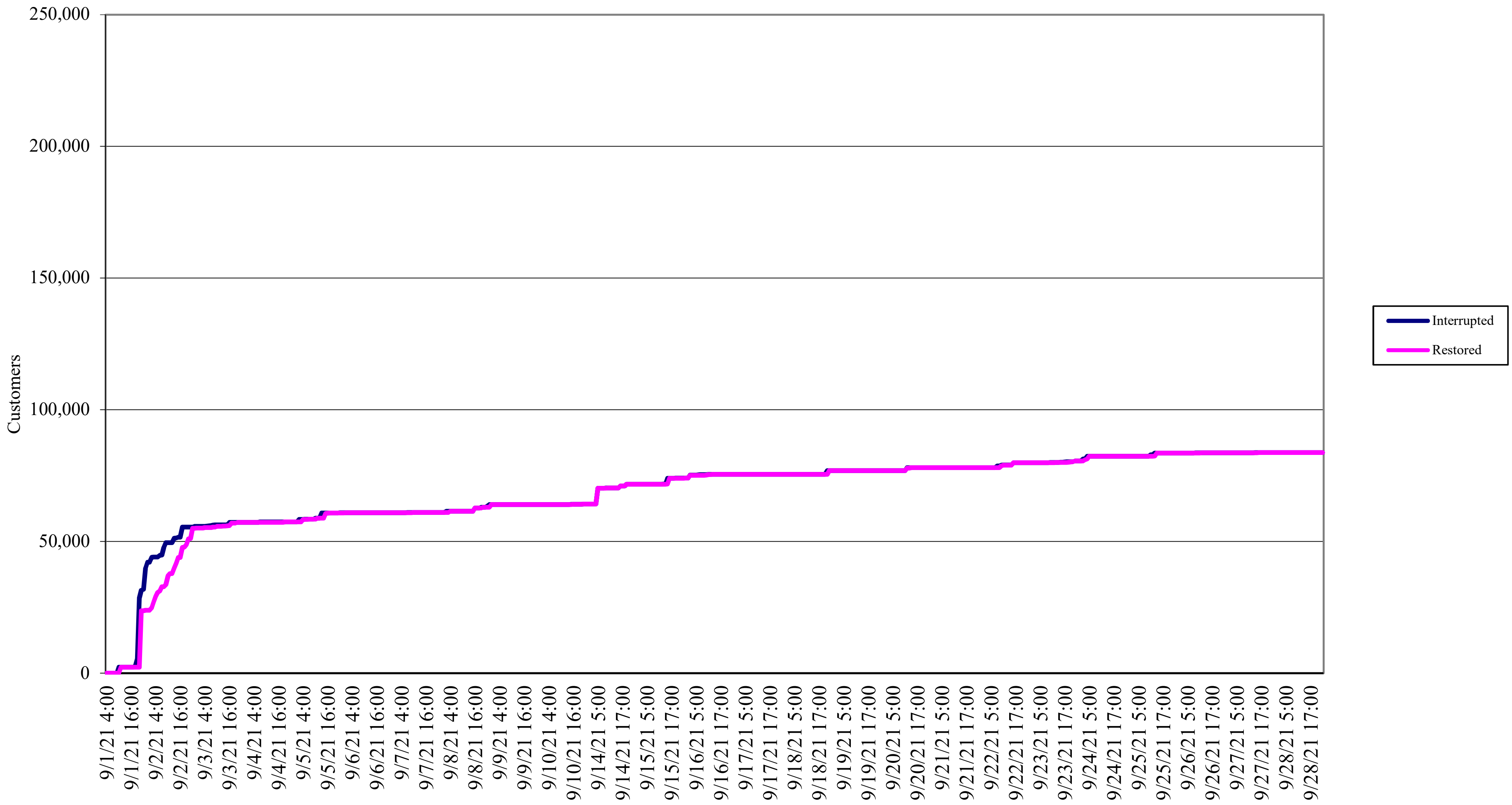
Attachment "A"
PSE&G
Customer Restoration Summary
State of Emergency - Remnants of Hurricane Ida – Flooding – Load Shedding – East Orange
September 1 - September 28, 2021
Company Wide



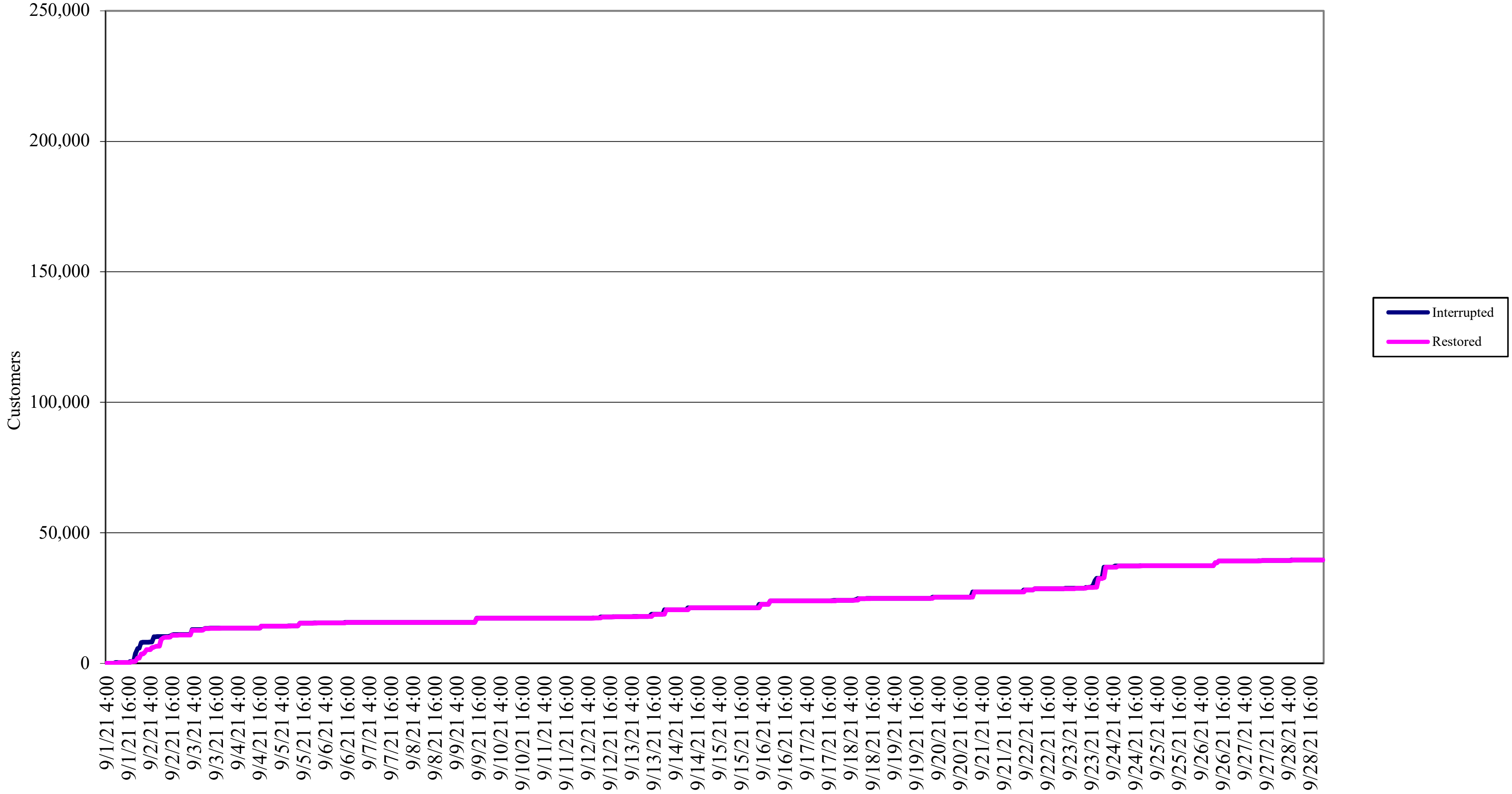
Attachment "B"
PSE&G
Customer Restoration Summary
State of Emergency - Remnants of Hurricane Ida – Flooding – Load Shedding – East Orange
September 1 - September 28, 2021
Central Division



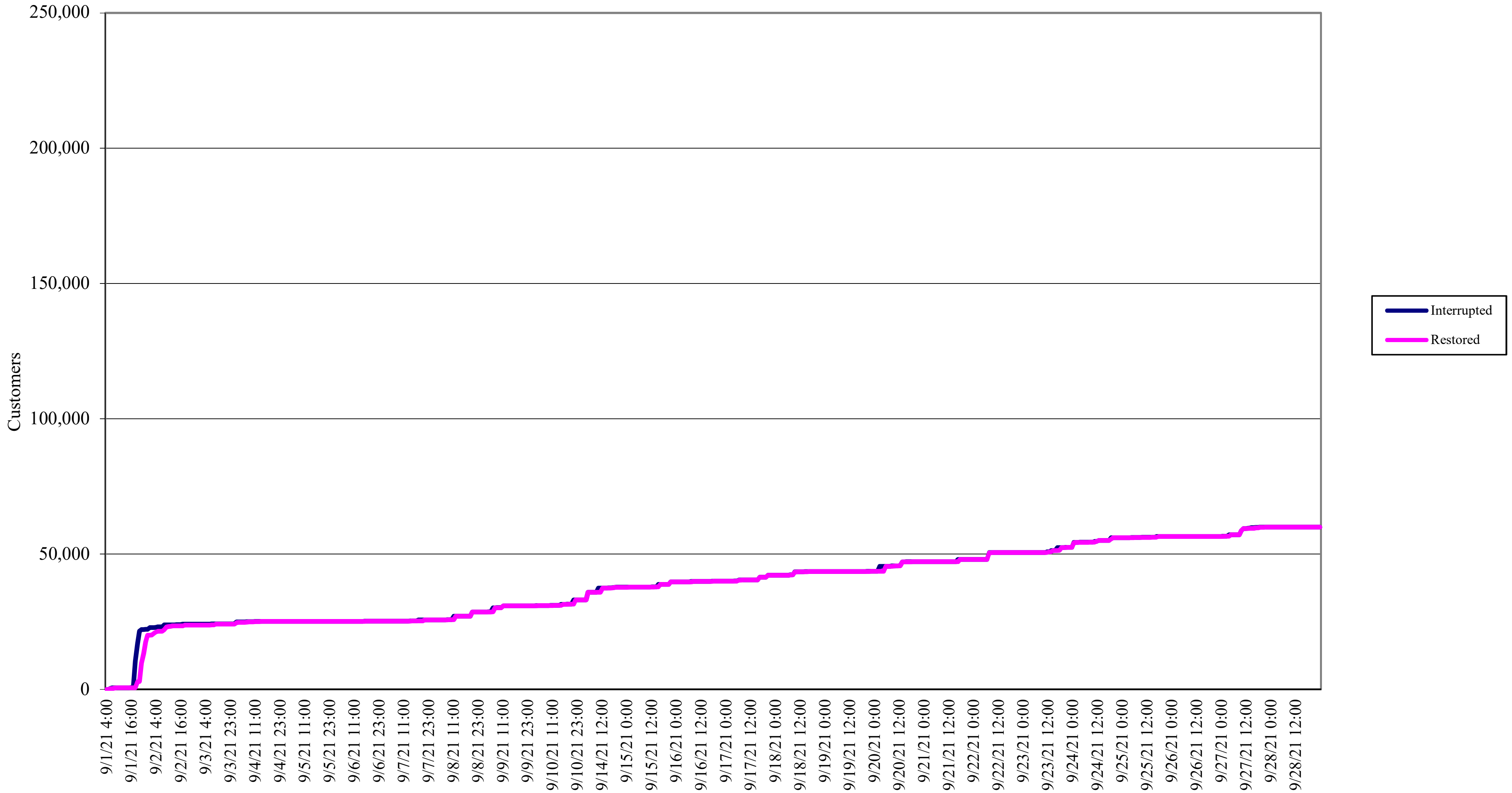
Attachment "C"
PSE&G
Customer Restoration Summary
State of Emergency - Remnants of Hurricane Ida – Flooding – Load Shedding – East Orange
September 1 - September 28, 2021
Metropolitan Division



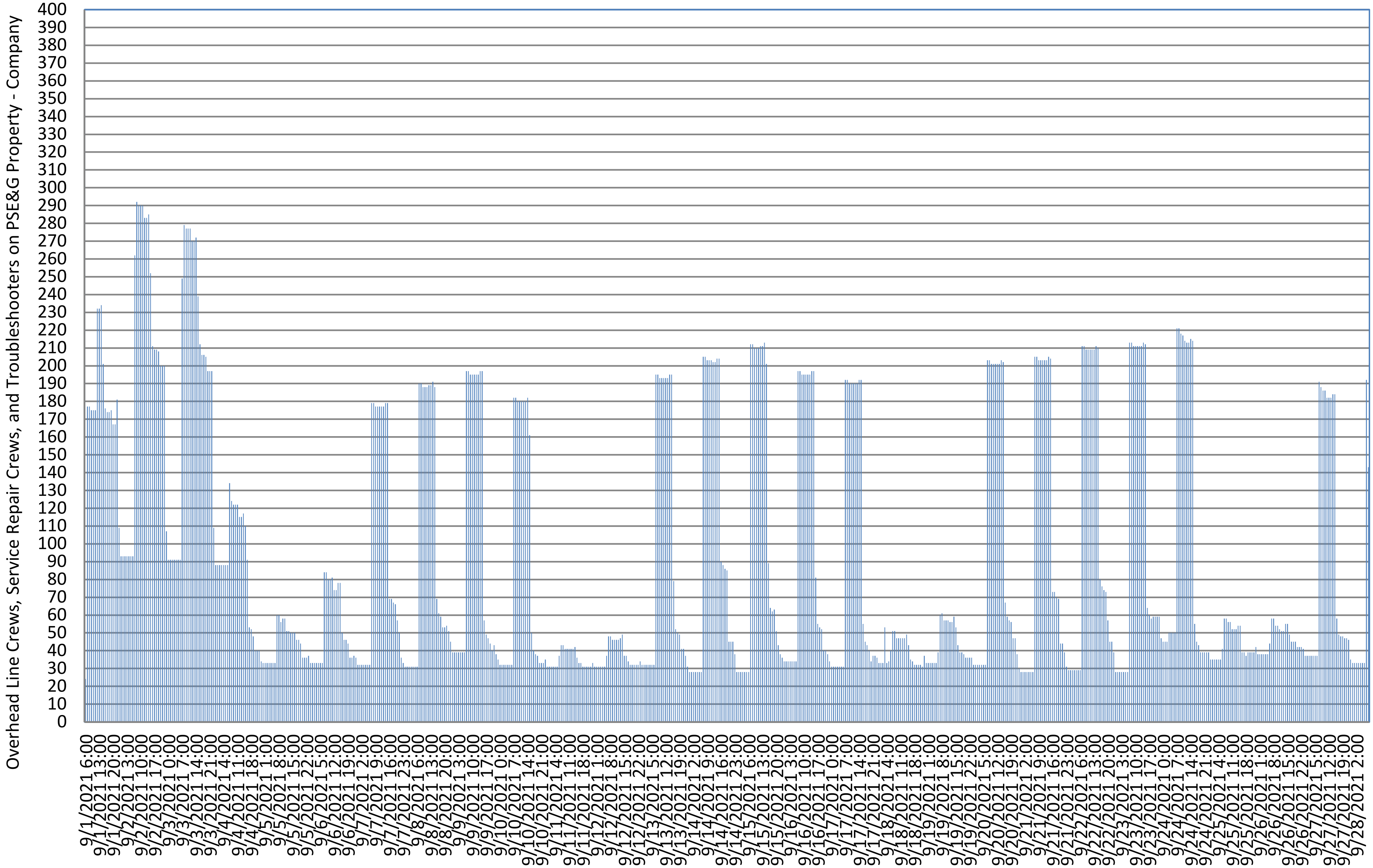
Attachment "D"
PSE&G
Customer Restoration Summary
State of Emergency - Remnants of Hurricane Ida – Flooding – Load Shedding – East Orange
September 1 - September 28, 2021
Palisades Division



Attachment "E"
PSE&G
Customer Restoration Summary
State of Emergency - Remnants of Hurricane Ida – Flooding – Load Shedding – East Orange
September 1 - September 28, 2021
Southern Division

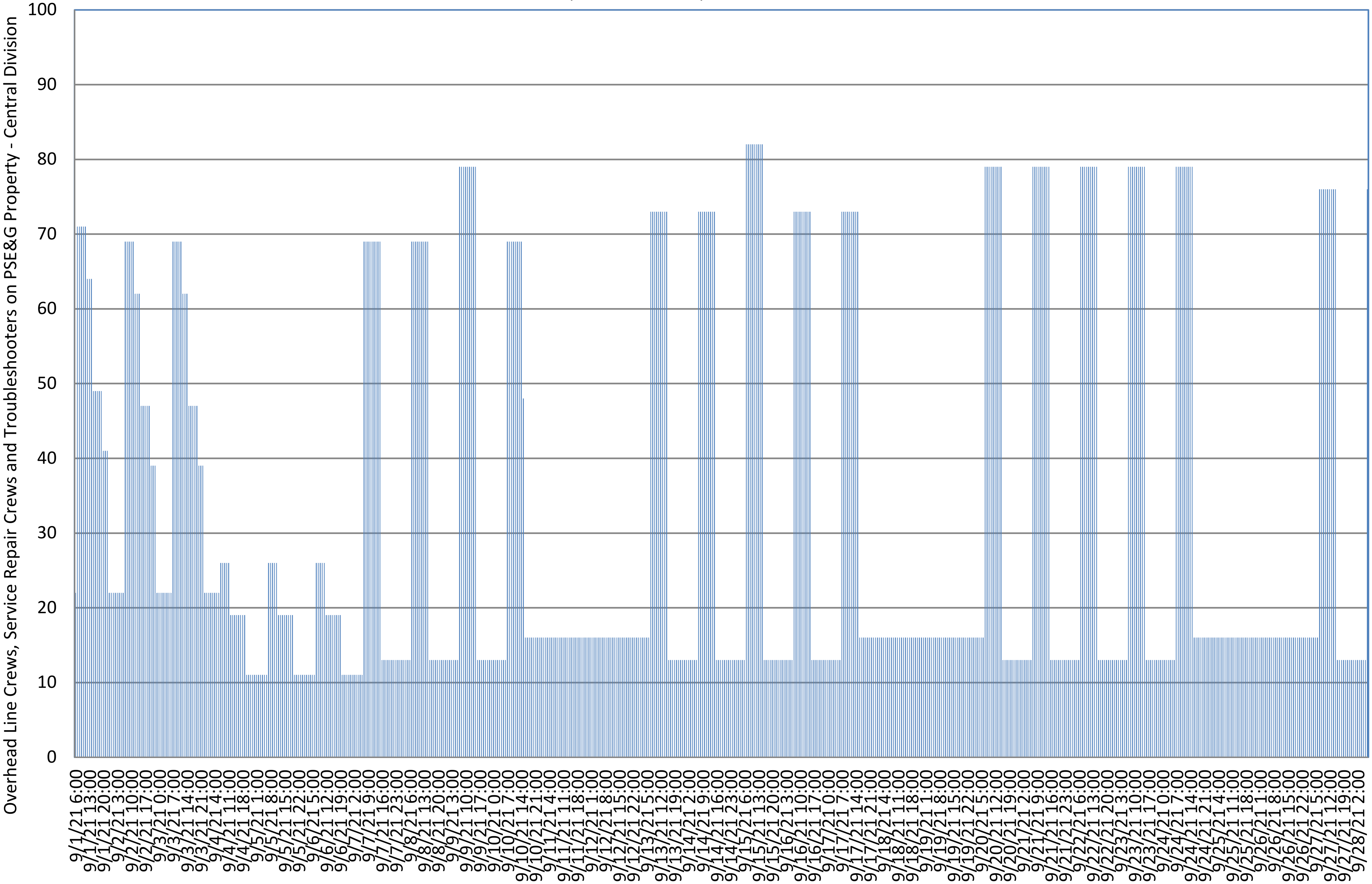


Attachment "F"
PSE&G
Overhead Line Crews, Service Repair Crews, and Troubleshooters on PSE&G Property - Company
State of Emergency - Remnants of Hurricane Ida – Flooding – Load Shedding – East Orange
- September 1st - September 28th, 2021

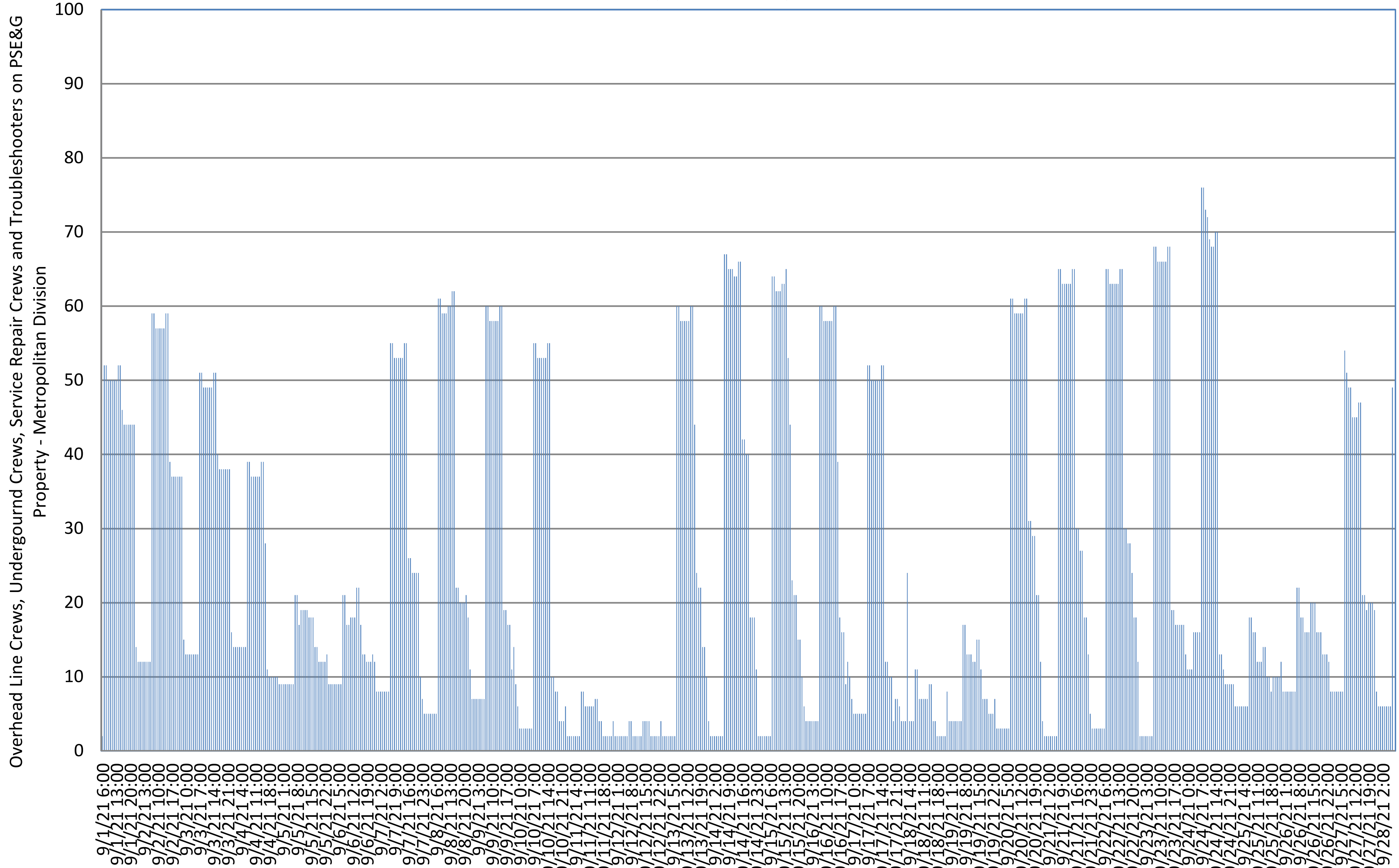


*These values include P&C Workforce Numbers

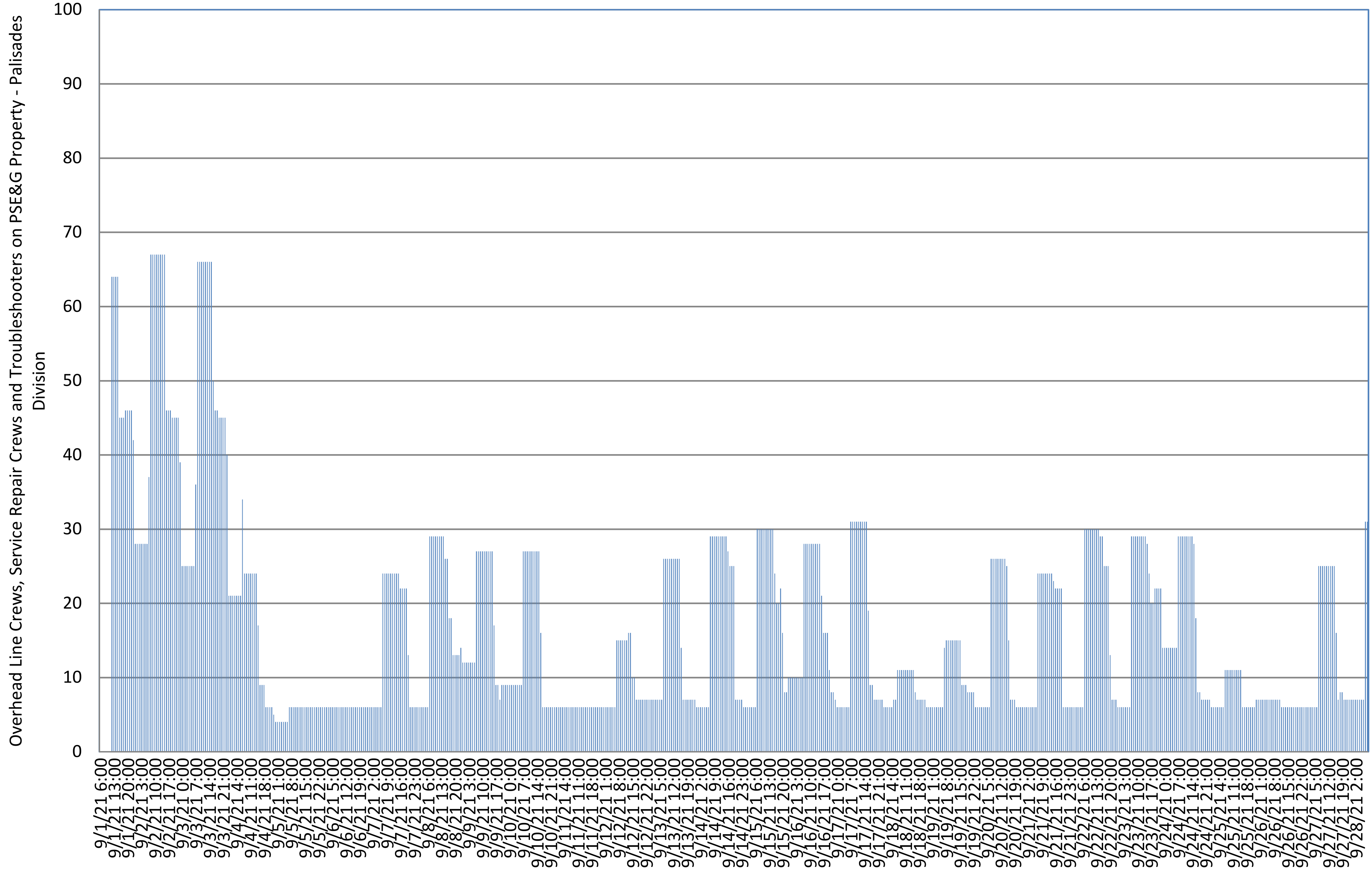
Attachment "G"
PSE&G
Overhead Line Crews, Service Repair Crews and Troubleshooters on PSE&G Property - Central Division
State of Emergency - Remnants of Hurricane Ida – Flooding – Load Shedding – East Orange
- September 1st - September 28th, 2021



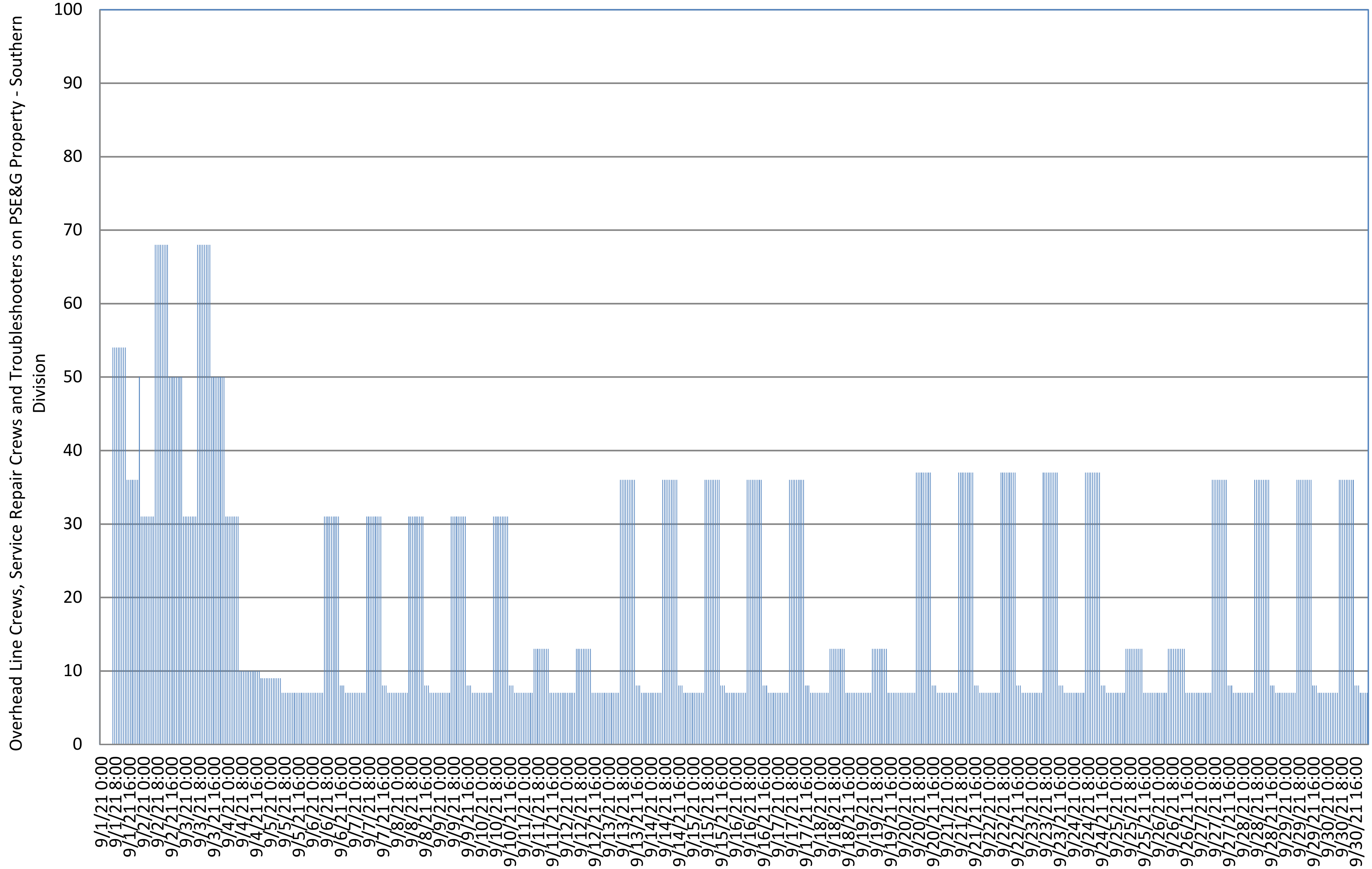
Attachment "H"
PSE&G
Overhead Line Crews, Undeground Crews, Service Repair Crews and Troubleshooters on PSE&G Property - Metropolitan Division
State of Emergency - Remnants of Hurricane Ida – Flooding – Load Shedding – East Orange
- September 1st - September 28th, 2021



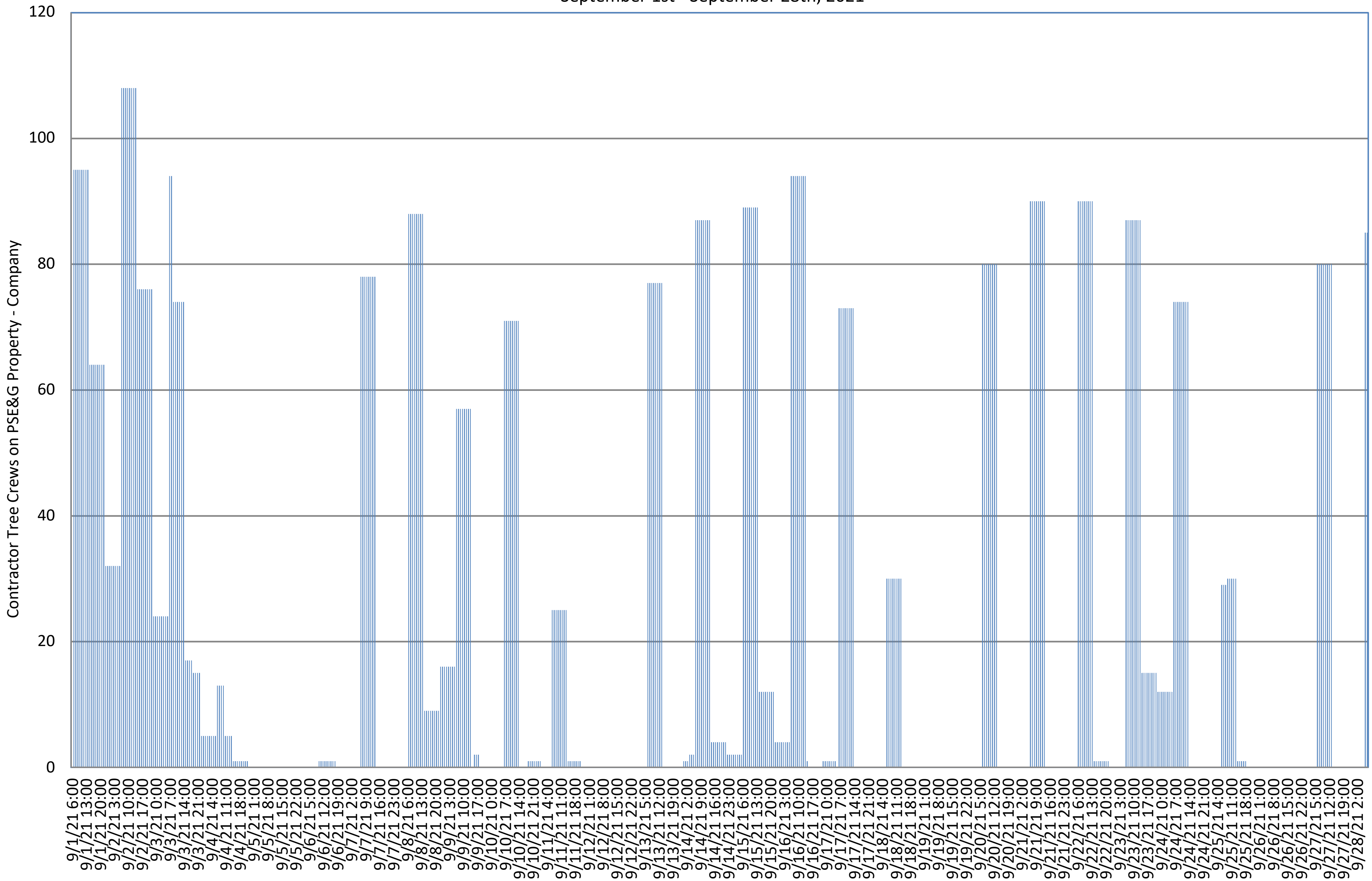
Attachment "I"
PSE&G
Overhead Line Crews, Service Repair Crews and Troubleshooters on PSE&G Property - Palisades Division
State of Emergency - Remnants of Hurricane Ida – Flooding – Load Shedding – East Orange
- September 1st - September 28th, 2021



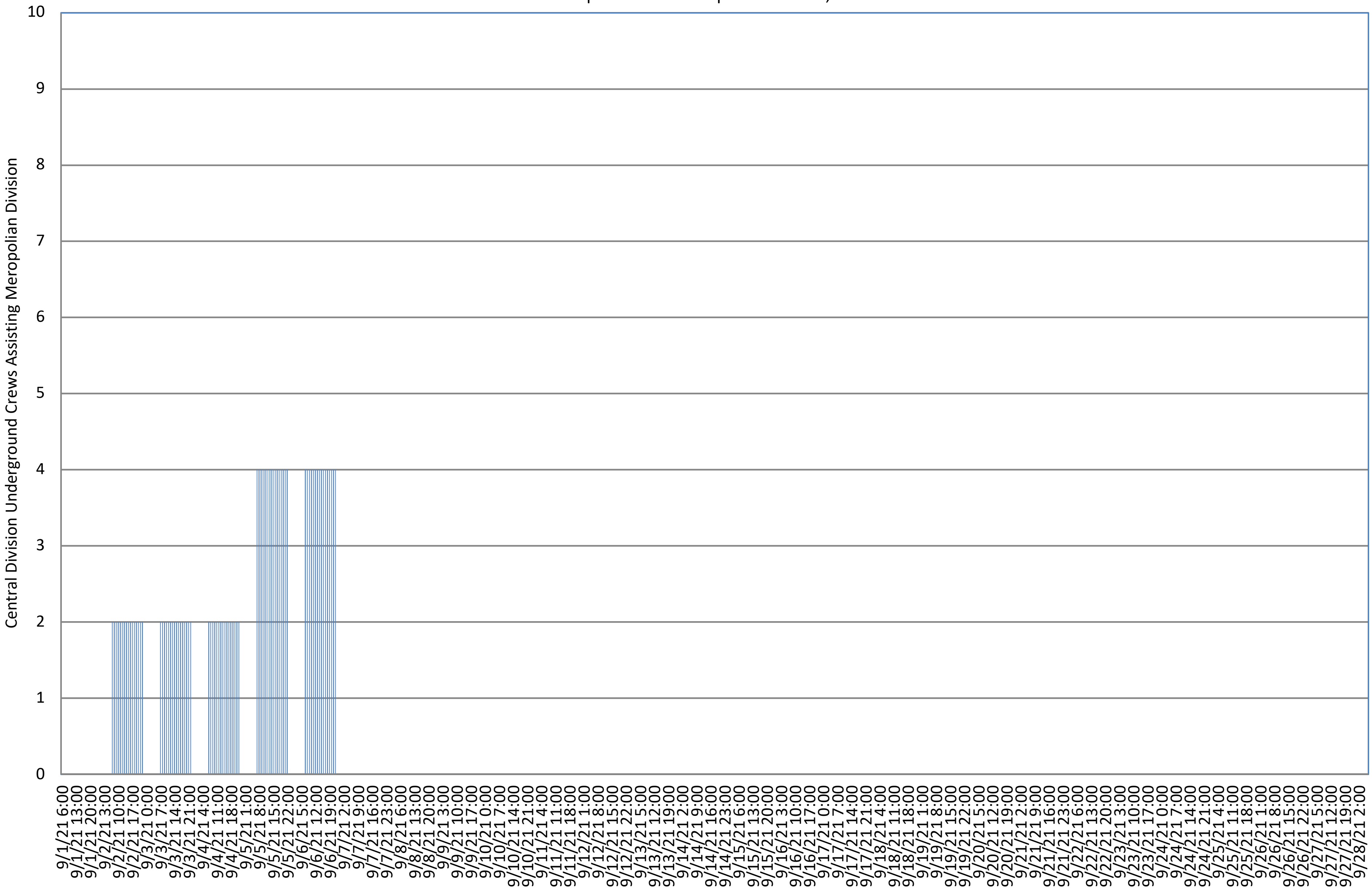
Attachment "J"
PSE&G
Overhead Line Crews, Service Repair Crews and Troubleshooters on PSE&G Property - Southern Division
State of Emergency - Remnants of Hurricane Ida – Flooding – Load Shedding – East Orange
- September 1st - September 28th, 2021



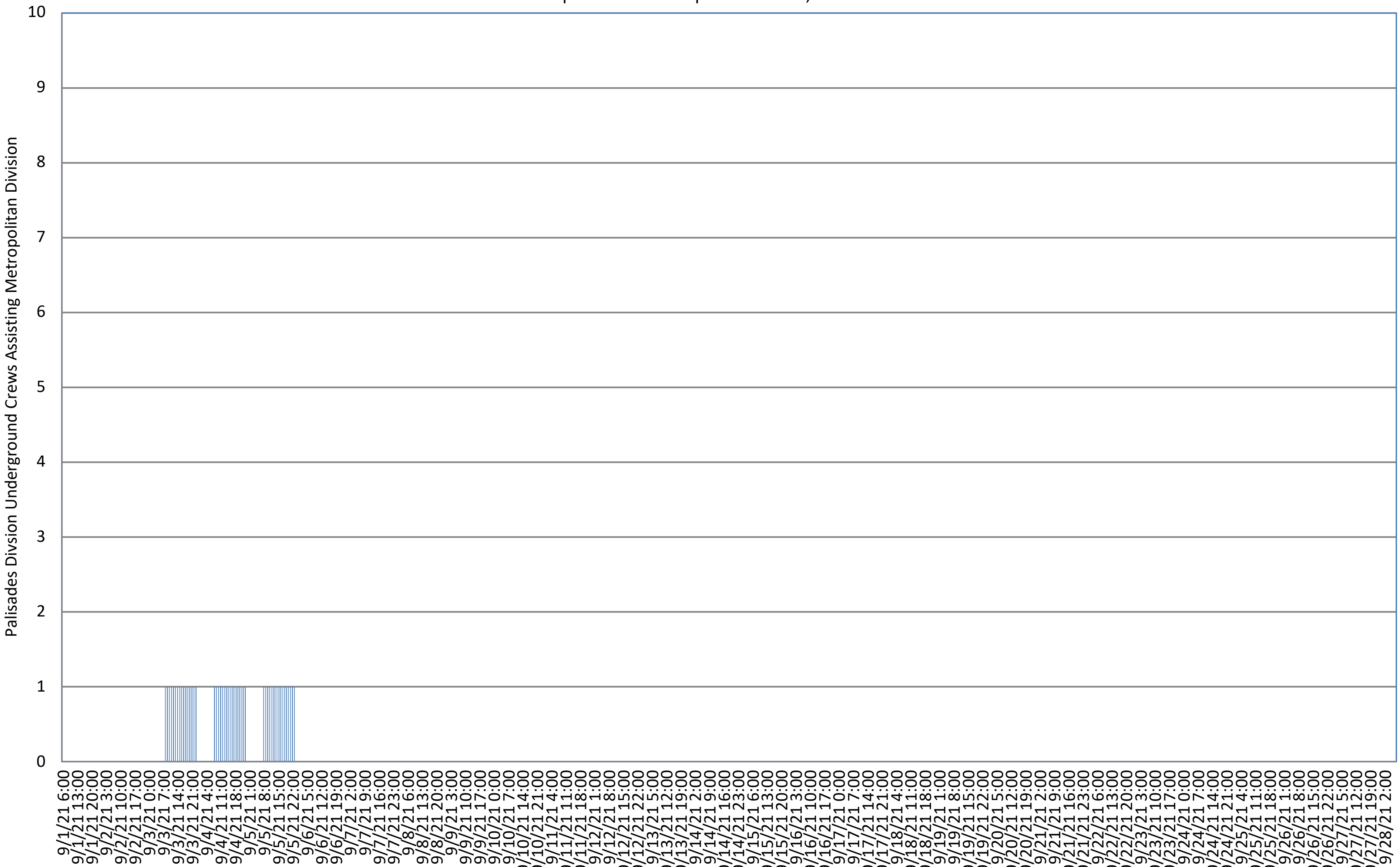
Attachment "K"
PSE&G
Contractor Tree Crews on PSE&G Property - Company
State of Emergency - Remnants of Hurricane Ida – Flooding – Load Shedding – East Orange
- September 1st - September 28th, 2021



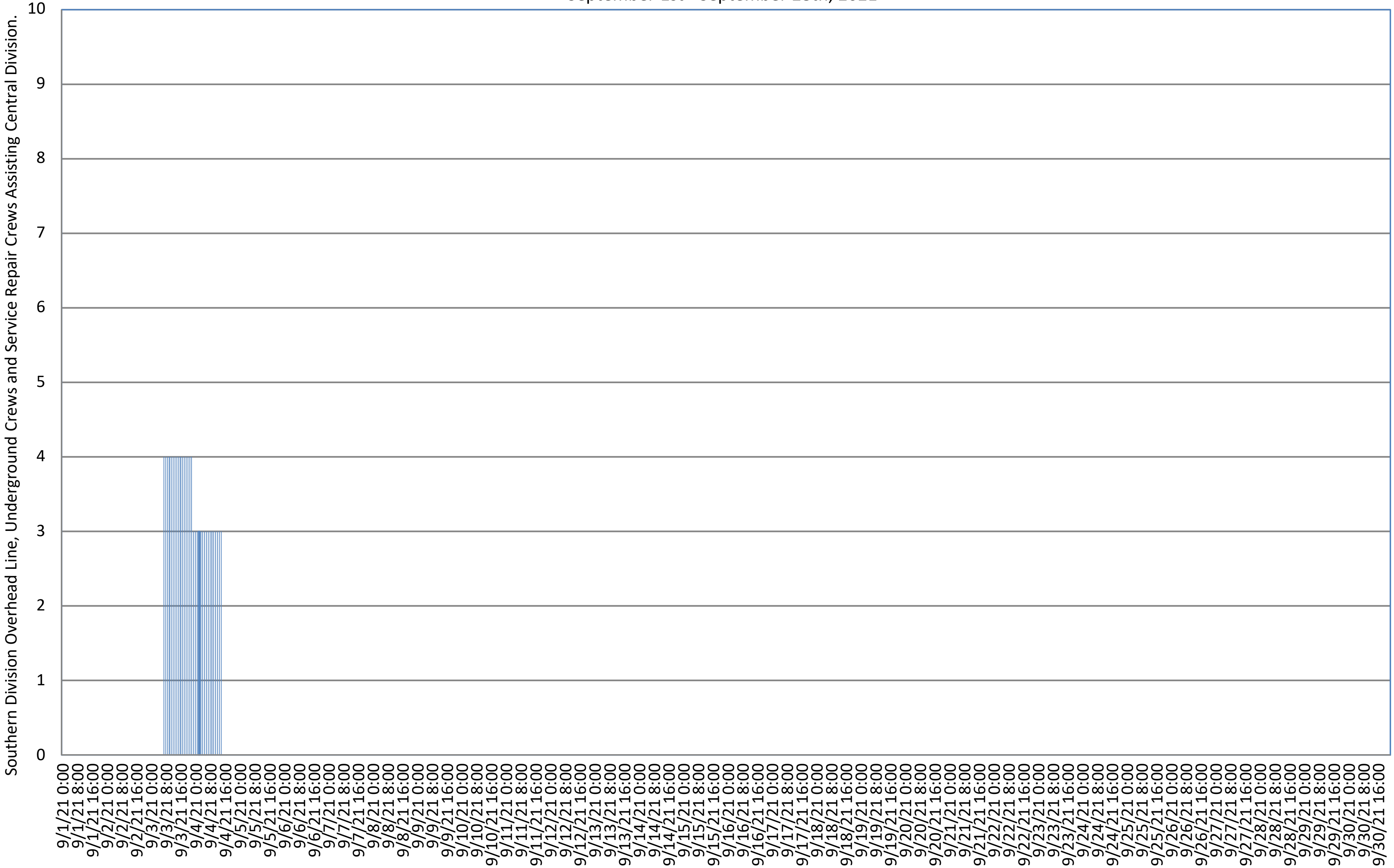
Attachment "L"
PSE&G
Central Division Underground Crews Assisting Metropolitan Division
State of Emergency - Remnants of Hurricane Ida – Flooding – Load Shedding – East Orange
- September 1st - September 28th, 2021



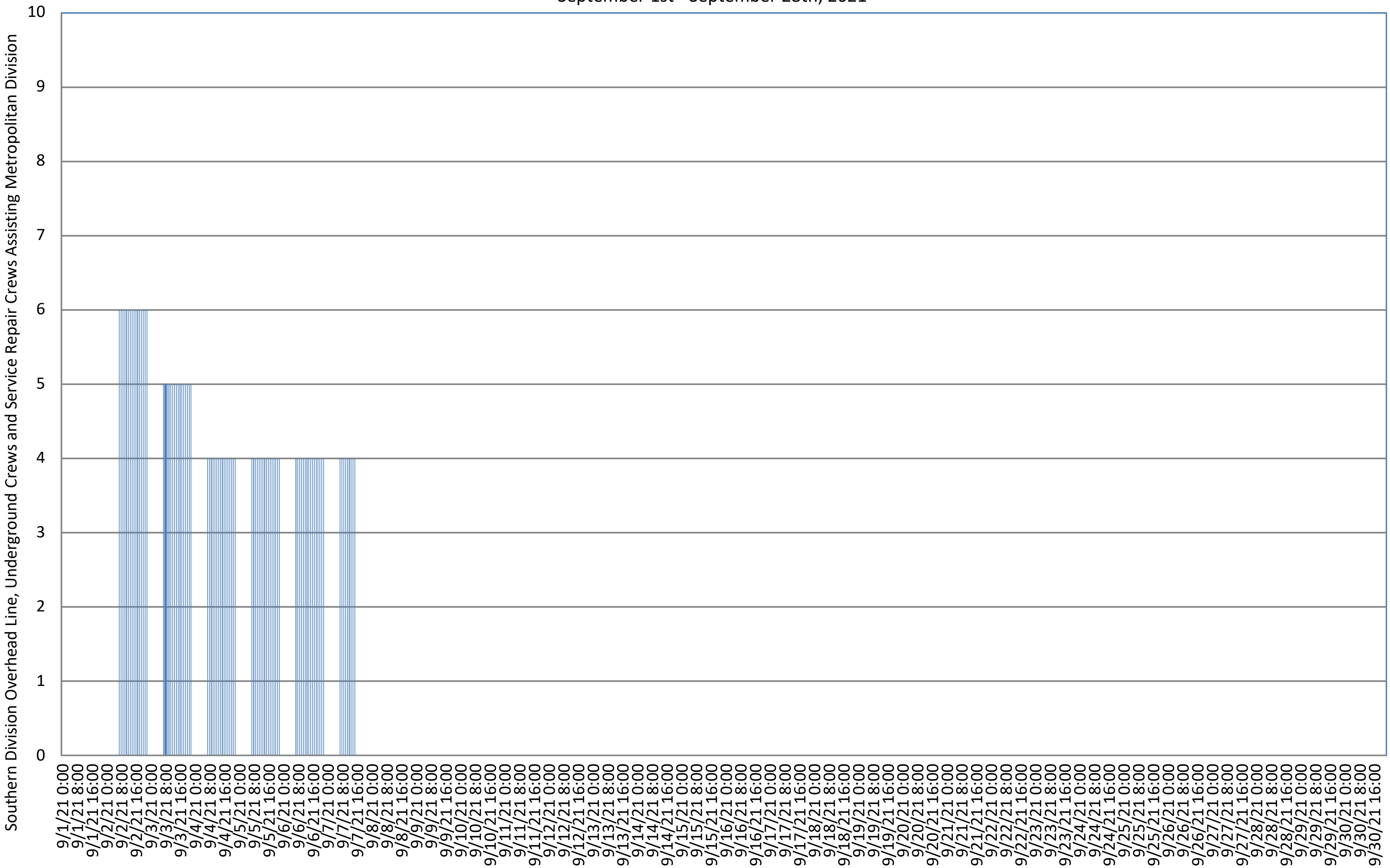
Attachment "M"
PSE&G
Palisades Division Undergound Crews Assisting Metropolitan Division
State of Emergency - Remnants of Hurricane Ida – Flooding – Load Shedding – East Orange
- September 1st - September 28th, 2021



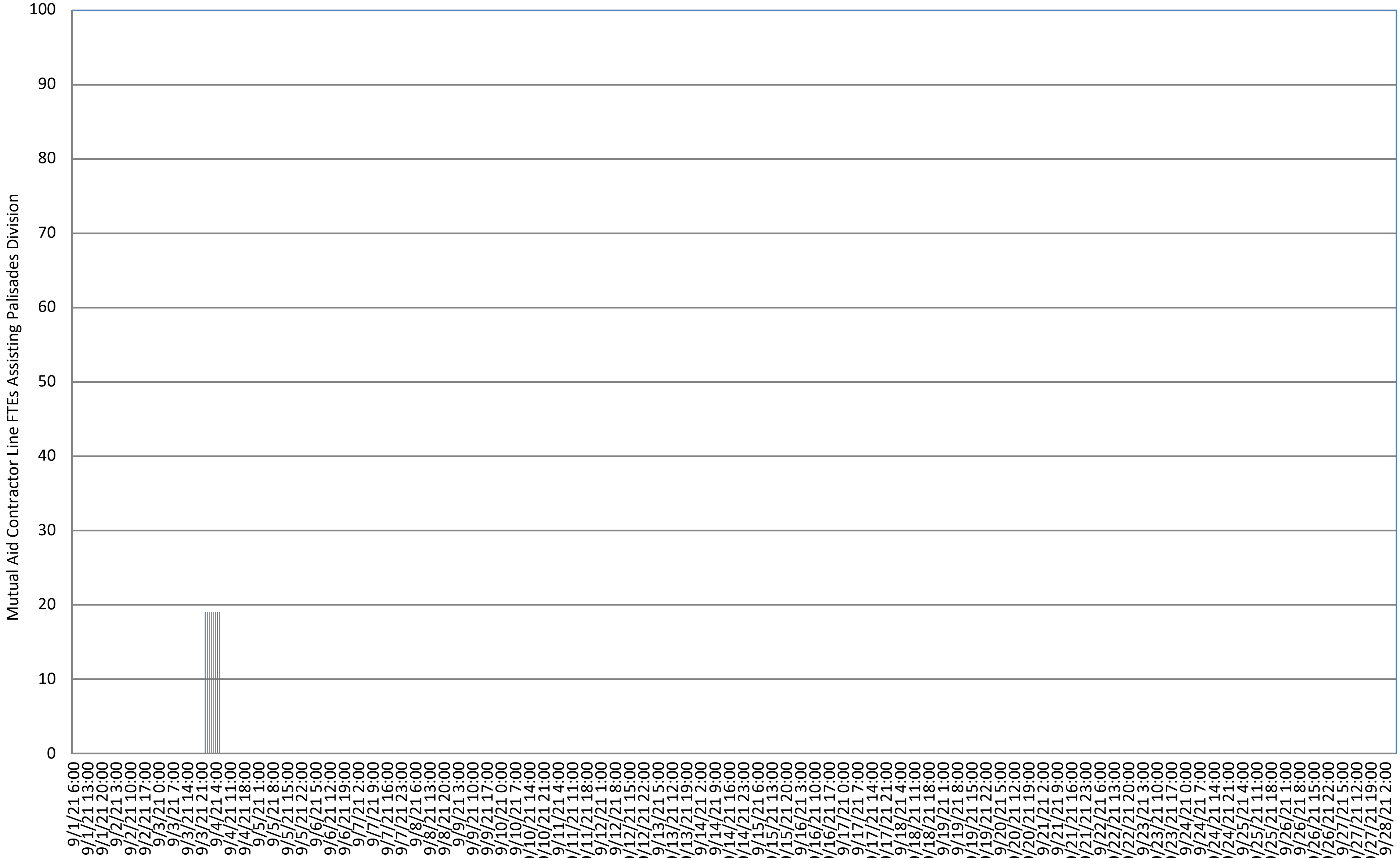
Attachment "N"
PSE&G
Southern Division Overhead Line, Underground Crews and Service Repair Crews Assisting Central Division
State of Emergency - Remnants of Hurricane Ida – Flooding – Load Shedding – East Orange
- September 1st - September 28th, 2021



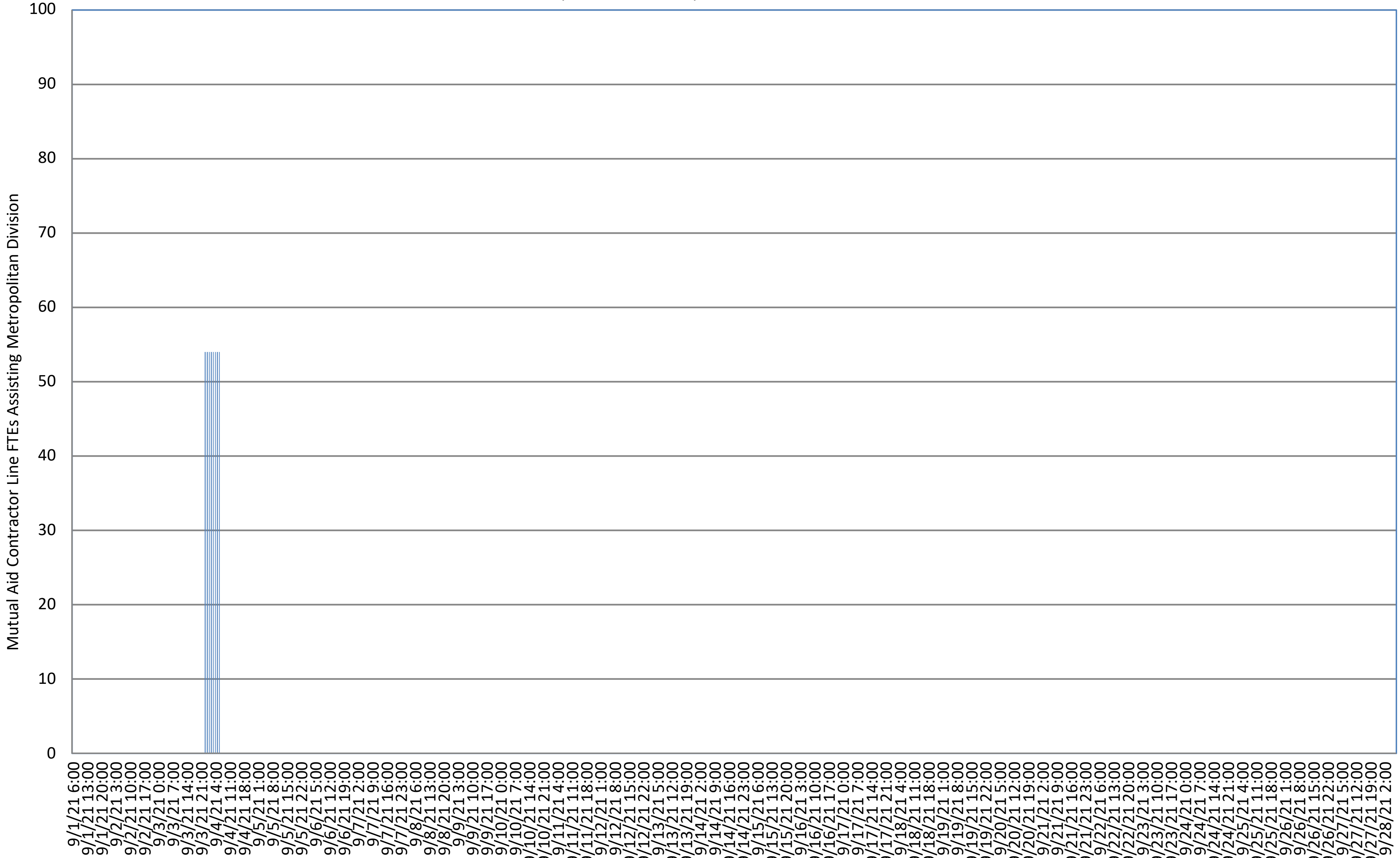
Attachment "O"
PSE&G
Southern Division Overhead Line, Underground Crews and Service Repair Crews Assisting Metropolitan Division
State of Emergency - Remnants of Hurricane Ida – Flooding – Load Shedding – East Orange
- September 1st - September 28th, 2021



Attachment "P"
PSE&G
Mutual Aid Contractor Line FTEs Assisting Palisades Division
State of Emergency - Remnants of Hurricane Ida – Flooding – Load Shedding – East Orange
- September 1st - September 28th, 2021



Attachment "Q"
PSE&G
Mutual Aid Contractor Line FTEs Assisting Metropolitan Division
State of Emergency - Remnants of Hurricane Ida – Flooding – Load Shedding – East Orange
- September 1st - September 28th, 2021



		9/1 Storm Electric Delivery Capital Expenditures (CapEx)	O&M Expenses	CapEx + O&M Expenses	Incremental O&M Expenses
1	Total Labor	**2,417,158**	**5,659,643**	**8,076,802**	**2,184,546**
2	Contractor/Mutual Aid	131,745	392,804	524,550	392,804
3	Tree Removal	309,308	554,967	864,275	554,967
4	Buses	-	-	-	-
5	Other Contractor	402,373	270,097	672,470	270,097
	Total Contractor	**843,427**	**1,217,868**	**2,061,295**	**1,217,868**
6	Material	**955,181**	**90,895**	**1,046,076**	**86,727**
7	Food	18,126	31,171	49,297	31,171
8	Lodging	7,995	10,631	18,626	10,631
9	Security	-	-	-	-
10	Water and Ice	-	201,293	201,293	201,293
14	Email Alerts	-	8,572	8,572	8,572
11	Other	96,317	148,100	244,417	18,502
	Total Other	**122,438**	**399,767**	**522,205**	**270,170**
	Total Incurred	**4,338,204**	**7,368,174**	**11,706,378**	**3,759,310**
12	O&M Base Rate Storm Costs	-	-	-	-
	Total	**4,338,204**	**7,368,174**	**11,706,378**	**3,759,310**

		9/1 Storm Gas Delivery Capital Expenditures (CapEx)	O&M Expenses	CapEx + O&M Expenses	Incremental O&M Expenses
1	Total Labor	**-**	**6,875,087**	**6,875,087**	**3,089,713**
2	Contractor/Mutual Aid	**-**	-	**-**	-
3	Tree Removal	**-**	-	**-**	-
4	Buses	**-**	-	**-**	-
5	Other Contractor	**-**	396,316	396,316	396,316
	Total Contractor		**396,316**	**396,316**	**396,316**
				-	
6	Material	**-**	**60,349**	**60,349**	**49,022**
				-	
7	Food	**-**	-	-	-
8	Lodging	**-**	-	-	-
9	Security	**-**	-	-	-
10	Water and Ice	**-**	-	-	-
14	Email Alerts	**-**	-	-	-
11	Other	**-**	337,531	337,531	210,130
	Total Other		**337,531**	**337,531**	**210,130**
				-	
	Total Incurred		**7,669,282**	**7,669,282**	**3,745,180**
12	O&M Base Rate Storm Costs	**-**	-	-	-
	Total	**-**	**7,669,282**	**7,669,282**	**3,745,180**

February 6, 2024

VIA ELECTRONIC MAIL ONLY
Francis Gaffney, Director
Division of Reliability and Security
New Jersey Board of Public Utilities
225 East State Street - 2nd Floor, Area 2W
Trenton, New Jersey 08625

**RE: MAJOR EVENT REPORT
STATE OF EMERGENCY – SEVERE WIND/RAINSTORM
JANUARY 9 - 11, 2024**

Dear Director Gaffney:

As required by 14:5-8.9 Major Event Report, enclosed is a copy of PSE&G's Major Event Report for the State of Emergency - Severe Wind/Rainstorm that affected PSE&G's entire service territory from January 9 - 11, 2024.

Questions concerning this matter can be directed to me or Donald W. Weyant, Manager - Regulatory Compliance at (973) 430-6730.

Respectfully submitted,

Matthew Weissman

Matthew M. Weissman

Attachments

C Christine Guhl-Sadovy, President
Dr. Zenon Christodoulou, Commissioner
Marian Abdou, Commissioner
Michael Bange, Commissioner
Stacy Peterson, Acting Director

PSE&G'S REPORT TO THE BPU
MAJOR EVENT
STATE OF EMERGENCY - SEVERE WIND AND RAINSTORM
JANUARY 9 - 11, 2024

EXECUTIVE SUMMARY

On January 9, 2024, PSE&G's entire service territory was affected by a severe wind and rainstorm. PSE&G's Southern Division was especially hard hit by the storm. Because of the weather predictions, Governor Phil Murphy declared a State of Emergency (SOE) effective at 1700 hrs. on January 9. The Governor ended the SOE on January 24 at 1700 hrs.

PSE&G began preparing for the storm on its January 5, 0800 hrs. operations conference call by monitoring weather forecasts and reviewing the 72/48/24 hour storm preparation check lists. Representatives from Electric Delivery's General Office Staff, the four operating divisions, Projects and Construction (P&C) and the Electric System Operations Center (ESOC) participated on the call. Personnel from other operating and staff departments of the Company were involved on that call as well as subsequent calls of this nature.

PSE&G opened its Emergency Operations Center (EOC) on January 9 at 1400 hrs. on a virtual basis, which is the storm start time. The storm impact end time occurred on January 10 at 0900 hrs. PSE&G closed its virtual EOC on January 11 at 1909 hrs. which is the storm end time. There were 79,204 customers that experienced extended interruptions between 1400 hrs. on January 9 and 1909 hrs. on January 11.

Beginning with the 1500 - 2300 hrs. shift on January 9, PSE&G scheduled its work force on basically a 1/3 - 2/3 schedule.

Communications with 12 County Offices of Emergency Management (OEM) and the City of Newark's Emergency Operations Center began on January 9.

Communications with Board staff began on January 8 and continued until January 12.

OPERATING REPORT

There were 79,204 customers that experienced extended interruptions during this weather event.

Division	# Customers Interrupted 1400 hrs. 1/9 to 0900 hrs. 1/10	Restoration	# Customers Interrupted 0900 hrs. 1/10 to 1909 hrs. 1/11	Final Restoration
Central	7,250	1/10 – 2130 hrs.	3,380	1/11 - 1023 hrs.
Metropolitan	6,627	1/10 – 1008 hrs.	1,966	1/11- 0148 hrs.
Palisades	5,884	1/10 - 0847 hrs.	-0-	1/10 - 0847 hrs.
Southern	44,991	1/11 – 2030 hrs.	9,106	1/12 - 1816 hrs.
Total	64,752		14,452	
Grand Total	79,204			

Attached are the following Customer Restoration Summary Graphs for this event:

Attachment “A” - Company Wide
Attachment “B” - Central Division
Attachment “C” - Metropolitan Division
Attachment “D” - Palisades Division
Attachment “E” - Southern Division

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Communications with Board staff began on January 8 and continued until January 12.

PERSONNEL DEPLOYMENT

Attached are the following Work Force Graphs for this event:

Attachment “F” - Overhead Line FTEs, Service Repair FTEs and Troubleshooters - Company
Attachment “G” - Overhead Line FTEs, Service Repair FTEs and Troubleshooters - Central Division
Attachment “H” - Overhead Line FTEs, Service Repair FTEs and Troubleshooters - Metropolitan Division
Attachment “I” - Overhead Line FTEs, Service Repair FTEs and Troubleshooters - Palisades Division
Attachment “J” - Overhead Line FTEs, Service Repair FTEs and Troubleshooters - Southern Division
Attachment “K” - Overhead Line FTEs, Service Repair FTEs - Central Division to Southern Division
Attachment “L” - Overhead Line FTEs, Service Repair FTEs - Metropolitan Division to Southern Division
Attachment “M” - Overhead Line FTEs, Service Repair FTEs - Palisades Division to Southern Division
Attachment “N” - Overhead Line FTEs, Service Repair FTEs - Projects and Construction to Southern Division
Attachment “O” - Contractor Overhead Line FTES and Service Repair FTES to Southern Division
Attachment “P” - Contractor Tree FTEs - Company

On January 9 at 1400 hrs., Central Division sent 4 Overhead Line FTEs to Southern Division to assist with storm restoration work.

Beginning at 0700 hrs., on January 10, Central, Metropolitan and Palisades Divisions and Projects and Construction sent 154 Overhead Line FTEs, 54 Service Repair FTEs and support personnel to Southern Division to assist with storm restoration work. 129 Contractor Overhead Line FTEs were also sent to Southern Division at that time.

Beginning at 0001 hrs. on January 11, Central, Metropolitan and Palisades Divisions and Projects and Construction sent 71 Overhead Line FTEs and 24 Service Repair FTEs to Southern Division to assist with storm restoration work. 38 Contractor Overhead Line FTEs were also sent to Southern Division at that time.

On January 10, of the 204 Tree Trimming FTEs on the property, 118 were assigned to Southern Division while the remainder worked in the other three Divisions. On January 11, of the 220 Tree Trimming FTEs on the property, 115 were assigned to Southern Division while the remainder worked in the other three Divisions.

PSE&G did not request any Mutual Aid Assistance during this weather event. On January 11, PSE&G released three Contractor Overhead Line Crews to ACE for storm restoration work.

TROUBLE LOCATIONS AND CLASSIFICATIONS

Outside plant damage locations are listed below:

69 & 26-kV	-	28
13 & 4-kV	-	341
Transformers	-	59
Secondaries	-	56
Services	-	129
Poles	-	97
Trees	-	120
Total	-	830

In addition, the estimated miles of wire replaced is 0.57 miles.

There were 35 roads that had to be cleared of PSE&G infrastructure.

COMMUNICATIONS

Communications with Board staff began on January 8 and continued until January 12.

Communications with 12 County OEMS and the City of Newark's Emergency Operations Center began on January 9.

PSE&G's Corporate Communications Department issued a press release on January 8 at 1600 hrs. and a media update on January 10 at 1200 hrs. Statements in these communications included updates on restoration efforts and important customer messages about: outage reporting, downed wire safety, flood safety, life-sustaining medical equipment, and generator / carbon monoxide safety.

PSE&G received media inquiries from NJ 101.5, News 12 NJ, CBS Philly, Fox National Weather, Pix 11, ABC Philly, The Philadelphia Inquirer, NJ Pen and NJ.com. PSE&G participated in five live TV interviews, one taped TV interview, one taped radio interview and responded to several requests for information and answers to specific questions.

Through proactive social media, PSE&G posted storm related content 44 times across multiple platforms from January 8 to 11. The total impressions (times messages were shown on platform timelines) were 48,492. PSE&G Facebook and Instagram messages reached 40,654 people.

On the PSE&G Website:

- On January 8, PSE&G posted the press release in the PSE&G newsroom.
- On January 9, PSE&G updated the banners on pseg.com to the PSE&G storm banner.
- On January 10, PSE&G posted a storm update press release in the PSE&G newsroom.
- On January 16, the storm banners were removed.

As requested, PSE&G staffed the Somerset County OEM from 1200 hrs. on January 9 to 0700 hrs. on January 10. PSE&G provided remote support to the other OEMs through January 10. During the weather event, specific issues identified by the Burlington, Camden, Gloucester, Mercer, Middlesex and Somerset OEMs were addressed.

PSE&G's Regional Public Affairs (RPA) Managers had individual discussions with County OEM coordinators, Municipal OEM coordinators, Mayors, Business Administrators and Police and Fire Chiefs during this weather event. Counties included Bergen, Burlington, Camden, Essex, Hudson, Mercer, Middlesex, Passaic and Somerset. Preliminary notification was made on January 8 using PSE&G's Constant Contact process with a second notification on January 10, giving a storm restoration update. Almost 2,000 contacts were made using this process.

As required in Recommendation 3 from the Tropical Storm Isaias Board Order, the following standardized Call Center information is provided:

Date	Number of calls Offered (NCO)	Number of calls Handled (NCH)	Number of calls Abandoned (NCA)	Call Abandonment Rate (CA%)	Average Speed of Answer (ASA)
* 1/9/2024	20,988	19,620	1,368	6.5%	80
1/10/2024	32,257	31,142	1,115	3.5%	57
1/11/2024	24,957	24,023	934	3.7%	63

*1/9/2024 data was collected from 12 noon until midnight

A notification to PSE&G's critical needs (P-4) customers was issued on January 8, informing them of the impending storm and recommending precautions they should take. This information was also included in outbound calls made with Estimated Times of Restoration (ETRs).

INCIDENTS

Bordentown Substation was shut down for 34 minutes on January 9 from 2034 – 2108 hrs. due to the loss of the three 26-kV supply lines. The Z-260 and L-428 had locked out at 1908 hrs. due to a tree contact and the station was shut down at 2034 hrs. when the S-123 locked out due to a flash from a failed tie recloser, interrupting 2,068 customers. These customers were restored to service at 2108 hrs. when the S-123 was cut-in. Note that

533 customers were already out of service at 2034 hrs. due to the lock out of BOR 4001 as indicated below, which occurred at 1908 hrs.

Chester Substation was shut down for 5 hrs. and 2 minutes from 2112 hrs. on January 9 to 0214 hrs. on January 10 due to the loss of the three 26-kV supply lines. The W-179 locked out at 2108 hrs. due to a broken crossarm. The K-141 locked out at 2112 hrs. due to a pole top fire and the F-292 locked out at the same time due to phases burning down, shutting down the station and interrupting 3,639 customers. The station was restored to service at 0214 hrs. on January 10 when the K-141 was cut-in.

Cherry Hill Mall Substation was shut down for 6 hrs. and 26 minutes from 2112 hrs. on January 9 to 0338 hrs. on January 10 due to the loss of both 26-kV supply lines. The X-128 locked out at 1840 hrs. January 9 due to a broken tree limb. The F-292 locked out at 2112 hrs. due to phases burning down, shutting down the station. The station was restored to service at 0338 hrs. on January 10 when the X-128 was cut-in

Westmount Substation was shutdown for 4 hrs. and 6 minutes from 1854 hrs. to 2300 hrs. on January 9 due to the loss of both 26-kV supply lines. The H-216 locked out at 1805 hrs. due to a tree burning down phases. The I-373 locked out at 1854 hrs. when a tree fell and broke two poles, shutting down the station and interrupting 3,875 customers. The station was restored to service at 2300 hrs. when the I-373 was sectionalized and cut-in.

The Johnstone Campus, which includes the Juvenile Female Detention Facility, was interrupted for 23 hrs. and 52 minutes from 1908 hrs. on January 9 to 1900 hrs. on January 10 when BOR 4001 locked out due to a tree condition burning down phases on the circuit and on the Z-260.

The New Jersey Juvenile Medium Security Prison was interrupted for 3 hours and 57 minutes from 1908 hrs. to 2305 hrs. on January 9. The cause was the same trouble location that interrupted the Johnstone Campus.

OUTAGE INFORMATION

The attached file entitled "Trouble Location Restoration Data" lists in sequential restoration order all outage events that were restored, the number of customers restored, the time at which they were restored and the municipality and county affected by the outage.

At no time during this weather event did high winds or telecommunication sector issues prevent restoration personnel from performing their job functions.

The following is a list of the estimated items of restoration (ETR) issued by PSE&G throughout the restoration process. Since the storm severely impacted Southern Division, a Global ETR was not necessary for the Company nor for the four operating Divisions. Customers were given ETRs as indicated below were based upon an analysis of the outage. Under "blue sky" conditions, customers are given the following ETRs for different types of outages causes:

Outage Cause	Normal (Default) ETR Duration (Hours)
Part Power / Flicker	5
Single No Power Call	5
Transformer	4
Fuse / Branch Recloser / Automatic Transfer Switch	3
Substation Circuit Breaker / Feeder Recloser	2

The following are the ETRs provided during this weather event:

Div (Area)	Multiplier Desc Desc	ETR Mult	Change Time
Central	CLEAR/OVERCAST(0-90 DEG)	1	Default
Central	1.5X RAIN	1.5	1/9/24 22:00
Central	4.0X STORM/HIGH WINDS	4	1/10/24 5:00
Central	2.0X HIGH WINDS	2	1/10/24 9:30
Central	CLEAR/OVERCAST(0-90 DEG)	1	1/11/24 20:00

Div (Area)	Multiplier Desc Desc	ETR Mult	Change Time
Metro	CLEAR/OVERCAST(0-90 DEG)	1	Default
Metro	1.5X RAIN	1.5	1/10/24 0:15
Metro	2.0X HIGH WINDS	2	1/10/24 4:00
Metro	4.0X STORM/HIGH WINDS	4	1/10/24 15:00
Metro	CLEAR/OVERCAST(0-90 DEG)	1	1/11/24 4:15

Div (Area)	Multiplier Desc Desc	ETR Mult	Change Time
Palisades	CLEAR/OVERCAST(0-90 DEG)	1	Default
Palisades	2.0X HIGH WINDS	2	1/10/24 10:52
Palisades	CLEAR/OVERCAST(0-90 DEG)	1	1/11/24 12:00

Div (Area)	Multiplier Desc Desc	ETR Mult	Change Time
Southern	CLEAR/OVERCAST(0-90 DEG)	1	Default
Southern	4.0X STORM/HIGH WINDS	4	1/10/24 1:11
Southern	6.0X STORM/HIGH WINDS	6	1/10/24 17:15
Southern	2.0X HIGH WINDS	2	1/11/24 5:15
Southern	CLEAR/OVERCAST(0-90 DEG)	1	1/12/24 22:11

SUMMARY

Restoration efforts during this event went extremely well. PSE&G was able to restore service to the 79,204 customers that experienced extended interruptions in an appropriate manner. PSE&G was able to send Overhead Line and Service Repair personnel from other divisions and P&C and its Contractor work force, plus support personnel, to Southern Division to assist with storm restoration work.

PSE&G's excellent relationships with its unions were beneficial during this event.

There were no issues involving equipment or material during this event.

As required in Recommendation 11 from the Tropical Storm Isaias Board Order, a review of past storms revealed that this event was somewhat similar to severe thunderstorms that affected PSE&G on July 8, 2014, interrupting 78,888 customers. The resiliency projects completed in PSE&G's Energy Strong I program and those that are currently underway in PSE&G's Energy Strong II program all contribute to improved reliability both during blue sky days and during Major Events. Comprehensive, comparison resiliency data involving Major Events is reported quarterly by PSE&G to the Independent Monitor as part of PSE&G's Energy Strong II Program, as it was during the Energy Strong I Program. The data referencing this event during the period January 9 - 11, 2024 will be submitted in PSE&G's First Quarter 2024 Energy Strong II Program Report.

DWW: bmc
2/2/24

Trouble Location Restoration Data

SOE - Severe Wind and Rain Storm - January 9-11, 2024

The purpose of this report is to list in sequential restoration order all outage events that were restored, the number of customers restored, the time at which they were restored and the municipality and county affected by the outage

Location ID	Creation Date	Energized Date	Job Cust	County Affecte	Munis Affected	Muni Cust
2007909290	01/09/2024 14:42	01/09/2024 15:24	90	Camden	Magnolia Boro	89
				Mercer	Trenton City	1
2007909258	01/09/2024 14:11	01/09/2024 15:45	33	Mercer	Hopewell Twp	33
2007909333	01/09/2024 15:34	01/09/2024 17:35	80	Bergen	Midland Park Boro	9
				Bergen	Wyckoff Twp	71
2007909429	01/09/2024 16:11	01/09/2024 17:40	12	Middlesex	North Brunswick Twp	1
				Middlesex	South Brunswick Twp	11
2007918736	01/09/2024 16:39	01/09/2024 18:00	36	Burlington	Southampton Twp	36
2007909825	01/09/2024 16:38	01/09/2024 18:00	654	Camden	Cherry Hill Twp	653
				Camden	Gloucester Twp	1
2007909328	01/09/2024 15:08	01/09/2024 18:37	769	Bergen	Fort Lee Boro	434
				Bergen	Leonia Boro	14
				Bergen	Palisades Park Boro	96
				Bergen	Ridgefield Boro	225
2007909729	01/09/2024 15:08	01/09/2024 18:37	926	Bergen	Fort Lee Boro	106
				Bergen	Leonia Boro	27
				Bergen	Palisades Park Boro	793
2007920470	01/09/2024 18:31	01/09/2024 19:10	1	Mercer	Hamilton Twp	1
2007910047	01/09/2024 19:02	01/09/2024 19:45	86	Bergen	Hackensack City	86
2007910106	01/09/2024 19:52	01/09/2024 19:59	699	Burlington	Moorestown Twp	699
2007909714	01/09/2024 18:39	01/09/2024 20:05	463	Mercer	West Windsor Twp	463
2007909916	01/09/2024 18:41	01/09/2024 20:10	22	Burlington	Cinnaminson Twp	1
				Burlington	Riverton Boro	21
2007911480	01/09/2024 20:08	01/09/2024 20:15	263	Essex	West Orange Twp	263
2007909612	01/09/2024 18:04	01/09/2024 20:25	221	Camden	Gloucester Twp	3
				Gloucester	Washington Twp	218
2007910818	01/09/2024 16:29	01/09/2024 20:25	12	Union	Elizabeth City	12
2007909946	01/09/2024 18:28	01/09/2024 20:25	13	Essex	Belleville Twp	13
2007922151	01/09/2024 18:53	01/09/2024 20:31	1	Mercer	Lawrence Twp	1
2007909622	01/09/2024 16:11	01/09/2024 20:44	4	Middlesex	North Brunswick Twp	1
				Middlesex	South Brunswick Twp	3
2007909820	01/09/2024 18:57	01/09/2024 20:50	70	Essex	West Orange Twp	70
2007909813	01/09/2024 18:56	01/09/2024 20:56	843	Burlington	Beverly City	27
				Burlington	Delanco Twp	310
				Burlington	Edgewater Park Twp	506
2007910708	01/09/2024 20:48	01/09/2024 20:58	852	Essex	Belleville Twp	163
				Essex	Nutley Twp	689
2007910514	01/09/2024 20:40	01/09/2024 20:59	75	Camden	Cherry Hill Twp	71
				Burlington	Mount Laurel Twp	4
2007918111	01/09/2024 20:34	01/09/2024 21:08	526	Burlington	Bordentown City	525
				Burlington	Bordentown Twp	1

Trouble Location Restoration Data

SOE - Severe Wind and Rain Storm - January 9-11, 2024

The purpose of this report is to list in sequential restoration order all outage events that were restored, the number of customers restored, the time at which they were restored and the municipality and county affected by the outage

Location ID	Creation Date	Energized Date	Job Cust	County Affecte	Munis Affected	Muni Cust
2007918112	01/09/2024 20:34	01/09/2024 21:08	398	Burlington	Bordentown City	364
				Burlington	Bordentown Twp	32
				Burlington	Chesterfield Twp	1
				Burlington	Southampton Twp	1
2007918114	01/09/2024 20:34	01/09/2024 21:08	20	Burlington	Bordentown City	20
2007918115	01/09/2024 20:34	01/09/2024 21:08	897	Burlington	Bordentown City	891
				Burlington	Chesterfield Twp	6
2007923532	01/09/2024 20:34	01/09/2024 21:08	227	Burlington	Bordentown City	42
				Burlington	Bordentown Twp	185
2007912392	01/09/2024 20:56	01/09/2024 21:10	2,014	Gloucester	Deptford Twp	1
				Burlington	Evesham Twp	1
				Gloucester	National Park Boro	891
				Mercer	Trenton City	1
				Gloucester	West Deptford Twp	1,120
2007910792	01/09/2024 21:08	01/09/2024 21:15	682	Burlington	Bordentown City	181
				Burlington	Bordentown Twp	501
2007910324	01/09/2024 19:19	01/09/2024 21:18	229	Burlington	Moorestown Twp	229
2007909451	01/09/2024 16:46	01/09/2024 21:18	39	Essex	West Orange Twp	39
2007910078	01/09/2024 18:33	01/09/2024 21:19	6	Middlesex	South Brunswick Twp	6
2007910793	01/09/2024 20:30	01/09/2024 21:22	558	Camden	Camden City	1
				Camden	Pennsauken Twp	557
2007910946	01/09/2024 21:07	01/09/2024 21:28	22	Middlesex	North Brunswick Twp	5
				Middlesex	South Brunswick Twp	17
2007909450	01/09/2024 16:49	01/09/2024 21:30	57	Gloucester	Deptford Twp	57
2007911444	01/09/2024 20:35	01/09/2024 21:42	514	Bergen	Oradell Boro	509
				Bergen	Paramus Boro	1
				Bergen	River Edge Boro	4
2007910049	01/09/2024 19:18	01/09/2024 22:02	19	Mercer	Hopewell Twp	19
2007911290	01/09/2024 19:15	01/09/2024 22:14	394	Camden	Cherry Hill Twp	393
				Camden	Gloucester Twp	1
2007911253	01/09/2024 21:06	01/09/2024 22:30	66	Union	Plainfield City	66
2007911350	01/09/2024 21:48	01/09/2024 22:30	32	Bergen	Haworth Boro	32
2007910511	01/09/2024 20:40	01/09/2024 22:38	444	Mercer	Hamilton Twp	444
2007910878	01/09/2024 21:02	01/09/2024 22:43	622	Gloucester	Deptford Twp	622
2007910875	01/09/2024 21:03	01/09/2024 22:43	26	Mercer	Hopewell Twp	26
2007920473	01/09/2024 22:37	01/09/2024 22:43	459	Mercer	Hamilton Twp	341
				Mercer	Robbinsville Twp	118
2007911191	01/09/2024 21:36	01/09/2024 22:51	805	Middlesex	Woodbridge Twp	805
2007910408	01/09/2024 20:25	01/09/2024 22:51	36	Bergen	Hackensack City	3
				Bergen	Maywood Boro	33

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Location ID	Creation Date	Energized Date	Job Cust	County Affecte	Munis Affected	Muni Cust
2007911760	01/09/2024 22:35	01/09/2024 22:53	1,220	Bergen	Little Ferry Boro	3
				Bergen	Ridgefield Boro	4
				Bergen	Ridgefield Park Villag	1,213
2007911555	01/09/2024 22:23	01/09/2024 22:55	263	Essex	West Orange Twp	263
2007909549	01/09/2024 18:54	01/09/2024 23:00	663	Camden	Audubon Boro	7
				Camden	Barrington Boro	1
				Camden	Haddon Heights Boro	14
				Camden	Haddon Twp	119
				Camden	Haddonfield Boro	522
2007909550	01/09/2024 18:54	01/09/2024 23:00	526	Camden	Haddonfield Boro	526
2007909551	01/09/2024 18:54	01/09/2024 23:00	356	Camden	Haddon Twp	6
				Camden	Haddonfield Boro	350
2007909552	01/09/2024 18:54	01/09/2024 23:00	485	Camden	Haddon Twp	479
				Camden	Haddonfield Boro	6
2007909634	01/09/2024 18:54	01/09/2024 23:00	414	Camden	Haddonfield Boro	414
2007909635	01/09/2024 18:54	01/09/2024 23:00	549	Camden	Haddon Twp	23
				Camden	Haddonfield Boro	526
2007909636	01/09/2024 18:54	01/09/2024 23:00	882	Camden	Haddonfield Boro	882
2007921149	01/09/2024 22:50	01/09/2024 23:00	70	Camden	Collingswood Boro	70
2007910103	01/09/2024 19:36	01/09/2024 23:02	223	Camden	Gloucester Twp	5
				Gloucester	Washington Twp	218
2007911949	01/09/2024 18:51	01/09/2024 23:02	1,376	Gloucester	Deptford Twp	1
				Camden	Gloucester Twp	2
				Gloucester	West Deptford Twp	1,061
				Gloucester	Woodbury City	70
				Gloucester	Woodbury Heights Bo	242
2007910102	01/09/2024 19:35	01/09/2024 23:03	250	Gloucester	Washington Twp	250
2007910185	01/09/2024 19:36	01/09/2024 23:03	109	Camden	Gloucester Twp	1
				Gloucester	Washington Twp	108
2007918931	01/09/2024 19:08	01/09/2024 23:05	191	Burlington	Bordentown City	152
				Burlington	Bordentown Twp	2
				Burlington	Fieldsboro Boro	37
2007911799	01/09/2024 19:36	01/09/2024 23:05	71	Gloucester	Washington Twp	71
2007911797	01/09/2024 19:36	01/09/2024 23:05	80	Gloucester	Washington Twp	80
2007911796	01/09/2024 19:36	01/09/2024 23:05	69	Burlington	Burlington City	1
				Gloucester	Washington Twp	68
2007910790	01/09/2024 21:08	01/09/2024 23:07	289	Burlington	Lumberton Twp	289
2007910992	01/09/2024 21:21	01/09/2024 23:07	903	Burlington	Hainesport Twp	1
				Burlington	Lumberton Twp	15
				Burlington	Mount Holly Twp	1
				Burlington	Pemberton Twp	146
				Burlington	Southampton Twp	740

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Location ID	Creation Date	Energized Date	Job Cust	County Affecte	Munis Affected	Muni Cust
2007909838	01/09/2024 18:52	01/09/2024 23:31	33	Union	Cranford Twp	33
2007910300	01/09/2024 20:20	01/09/2024 23:44	403	Burlington	Evesham Twp	403
2007910206	01/09/2024 19:36	01/09/2024 23:45	30	Burlington	Medford Twp	30
2007911934	01/09/2024 23:21	01/09/2024 23:50	1,526	Passaic	Clifton City	1,526
2007910515	01/09/2024 20:41	01/10/2024 00:04	544	Essex	Irvington Twp	44
				Essex	Newark City	500
2007917986	01/09/2024 21:07	01/10/2024 00:06	3	Gloucester	Deptford Twp	3
2007911910	01/09/2024 22:44	01/10/2024 00:10	134	Hudson	North Bergen Twp	134
2007911941	01/09/2024 18:44	01/10/2024 00:11	1,514	Camden	Gloucester City	1
				Camden	Gloucester Twp	1,513
2007920262	01/09/2024 22:17	01/10/2024 00:12	130	Mercer	Hamilton Twp	130
2007920260	01/09/2024 22:17	01/10/2024 00:12	547	Mercer	Hamilton Twp	547
2007911197	01/09/2024 21:24	01/10/2024 00:15	219	Somerset	Hillsborough Twp	119
				Somerset	Montgomery Twp	100
2007926297	01/09/2024 19:42	01/10/2024 00:18	768	Gloucester	Deptford Twp	768
2007920168	01/10/2024 00:11	01/10/2024 00:19	803	Camden	Gloucester Twp	123
				Camden	Haddon Heights Boro	3
				Camden	Runnemede Boro	677
2007909826	01/09/2024 19:00	01/10/2024 00:20	11	Camden	Gloucester Twp	11
2007911564	01/09/2024 22:31	01/10/2024 00:23	351	Bergen	Moonachie Boro	351
2007911773	01/09/2024 23:02	01/10/2024 00:29	96	Union	Union Twp	96
2007910537	01/09/2024 20:23	01/10/2024 00:30	42	Burlington	Willingboro Twp	42
2007911854	01/09/2024 22:51	01/10/2024 00:30	37	Bergen	Westwood Boro	37
2007910380	01/09/2024 20:19	01/10/2024 01:00	50	Burlington	Delran Twp	50
2007911810	01/09/2024 23:11	01/10/2024 01:05	253	Passaic	Clifton City	1
				Bergen	Garfield City	252
2007910928	01/09/2024 21:00	01/10/2024 01:05	14	Middlesex	North Brunswick Twp	14
2007910929	01/09/2024 21:00	01/10/2024 01:05	13	Middlesex	North Brunswick Twp	13
2007911673	01/09/2024 22:41	01/10/2024 01:07	39	Bergen	Carlstadt Boro	19
				Bergen	Moonachie Boro	20
2007914148	01/09/2024 22:27	01/10/2024 01:14	252	Middlesex	Woodbridge Twp	252
2007920348	01/09/2024 21:19	01/10/2024 01:14	312	Mercer	Hamilton Twp	312
2007918812	01/10/2024 01:13	01/10/2024 01:24	737	Burlington	Bordentown City	1
				Burlington	Bordentown Twp	711
				Burlington	Chesterfield Twp	1
				Burlington	Fieldsboro Boro	1
				Burlington	Florence Twp	2
				Burlington	Mansfield Twp	18
				Hunterdon	West Amwell Twp	1
2007909718	01/09/2024 18:39	01/10/2024 01:25	25	Burlington	Willingboro Twp	25
2007926967	01/09/2024 22:27	01/10/2024 01:44	185	Middlesex	Woodbridge Twp	185

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Location ID	Creation Date	Energized Date	Job Cust	County Affecte	Munis Affected	Muni Cust
2007926968	01/09/2024 22:27	01/10/2024 01:44	88	Middlesex	Woodbridge Twp	88
2007926969	01/09/2024 22:27	01/10/2024 01:44	146	Middlesex	Woodbridge Twp	146
2007910003	01/09/2024 18:58	01/10/2024 02:00	20	Burlington	Southampton Twp	20
2007912335	01/09/2024 20:50	01/10/2024 02:12	1,214	Middlesex	Dunellen Boro	927
				Somerset	Green Brook Twp	130
				Somerset	North Plainfield Boro	1
				Middlesex	Piscataway Twp	67
				Union	Plainfield City	89
2007910588	01/09/2024 20:50	01/10/2024 02:13	1,237	Middlesex	Dunellen Boro	438
				Somerset	Green Brook Twp	106
				Middlesex	Piscataway Twp	683
				Somerset	Somerville Boro	1
				Middlesex	South Plainfield Boro	9
2007923213	01/09/2024 21:12	01/10/2024 02:14	280	Burlington	Maple Shade Twp	28
				Burlington	Moorestown Twp	252
2007923214	01/09/2024 21:12	01/10/2024 02:14	908	Burlington	Maple Shade Twp	908
2007923215	01/09/2024 21:12	01/10/2024 02:14	787	Burlington	Maple Shade Twp	787
2007923216	01/09/2024 21:12	01/10/2024 02:14	321	Burlington	Maple Shade Twp	321
2007923217	01/09/2024 21:12	01/10/2024 02:14	589	Burlington	Maple Shade Twp	14
				Burlington	Moorestown Twp	575
2007923218	01/09/2024 21:12	01/10/2024 02:14	754	Burlington	Moorestown Twp	754
2007912389	01/09/2024 20:54	01/10/2024 02:21	1,620	Mercer	Hamilton Twp	1,618
				Mercer	Robbinsville Twp	2
2007912391	01/09/2024 18:48	01/10/2024 02:28	20	Mercer	Ewing Twp	20
2007909990	01/09/2024 19:13	01/10/2024 02:41	641	Camden	Cherry Hill Twp	641
2007910735	01/09/2024 19:44	01/10/2024 02:45	104	Burlington	Bordentown City	104
2007911664	01/09/2024 21:48	01/10/2024 03:00	17	Bergen	Haworth Boro	17
2007911679	01/09/2024 22:22	01/10/2024 03:02	23	Bergen	Englewood Cliffs Boro	23
2007912235	01/09/2024 19:09	01/10/2024 03:14	497	Camden	Cherry Hill Twp	13
				Camden	Merchantville Boro	369
				Camden	Pennsauken Twp	115
2007912332	01/10/2024 01:56	01/10/2024 03:15	329	Bergen	Englewood City	49
				Bergen	Tenafly Boro	280
2007909943	01/09/2024 18:50	01/10/2024 03:15	45	Mercer	Princeton	45
2007922678	01/09/2024 22:12	01/10/2024 03:24	287	Middlesex	Cranbury Twp	287
2007910995	01/09/2024 21:23	01/10/2024 03:32	468	Somerset	Hillsborough Twp	468
2007912495	01/10/2024 03:25	01/10/2024 03:32	560	Somerset	Hillsborough Twp	560
2007911556	01/09/2024 22:25	01/10/2024 03:58	885	Essex	West Orange Twp	885
2007910945	01/09/2024 21:20	01/10/2024 03:59	333	Gloucester	Woodbury City	333
2007911141	01/09/2024 21:17	01/10/2024 04:05	93	Middlesex	Edison Twp	93

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Location ID	Creation Date	Energized Date	Job Cust	County Affecte	Munis Affected	Muni Cust
2007912531	01/10/2024 02:28	01/10/2024 04:12	940	Bergen	Englewood City	1
				Bergen	Paramus Boro	252
				Bergen	River Edge Boro	687
2007912594	01/10/2024 02:27	01/10/2024 04:13	11	Bergen	Paramus Boro	11
2007912650	01/10/2024 04:41	01/10/2024 04:47	885	Essex	West Orange Twp	885
2007911714	01/09/2024 21:27	01/10/2024 04:50	107	Gloucester	West Deptford Twp	57
				Gloucester	Woodbury City	50
2007911935	01/09/2024 23:25	01/10/2024 05:00	16	Passaic	Clifton City	16
2007911936	01/09/2024 23:25	01/10/2024 05:00	6	Passaic	Clifton City	6
2007910594	01/09/2024 20:52	01/10/2024 05:14	359	Burlington	Evesham Twp	359
2007911329	01/09/2024 21:06	01/10/2024 05:15	14	Union	Plainfield City	14
2007912011	01/09/2024 18:44	01/10/2024 05:30	964	Camden	Gloucester Twp	889
				Camden	Runnemede Boro	75
2007922153	01/09/2024 18:53	01/10/2024 05:30	5	Mercer	Princeton	5
2007912748	01/10/2024 05:06	01/10/2024 05:55	2,553	Mercer	Trenton City	2,553
2007912491	01/09/2024 21:28	01/10/2024 06:00	40	Gloucester	West Deptford Twp	40
2007911572	01/09/2024 22:13	01/10/2024 06:12	23	Middlesex	North Brunswick Twp	23
2007911985	01/10/2024 00:04	01/10/2024 06:22	116	Middlesex	Edison Twp	116
2007918107	01/09/2024 22:19	01/10/2024 07:01	543	Burlington	Chesterfield Twp	108
				Mercer	Hamilton Twp	151
				Monmouth	Upper Freehold Twp	284
2007911586	01/09/2024 21:46	01/10/2024 07:30	28	Somerset	Montgomery Twp	28
2007912774	01/10/2024 03:32	01/10/2024 07:45	1,376	Gloucester	Deptford Twp	1
				Camden	Gloucester Twp	2
				Gloucester	West Deptford Twp	1,061
				Gloucester	Woodbury City	70
				Gloucester	Woodbury Heights Bo	242
2007913148	01/10/2024 07:42	01/10/2024 07:48	1,051	Middlesex	Perth Amboy City	1,050
				Union	Roselle Boro	1
2007911800	01/09/2024 18:52	01/10/2024 08:00	18	Essex	West Orange Twp	18
2007921055	01/10/2024 04:16	01/10/2024 08:00	40	Camden	Haddonfield Boro	40
2007913150	01/10/2024 07:56	01/10/2024 08:04	93	Essex	Cedar Grove Twp	93
2007913273	01/10/2024 08:14	01/10/2024 08:40	329	Bergen	Englewood City	49
				Bergen	Tenafly Boro	280
2007913030	01/10/2024 06:45	01/10/2024 08:47	11	Bergen	Tenafly Boro	11
2007921156	01/09/2024 21:33	01/10/2024 08:50	253	Middlesex	Cranbury Twp	253
2007912689	01/10/2024 03:59	01/10/2024 08:53	114	Burlington	Willingboro Twp	114
2007912925	01/10/2024 06:33	01/10/2024 09:00	78	Union	Plainfield City	78
2007912769	01/10/2024 05:54	01/10/2024 09:15	370	Camden	Cherry Hill Twp	174
				Camden	Pennsauken Twp	196

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Location ID	Creation Date	Energized Date	Job Cust	County Affecte	Munis Affected	Muni Cust
2007920255	01/10/2024 08:57	01/10/2024 09:23	445	Burlington	Delran Twp	314
				Burlington	Moorestown Twp	131
2007921277	01/09/2024 21:45	01/10/2024 09:44	564	Camden	Cherry Hill Twp	1
				Burlington	Evesham Twp	331
				Burlington	Medford Lakes Boro	1
				Burlington	Medford Twp	231
2007920200	01/09/2024 21:45	01/10/2024 09:44	434	Burlington	Medford Twp	325
				Burlington	Southampton Twp	109
2007913697	01/10/2024 07:54	01/10/2024 09:48	1,190	Burlington	Burlington City	1,141
				Burlington	Burlington Twp	48
				Burlington	Florence Twp	1
2007913277	01/10/2024 08:27	01/10/2024 09:50	45	Gloucester	West Deptford Twp	45
2007913704	01/10/2024 09:50	01/10/2024 09:57	463	Mercer	West Windsor Twp	463
2007913270	01/10/2024 08:03	01/10/2024 10:08	901	Essex	South Orange Village	901
2007911199	01/09/2024 21:41	01/10/2024 10:53	515	Mercer	Lawrence Twp	1
				Somerset	Montgomery Twp	514
2007911006	01/09/2024 21:19	01/10/2024 11:15	102	Camden	Pennsauken Twp	102
2007914131	01/10/2024 10:41	01/10/2024 11:15	522	Middlesex	Woodbridge Twp	522
2007920248	01/10/2024 09:43	01/10/2024 11:30	3	Burlington	Moorestown Twp	3
2007914390	01/10/2024 11:42	01/10/2024 11:50	387	Mercer	Trenton City	387
2007910428	01/09/2024 20:27	01/10/2024 11:57	104	Burlington	Willingboro Twp	104
2007922414	01/09/2024 19:00	01/10/2024 11:58	175	Burlington	Chesterfield Twp	1
				Burlington	Mansfield Twp	174
2007914392	01/10/2024 11:46	01/10/2024 12:01	79	Essex	Newark City	79
2007910107	01/09/2024 18:28	01/10/2024 12:06	107	Camden	Lawnside Boro	95
				Camden	Magnolia Boro	12
2007909640	01/09/2024 18:09	01/10/2024 12:08	3	Mercer	Princeton	3
2007912848	01/09/2024 23:20	01/10/2024 12:09	78	Middlesex	Edison Twp	49
				Middlesex	South Plainfield Boro	29
2007909627	01/09/2024 18:31	01/10/2024 12:30	79	Camden	Cherry Hill Twp	79
2007911328	01/09/2024 21:43	01/10/2024 12:39	57	Burlington	Willingboro Twp	57
2007914102	01/09/2024 21:43	01/10/2024 12:40	26	Mercer	Princeton	26
2007910789	01/09/2024 21:01	01/10/2024 12:45	3	Hunterdon	East Amwell Twp	3
2007912118	01/09/2024 20:43	01/10/2024 12:50	56	Gloucester	Deptford Twp	56
2007912124	01/10/2024 00:11	01/10/2024 13:00	40	Gloucester	Deptford Twp	39
				Gloucester	National Park Boro	1
2007912173	01/10/2024 00:15	01/10/2024 13:00	22	Gloucester	Deptford Twp	22
2007914427	01/10/2024 11:43	01/10/2024 13:00	6	Essex	West Orange Twp	6
2007914691	01/10/2024 12:52	01/10/2024 13:03	959	Middlesex	Edison Twp	6
				Middlesex	Metuchen Boro	953
2007911551	01/09/2024 22:18	01/10/2024 13:05	93	Burlington	Willingboro Twp	93

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Location ID	Creation Date	Energized Date	Job Cust	County Affecte	Munis Affected	Muni Cust
2007911129	01/09/2024 19:22	01/10/2024 13:21	588	Camden	Barrington Boro	24
				Camden	Haddon Heights Boro	5
				Camden	Haddonfield Boro	559
2007914451	01/10/2024 11:51	01/10/2024 13:25	500	Camden	Barrington Boro	405
				Camden	Haddon Heights Boro	95
2007914749	01/10/2024 06:44	01/10/2024 13:29	65	Burlington	Mount Laurel Twp	65
2007911481	01/09/2024 21:46	01/10/2024 13:30	48	Gloucester	West Deptford Twp	48
2007912331	01/09/2024 19:22	01/10/2024 13:36	184	Camden	Haddonfield Boro	184
2007911346	01/09/2024 21:05	01/10/2024 13:45	13	Mercer	Princeton	13
2007909997	01/09/2024 19:15	01/10/2024 13:55	75	Mercer	Trenton City	75
2007910229	01/09/2024 19:43	01/10/2024 14:00	6	Gloucester	West Deptford Twp	6
2007910520	01/09/2024 19:36	01/10/2024 14:00	74	Somerset	Franklin Twp	73
				Somerset	Rocky Hill Boro	1
2007911230	01/09/2024 21:24	01/10/2024 14:00	165	Burlington	Burlington Twp	165
2007911737	01/09/2024 22:53	01/10/2024 14:00	43	Camden	Haddon Twp	43
2007914609	01/10/2024 12:30	01/10/2024 14:00	27	Burlington	Burlington Twp	27
2007910415	01/09/2024 20:23	01/10/2024 14:00	63	Burlington	Willingboro Twp	63
2007914129	01/10/2024 10:57	01/10/2024 14:28	880	Essex	Newark City	880
2007912592	01/09/2024 21:17	01/10/2024 14:30	16	Middlesex	Edison Twp	16
2007910996	01/09/2024 20:49	01/10/2024 14:40	11	Camden	Cherry Hill Twp	11
2007914970	01/10/2024 14:02	01/10/2024 14:40	71	Camden	Cherry Hill Twp	71
2007911548	01/09/2024 21:36	01/10/2024 14:45	10	Mercer	Princeton	10
2007912449	01/09/2024 22:14	01/10/2024 14:50	37	Mercer	Hamilton Twp	37
2007915070	01/10/2024 14:44	01/10/2024 14:50	349	Monmouth	Allentown Boro	156
				Mercer	Hamilton Twp	120
				Monmouth	Upper Freehold Twp	73
2007920257	01/09/2024 20:19	01/10/2024 15:00	10	Burlington	Delran Twp	10
2007911806	01/09/2024 21:48	01/10/2024 15:00	17	Mercer	Hamilton Twp	17
2007911258	01/09/2024 21:27	01/10/2024 15:15	84	Burlington	Willingboro Twp	84
2007932759	01/10/2024 11:13	01/10/2024 15:28	1	Burlington	Moorestown Twp	1
2007909797	01/09/2024 18:53	01/10/2024 15:30	13	Mercer	Lawrence Twp	13
2007911417	01/09/2024 21:25	01/10/2024 15:30	13	Somerset	Montgomery Twp	13
2007914633	01/10/2024 06:47	01/10/2024 15:30	57	Hunterdon	East Amwell Twp	4
				Mercer	Hopewell Twp	53
2007910699	01/09/2024 20:44	01/10/2024 15:52	35	Burlington	Medford Twp	35
2007911539	01/09/2024 22:09	01/10/2024 15:54	38	Camden	Haddon Twp	36
				Camden	Haddonfield Boro	2
2007910522	01/09/2024 20:29	01/10/2024 15:58	23	Burlington	Medford Twp	22
				Burlington	Moorestown Twp	1
2007911418	01/09/2024 21:55	01/10/2024 16:15	8	Somerset	Montgomery Twp	8
2007912189	01/09/2024 22:27	01/10/2024 16:15	68	Middlesex	Woodbridge Twp	68

Trouble Location Restoration Data

SOE - Severe Wind and Rain Storm - January 9-11, 2024

The purpose of this report is to list in sequential restoration order all outage events that were restored, the number of customers restored, the time at which they were restored and the municipality and county affected by the outage

Location ID	Creation Date	Energized Date	Job Cust	County Affecte	Munis Affected	Muni Cust
2007912190	01/09/2024 22:27	01/10/2024 16:15	9	Middlesex	Woodbridge Twp	9
2007912191	01/09/2024 22:27	01/10/2024 16:15	1	Middlesex	Woodbridge Twp	1
2007910930	01/09/2024 20:44	01/10/2024 16:25	50	Mercer	Trenton City	50
2007914281	01/10/2024 10:10	01/10/2024 16:52	16	Middlesex	Woodbridge Twp	16
2007914865	01/10/2024 03:59	01/10/2024 17:00	3	Burlington	Mount Laurel Twp	3
2007921054	01/10/2024 04:16	01/10/2024 17:00	11	Camden	Haddonfield Boro	11
2007913279	01/10/2024 03:03	01/10/2024 17:08	32	Burlington	Moorestown Twp	32
2007913584	01/10/2024 05:54	01/10/2024 17:13	403	Camden	Cherry Hill Twp	403
2007911712	01/09/2024 21:52	01/10/2024 17:17	59	Burlington	Bordentown Twp	1
				Burlington	Chesterfield Twp	58
2007915490	01/10/2024 17:09	01/10/2024 17:19	779	Passaic	Clifton City	779
2007910993	01/09/2024 21:22	01/10/2024 17:21	265	Middlesex	South Brunswick Twp	265
2007911352	01/09/2024 21:46	01/10/2024 17:30	18	Mercer	Hopewell Twp	18
2007915287	01/09/2024 21:06	01/10/2024 18:11	14	Burlington	Bordentown Twp	14
2007914736	01/10/2024 12:25	01/10/2024 18:19	8	Burlington	Pemberton Twp	1
				Burlington	Springfield Twp	7
2007913694	01/09/2024 21:09	01/10/2024 18:20	14	Camden	Gloucester Twp	14
2007911931	01/09/2024 20:37	01/10/2024 18:45	25	Burlington	Willingboro Twp	25
2007920474	01/09/2024 23:03	01/10/2024 18:52	9	Mercer	Hamilton Twp	9
2007909932	01/09/2024 18:53	01/10/2024 18:54	32	Mercer	West Windsor Twp	32
2007911559	01/09/2024 22:10	01/10/2024 19:00	168	Middlesex	Metuchen Boro	168
2007918928	01/09/2024 19:08	01/10/2024 19:00	169	Burlington	Bordentown Twp	29
				Burlington	Fieldsboro Boro	140
2007918929	01/09/2024 19:08	01/10/2024 19:00	95	Burlington	Bordentown Twp	24
				Burlington	Fieldsboro Boro	71
2007918930	01/09/2024 19:08	01/10/2024 19:00	78	Burlington	Bordentown Twp	26
				Burlington	Fieldsboro Boro	52
2007921051	01/09/2024 21:20	01/10/2024 19:00	22	Gloucester	Woodbury City	22
2007921052	01/09/2024 21:20	01/10/2024 19:00	1	Gloucester	Woodbury City	1
2007912839	01/10/2024 06:28	01/10/2024 19:30	5	Burlington	Chesterfield Twp	5
2007914438	01/09/2024 22:17	01/10/2024 19:33	12	Mercer	Ewing Twp	1
				Mercer	Hamilton Twp	11
2007915773	01/10/2024 19:04	01/10/2024 19:37	570	Middlesex	Carteret Boro	32
				Middlesex	Edison Twp	1
				Middlesex	Woodbridge Twp	537
2007915870	01/10/2024 19:53	01/10/2024 20:01	38	Union	Elizabeth City	38
2007911769	01/09/2024 21:07	01/10/2024 20:15	53	Middlesex	South Brunswick Twp	53
2007911771	01/09/2024 21:07	01/10/2024 20:15	5	Middlesex	South Brunswick Twp	5
2007920256	01/10/2024 20:15	01/10/2024 20:25	259	Burlington	Moorestown Twp	259

Trouble Location Restoration Data

SOE - Severe Wind and Rain Storm - January 9-11, 2024

The purpose of this report is to list in sequential restoration order all outage events that were restored, the number of customers restored, the time at which they were restored and the municipality and county affected by the outage

Location ID	Creation Date	Energized Date	Job Cust	County Affecte	Munis Affected	Muni Cust
2007915871	01/10/2024 19:56	01/10/2024 20:27	569	Middlesex	Carteret Boro	32
				Middlesex	Edison Twp	1
				Middlesex	Woodbridge Twp	536
2007915810	01/10/2024 19:31	01/10/2024 21:13	190	Camden	Cherry Hill Twp	190
2007912529	01/09/2024 20:50	01/10/2024 21:30	31	Middlesex	Dunellen Boro	31
2007922235	01/09/2024 18:53	01/10/2024 21:35	19	Mercer	West Windsor Twp	19
2007915644	01/10/2024 18:22	01/10/2024 21:38	2,156	Mercer	Ewing Twp	1
				Mercer	Hopewell Twp	1
				Somerset	Montgomery Twp	1,319
				Middlesex	North Brunswick Twp	6
				Mercer	Princeton	799
				Somerset	Rocky Hill Boro	34
2007916031	01/10/2024 21:41	01/10/2024 21:47	678	Middlesex	Woodbridge Twp	678
2007922254	01/09/2024 18:55	01/10/2024 22:08	73	Mercer	Lawrence Twp	73
2007916148	01/10/2024 17:33	01/10/2024 23:01	3	Somerset	Montgomery Twp	3
2007920259	01/10/2024 07:42	01/11/2024 01:00	3	Burlington	Cinnaminson Twp	3
2007916200	01/11/2024 01:15	01/11/2024 01:48	222	Essex	Newark City	222
2007915227	01/10/2024 15:29	01/11/2024 02:37	2	Mercer	Hopewell Twp	2
2007920350	01/10/2024 15:09	01/11/2024 03:00	42	Burlington	Bordentown Twp	42
2007916288	01/11/2024 03:12	01/11/2024 03:23	247	Somerset	Montgomery Twp	13
				Middlesex	North Brunswick Twp	6
				Mercer	Princeton	228
2007916289	01/11/2024 03:55	01/11/2024 04:29	50	Gloucester	Westville Boro	50
2007920351	01/09/2024 21:08	01/11/2024 05:00	9	Burlington	Bordentown Twp	9
2007915463	01/09/2024 20:49	01/11/2024 05:30	166	Camden	Gloucester City	166
2007914508	01/10/2024 07:19	01/11/2024 06:14	6	Somerset	Montgomery Twp	6
2007910715	01/09/2024 19:37	01/11/2024 07:25	27	Somerset	Franklin Twp	27
2007916394	01/11/2024 07:15	01/11/2024 08:46	69	Burlington	Cinnaminson Twp	69
2007922149	01/09/2024 18:53	01/11/2024 09:00	17	Mercer	Hopewell Twp	17
2007916609	01/11/2024 08:55	01/11/2024 09:07	852	Burlington	Mount Laurel Twp	852
2007916608	01/11/2024 08:55	01/11/2024 09:08	1,314	Burlington	Lumberton Twp	35
				Burlington	Moorestown Twp	1
				Burlington	Mount Holly Twp	1
				Burlington	Mount Laurel Twp	1,277
2007916201	01/10/2024 08:46	01/11/2024 09:22	3	Mercer	Princeton	3
2007914200	01/10/2024 11:07	01/11/2024 09:30	6	Burlington	Pemberton Twp	6
2007916481	01/11/2024 07:58	01/11/2024 09:35	1	Middlesex	Piscataway Twp	1
2007917891	01/11/2024 08:48	01/11/2024 10:00	2	Burlington	Burlington Twp	2
2007911390	01/09/2024 21:57	01/11/2024 10:19	2	Burlington	Chesterfield Twp	2
2007916759	01/11/2024 09:55	01/11/2024 10:23	27	Union	Hillside Twp	27
2007913587	01/10/2024 08:58	01/11/2024 10:28	2	Camden	Gloucester Twp	2

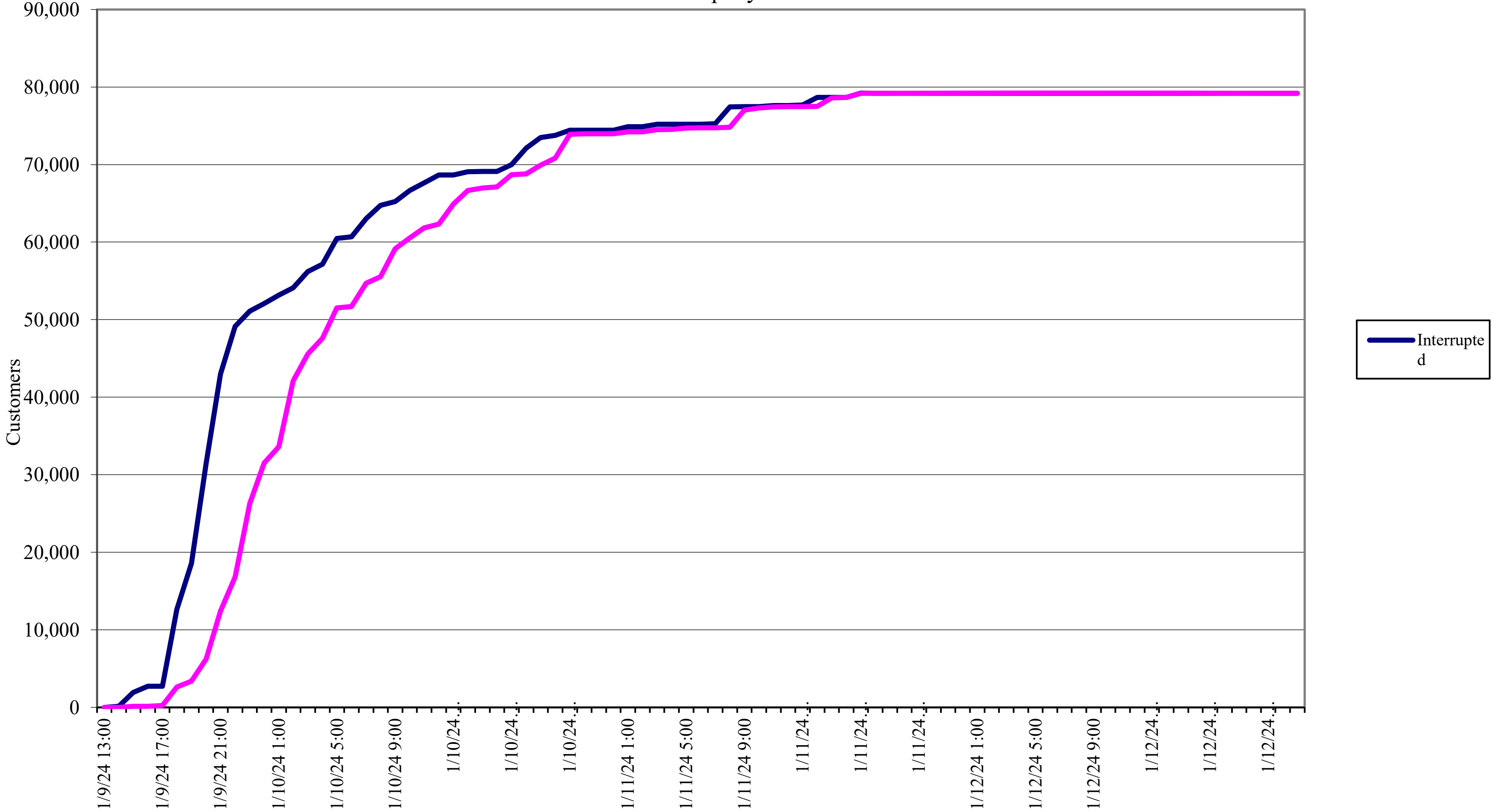
Trouble Location Restoration Data

SOE - Severe Wind and Rain Storm - January 9-11, 2024

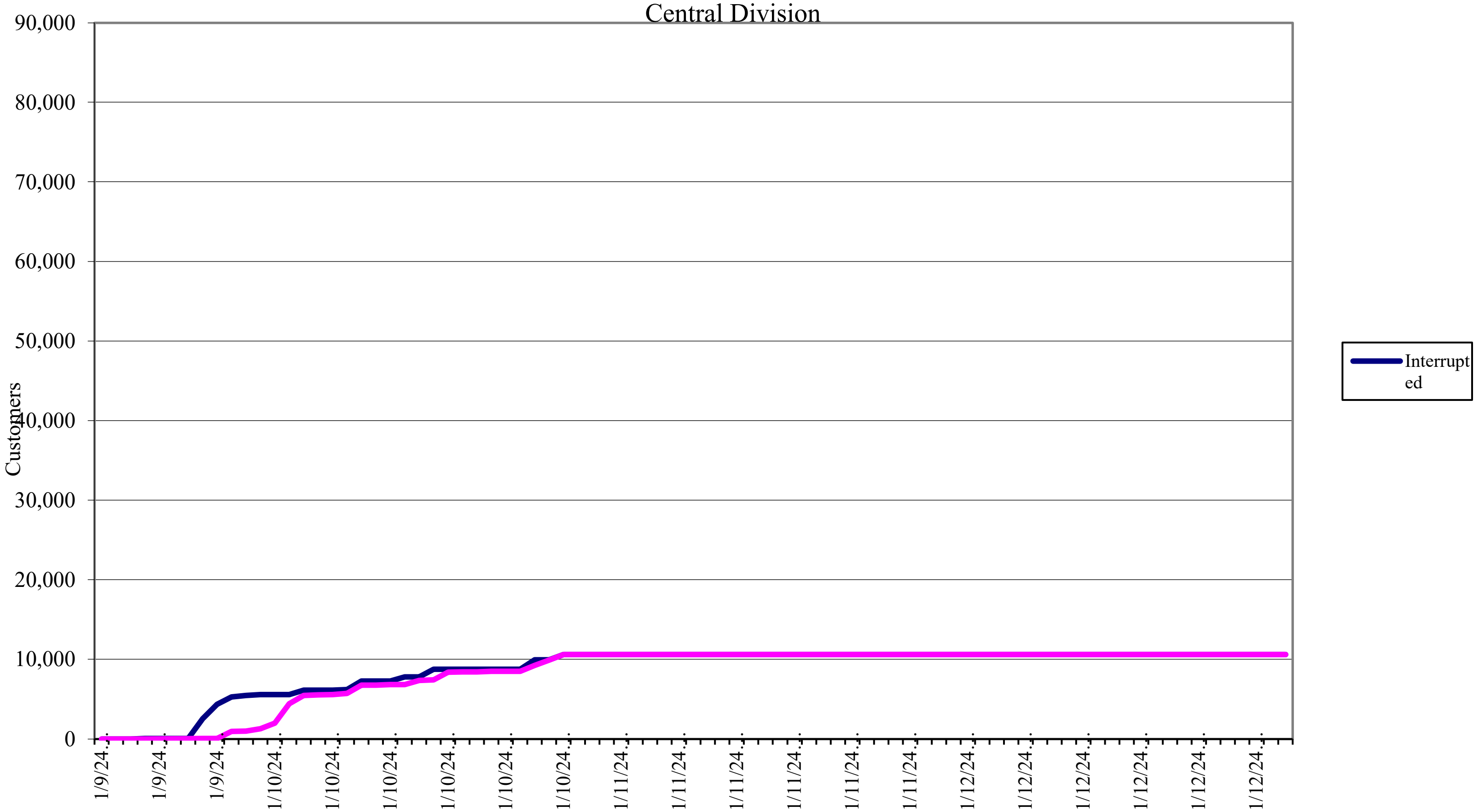
The purpose of this report is to list in sequential restoration order all outage events that were restored, the number of customers restored, the time at which they were restored and the municipality and county affected by the outage

Location ID	Creation Date	Energized Date	Job Cust	County Affecte	Munis Affected	Muni Cust
2007916228	01/11/2024 01:29	01/11/2024 10:30	230	Burlington	Willingboro Twp	230
2007916735	01/11/2024 09:51	01/11/2024 10:41	1	Mercer	Princeton	1
2007916145	01/09/2024 21:21	01/11/2024 11:11	2	Mercer	Lawrence Twp	2
2007916937	01/11/2024 11:38	01/11/2024 11:46	158	Burlington	Medford Twp	158
2007922620	01/10/2024 09:23	01/11/2024 11:55	4	Camden	Cherry Hill Twp	4
2007915756	01/10/2024 17:33	01/11/2024 12:40	42	Somerset	Hillsborough Twp	2
				Somerset	Montgomery Twp	40
2007922148	01/09/2024 18:53	01/11/2024 14:00	25	Mercer	Hopewell Twp	25
2007910403	01/09/2024 20:29	01/11/2024 14:16	1	Burlington	Mansfield Twp	1
2007917209	01/11/2024 14:55	01/11/2024 15:06	988	Camden	Audubon Boro	288
				Camden	Collingswood Boro	1
				Camden	Haddon Twp	519
				Camden	Oaklyn Boro	180
2007917018	01/11/2024 13:15	01/11/2024 15:10	72	Camden	Woodlynne Boro	72
2007913995	01/09/2024 21:41	01/11/2024 15:57	2	Somerset	Montgomery Twp	2
2007913993	01/09/2024 21:41	01/11/2024 15:58	1	Somerset	Montgomery Twp	1
2007913996	01/09/2024 21:41	01/11/2024 15:58	6	Somerset	Montgomery Twp	6
2007917807	01/11/2024 07:31	01/11/2024 16:00	2	Mercer	Ewing Twp	2
2007915584	01/10/2024 10:29	01/11/2024 16:04	24	Mercer	Hopewell Twp	24
2007916149	01/10/2024 17:33	01/11/2024 16:14	3	Somerset	Hillsborough Twp	3
2007916151	01/10/2024 17:33	01/11/2024 16:14	31	Somerset	Hillsborough Twp	31
2007916136	01/10/2024 17:33	01/11/2024 16:14	13	Somerset	Montgomery Twp	13
2007915541	01/10/2024 06:44	01/11/2024 16:55	14	Burlington	Mount Laurel Twp	14
2007917331	01/11/2024 17:00	01/11/2024 17:46	533	Burlington	Bordentown City	152
				Burlington	Bordentown Twp	81
				Burlington	Fieldsboro Boro	300
2007922150	01/09/2024 18:53	01/11/2024 20:30	1	Mercer	Lawrence Twp	1
2007917682	01/11/2024 18:34	01/11/2024 22:30	1	Somerset	Montgomery Twp	1
2007917244	01/11/2024 09:07	01/12/2024 11:45	1	Burlington	Moorestown Twp	1
2007917995	01/11/2024 08:28	01/12/2024 18:16	2	Burlington	Southampton Twp	2

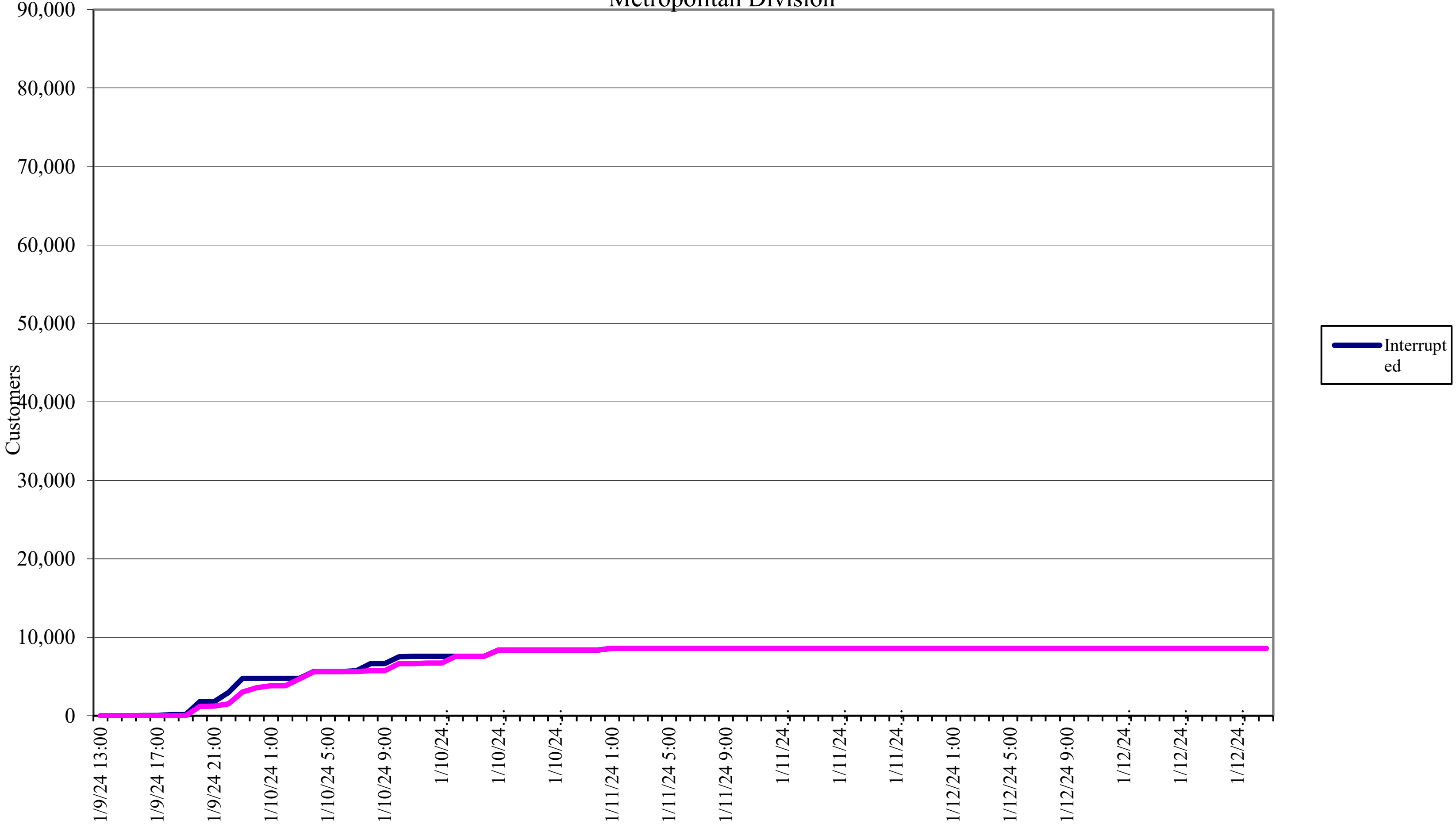
Attachment "A"
PSE&G
Customer Restoration Summary
SOE - Severe Wind and Rain Storm Jainuary 9-11, 2024
Company Wide



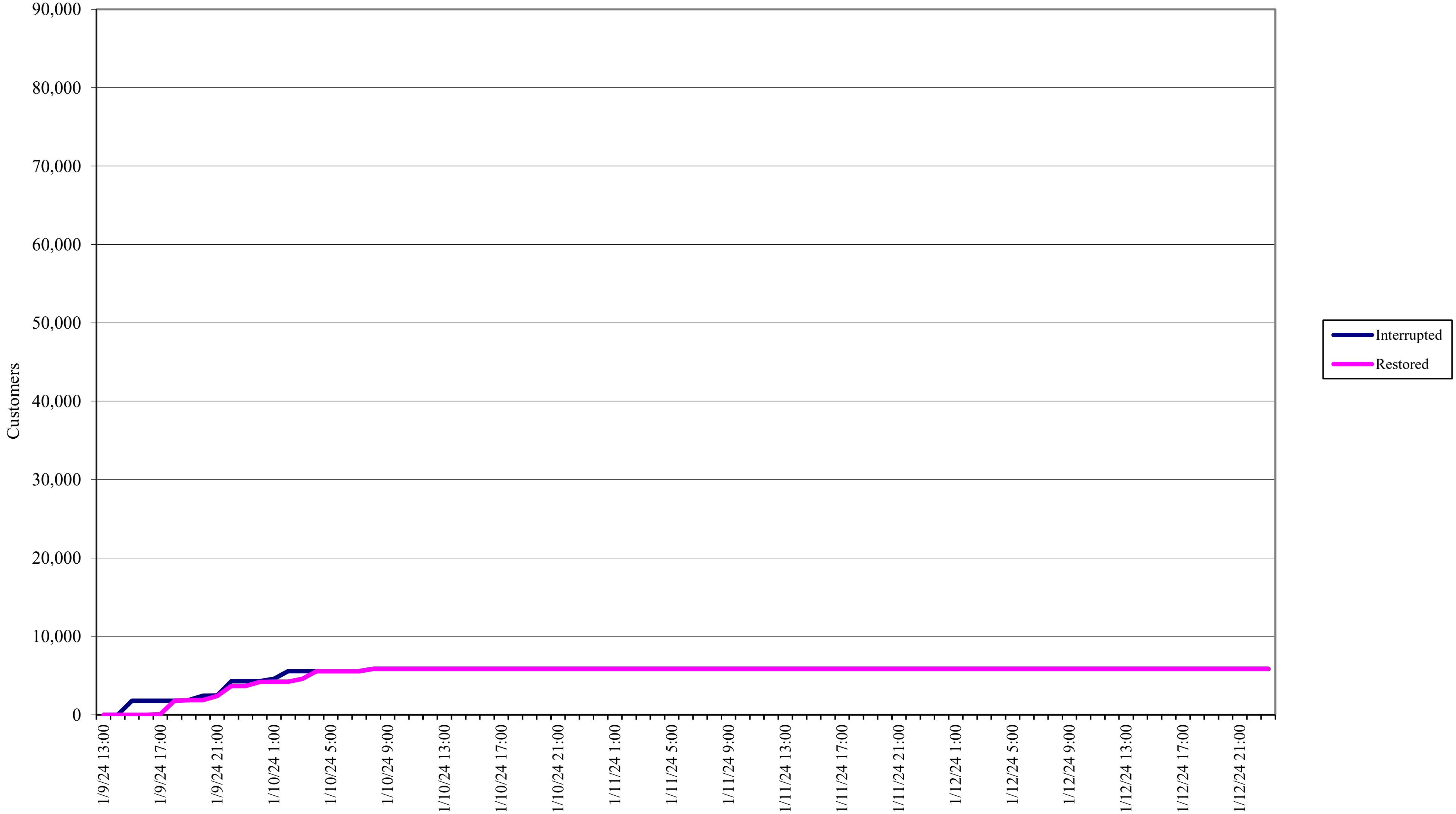
Attachment "B"
PSE&G
Customer Restoration Summary
SOE - Severe Wind and Rain Storm Jainuary 9-11, 2024
Central Division



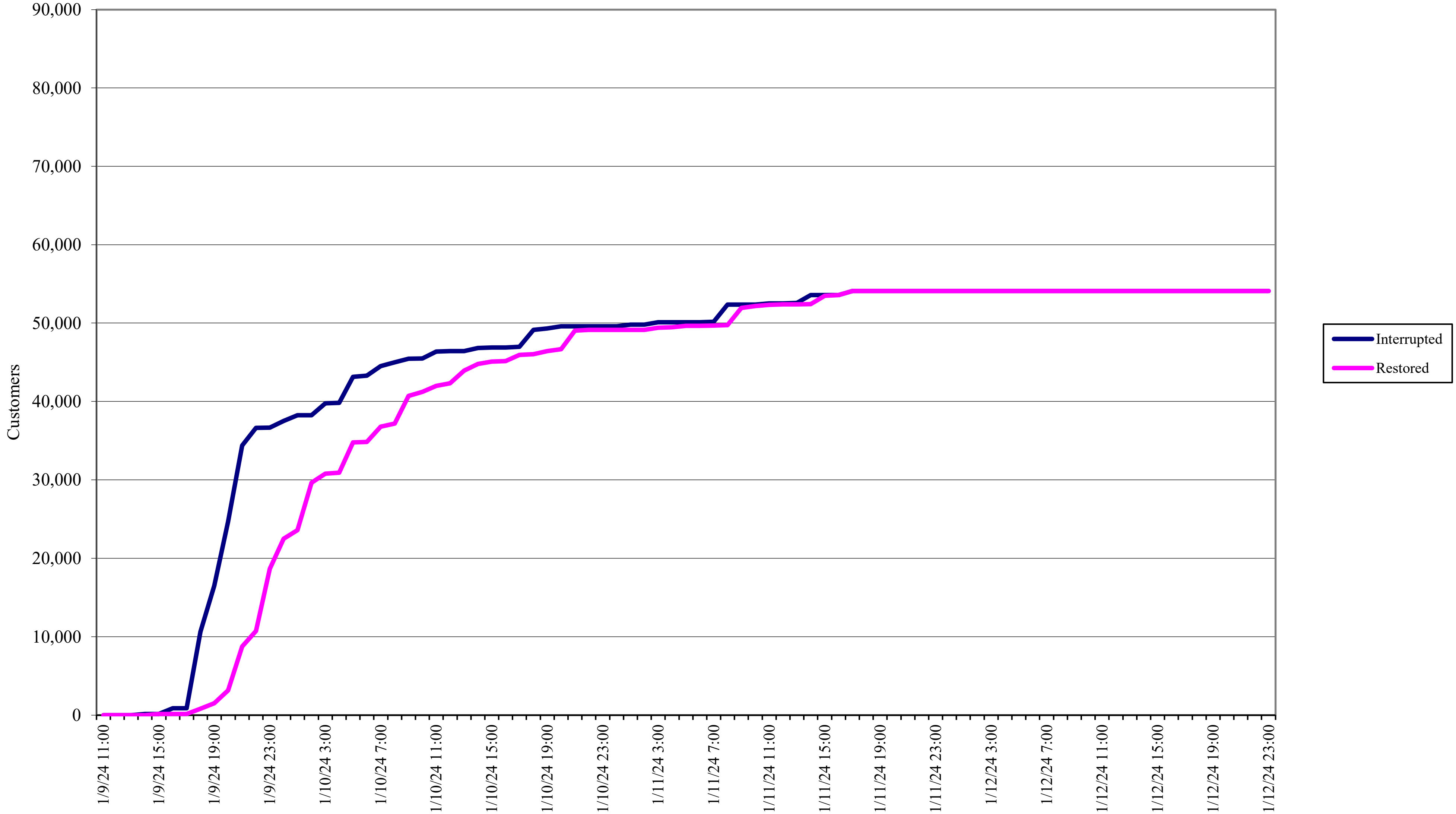
Attachment "C"
PSE&G
Customer Restoration Summary
SOE - Severe Wind and Rain Storm Jainuary 9-11, 2024
Metropolitan Division



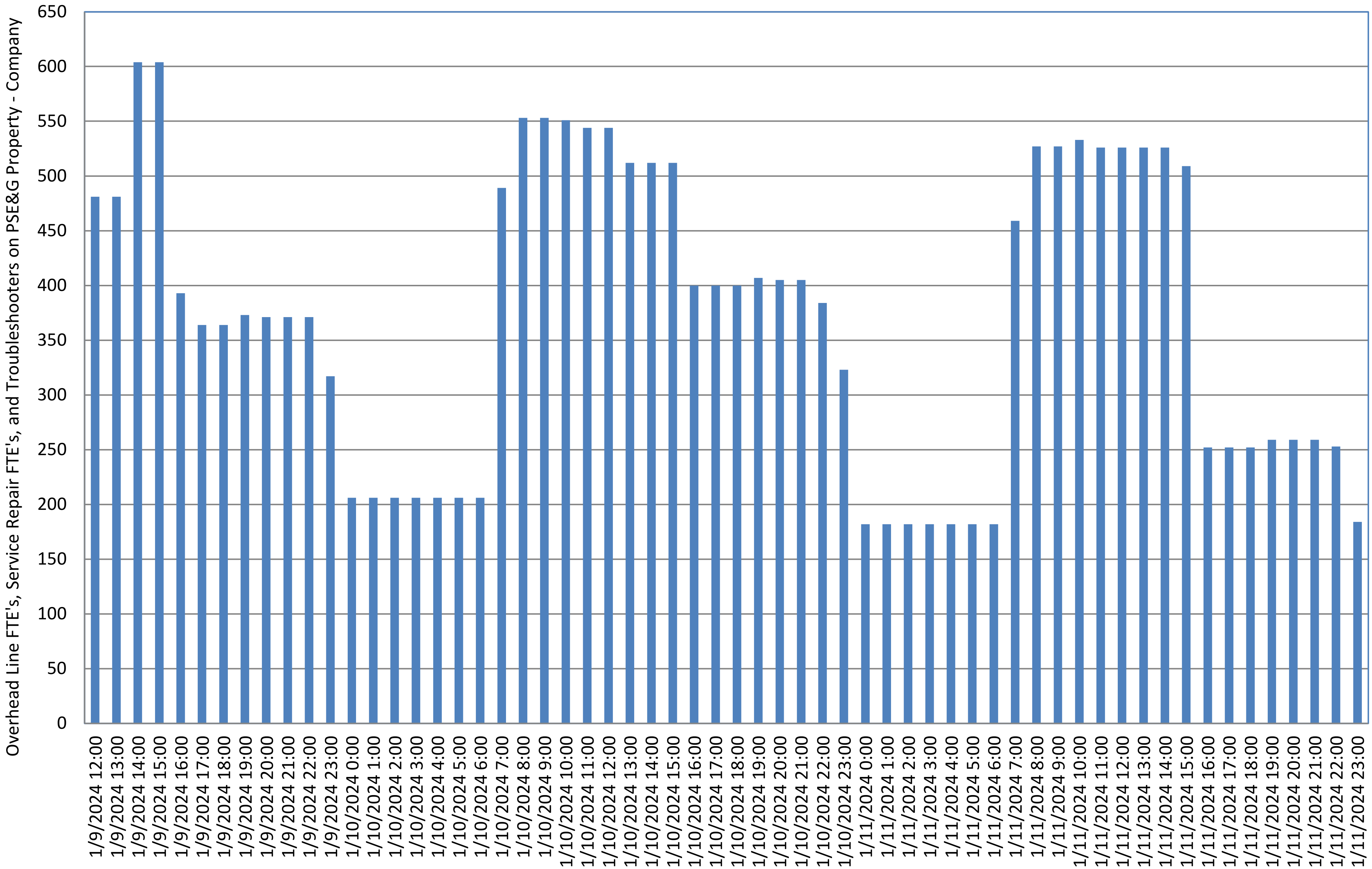
Attachment "D"
PSE&G
Customer Restoration Summary
SOE - Severe Wind and Rain Storm Jainuary 9-11, 2024
Palisades Division



Attachment "E"
PSE&G
Customer Restoration Summary
SOE - Severe Wind and Rain Storm Jainuary 9-11, 2024
Southern Division

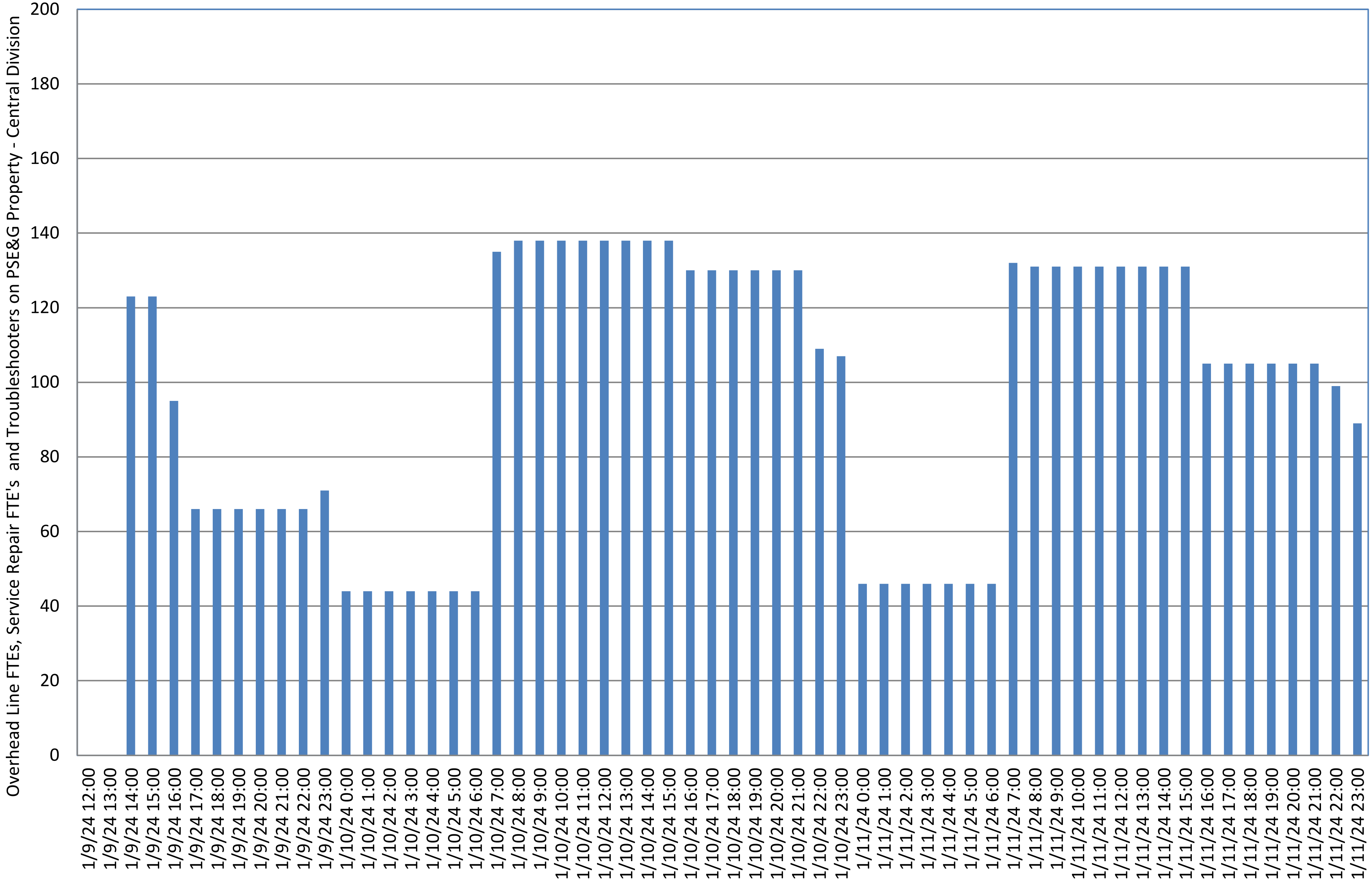


Attachment "F"
PSE&G
Overhead Line FTE's, Service Repair FTE's, and Troubleshooters on PSE&G Property - Company
SOE/Severe Wind and Rainstorm – January 9-11, 2024

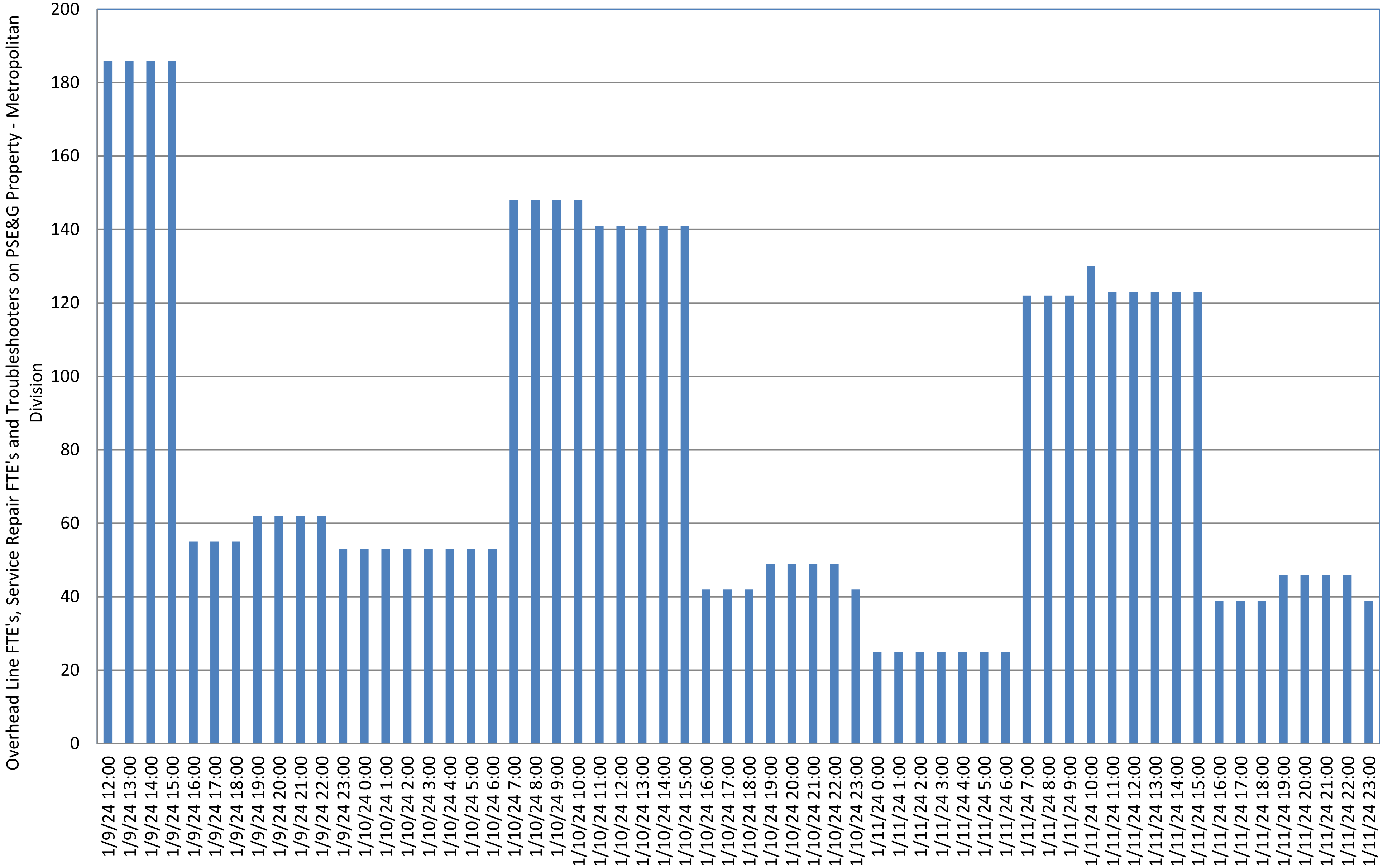


*These values include P&C Workforce Numbers

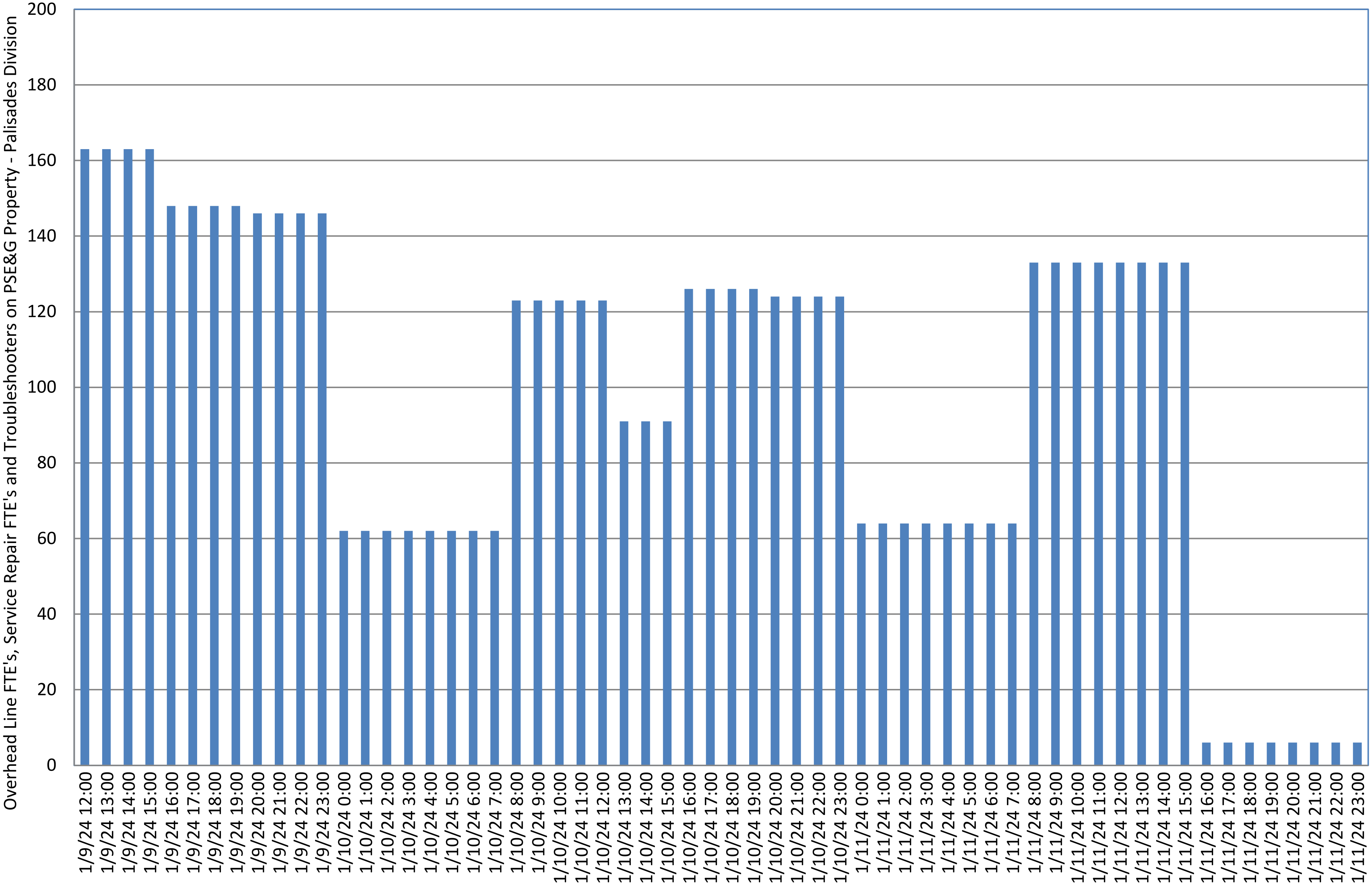
Attachment "G"
PSE&G
Overhead Line FTE's, Service Repair FTE's, and Troubleshooters on PSE&G Property - Central Division
SOE/Severe Wind and Rainstorm – January 9-11, 2024



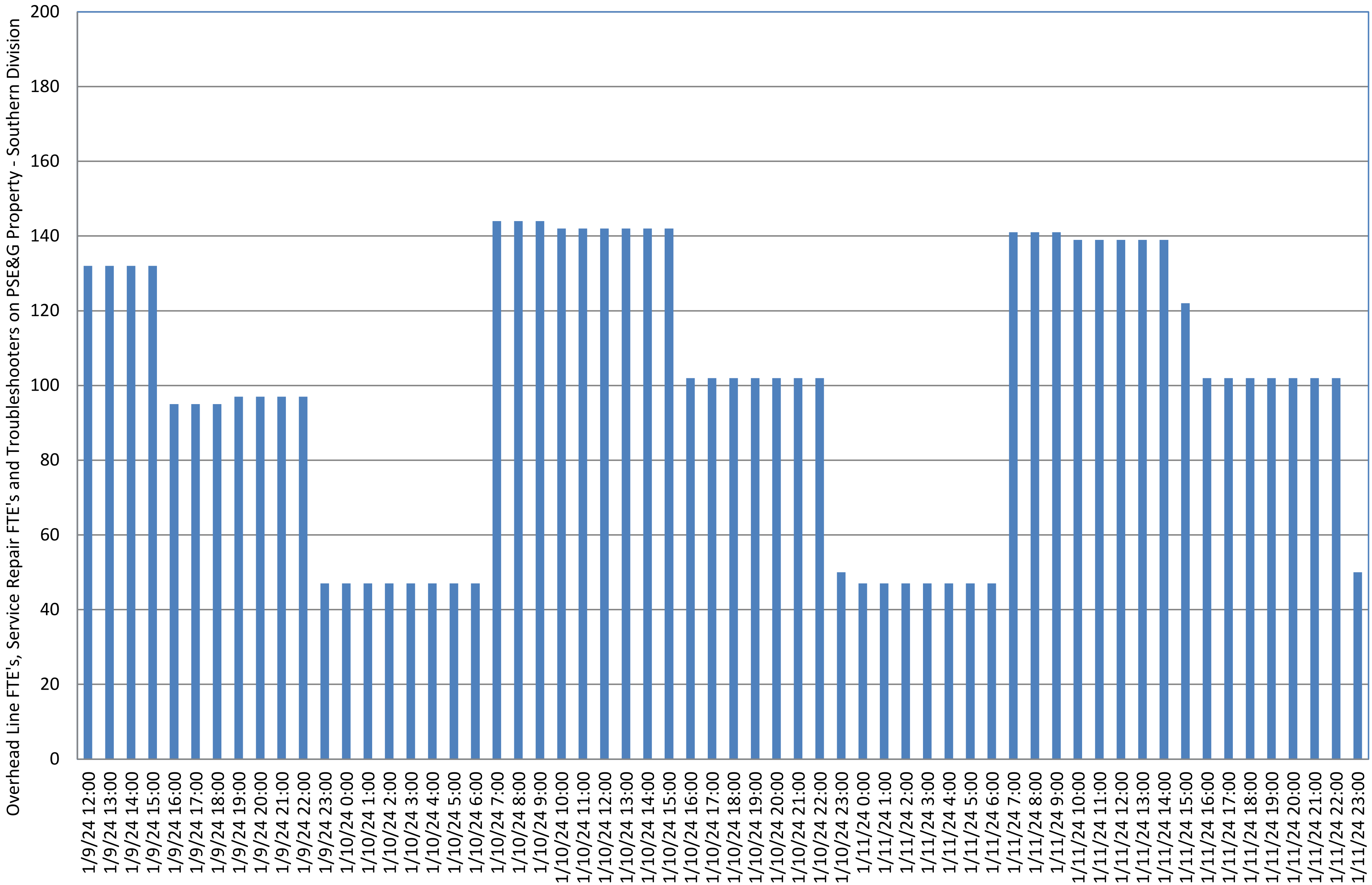
Attachment "H"
PSE&G
Overhead Line FTE's, Service Repair FTE's, and Troubleshooters on PSE&G Property - Metropolitan Division
SOE/Severe Wind and Rainstorm – January 9-11, 2024



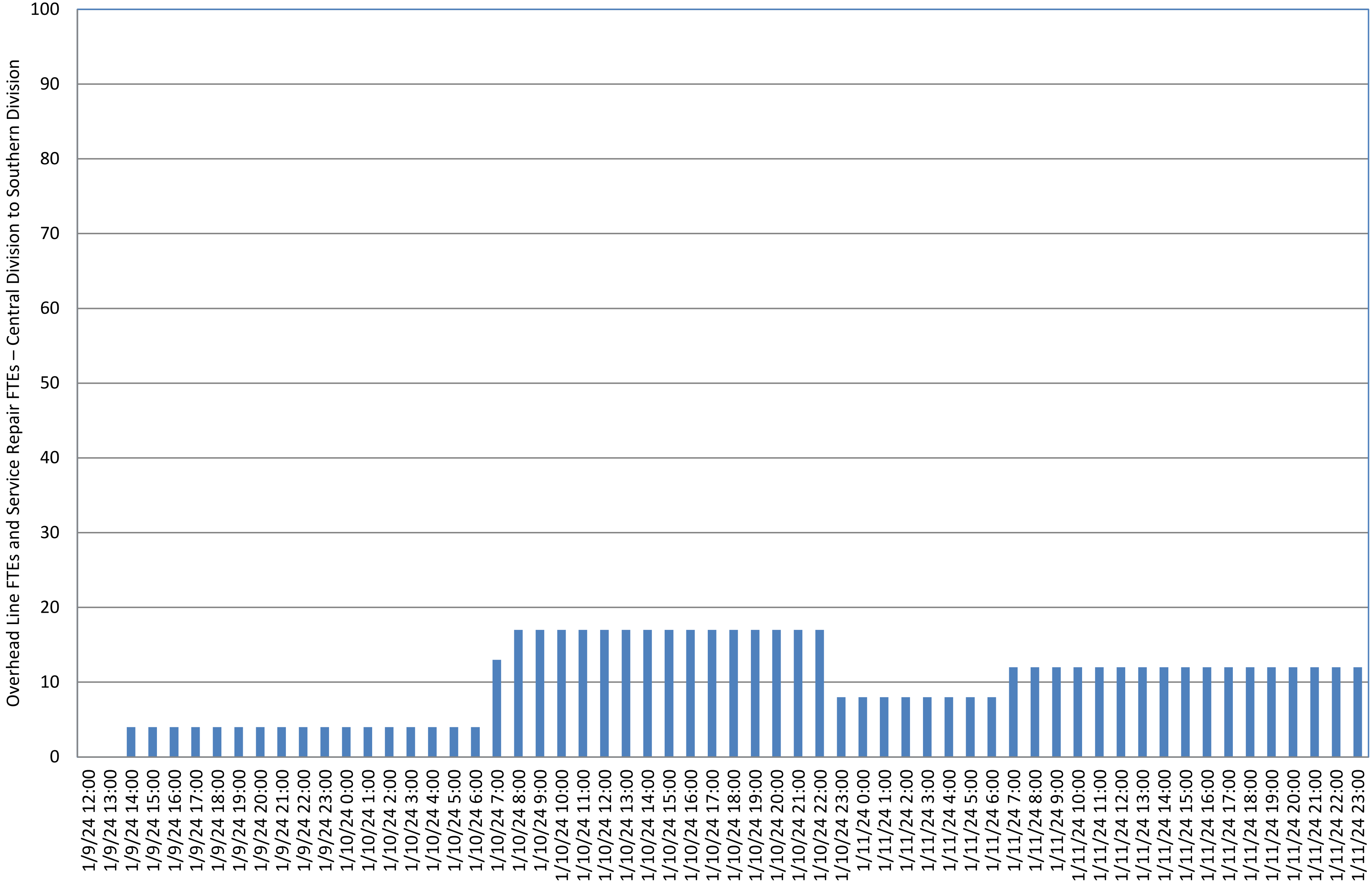
Attachment "I"
PSE&G
Overhead Line FTE's, Service Repair FTE's, and Troubleshooters on PSE&G Property - Palisades Division
SOE/Severe Wind and Rainstorm – January 9-11, 2024



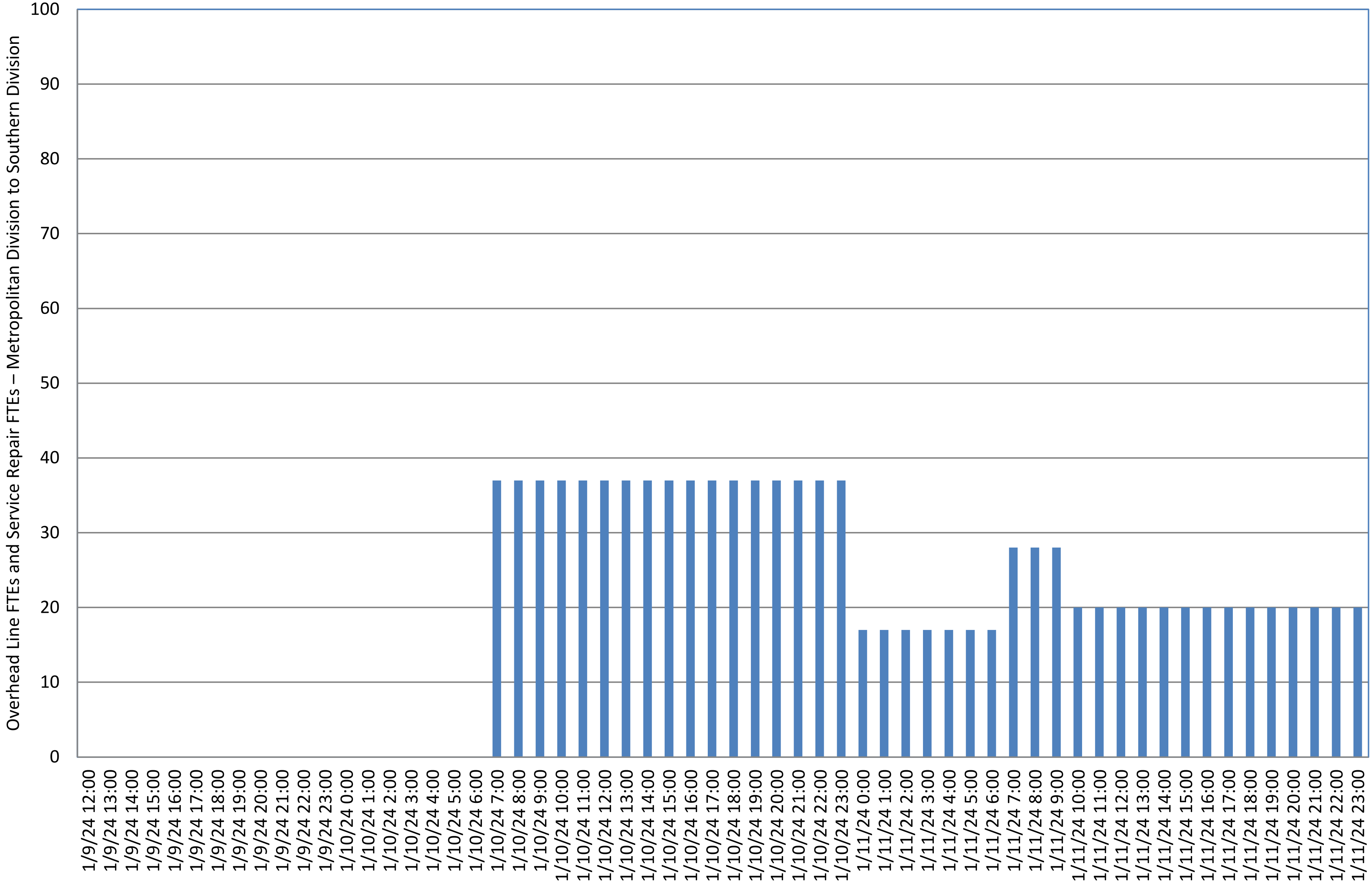
Attachment "J"
PSE&G
Overhead Line FTE's, Service Repair FTE's, and Troubleshooters on PSE&G Property - Southern Division
SOE/Severe Wind and Rainstorm – January 9-11, 2024



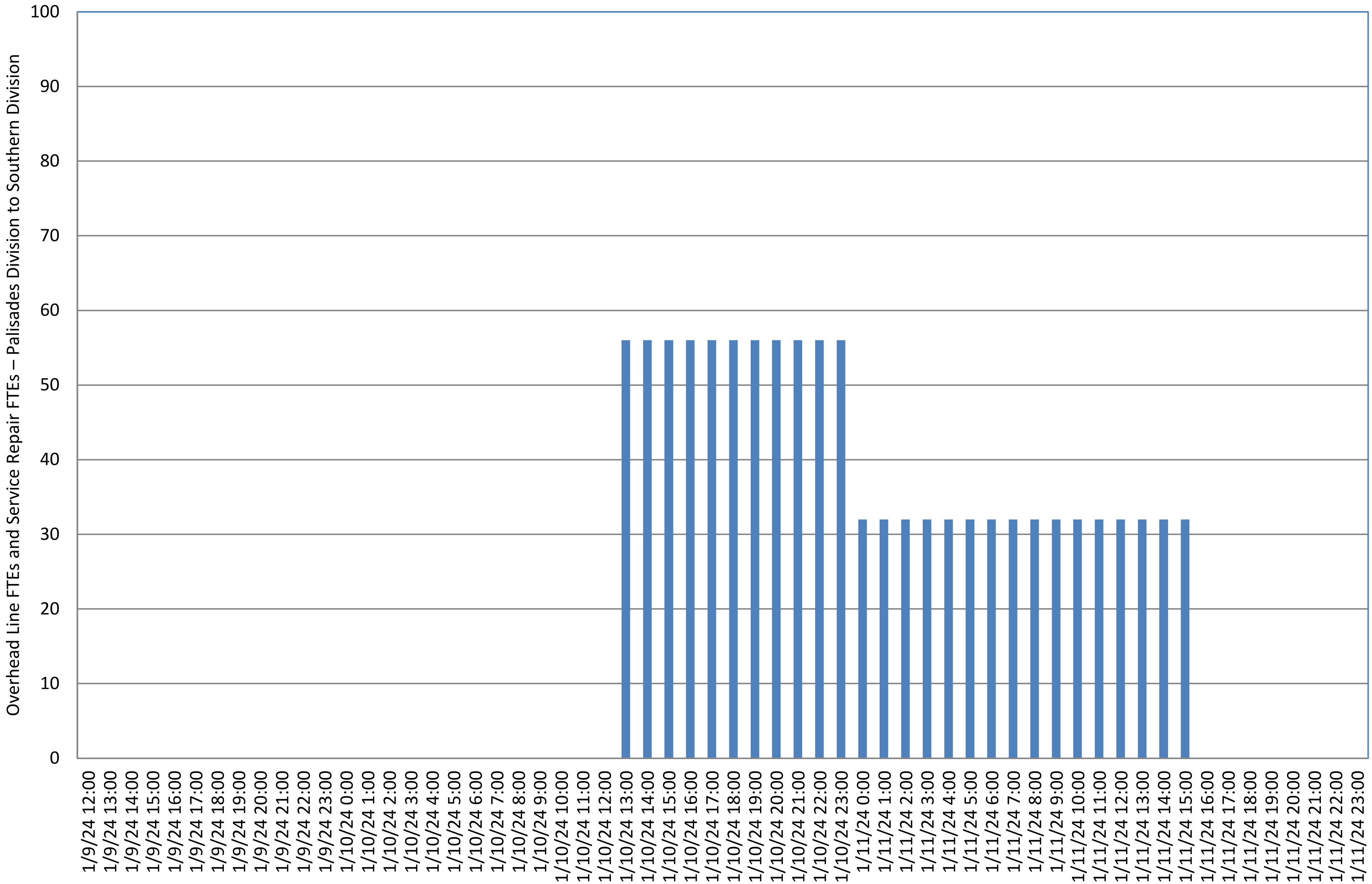
Attachment "K"
PSE&G
Overhead Line FTEs and Service Repair FTEs – Central Division to Southern Division
SOE/Severe Wind and Rainstorm – January 9-11, 2024



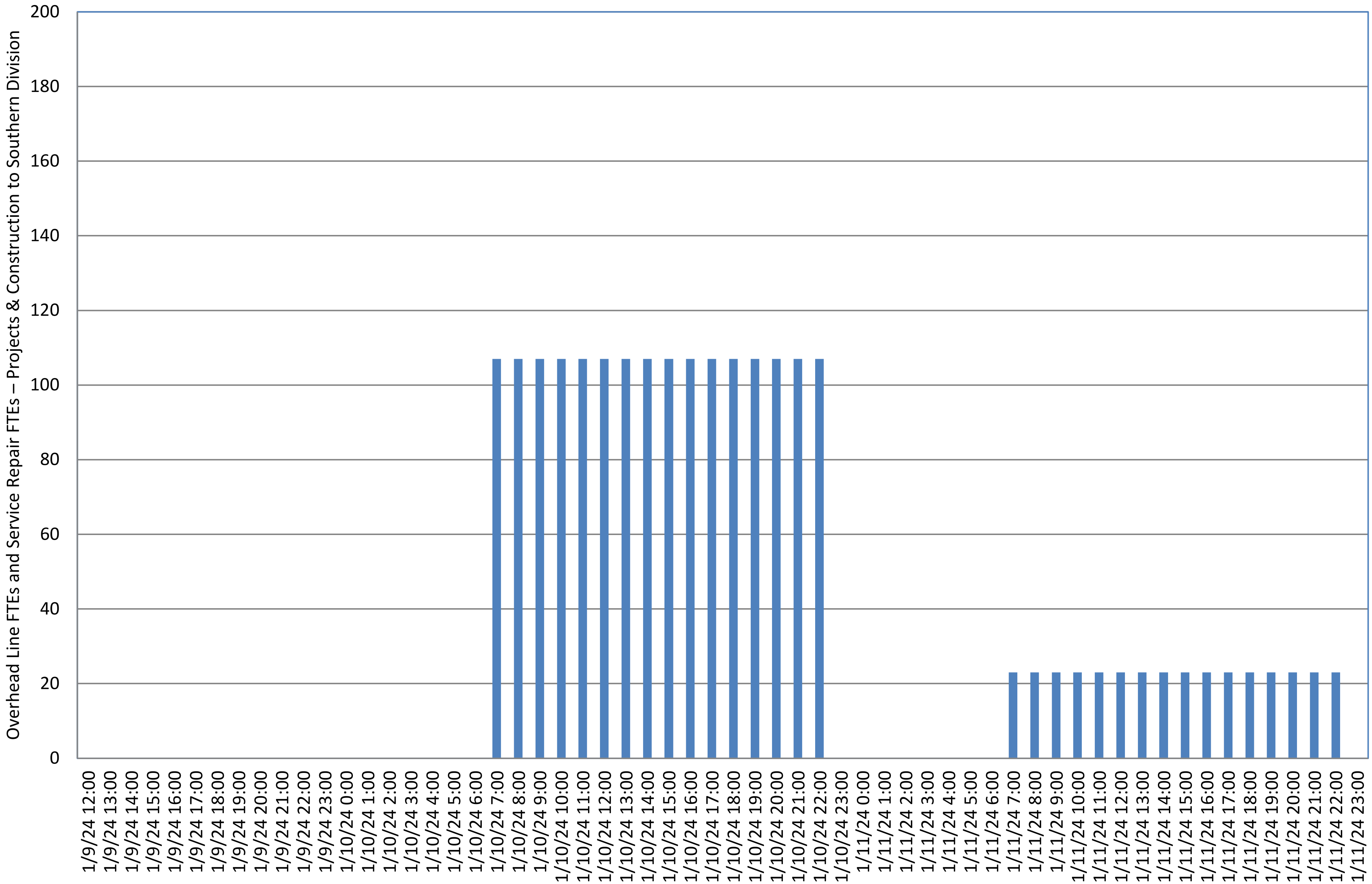
Attachment "L"
PSE&G
Overhead Line FTEs and Service Repair FTEs – Metropolitan Division to Southern Division
SOE/Severe Wind and Rainstorm – January 9-11, 2024



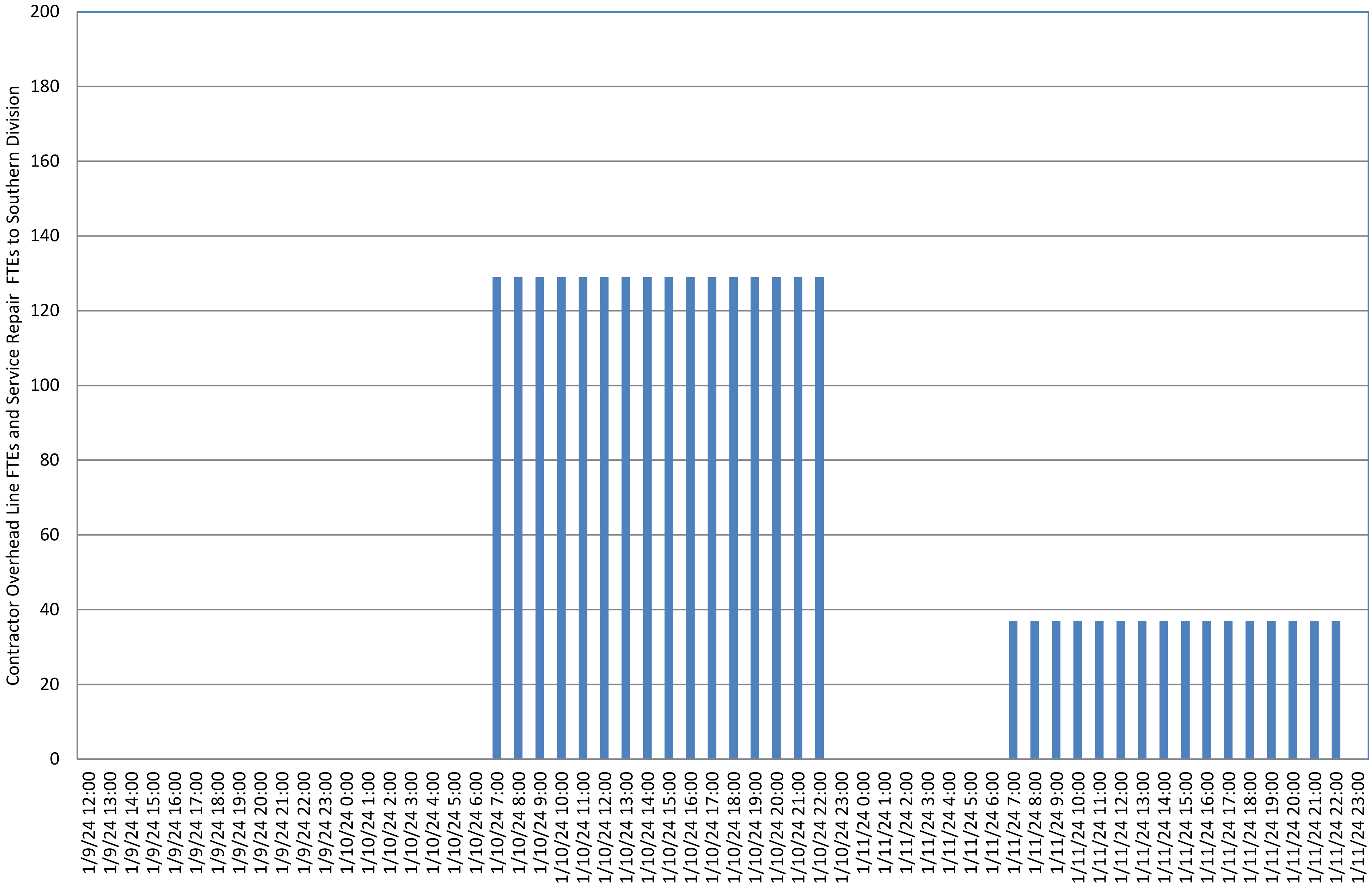
Attachment "M"
PSE&G
Overhead Line FTEs and Service Repair FTEs – Palisades Division to Southern Division
SOE/Severe Wind and Rainstorm – January 9-11, 2024



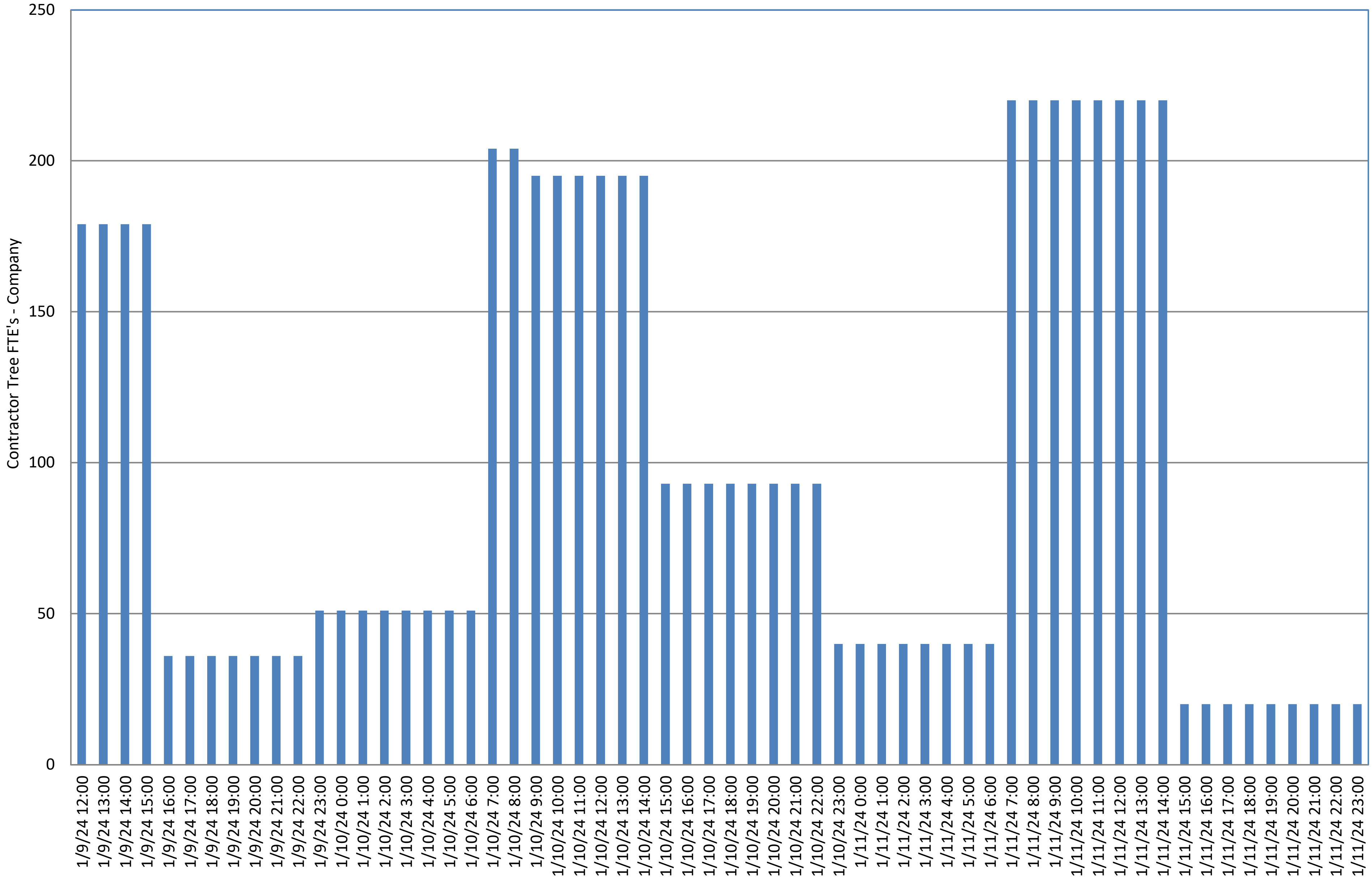
Attachment "N"
PSE&G
Overhead Line FTEs and Service Repair FTEs – Projects & Construction to Southern Division
SOE/Severe Wind and Rainstorm – January 9-11, 2024



Attachment "O"
PSE&G
Contractor Overhead Line FTEs and Service Repair FTEs to Southern Division
SOE/Severe Wind and Rainstorm – January 9-11, 2024



Attachment "P"
PSE&G
Contractor Tree FTE's - Company
SOE/Severe Wind and Rainstorm – January 9-11, 2024



ENERGY STRONG 2 PROGRAM INDEPENDENT MONITOR CORRECTED 2020 FIRST QUARTER REPORT

PREPARED AND SUBMITTED BY

PEGASUS GLOBAL HOLDINGS, INC. ®

CONFIDENTIAL

11 MAY 2021

Table of Contents

Appendices

List of Acronyms and Abbreviations

Advanced Distribution Management Systems .... ADMS

Advanced Metering Infrastructure .... AMI

Allowance for Funds Used During Construction .... AFUDC

Architectural and Engineering .... A/E

Board of Public Utilities .... BPU

Construction Management Association of America .... CMAA

Construction Work In Progress .... CWIP

Costs of Removal .... COR

Distribution Management System .... DMS

Distributed Energy Resource Management System .... DERMS

Energy Strong 2 .... ES 2

Environmental Protection Agency .... EPA

Federal Emergency Management Agency .... FEMA

Federal Energy Regulatory Commission .... FERC

Gas Metering & Regulating .... Gas M&R

Generally Accepted Accounting Principles .... GAAP

Geographic Information System .... GIS

Hazardous Water Operations and Emergency Response .... HAZWOPER

Independent Monitor .... IM

New Jersey Department of Environmental Projection .... NJDEP

Open Systems International Inc. .... OSII

Operations & Maintenance .... O&M

Outage Management System .... OMS

Project Execution Plan .... PEP

Project Management Body of Knowledge .... PMBOK

Project Management Institute .... PMI

Project Management Office .... PMO

Projects & Construction .... P&C

Public Service Electric & Gas .... PSE&G

Request for Proposals ....RFP

Record of Decision .... ROD

Risk and Contingency .... R&C

Supervisory Control and Data Acquisition.. SCADA

System Average Interruption Duration Index .... SAIDI

Utility Review Board .... URB

I. Executive Summary

The Energy Strong 2 (ES 2) Program was established from a Stipulation that the involved parties agreed to in August 2019, as approved by a Board of Public Utilities (BPU) Order with an effective date of September 21, 2019. The Stipulation provided the ES 2 Program would be comprised of five primary subprograms: Electric Station Flood Mitigation; Contingency Reconfiguration; Grid Modernization – Communications; Grid Modernization – Advanced Distribution Management Systems (ADMS); and Gas Metering & Regulating (M&R) Station Upgrades. In addition, a Stipulated Base spend was established that includes both an electric component (higher outside plant design standards and station lifecycle upgrades) and a gas component (overlapping with the Gas M&R subprogram).

Upon approval of the Stipulation, various planning efforts were initiated on the ES 2 Program through the end of 2019 and the first part of 2020. The planning led to certain projects moving forward into execution (primarily the recloser installations within the Contingency Reconfiguration subprogram and outside plant construction on two of the Electric Station Flood Mitigation projects). **Table 1 – ES 2 Subprogram Status as of March 31, 2020** below provides the spend to date on the subprograms within the ES 2 Program and Stipulated Base compared to the total forecast and forecasted completion for each.

Table 1 – ES 2 Subprogram Status as of March 31, 2020

Subprogram	Q4 2019 Spend	Q1 2020 Spend	Total Spend*	Total Forecast*	% of Actuals to Forecast	Forecasted Completion**
Electric Station Flood Mitigation	**$1,977,398**	**$5,118,886**	**$7,096,284**	**$309,160,283**	**2%**	**Dec 2023**
Contingency Reconfiguration	**$9,600,174**	**$14,933,431**	**$24,533,604**	**$119,496,564**	**21%**	**Aug 2023**
Grid Modernization – Communications	**$83,766**	**$2,214,312**	**$2,298,078**	**$65,079,990**	**4%**	**Dec 2023**
Grid Modernization – ADMS	**$36,213**	**$925,689**	**$961,902**	**$40,375,128**	**2%**	**Dec 2023**
Electric Stipulated Base	**$0**	**$0**	**$0**	**Under Development**	**N/A**	**Under Development**
Gas M&R Station Upgrades^	**$52,406**	**$235,922**	**$288,328**	**$65,621,877**	**0%**	**Jul 2023**
Total*	**$11,749,957**	**$23,428,239**	**$35,178,195**	**$599,733,842**	**6%**	**Dec 2023**

-Note: total figures may not fully align due to rounding. Additionally, the total forecast includes only the base cost for the Electric Station Flood Mitigation and Gas M&R subprograms as PSE&G does not include risk and contingency (R&C) in its forecasts for these projects. See **Table 9 and **Table 15** for the Electric Station Flood Mitigation and Gas M&R project estimates with base costs and R&C shown.*
***-Final in-service date.*
^-Includes both the ES 2 projects and the Stipulated Base gas projects.

As shown in **Table 1**, the Electric Stipulated Base component remains in a planning stage as of the end of the first quarter of 2020, with approval on the initial projects expected to occur during the second quarter of 2020.

Given the prominence of the Electric Station Flood Mitigation subprogram, which represents over half of the total ES 2 Program spending, a summary of the projects within this subprogram is provided below in **Table 2 – ES 2 Program Electric Station Flood Mitigation Status as of March 31, 2020**.

Table 2 – ES 2 Program Electric Station Flood Mitigation Status as of March 31, 2020

Project	Total Estimate	Actuals	% of Actuals to Estimate	Forecasted In-Service Date
1. Academy Street	$17,000,000	$250,291	1%	10/25/2021
2. Clay Street	$42,000,000	$336,116	1%	1/26/2023
3. Constable Hook	$5,300,000	$69,647	1%	TBD
4. Hasbrouck Heights	$18,000,000	$343,727	2%	11/18/2022
5. Kingsland	$10,000,000	$212,398	2%	10/4/2023
6. Lakeside Avenue	$36,100,000	$321,167	1%	9/20/2023
7. Leonia	$32,200,000	$289,114	1%	12/2/2022
8. Market Street	$30,000,000	$2,189,906	7%	9/22/2021
9. Meadow Road	$9,000,000	$206,074	2%	9/21/2023
10. Orange Valley	$26,600,000	$173,611	1%	TBD
11. Ridgefield 13kV	$25,500,000	$523,271	2%	9/27/2022
12. Ridgefield 4kV	$21,100,000	$836,542	4%	6/30/2021
13. State Street	$28,600,000	$205,878	1%	9/23/2022
14. Toney's Brook	$19,700,000	$327,687	2%	4/11/2023
15. Waverly	$35,400,000	$459,454	1%	12/7/2023
16. Woodlynne	$19,400,000	$351,400	2%	9/25/2023

As indicated in **Table 2**, the Market Street and Ridgefield 4kV projects are the only two projects to have actual spend beyond 2% of the total project estimate, which is reflective of these two projects being the only projects that have entered into construction.

While early in the subprogram, the Independent Monitor (IM) has found nothing to date that would jeopardize the ES 2 Program being completed on time and/or on budget.

The IM has conducted its assessment in accordance with Generally Accepted Government Auditing Standards (GAGAS, or more commonly referred to as the "Yellow Book" standards). Those standards require that the IM plan and perform the assessment to obtain sufficient, appropriate evidence to provide a reasonable basis for the IM's findings and observations based on the IM's objectives. To date, the IM has been provided access to PSE&G personnel and document records as requested by the IM during the execution of the independent monitoring. The personnel interviewed responded fully to every issue raised and questions asked by the IM. The findings contained within this initial report are based upon the oral interviews and documents provided by PSE&G. The IM finds that the information obtained provides a reasonable basis for the IM's findings and observations.

The Yellow Book provides a framework for conducting performance management reviews/audit engagements with competence, integrity, objectivity, and independence that result in information used for oversight, accountability, transparency, and improvements of the audited programs and operations. On July 15, 2020, a draft report was presented and submitted to PSE&G, BPU Staff, and Rate Counsel, and on August 13, 2020 the draft report was reviewed with the same parties over teleconference. Per the Yellow Book, the transmittal of a draft report is intended to allow for review and comment by the audited entity and others to develop a fair, complete, and objective report. A summary of the comments on the draft report and the IM's response is provided in **Appendix A – Draft Report Comments and Responses**. This **Appendix A** also identifies specific sections within this IM 2020 First Quarter Report that have been edited, supplemented with additional information, or otherwise revised in response to the comments received.

II. Program Status

A. Background

On June 12, 2018, Public Service Electric & Gas (PSE&G) filed a petition in support of the ES 2 Program, which sought to continue the progress made under the original Energy Strong Program as to improving the reliability and resiliency of its electric and gas systems. After a period of discovery, filing of testimony, evidentiary hearings, and settlement conferences, a Stipulation was reached on August 23, 2019 that established the agreed upon parameters of the ES 2 Program, including:

- Established the Energy Strong 2 Accelerated Rate Recovery Mechanism;
- Set the Program to be conducted from October 1, 2019 through December 31, 2023, with PSE&G having the ability to request an extension of the Program beyond this term;
- Defined the five subprograms that comprise the ES 2 Program, including the investment amounts:
    - Electric Station Flood Mitigation – $389 million (and further identified the specific stations included and the anticipated mitigation method for each);
    - Contingency Reconfiguration – $145 million;
    - Grid Modernization, Communication System – $72 million;
    - Grid Modernization, ADMS – $35 million; and
    - Gas M&R Station Upgrades (and further identified the specific stations) – $50.5 million.
- Provided the ability for PSE&G to reallocate funds between electric subprograms:
    - Reallocations of 5% or less of the overall electric investment to be made immediately, with written notice required within 30 days of the change; and
    - Any reallocations over 5% allowing Board Staff and Rate Counsel a 15-day period to object before the change is implemented.
- Provided the ability for PSE&G to change the electric substation mitigation method from what was originally anticipated if the proposed change would reduce costs while achieving the same benefits or if permitting or other circumstances make it impossible or inappropriate to use the originally anticipate mitigation method;
- If the Electric Station Flood Mitigation subprogram is completed under the budgeted $389 million amount, PSE&G may reallocate any remaining funds to stations identified in the filing for life cycle station upgrades for accelerated recovery;
- If the Electric Station Flood Mitigation or Gas M&R subprograms cannot be completed within their respective approved amounts, PSE&G may seek recovery of additional amounts in its next base rate case and any prudently incurred costs beyond the approved amount will be credited towards the baseline capital expenditure requirement (electric) or the stipulated base requirement (gas);
- Established the Stipulated Base, with $100 million to be spent at PSE&G's discretion toward electric outside plant higher design and construction standards and/or electric life cycle subprograms identified in the initial ES 2 filing and $50.5 million to be spent in completing the Gas M&R Station Upgrades specified in the ES 2 Program (and additional stations if the initial six stations are completed within the approved amount);

- Specified the reporting requirements for PSE&G's quarterly reports to Board Staff and Rate Counsel; and
- Required PSE&G retain an independent monitor to review and report on the impact of the ES 2 Program on overall system performance during severe weather events; cost effectiveness and efficiency; appropriate cost assignment; and other information deemed appropriate by PSE&G, Board Staff, and Rate Counsel.

The Stipulation was approved by a September 11, 2019 BPU Order with an effective date of September 21, 2019.

1. Energy Strong 2 Program Accelerated Rate Recovery Mechanism

The ES 2 accelerated recovery roll-in schedule contemplates six rate adjustment periods, beginning with an initial filing on November 1, 2020 and continuing with annual or semi-annual filings through November 1, 2023. PSE&G's planning has structured the ES 2 Program deliverables around these roll-in filings as shown in **Table 3 – ES 2 Program Roll-in Filings**.

Table 3 – ES 2 Program Roll-in Filings

Roll-In Filing (initial filing)	Electric Station Flood Mitigation	Contingency Reconfiguration	Grid Modernization – Communication	Grid Modernization - ADMS	Gas M&R Station Upgrades
(1) Nov 2020		X	X		
(2) Nov 2021	X	X	X		X
(3) May 2022	X	X	X	X	X
(4) Nov 2022	X	X	X	X	X
(5) May 2023	X	X	X		X
(6) Nov 2023	X		X		X
Note: Office-Level Schedule					

2. Stipulated Base

The Stipulation included Stipulated Base investments totaling $150.5 million that are to be recovered through PSE&G's next base rate case, provided the investments are found to be prudent. The $150.5 million is split between $100 million for electric outside plant higher design and construction standards and/or electric life cycle subprograms and $50.5 million towards the completion of the Gas M&R station upgrades defined in the Stipulation (effectively meaning half of this subprogram is eligible for recovery through the ES 2 accelerated rate recovery mechanism, and half through PSE&G's next base rate case).

3. The Independent Monitor

As set forth by the Stipulation, PSE&G was mandated to retain an independent monitor to review and report on the progress of the ES 2 Program. The scope of work established by PSE&G for the IM services expanded on the tasks identified in the Stipulation as follows:

1. Review and report on the impact of the ES 2 Program on overall system performance during severe weather events, including:
    a. Whether any station with flood mitigation work completed goes out of service due to water intrusion from flooding or storm surge within the applicable Federal Emergency Management Agency (FEMA) Advisory Base Flood Elevation that the station is designed to withstand;

   b. Storm circuit System Average Interruption Duration Index (SAIDI) savings – customer outages and customer minutes saved due to increased sectionalization; and
   c. System SAIDI savings – customer outages and minutes saved. To the extent there are no observable events to provide data during this construction time period or insufficient construction or completion of investments when such an event occurs, the IM shall analyze and advise on the reasonable anticipated performance of such events of the type the PSE&G system has experienced in the five years preceding the BPU Order effective September 21, 2019. In addition, the IM shall make any recommendations it deems appropriate to improve ES 2 investment performance during severe weather events.
2. Review and report on cost effectiveness and efficiency – such review shall include the contracting, procurement, permitting, oversight, and management of the projects, whether the work is performed and resulting costs are incurred by PSE&G personnel or outside contractors. Such review shall also include consideration of whether any change in electric or gas flood mitigation method or approach was appropriate. In addition, the IM shall make any recommendations it deems appropriate to improve the cost effectiveness and efficiency of the design, implementation, or operation of the ES 2 investments.
3. Review and report on appropriate cost assignment – the IM shall determine whether the costs charged to the ES 2 Program are in fact costs properly attributable to ES 2 distribution investments that are part of the Program as approved by the BPU Order effective September 21, 2019.

Pegasus-Global submitted a proposal to serve as the IM on the ES 2 Program and was awarded the work under a contract executed on January 15, 2020. The commencement of the IM work was slightly delayed due to Covid-19 related impacts that delayed completion of the PSE&G required background checks and other administrative steps. The IM work was officially initiated with a kickoff meeting held with PSE&G on April 13, 2020. Since that time, the IM has submitted and received responses to numerous document requests and has held multiple interviews with ES 2 Program individuals, including each of the subprogram leads.

B. Key Decisions

In order to capture formalized key decisions regarding the ES 2 Program, PSE&G completes a "Record of Decision" (ROD) that includes a description of the decision; alternatives considered; the decision made; and rationale for the decision. The RODs are assessed by the IM as they are completed to review their impact to the Program. In addition, the IM may request PSE&G complete a ROD to formalize a decision if such a decision has not yet been formalized through the ROD process.

The current and pending RODs as of the date of this initial IM 2020 First Quarter Report are presented below in **Table 4 – ES 2 Program Records of Decisions**.

Table 4 – ES 2 Program Records of Decisions

Subprogram	Record of Decision	IM Comments
Electric Station Flood Mitigation	Academy Street & State Street Change in Mitigation Method	Reasonable and appropriate *(See Section B.1. in this IM 2020 First Quarter Report)*
Electric Station Flood Mitigation	Engineering Support for Energy Strong Program Projects	Reasonable and appropriate *(See Section B.2. in this IM 2020 First Quarter Report)*

1. Electric Station Flood Mitigation – Academy Street & State Street Change in Mitigation Method

On April 16, 2020, PSE&G notified the BPU of a change of mitigation for the Academy Street and State Street substations. For Academy Street the mitigation change was based on lower costs to rate payers, lower construction risk by constructing on a new site and flood risk reduction by moving the station out of the flood zone. The original Academy Street scope required the acquisition of additional property adjacent to the existing substation. PSE&G proposed to eliminate the Academy Street substation, transferring the load to a new Fairmount substation on property acquired under a separate project. The outside plant work required to convert existing Academy Street customers from 4kV to a 13kV supply will be funded under a separately approved base capital project, which will also fund connection to the new Fairmount substation.

In the same notification to BPU, PSE&G also notified the BPU that it would be changing the mitigation method of the State Street substation from a raise and rebuild to a relocation to Cooper Street. The State Street Substation was originally planned to be a raise and rebuild due to its location within the City of Camden flood zone. Since its original application of ES 2, the City of Camden has targeted the existing station for purchase by the City. The City further opposes any expansion of the substation due to its Waterfront Redevelopment Plan. Based on this opposition, PSE&G met with the City of Camden to discuss alternatives to address the need to remove the substation from the flood hazard zone.

Alternatives were investigated within a one-mile radius of the current State Street substation. However, given the Waterfront Redevelopment Plan, no substation development was permitted. Locating further away also presented construction challenges, in particular the boundary crossings with Interstate 676, NJ Light Rail Transit, and Cooper River. These crossings would have necessitated horizontal directional drilling at a cost between $5-10 million and the reality of 12 circuits being routed further away from the load pocket which would decrease reliability.

A site was identified just outside the FEMA Flood Zone and the Waterfront Development Plan with sufficient space for buildout of a new station. The undeveloped parcel will also facilitate customer supply reliability as existing capacity can remain in service without contingency required with new existing 4kV circuits cut over to the new station at Cooper Station.

The original estimate for the State Street project was $28.6 million ($21.2 million base cost plus $7.4 million for R&C); the new estimate with the relocation is $45.1 million ($37.1 million plus $8 million R&C). The reason for the increased cost is because the new location will require extensive underground installation that was not included in the original scope including manholes and associated duct banks. The original estimate for the Academy Street project was $17.0 million ($12.6 million base cost plus $4.4 million R&C); the new estimate is $12.8 million ($9.9 million base cost plus $2.9 million R&C), which includes the costs related to the new 13kV switchgear at the Fairmount site outside of the flood zone and retiring the existing Academy Street site. The reason for the decreased cost is largely due to no longer needing a contingency to support customer supply during construction as originally planned.

On April 22, 2020, Rate Counsel responded to PSE&G's notice indicating it objects to the changes to the Academy Street and State Street substations without additional information and clarification on the changes. On May 22, 2020, PSE&G responded to Rate Counsel's request with additional information concerning the proposed changes to the Academy Street and State Street projects.

Findings & Observations:

- The changes in mitigation will:
  - Reduce risks during severe events
  - Reduce risk of customer interruptions associated with construction of a temporary facility to maintain supply during the re-build
  - Allow cutoff without disruption
- The IM finds that PSE&G conducted the appropriate due diligence once it was determined that the original plan and scope for the State Street and Academy Street substations was not going to be a viable option.
- The IM finds that while the cost for the revised State Street mitigation is higher than initially planned, PSE&G appropriately selected a location that minimizes the cost and reliability concerns that would have otherwise occurred had the relocation been further away than the approximate one mile radius.

2. Electric Station Flood Mitigation – Engineering Support for Energy Strong Program Projects

On August 22, 2019, PSE&G documented its decision to solicit external Architectural and Engineering (A/E) firms for ES 2 based on firms previously selected during the competitive bid process for the 69kV transmission upgrade project and/or due to work being performed by a particular A/E on a particular substation that is planned in the ES 2 scope of work.

Similar to the decision made in the original Energy Strong Program, PSE&G engaged the A/E firms that had existing 69kV design contracts to bid on the projects that were aligned with the relevant 69kV projects. All stations, including those relevant 69kV stations, were competitively bid as part of the vetting and selection process utilized by PSE&G. PSE&G's decision-making process evaluated the design configuration. Design configuration refers to processes and methods that assure that the latest approved revision of drawings and other design documents are available to those who need them. In addition, and equally important, is that all changes to those design documents are controlled to include the appropriate reviews, references, justifications, and approvals to assure that changes do not result in a design that no longer fulfills the original design requirements. PSE&G believes that in order to achieve this design configuration control, design work for inside the plant (the substation) should be awarded by this single source process to the design firm who are providing or will provide design services previously for that substation and to not go out for competitive bid on substation design work. This approach will add assurance that the design firm will be working from the latest approved drawings, which will further assure the integrity of the design.

In assessing this decision, the IM asked PSE&G whether this single source contracting strategy results in additional costs than it otherwise might in a competitive bid strategy. During the original Energy Strong Program, PSE&G shared with the IM the documents that support its decision for its single source contracting strategy in this area originally dated May 30, 2014, titled "Engineering Support for Energy Strong Program Projects," and updated on January 12, 2015.[1] The documentation identified the electric stations in the original Energy Strong Program and the design firms that will be asked to bid or have already bid. The firms are only awarded the design work provided the pricing in their proposals is consistent with the work scope and their proposals are otherwise acceptable.

[1] As discussed in the IM 2014 Annual Report (original Energy Strong Program), pp. 91-92

In ES 2, PSE&G's reasoning for the single source selection added that in addition to A/E firms that had or are currently working on a particular substation, that in its decision to meet or exceed PJM requirements in upgrading and improving the overall capacity and rehabilitation of its transmission lines, PSE&G is embarking on an upgrade to a portion of its existing 26kV line to 69kV to provide greater system reliability. As part of the transmission upgrade project, PSE&G issued Request for Proposals (RFP) to various A/E firms and based on a competitively bid process, selected a pool of three A/E firms to award the work. Based on this selection, PSE&G made the determination through its decision-making process to allow the same A/E firms that were selected through this competitive bid process to be awarded work on a specific substation. In addition, PSE&G retained the first right of refusal to complete engineering for some projects in-house versus awarding to an outside A/E firm based on the capabilities and resources available internally. PSE&G made the decision to perform engineering in-house for the following substation projects:

- Ridgefield 4kV
- Ridgefield 13kV
- Market Street
- State Street
- Meadow Road
- Kingsland
- Leonia

For all other work where an A/E is not performing work on a substation for the 69kV transmission project, PSE&G will choose the A/E firm from the top-rated vendors based on the bids received.

Three reasons are cited as to why this contracting strategy is critical to the success of the ES 2 Program:

1. These design firms have worked previously with PSE&G at other electric substations, thus developing a strong relationship with and knowledge of the PSE&G personnel and processes. These firms have the technical experience to do this work that will result in less operational and execution risks. These firms know the PSE&G engineering and construction standards, the outage planning process, and are knowledgeable of the PSE&G system and outage sequencing processes.
2. PSE&G's project execution practice is that multiple design firms cannot be working on the same station drawings at the same time, to avoid coordination issues and decrease the likelihood of commissioning, testing, and energization errors. Using design firms that are currently or will work at specific substations decreases the number of drawing conflicts (design configuration).
3. The engineering/design work traditionally accounts for a very small portion of a project's total cost, approximately 5%. Construction Management work is typically 2-3%. The majority of the cost (>90%) for projects of this nature is in the procurement of materials and the actual construction costs, which will both be competitively bid.

The August 22, 2019 documentation includes additional information that clarifies points that are relevant to PSE&G's single source contracting strategy for design work. The first is that PSE&G already has the competitively bid time and material rates for the design firms in the original 69kV portfolio, in addition to lump sum pricing on certain station options. Those rates will be compared to the rates these same three design firms include in their bid responses to the work inside the plant under the ES 2 Program to ensure no significant variances in the competitively bid rates. The second point is that PSE&G will perform an analysis of the differences between the competitively bid rates and the lump sum rates submitted for the ES 2 Program. This second point is an important commitment in that for every bid to perform design work inside a substation under the ES 2 Program there will be an evaluation to ensure the costs are reasonable and support the overall execution of the Program.

Findings and Observations:

- The justification to award the engineering/design on specific Electric Station Flood Mitigation subprogram projects on a single source basis is appropriate and supports the overall cost objectives of the subprogram. The cost effectiveness of this decision is supported by the pricing analysis undertaken by PSE&G on the proposals received, including comparing against bids received in the 69kV portfolio.

C. Program Management

1. Program Governance & Oversight

PSE&G established an organizational structure for the ES 2 Program that is similar to the model utilized for the original Energy Strong Program. The ES 2 Program's overall direction and oversight is managed by several key personnel, including:

- Danny Nembhard – ES 2 Electric & Gas Program Manager;
- Ed Gray – Director Electric Transmission & Distribution Engineering (electric program sponsor);
- Wade Miller – Director Gas Transmission and Distribution Engineering (gas program sponsor);
- Damon LoBoi – Senior Director, PSE&G Smart Operations Technology; and,
- Gino Leonardis – Project Director.

The program organization includes functional support from contract administration/procurement, the project management office (PMO), and legal/regulatory. The subprograms within ES 2 have been assigned leads, who are the technical leads for that subprogram and responsible for all aspects of their assigned subprogram, including engineering/design, procurement, construction, commissioning, and turnover to operations. The Leads for the ES 2 subprograms are as follows:

- Electric Substation Flood Mitigation/Lifecycle Upgrades – Christina Ker;
- Contingency Reconfiguration – Donald Gordon;
- Grid Modernization – Communication and ADMS – Al Balletto; and,
- Gas M&R – Charlie Miracola.

Additional discussion on the individual subprograms' organizations is provided within **Section III** for each of the subprograms.

In addition to the above subprogram leads, Nicole Severt is the PMO Manager and provides support for the entire ES 2 Program Electric Program. Sonia Zacher-Martini provides similar PMO support for the ES 2 Gas. Ayo Fapohunda is the PMO Project Control Manager responsible for program reporting. The PMO provides support to the ES 2 Program in a variety of ways including:

- Managing, supporting, and compiling internal and external program status reports;
- Developing monthly cost and schedule project forecasts;
- Preparing interim reporting and variance explanations;
- Managing all schedule and financial tasks (e.g. schedule updates, purchase orders, invoices, accrual management, etc.); and,
- Monitoring and controlling installation completion records, work orders, in-service dates, etc.

Findings & Observations:

- PSE&G has established an effective organization to lead the implementation of the ES 2 Program that includes well-qualified and experienced individuals. The Program is also supported by a PMO and other functional groups (e.g. licensing and permitting, legal, procurement, etc.) to facilitate successful execution.

2. Projects & Construction

The Projects & Construction (P&C) group is responsible for executing large capital projects within PSE&G, which for the purposes of ES 2 includes the projects under the Electric Station Flood Mitigation and Gas M&R subprograms.

Two primary references manuals utilized by the P&C group are *RM-01 Project Controls Engineering* and *RM-02 Project Controls Scheduling*. These reference manuals provide the framework and methodology by which P&C projects are supported by Project Controls Engineers/Project Controls Schedulers, from project initiation through closeout. Each of these references manuals is exceptionally detailed, walking through the required project components for each of the project phases, establishing the applicable methodologies to be used, and providing instruction on how to apply such practices and methodologies within PSE&G's internal systems.

The P&C group also relies on a set of Project Management Procedures to provide the necessary guidance and requirements in elements of project management such as scope management, cost estimating, risk management, and status reporting, among others. The procedures are intended to be adaptable for projects of different sizes and complexity and as such, has different thresholds for projects; for example, the projects under $5 million do not require a full Project Execution Plan (PEP), but instead utilizing a project execution strategy summary that contains information pertaining to scope, schedule, estimate, and other relevant information. A review of this set of procedures is provided as follows, with more detailed examples of the individual functional areas provided in the detailed project discussions under **Section III.A.**, the brackets next to the procedure name identify the specific project where the implementation of the procedure was reviewed and discussed.

PMP-01 – Project Execution Plan: Establishes the guidelines for developing a PEP for new projects and conducting periodic reviews of the Project Team's execution strategy. The PEPs developed for new projects consist of three primary parts: project charter; scope management and control plan; and project management plans. Each of those primary parts may contain several component sections, for example, the project management plans include a project estimating plan, project scheduling plan, project risk management plan, and other functional plans to support the execution of the project.

PMP-02 – Scope Management [Hasbrouck]: Establishes the guidelines for scope development, using a phased approach for electric projects, from feasibility, to turnover, to study, with each stage leading to a more refined scope. The gas projects scope development is initiated from the high-level requirements from a request for estimate, which leads to the development of a detailed scope. With agreement from the Project Team and key stakeholders, the scope document is locked as the final approved scope for the project. During execution of a project if scope changes are identified, a project scope change request (if no additional funding beyond the currently approved budget is required) or a capital project change request and capital funding change form (if additional funding is required) is completed and reviewed for approval by the Project Manager, Director – Projects, and other key stakeholders as warranted.

PMP-03 – Project Estimating [Market St.]: Establishes the process for developing and reviewing estimates, with specific applicability to capital projects in excess of $5 million or any blanket project under $5 million for which an estimate has been requested. The estimating process used a phased approach, beginning at the feasibility/turnover, or "office" stage (representing a confidence level of 15%-40%) and continuing through the study stage (50% confidence level), conceptual stage (70% confidence level), and ultimately the definitive stage (90% confidence level). In developing an estimate, estimate checklists are followed to ensure completeness and uniformity. When completed, the estimate is subject to review and challenge sessions and once specified criteria are met, a target budget is established that is utilized as a measure of the project's success.

PMP-04 – Project Scheduling [Kingsland]: Establishes the methodologies for developing, reviewing, and approving project schedules for capital projects. It is applicable to capital projects over $1 million in cost and blanket projects under $1 million that may require schedules upon specific requests at designated levels. Industry standard schedule fundamentals such as ensuring the schedule is inclusive of all work and consistent with the work breakdown structure, that it is developed with consideration of available and required resources and internal or external constraints, and that it is maintained throughout the project to measure performance are listed for adherence in developing schedules. As with the other project management functions, project scheduling occurs in a phased approach that increases with detail as the project moves from initiation through approval.

PMP-05 – Project Authorization [Academy]: Establishes the process for obtaining project funding authorization, change requests, and financial project closeouts on capital and blanket projects managed by P&C. It walks through the different project development phases, from approval for preliminary engineering funding, through authorization and phased funding (if applicable), through managing change requests, and ultimately project closeout. The requirements at these different phases are largely dependent on the deliverables created through other project management procedures (e.g. cost estimate, schedule, etc.).

PMP-06 – Invoice Management [Ridgefield 13kV]: Establishes the process for reviewing and approving vendor or contractor invoices on capital and operations & maintenance (O&M) projects. It provides a review of typical invoice contents and notes the delegation of authority levels of approvals by dollar value, including the responsibilities tasked to those with approval authority. It also provides a responsibilities guideline that details by project function (e.g. contracting, licensing, and permitting, engineering, etc.) how invoices are typically received, where the accounting or services verification takes place, and who is responsible for processing the invoice. The invoice validation process is defined by a seven-step process that includes verification of: schedule, quantity, quality, pricing, sales and use tax, mathematical accuracy, and documentation.

PMP-07 – Quality Assurance and Control [State St.]: Establishes the standards that ensure P&C products and services comply with quality requirements, codes, and applicable specifications. It includes individual requirements for inside plant electric, outside plant electric, and gas projects, as well as by project phase (e.g. engineering, procurement, construction, etc.). The degree of applicability dependent on project-specific factors (e.g. cost, risk, contracting strategy, etc.) with the Project (or Program) Manager responsible to assess and define the project-specific requirements.

PMP-08 – Project and Contractor Safety [Market St.]: Provides assistance to the P&C Project Teams in carrying out health and safety management of construction projects and is applicable to all P&C projects. It details the purpose and functions of the P&C Project Safety Management Program, which is intended to ensure continuous and controlled safety management between P&C and project contractors. The procedure also outlines the requirements for safety management plans and site-specific health and safety plans, evaluating and pre-qualifying contractors, oversight, training, and other aspects of ensuring effective safety practices.

PMP-09 – Contract Administration [Toney's Brook]: Establishes the process for development, award, administration, and closeout for material, professional, and construction services contracts managed by P&C. It is structured around those four-phases of the contract lifecycle and provides key activities and responsibilities associated with each of these phases. It also details the change control process utilized on these types of contracts and the process for qualifying new vendors to ensure they meet PSE&G's standards.

PMP-10 – Project Construction Oversight [Ridgefield 4kV]: Establishes the process for P&C to ensure that all project work is completed in full compliance with the scope, plan, budget, schedule, and any contractual obligations. It provides a framework that identifies the oversight requirements by functional area (e.g. schedule and cost, labor workmanship, quality, safety, etc.) noting the process and requirements under each area.

PMP-11 – Project Risk Management [Woodlynne]: This procedure establishes the process of identifying, assessing, monitoring, controlling, and reporting project risks. It provides direction and responsibilities to each of those risk management aspects and is scalable based on the size and complexity of the project, with full implementation required for projects over $5 million. The procedure also explains the common risk management tools utilized in project management including the project risk register and risk management plan.

PMP-12 – Materials Management [Kingsland]: This procedure establishes the requirements for management of materials and equipment, including receiving, identification, handling, storage, maintenance, inspection, and management and control. Proper materials management supports improved productivity, reduces materials surplus, supports the project schedule, and can achieve cost savings. The procedure also includes the actions and responsibilities for treatment of removed equipment in demolition projects.

PMP-14 – Status Reporting [Academy]: This procedure establishes the requirements for producing, reviewing, and managing status reports for all P&C-managed projects. Actions and responsibilities are noted for the production of accurate and timely status reports. It also includes a description of the various types of status reports that may be generated depending on the project type and needs of stakeholders (e.g. portfolio status report, monthly variance explanation report, project closeout report, monthly cost reports, etc.).

PMP-15 – Inside Plant Commissioning [Ridgefield 13kV]: This procedure provides the requirements for inside plant commissioning, testing, and startup activities to ensure all project work is completed in full compliance with the required specifications. It is adaptable in scope to match the size and complexity of the individual project, with general concepts typically applied to all projects. The procedure covers all aspects of startup and commissioning, beginning with the planning phase, carrying through to scheduling requirements and actual project commissioning actions.

PMP-16 – Environmental Management Plan [Hasbrouck]: This procedure establishes the requirements for developing a project-specific environmental management plan to ensure compliance with applicable land use and environmental regulations. The requirements are aligned with the primary project phases (initiation, preliminary engineering/design, detailed engineering/design, construction/testing and commissioning, and closeout/completion) and begins with development of a permitting matrix that defines all major regulatory permits required and the timeframes associated with obtaining them.

Findings & Observations:

- The P&C policies and procedures provide the project teams with the appropriate guidance to execute the projects under their responsibility. This set of policies and procedures is based on a foundation of project management practices that are aligned with industry standards.

D. Cost Assignments

In order to monitor PSE&G's compliance with cost accounting-related provisions of the Stipulation, the IM reviewed the Company's policies and procedures with respect to the relevant accounting practices. PSE&G's (the regulated utility) accounting practices are subject to Generally Accepted Accounting Principles (GAAP), as well as Federal Energy Regulatory Commission (FERC) practices and relevant instructions as contained in the Uniform Systems of Accounts. In addition, the company is subject to Financial Accounting Standards Board pronouncements as they relate to rate regulated entities, and practices accepted and/or mandated by the BPU. Finally, the Company is subject to the Sarbanes-Oxley Act of 2002, and specifically here, section 401, as it relates to accurate recording of fixed asset values. Collectively, this documentation provides the guidance needed to ensure proper accounting treatment.

Although interviews with the appropriate Accounting personnel are being scheduled, the IM, through its review to date of the Company's relevant accounting policies, has gained a general understanding of the Company's accounting practices that have bearing on the ES 2 Program. The IM began with a review of *Accounting Services Practice 630-4* regarding journal entries. This was done to ensure a procedure exists that supports the accuracy, timeliness and validity of the fundamental accounting information that is entered into the general ledger from which financial, cost, and other important business information is ultimately retrieved. Practice 630-4 covers proper accruals, required journal entry documentation, necessary review and approvals, and timely posting. The practice document is clear and comprehensive.

There are a number of general accounting areas the IM will be monitoring on a consistent basis arising from the provisions of the Stipulation. The IM has reviewed whether these areas are covered by specific policies beyond guidance promulgated by GAAP, FERC instructions, and BPU-approved accounting treatments. These general areas, along with subsets, are described below:

Proper Capitalization of ES 2 Program Project Costs: Proper capitalization of costs covers considerations ranging from when initial capitalization should begin as costs are recorded in Construction Work In Progress (CWIP) accounts, to the ultimate transfer of costs to plant-in-service for financial accounting and ratemaking purposes. The IM has reviewed the existence of documentation for each stage in this process, as noted below:

- Most projects begin with preliminary investigative work and feasibility studies before presentation to the relevant committees in the Company's capital approval process. When and under what circumstances these costs are capitalized or expensed is covered by *Accounting Practice 650-16, Practice for Use of Account E183*. To qualify as eligible for capitalization, project costs must, among other things, be approved as potentially part of the Company's long-term plan or mandated by regulators and proceed along a path in the capital approval process. If the project is denied at any point, costs are expensed. When the project is ultimately approved, costs incurred are journaled to a CWIP capital account. The account where pending costs are held is reviewed and approved quarterly for disposition. *Capitalization and Related Policies for*

PSE&G, 650-3, covers on-going criteria for capitalizing fixed asset costs, including differentiation of costs to be capitalized vs. expensed, as well as guidance on depreciable lives once costs are transferred to plant-in-service. Projects will be charged to or transferred into CWIP if they exceed $5,000 and take in excess of 60 days to complete, among other parameters. This also begins the capitalization of allowance for funds used during construction (AFUDC).

- Additional on-going cost capitalization guidance is also covered by Company *Property Record Unit Manual Policies GI-6, GI-7 and GI-8.* These documents provide further guidance on capitalization vs. expensing of costs incurred. Additionally, in cases where these policies do not specifically address aspects of a proposed capital project, the Company's *Sarbanes-Oxley Control FA005* requires a written determination from the Utility Property Accounting area.

- Once a project is substantially complete and ready for its intended use, or otherwise energized and carrying load, and/or considered used and useful, it is transferred out of CWIP to plant-in-service. This procedure is covered by *Accounting Practice 650-10, In-Service Transfers*. The responsible operating department notifies the Property Accounting department of the in-service date, and actual costs plus trailing costs are added to plant-in-service. AFUDC also ceases. This is the normal progression for accumulation and disposition of project costs.

- Finally, *Retirements and Transfers of Property, Practice 650-11*, gives additional guidance and sample journal entries for transfers and retirements of utility plant. The appropriate costs will be credited to depreciation reserve and debited to depreciable plant. As a result, no gains or losses will be recorded in the retirement of utility plant.

The IM will be monitoring the proper capitalization of costs (capital vs. expense), recordation of costs as ES 2 Program distribution costs, and the Company's CWIP accounts and asset transfers to plant on an on-going basis for compliance with proper accounting treatment of ES 2 Program expenditures.

Allocations of Overheads and Surcharges: The IM is in the process of scheduling interviews with appropriate personnel to discuss the area of allocations; however, due to its work in Energy Strong I, the IM has some familiarity with many of the Company's cost allocation policies and methodology as they are contained in its *Cost Accounting Manual, 660-1*. The Company follows a philosophy of allocating costs, whether at the Service Company or from utility support organizations, to the operating company or unit receiving the benefit, and ultimately, if appropriate, settling costs to individual assets. Where possible, services are charged directly to the entity receiving the benefit based on either fully loaded hourly rates multiplied by the number of hours spent, or through a transactional count multiplied by a predetermined unit cost. Where direct charging is not possible, cost allocations from the Service Company to operating companies are prescribed in a BPU-approved schedule issued pursuant to a BPU order issued in July 2003.

Cost allocations are performed automatically at each monthly closing within the Company's SAP system. SAP is an enterprise planning, accounting, and reporting software system. It is module-based, and the Company uses it as its system tool for general ledger, finance, and accounting/control (but not fixed assets).

The Stipulation requires the Company to follow its current practices with regard to capitalized overheads and calls for separate disclosure of allocation amounts in each rate adjustment filing. Based on work to date, the IM believes that the ES 2 Program should not create any changes to the Company's allocation methodology. Further, the IM anticipates that most allocated costs for ES 2 projects will come from utility, rather than Service Company, cost pools. These expectations will be verified in interviews with Company personnel and will be tested when formal audits of the ES 2 Program commence.

Costs of Removal (COR), Net of Salvage: The Stipulation calls for separate disclosure of COR in each rate adjustment filing. The IM will be reviewing and disclosing charges to COR arising from the ES 2 Program.

Proper accounting treatment for costs of removal is detailed in *Capitalization and Related Policies for PSE&G, 650-3*. While the Stipulation does not directly address the accounting treatment of COR, PSE&G's historical accounting for these costs reflects their potential inclusion as capitalized costs under certain prescribed circumstances, along with amortization of costs of removal to the extent they are reflected in depreciation rates (or, in the case of gas assets, through an annual fixed amortization amount). The IM notes that the Company proposed a different method for recovery through depreciation expense of COR, or net salvage, in its last base rate filing (ER18010029 and GR18010030). The Company proposed to change the method of recovery for net salvage from its then-current five-year amortization method to what is known as the traditional method. This change was not reflected in the rate case stipulation, although new depreciation rates were adopted. The IM will discuss the effects of this change, if any, on accounting for COR in its interviews with Company personnel.

The IM intends to disclose gross COR in its periodic reporting but will track salvage values as well for accounting and ratemaking reconciliation purposes.

Allowance for Funds Used During Construction: The Stipulation permits recovery of AFUDC on ES 2 Program projects without regard to the maximum $691.5 million of costs eligible for recovery under the accelerated rate mechanism. In addition, the Stipulation states accrual of AFUDC should be calculated using the same methodology used for other distribution assets and consistent with Company policy. AFUDC should be calculated as permitted in FERC Order 561, which includes compounding on a semi-annual basis. The IM will be reviewing and disclosing both the amounts of AFUDC accrued and the Company's calculations of the AFUDC rate on an on-going basis. The IM will also monitor the initial recording and ultimate cessation of AFUDC with regard to projects within the ES 2 Program.

Guidelines for capitalization of AFUDC are provided by the Company's *Accounting Practice 650-9, Allowance for Funds Used During Construction and Rate Calculations*. The procedures therein define eligible projects, initial recording, the ultimate cessation of AFUDC, and the rate calculation formulas. Although the rate is determined annually, the Company historically has periodically recalculated and examined the AFUDC rate for material changes. An interim rate adjustment may occur if the recalculated rate deviates from the current rate by more than 25 basis points.

The Company's practices with respect to AFUDC are in accordance with Electric/Gas Plant Instruction 3(17) of the FERC's Uniform Systems of Accounts prescribed for public utilities (formerly FERC Order 561).

Findings & Observations:

- In review of PSE&G accounting practices, the IM has not discovered anything thus far in PSE&G's accounting for ES 2 Program projects that is in contravention of GAAP, FERC regulations, or any other known policy or practice.

1. Costs of Removal (COR)

COR generally include costs for such activities as environmental removal, removal of inside station equipment, structures, foundations, towers and fixtures, conductors and other electrical devices, poles and fixtures, transformers, plant demolition, foundations, and removal of underground conduit and other wiring. Generally, COR are charged to Accumulated Depreciation and are amortized and recovered through a component of depreciation expense. The specific method and amount of recovery is determined in gas and electric rate cases before the BPU.

Table 5 – ES 2 Program Costs of Removal as of March 31, 2020 below itemizes the charges to COR for the first quarter of 2020, the fourth quarter of 2019 and total ES 2 Program COR to date. These amounts do not reflect any salvage value reductions, which have been zero in the ES 2 Program through March 31, 2020.

Table 5 – ES 2 Program Costs of Removal as of March 31, 2020

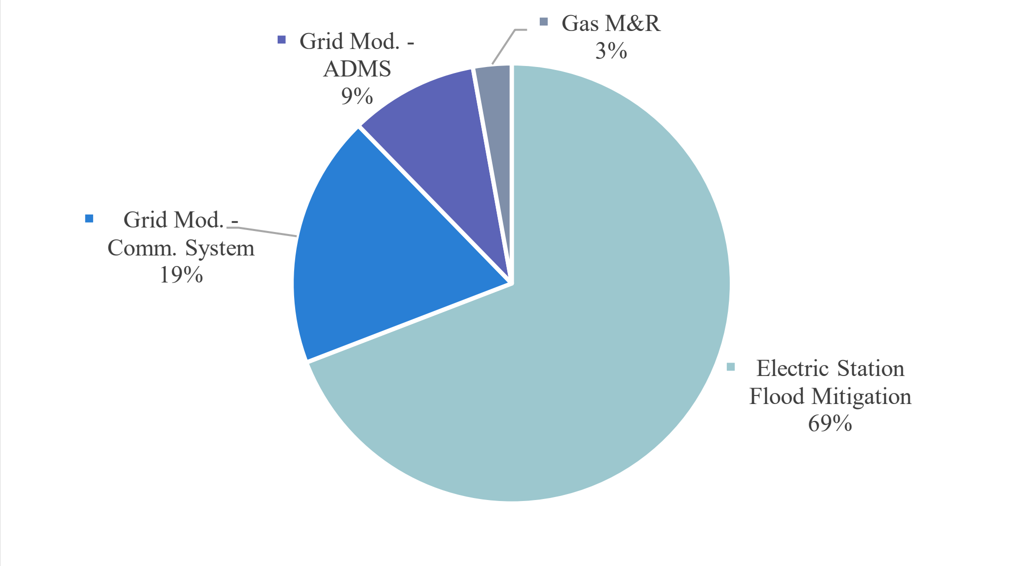
Subprogram	Q4 2019 COR	Q1 2020 COR	Total COR
Electric Station Flood Mitigation	**$0**	**$67,332**	**$67,332**
Contingency Reconfiguration	**$431,030**	**$616,752**	**$1,047,782**
Grid Modernization – Communications	**$0**	**$0**	**$0**
Electric Stipulated Base	**$0**	**$0**	**$0**
Gas M&R Station Upgrades	**$0**	**$0**	**$0**
Total	**$431,030**	**$684,084**	**$1,115,114**

For the first quarter of 2020, Electric Station Flood Mitigation subprogram COR charges are attributed to the conversion of 4kV circuits at Market Street substation. Contingency Reconfiguration COR charges reflect work on the recloser replacement efforts in all districts.

2. Construction Work-in-Progress (CWIP) & In-Service Transfers

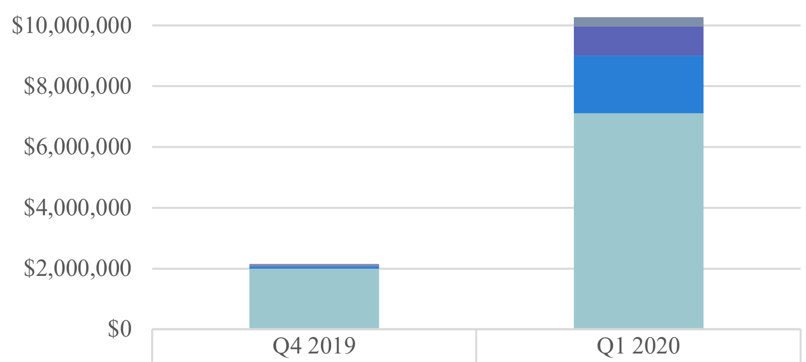
As of March 31, 2020, the ES 2 Program CWIP balance was $10.3 million, compared to $2.2 million as of December 31, 2019. The three largest components of March 31, 2020 CWIP were the conversion of circuits at Market Street and Ridgefield substations, and design and contract work at Waverly substation. The Electric Station Flood Mitigation subprogram comprises the largest component of total end of period CWIP outstanding, as depicted in **Figure 1 – ES 2 Program CWIP as of March 31, 2020** below.

Figure 1 – ES 2 Program CWIP as of March 31, 2020



In addition, **Figure 2 – ES 2 Program CWIP Balances by Subprogram** below depicts the composition of end-of-quarter CWIP balances by subprogram for both the fourth quarter of 2019 and the first quarter of 2020.

Figure 2 – ES 2 Program CWIP Balances by Subprogram



	Q4 2019	Q1 2020
Gas M&R	$52,661	$290,933
Grid Mod. - ADMS	$36,309	$969,089
Grid Mod. - Comm. System	$74,531	$1,907,846
Electric Station Flood Mitigation	$1,987,285	$7,101,458

There have been no transfers to date from CWIP to plant in-service.

3. Allowance for Funds Used During Construction (AFUDC)

The amount of quarterly AFUDC recorded by the Company for each ES 2 Program subprogram during the first quarter of 2020, the fourth quarter of 2019, and total ES 2 Program AFUDC accrued to date, is shown below in **Table 6 – ES 2 Program AFUDC**.

Table 6 – ES 2 Program AFUDC

Subprogram	Q4 2019 AFUDC	Q1 2020 AFUDC	Total AFUDC
Electric Station Flood Mitigation	**$9,887**	**$62,618**	**$72,505**
Contingency Reconfiguration	**$0**	**$0**	**$0**
Grid Modernization – Communications	**$225**	**$14,572**	**$14,977**
Grid Modernization - ADMS	**$96**	**$7,092**	**$7,188**
Electric Stipulated Base	**$0**	**$0**	**$0**
Gas M&R Station Upgrades	**$254**	**$2,590**	**$2,844**
Total	**$10,462**	**$87,052**	**$97,514**

During the first quarter of each year, the AFUDC rate is reviewed for possible reset as it applies to the current year based on updated capital structure and component cost data. For the year 2020, the new AFUDC rate was calculated to be 6.95%, using the capital structure and component costs as of January 31, 2020. This rate is higher than the 2019 rate of 6.34%, primarily due to a significantly lower average short-term debt balance during the first quarter of 2020, with its lower associated component cost relative to the cost of equity and embedded cost of long-term debt. In calculating the 2020 AFUDC rate, the Company used (i) a 4.02% embedded cost of long-term debt, (ii) a short-term debt rate of 1.86%, and (iii) a cost of equity of 9.60%.

Subsequent to the annual reset calculation referred to above, and during the course of each year, the AFUDC rate is also recalculated as it applies to each fiscal quarter. If the recalculated rate changes by 25 basis points from the rate then in effect, the rate is reset and retroactively applied to January 1 of that year. For the first quarter of 2020, based on data as of March 31, 2020, the recalculated weighted average AFUDC accrual rate (6.95%) did not meet this criterion to warrant changing from the annual rate (6.95%) in effect. Therefore, AFUDC was accrued during the first quarter of 2020 at the calculated rate of 6.95%.

AFUDC accrued for ES 2 Program projects during the first quarter of 2020 increased significantly over AFUDC accrued during the fourth quarter of 2019 as the result of the large increase in total average CWIP balances.

The IM observes that the Company's calculation of the AFUDC rate and its application is in accordance with both PSE&G's accounting policy and Plant Instruction 3(17) of the Federal Regulatory Commission's Uniform Systems of Accounts prescribed for public utilities.

The IM also notes that the relevant AFUDC information as it relates to first quarter 2020 ES 2 Program project costs is consistent with the applicable dictates of the Stipulation entered into with respect to these ES 2 Program projects. The IM will continue to review future ES 2 Program AFUDC accruals for consistency with relevant provisions of the Stipulation for accounting and reporting purposes only, and not as a party to, or in expressing an opinion concerning, any rate proceedings.

E. System Performance

From the commencement of the ES 2 Program through the end of the first quarter of 2020, there have been no Major Events. The IM has additionally requested and received baseline circuit performance metrics from the prior five-year period to help facilitate its analysis of PSE&G's system performance.

III. Project Status

A. Electric Station Flood Mitigation

The Stipulation established the 16 electric stations that comprise the Electric Station Flood Mitigation subprogram and included an identification of the anticipated mitigation method for each station, with 14 identified with raise and rebuild and two identified with elimination as the preferred mitigation method.

The Electric Station Flood Mitigation subprogram is led by Christina Ker, with the subprogram organization split between standalone stations (Market Street, Leonia, Ridgefield 4kV, Ridgefield 13kV, Waverly, and Constable Hook) and stations that are aligned with 69kV projects (Woodlynne, State Street, Academy Street, Clay Street, Hasbrouck Heights, Meadow Road, Lakeside Avenue, Toney's Brook, and Orange Valley). For the standalone stations, there are three project managers assigned to the six stations; and for the stations aligned with 69kV projects, there is a Division Lead overseeing projects within their respective Division to whom project managers report.

The projects aligned with 69kV projects are treated as separate projects but utilized a common project team. This benefits the ES 2 Program as it allows cost sharing rather than having entirely separate project teams, in addition to benefiting from a common team that has intimate familiarity with any interdependencies between the projects. Other benefits realized by these 69kV-aligned projects include: having a common site plan submitted to the municipalities for review (if the 69KV project has not already started); sharing leased laydown space; and, from having the 69kV construction start first (providing more information on below grade condition and water table levels).

Each of the projects within the subprogram is governed by a PEP and the IM has reviewed all the PEPs developed to date (some of the project PEPs are still in development), finding them to be robust documents that contain all the required information and will be an effective tool in managing and monitoring the projects' execution. Rather than repeat all the information contained in the PEP for each project, the IM has provided selected commentary on different functional areas for the individual projects as discussed in the specific project subsections that follow.

Licensing and permitting on the Electric Station Flood Mitigation projects is managed by a dedicated licensing and permitting manager assigned to each project, who interfaces with the project team, develops a permitting matrix for each project, and is responsible for obtaining the necessary permits. Public outreach on the projects is handled by PSE&G's public outreach group, who informs public stakeholders of relevant project information, answers questions from the public, and holds public workshops as needed.

The subprogram was initiated following approval of the ES 2 Program on September 11, 2019. PSE&G then held a kickoff meeting with its internal stakeholders on October 10, 2019. This internal kickoff meeting reviewed all 16 projects in the Electric Station Flood Mitigation subprogram. The planning process has been more integrated on the ES 2 Program than in the original Energy Strong Program, including centralized work planning and scheduling and a more robust front end planning effort that supported a more thorough stakeholder review, which should help limit scope changes, design layout issues, and similar challenges. Shortly after the subprogram kickoff meeting, the process to bid out major equipment and A/E support needed for the subprogram was initiated, and through the end of the first quarter of 2020, work continued to advance based on the anticipated schedules for each of the projects. Relative to Covid-19 impacts, to date there has been minimal disruption to the subprogram, with the primary change being in-person meetings transitioning to virtual settings. In addition, construction on the

Ridgefield 4kV project had a one-day stoppage from the local municipality stopping all work in response to Covid-19 (which was followed one day later by a directive from the Governor that allowed utility work to resume). A summary of the subprogram plan as of the end of 2019 and as of March 31, 2020 is provided below in **Table 7 – ES 2 Electric Station Flood Mitigation Subprogram Milestone Schedule**.

Table 7 – ES 2 Electric Station Flood Mitigation Milestone Schedule

Project	Plan Status Point	2019		2020				2021				2022				2023					2024
		Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4		
1. Academy Street	Dec. 2019		KO					C					IS		CO					*December 31, 2023 - Energy Strong 2 Program End Date*	
	Mar. 2020		KO				C				IS			CO							
2. Clay Street	Dec. 2019	*Schedule Under Development*																			
	Mar. 2020			KO							C					IS					CO (Q2)
3. Constable Hook	Dec. 2019	*Schedule Under Development*																			
	Mar. 2020	*Schedule Under Development*																			
4. Hasbrouck Heights	Dec. 2019		KO						C						IS		CO				
	Mar. 2020		KO						C						IS		CO				
5. Kingsland	Dec. 2019			KO				C			IS		CO								
	Mar. 2020			KO										C					IS		CO (Q2)
6. Lakeside Avenue	Dec. 2019				KO				C										IS		CO (Q2)
	Mar. 2020						KO				C							IS			CO (Q3)
7. Leonia	Dec. 2019	*Schedule Under Development*																			
	Mar. 2020			KO		C									IS				CO		
8. Market Street	Dec. 2019			KO				C	OS		CO										
	Mar. 2020			KO						OS/C				CO							
9. Meadow Road	Dec. 2019	*Schedule Under Development*																			
	Mar. 2020			KO											C			IS			CO (Q2)
10. Orange Valley	Dec. 2019	*Schedule Under Development*																			
	Mar. 2020	*Schedule Under Development*																			
11. Ridgefield 13kV	Dec. 2019			KO	C										IS		CO				
	Mar. 2020			KO		C								IS			CO				
12. Ridgefield 4kV	Dec. 2019			KO						C	OS			CO							
	Mar. 2020			KO	C					OS			CO								
13. State Street	Dec. 2019		KO					C								IS					CO (Q1)
	Mar. 2020		KO					C						IS							CO (Q1)
14. Toney's Brook	Dec. 2019			KO						C									IS		CO (Q2)
	Mar. 2020			KO										C			IS				CO (Q2)
15. Waverly	Dec. 2019	*Schedule Under Development*																			
	Mar. 2020			KO			C												IS		CO (Q3)
16. Woodlynne	Dec. 2019		KO												C				IS		CO (Q2)
	Mar. 2020		KO												C			IS			CO (Q2)

Legend: KO = Kickoff; C = Construction; IS = Fully In-Service; OS = Out-of-Service (if eliminated); CO = Closeout
-Actuals are indicated with an underline

A summary of the subprogram status as of the end of the first quarter of 2020 is provided below **Table 8 – ES 2 Electric Station Flood Mitigation Summary Status as of March 31, 2020**. Additional information on the individual projects is discussed in the respective project's subsection.

Table 8 – ES 2 Electric Station Flood Mitigation Summary Status as of March 31, 2020

Activity	Total # of Projects	Specific Projects
Kickoff Meeting	13	Academy Street; Clay Street; Hasbrouck Heights; Kingsland; Leonia; Market Street; Meadow Road; Ridgefield 13kV; Ridgefield 4kV; State Street; Toney's Brook; Waverly; Woodlynne
Key Drawing Review	13	Academy Street; Clay Street; Hasbrouck Heights; Kingsland; Leonia; Market Street; Meadow Road; Ridgefield 13kV; Ridgefield 4kV; State Street; Toney's Brook; Waverly; Woodlynne
Scope Locked	7	Academy Street; Hasbrouck Heights; Kingsland; Market Street; State Street; Toney's Brook; Woodlynne
Major Equipment POs	7	Academy Street; Hasbrouck Heights; Leonia; Ridgefield 13kV; State Street; Toney's Brook; Woodlynne
A/E Contract Award (or selection of PSE&G internal engineering)	10	Academy Street; Clay Street; Kingsland*; Market Street*; Ridgefield 13kV*; Ridgefield 4kV*; State Street*; Toney's Brook; Waverly; Woodlynne
Construction Start	2	Market Street; Ridgefield 4kV
**-Indicates PSE&G internal resources are serving as the A/E.*		

The IM evaluated PSE&G's vendor selection decision for the switchgear at multiple projects within the Electric Station Flood Mitigation subprogram, some of which were bid in project bundles as follows:

- 5kV-rated Switchgear: State Street, Toney's Brooke, Woodlynne;
- 5kV-rated Switchgear: Hasbrouck
- 15kV-rated Switchgear: Kingsland, Leonia (2), Meadow Road, Ridgefield 13kV (2)
- 15kV-rated Switchgear: Fairmount
- 38kV-rated Switchgear: Waverly

In each project sampled, PSE&G followed the same comprehensive bid evaluation process used in the original Energy Strong Program that saw multiple bidders respond, with PSE&G reviewing the technical and commercial aspects of the bids before making a recommendation to award based on a weighted rating criteria.

The current project estimates, including base and R&C amounts, is shown below in **Table 9 – ES 2 Electric Station Flood Mitigation Project Cost Status as of March 31, 2020**. This table also shows the current estimate level based on PSE&G's estimating processes, the actual spend and percentage of actuals to estimate as of the end of the first quarter of 2020, and the forecasted in-service date.

Table 9 – ES 2 Electric Station Flood Mitigation Project Cost Status as of March 31, 2020

Project	Estimate Level	Base	Risk & Contingency	Total	Actuals	% of Actuals to Estimate
1. Academy Street	Office	$12,600,000	$4,400,000	$17,000,000	$250,291	1%
2. Clay Street	Study	$34,800,000	$7,200,000	$42,000,000	$336,116	1%
3. Constable Hook	Office	$3,900,000	$1,400,000	$5,300,000	$69,647	1%

Project	Estimate Level	Base	Risk & Contingency	Total	Actuals	% of Actuals to Estimate
4. Hasbrouck Heights	Study	$14,900,000	$3,100,000	$18,000,000	$343,727	2%
5. Kingsland	Study	$7,100,000	$2,900,000	$10,000,000	$212,398	2%
6. Lakeside Avenue	Office	$26,800,000	$9,400,000	$36,100,000	$321,167	1%
7. Leonia	Study	$27,700,000	$4,500,000	$32,200,000	$289,114	1%
8. Market Street	Study	$24,200,000	$5,800,000	$30,000,000	$2,189,906	7%
9. Meadow Road	Study	$7,200,000	$1,800,000	$9,000,000	$206,074	2%
10. Orange Valley	Office	$19,700,000	$6,900,000	$26,600,000	$173,611	1%
11. Ridgefield 13kV	Study	$19,600,000	$5,900,000	$25,500,000	$523,271	2%
12. Ridgefield 4kV	Study	$16,800,000	$4,300,000	$21,100,000	$836,542	4%
13. State Street	Office	$21,200,000	$7,400,000	$28,600,000	$205,878	1%
14. Toney's Brook	Study	$14,300,000	$5,400,000	$19,700,000	$327,687	2%
15. Waverly	Study	$29,400,000	$6,000,000	$35,400,000	$459,454	1%
16. Woodlynne	Study	$15,800,000	$3,600,000	$19,400,000	$351,400	2%
Subprogram Total		**$309,000,000**	**$80,000,000**	**$389,000,000**	**$7,096,284**	**2%**

Findings & Observations

- The IM finds the organization of the subprogram, and specifically the split between 69kV-aligned projects and standalone projects, to be an appropriate arrangement that should benefit each of the projects by recognizing the varying complexities involved in these alignments, as well as provide potential cost benefits for the 69kV-aligned projects.
- The majority of projects within the subprogram have had both a kickoff meeting and a review of the key drawings, with the exception being the Constable Hook, Lakeside, and Orange Valley projects that are tied to 69kV projects that are in the planning and development stages.
- While early in the subprogram, the IM has found nothing to date that would jeopardize the subprogram being completed on time and/or on budget.

1. Academy Street

The original Academy Street substation scope called for replacing the substation's existing 4kV feeder rows with 13kV sheltered aisle switchgear that is elevated one foot above the flood elevation. After further evaluation, PSE&G determined that the preferred mitigation method for this substation was to demolish the existing station and convert the outside plant circuits from 4kV to 13kV, transferring the load to the nearby Fairmount station, as documented in a notice to the BPU on April 16, 2020. The final scope achieves the same primary objective, which is to eliminate flood related impacts, while doing so at a lower estimated cost (original scope was estimated at $17.0 million vs. the final scope at $12.8 million[2]). The Fairmount station is located less than 0.5 miles from the existing Academy Street substation and has multiple Academy Street circuits in close proximity, so minimal new circuit mileage is required, and it will not increase distribution circuit exposure. On April 22, 2020, Rate Counsel responded to PSE&G's notice indicating it objects to the change (as well as the change to the State Street substation) without additional information and clarification on the changes.

The Academy Street PEP follows the P&C PMP set of procedures discussed above in **Section C.2.** On this PEP, the IM is providing comments on the project charter/project authorization and status reporting.

- Project Charter/Project Authorization: The Project Management Institute's (PMI's) Project Management Body of Knowledge (PMBOK) provides that the project charter is the "document that formally authorizes the existence of a project and provides the project manager with the authority to apply organizational resources to project activities. It documents the high-level information on the project…"[3] Within the Academy Street PEP, it notes the project investment request serves as the charter document for the project, which is provided as an attachment to the PEP. The Academy Street investment request form provides the annual estimated expenditures on the project, a summary of the project scope, the assumptions utilized, major timing commitments (e.g. long-lead equipment, permitting, etc.), and other similar summary information that defines the project. The IM finds the Academy Street project charter and project authorization, as established by the investment request form, aligns with industry standards.
- Status Reporting: The PMBOK provides that "During project execution, the work performance data is collected and communicated to the applicable controlling processes for analysis. Work performance data analysis provides information about the completion status of deliverables and other relevant details about project performance."[4] Within the Academy Street PEP, it notes that status reports will include status and forecast information, referencing the PMP-14 procedure on status reporting and providing a sample monthly progress report as an attachment. The monthly progress report reviews the summary activities on the project, provides functional performance indicators, and cost, schedule, and risk information. The IM finds the Academy Street project status reporting, and specifically the sample monthly progress report, aligns with industry standards.

Through the end of the first quarter of 2020, approximately $250,000 was spent on the Academy Street project, primarily on project management and engineering costs. Notable activities completed to date include:

- Project kickoff meeting held;
- Issuance of key drawing packages;
- Permitting matrix completed;

[2] Note: the Academy Street project Study level estimate, which features the updated estimate based on the change in mitigation method, is expected to go for approval before the Utility Review Board (URB) in May 2020. The $17.0 estimate shown in this report is the last approved estimate for the project.
[3] Project Management Institute, *A Guide to the Project Management Body of Knowledge – PMBOK Guide,* Sixth Edition, p. 81, 2017
[4] Project Management Institute, *A Guide to the Project Management Body of Knowledge – PMBOK Guide,* Sixth Edition, p. 92, 2017

- A/E contract was awarded, and detailed design has commenced;
- Licensing and permitting package for the project issued; and,
- Switchgear purchase order was awarded, and delivery is scheduled for November 2020.

Upcoming activities in the second quarter of 2020 include commencement of detailed design and civil, demolition, and electrical drawings issued for review. The actual spend by quarter for the Academy Street project as compared to the last approved estimate is provided below.

Q4 2019	Q1 2020	Total	Estimate	% of Actuals to Estimate
Actuals				
$150,398	$99,893	$250,291	$17,000,000	1%

2. *Clay Street*

The Clay Street substation scope calls for building new manholes, feeder rows, switchgear, buildings, and associated equipment to allow relocation of existing 4kV transformer connections, circuits, and capacitor bank to the new 4kV switchgear. The existing 4kV switchgear at the substation is housed in the ground floor of the station building, which is below the flood elevation level and the site has a history of flooding from the adjacent sanitary/storm water pumping station. By raising and rebuilding the equipment, the Clay Street substation will have increased reliability and resiliency against flooding impacts and will increase the lifespan of the station.

Through the end of the first quarter of 2020, $336,116 was spent on the Clay Street project. Notable activities completed to date include:

- Project kickoff meeting held;
- Issuance of key drawing packages;
- Permitting matrix completed; and,
- A/E contract was awarded.

Upcoming activities in the second quarter of 2020 include locking the scope and commencing design on the licensing and permitting package. The actual spend by quarter for the Clay Street project as compared to the last approved estimate is provided below.

Q4 2019	Q1 2020	Total	Estimate	% of Actuals to Estimate
Actuals				
$116,409	$219,707	$336,116	$42,000,000	1%

3. *Constable Hook*

The Constable Hook substation scope calls for modifying the existing unit substation 8002 foundation to raise it one foot above the flood elevation level (as it currently sits two and a half feet below it), removing the existing unit substation 8001 and its structures and foundations to install a new unit substation 8001 (this will involve temporary installation of the unit sub to provide service during construction of the new foundation and oil containment). By implementing this scope, the Constable Hook substation will increase its reliability and resiliency against flooding impacts and benefit from an increased station lifespan.

Through the end of the first quarter of 2020, the Constable Hook project largely remained in the initial planning and origination stages, with the property acquisition for associated 69kV projects planned at the same area still being reviewed. The actual spend by quarter for the Constable Hook project as compared to the last approved estimate is provided below.

Q4 2019	Q1 2020	Total	Estimate	% of Actuals to Estimate
Actuals				
$17,889	$51,758	$69,647	$5,300,000	1%

4. Hasbrouck Heights

The Hasbrouck Heights substation scope calls for replacing the existing 4kV feeder rows with 4kV sheltered aisle switchgear and related equipment. The existing equipment is below the flood elevation level, and the new equipment will be installed one foot above the flood elevation level in order to increase the reliability and resiliency of the substation, while also extending the lifespan of the station.

The Hasbrouck Heights PEP follows the P&C PMP set of procedures discussed above in **Section C.2.** On this PEP, the IM is providing comments on the scope management plan and the environmental management plan.

- Scope Management Plan: The PMBOK provides that the project scope statement is "the description of the project scope, major deliverables, assumptions, and constraints."[5] Within the Hasbrouck Heights PEP, the project scope document is provided as an attachment to the PEP. The Hasbrouck Heights project scope document provides an overview of the project, its goals and objectives, the projected in-service and completion dates, the project deliverables, assumptions, risks, constraints, operating contingency, an environmental land use checklist, lists responsibilities for design, construction, and support, and similar information related to defining the project scope. The IM finds the Hasbrouck Heights project scope document aligns with industry standards for a project scope statement and can be effectively used to monitor and validate the scope.
- Environmental Management Plan: The Construction Management extension to the PMBOK notes that "The project environmental management plan essentially defines the strategy or methodology to be adopted by the performing organization to undertake environmental management and to fulfill the requirements of the project…"[6] Within the Hasbrouck Heights PEP, environmental compliance/remediation and soil, groundwater, and waste management are included as distinct PEP sections. For this site, the PEP notes a Licensed Site Remediation Professional will be used until monitoring wells are reinstalled (expected to be installed during 2020), with the New Jersey Department of Environmental Protection (NJDEP) still reviewing the soil remedial action report. It also provides project-specific strategies for soil and groundwater management to ensure compliance with regulations and requirements. The permit matrix for the project is also provided as an attachment to the PEP and lists the permits by agency with the expected permit approval duration and additional notes as appropriate (i.e. explaining the applicability or non-applicability of specific permits as well as any assumptions).

[5] Project Management Institute, *A Guide to the Project Management Body of Knowledge – PMBOK Guide,* Sixth Edition, p. 135, 2017
[6] Project Management Institute, *Construction Extension to The PMBOK Guide Third Edition*, Second Edition, p. 147, 2007

Through the end of the first quarter of 2020, $343,727 was spent on the Hasbrouck Heights project. The major activities completed to date on the Hasbrouck Heights project include:

- Kickoff meeting held;
- Key drawings reviewed;
- Permit compliance matrix completed;
- Scope locked; and,
- Major equipment (4kV sheltered aisle switchgear) purchase order issued.

Upcoming activities in the second quarter of 2020 include preparing and issuing the licensing and permitting package and commencing detailed engineering design. The actual spend by quarter for the Hasbrouck Heights project as compared to the last approved estimate is provided below.

Q4 2019	Q1 2020	Total	Estimate	% of Actuals to Estimate
Actuals				
$149,848	$193,879	$343,727	$18,000,000	2%

5. Kingsland

The Kingsland substation scope calls for rebuilding and replacing the existing 13kV feeder row switchgear that sits below the flood elevation level with new 13kV sheltered aisle switchgear that will be installed above the flood elevation level. This will increase the reliability and resiliency of the substation against flooding impacts and increase the lifespan of the station.

The Kingsland PEP follows the P&C PMP set of procedures discussed above in **Section C.2.** On this PEP, the IM is providing comments on the schedule management plan and materials management.

- Schedule Management Plan: The PMBOK provides that the schedule management plan "is a component of the project management plan that establishes the criteria and the activities for developing, monitoring, and controlling the schedule."[7] Within the Kingsland PEP, the schedule management plan is included as a section of the main PEP. The Kingsland schedule management plan notes the schedule will be managed based on project objectives and resource constraints, including identification of all interconnections, interfaces, and interdependent deliverables. On a monthly basis, the schedule will be reviewed and updated accordingly to reflect actual progress and planned activities. The IM finds the Kingsland schedule management plan aligns with industry standards for a schedule management and can be effectively used to monitor and control the schedule.
- Materials Management: The topic of materials management can be considered part of the larger procurement process, and as such, is often not a focal point of industry standards on project management. However, the Construction Management Association of America (CMAA) notes that "Prior to construction, the [construction manager] identifies long lead materials and equipment for pre-purchasing…"[8] Within the PEP, the major equipment required for the project is identified (13kV sheltered aisle switchgear) and included in the risk register, schedule, and other key project documents. Also, the Kingsland PEP references to the PEP-12 procedure on materials management for the requirements regarding material and equipment receiving,

[7] Project Management Institute, *A Guide to the Project Management Body of Knowledge – PMBOK Guide,* Sixth Edition, p. 135, 2017
[8] Construction Management Association of America, *Standards of Practice*, p. 21, 2015

identification, handling, storage, and control of these processes. The IM finds the Kingsland materials management plan appropriately utilizes existing PSE&G processes and also has identified the major and long-lead equipment that aligns with industry standards.

Through the end of the first quarter of 2020, $212,398 was spent on the Kingsland project. The major activities completed to date include:

- Kickoff meeting held;
- Key drawings reviewed;
- Permit compliance matrix completed;
- Scope locked;
- Major equipment (13kV sheltered aisle switchgear) purchase order issued; and,
- Commencement of the licensing and permitting design package.

Upcoming activities in the second quarter of 2020 include vendor drawings (mechanical and wiring) submitted to PSE&G. The actual spend by quarter for the Kingsland project as compared to the last approved estimate is provided below.

Q4 2019	Q1 2020	Total	Estimate	% of Actuals to Estimate
Actuals				
$104,112	$108,286	$212,398	$10,000,000	2%

6. Lakeside Avenue

The Lakeside Avenue substation scope calls for replacing the existing 4kV building that sits below the flood elevation level with 4kV sheltered aisle switchgear, including reactors and regulators, that will be installed one foot above the flood elevation level. The scope also includes expanding the station fence to encompass additional property acquired and installing (and later demolishing) a temporary 26kV control house to maintain service. This will increase the reliability and resiliency of the Lakeside Avenue substation against flooding impacts and increase the lifespan of the substation.

Through the end of the first quarter of 2020, $321,167 was spent on the Lakeside Avenue project. The project largely remained in the initial planning and origination stages, with the property acquisition for associated 69kV projects planned at the same sites still being reviewed. The actual spend by quarter for the Lakeside Avenue project as compared to the last approved estimate is provided below.

Q4 2019	Q1 2020	Total	Estimate	% of Actuals to Estimate
Actuals				
$148,943	$172,224	$321,167	$36,100,000	1%

7. Leonia

The Leonia substation scope calls for expanding the existing fence to the property line, installing new 13kV sheltered aisle switchgear above the flood elevation level, demolishing existing 13kV structures that are below the flood elevation level, and installing new manhole, ducts and feeders to support the 13kV system. This will increase the reliability and resiliency of the Leonia substation against flooding impacts and increase the lifespan of the substation.

Through the end of the first quarter of 2020, $289,114 was spent on the Leonia project. The major activities completed to date include:

- Kickoff meeting held;
- Key drawings reviewed; and,
- Major equipment (13kV sheltered aisle switchgear) purchase order issued.

Upcoming activities in the second quarter of 2020 include completion of the permitting matrix, constructability reviews, and locking the scope. The actual spend by quarter for the Leonia project as compared to the last approved estimate is provided below.

Q4 2019	Q1 2020	Total	Estimate	% of Actuals to Estimate
Actuals				
$44,792	$244,323	$289,114	$32,200,000	1%

8. Market Street

The Market Street substation scope calls for converting the 4kV outside plant circuits to 13kV, feeding the 13kV circuits from the Locust Street and Deptford substations, and eliminating the Market Street substation. The substation's existing 4kV feeder rows are below the flood elevation level and PSE&G identified that open capacity at the neighboring substations was available to increase the reliability of the Market Street 4kV network.

The Market Street PEP follows the P&C PMP set of procedures discussed above in **Section C.2.** On this PEP, the IM is providing comments on the project estimating/cost management plan and the health and safety management plan.

- Project Estimating/Cost Management Plan: The PMBOK provides that cost management "includes the processes involved in planning, estimating, budgeting, financing, funding, managing, and controlling costs…"[9] Within the Market Street PEP, the cost management plan is included as a section of the main PEP. The Market Street cost management plan reviews the estimating process used on the project, noting the Study level estimate will serve as the project baseline estimate until the future estimates at the Conceptual and Definitive levels are completed, at which point they will become the new project targets for monitoring and reporting costs. The cost management plan goes on to explain the budgeting process consists of two primary elements – the plan and the forecast, with updates to the budgeted plan being managed through the change control process and with the actuals and annual to-go cash flow updated on a monthly basis. The IM finds the Market Street cost management plan aligns with industry standards for project cost management and can be effectively used to monitor and control costs.
- Health and Safety Management Plan: The Construction Management extension to the PMBOK notes that project safety management processes "include all activities of the project sponsor/owner and the performing organization which determine safety policies, objectives, and, responsibilities so the project is planned and executed in a manger that prevents accidents…The performing organization implements the safety management system through the policy, procedures, and processes of safety planning, safety assurance, and safety control, and undertaking continuous improvement activities throughout the project, as appropriate."[10] Within the Market Street PEP, it notes that the PMP-08 procedure on project and contractor safety will

[9] Project Management Institute, *A Guide to the Project Management Body of Knowledge – PMBOK Guide,* Sixth Edition, p. 231, 2017

[10] Project Management Institute, *Construction Extension to The PMBOK Guide Third Edition*, Second Edition, p. 119, 2007

be implemented. It also provides that the contractor will submit a project health and safety plan for approval prior to construction. The Market Street site is a designated Superfund study area and the PEP notes that the project team has engaged Environmental Protection Agency (EPA) representatives and will follow appropriate guidance on health and safety measures, including utilizing trained hazardous water operations and emergency response (HAZWOPER) personnel as appropriate.

Through the end of the first quarter of 2020, $2,189,906 was spent on the Market Street project. The major activities completed to date include:

- Kickoff meeting held;
- Key drawings reviewed;
- Permit compliance matrix completed;
- Scope locked;
- Commencement of detailed design; and,
- Start of outside plant construction.

Upcoming activities in the second quarter of 2020 include civil and electrical drawings being issued for construction. The outside plant area of the Market Street site (along the road) was identified as having radioactive soil, which had the potential to affect the project completion; however, PSE&G engaged qualified contractors to handle the required soil removal in alignment with the project schedule. The total estimated costs for the environmental contaminated soil issue is $2.3 million and is included in the current $30 million estimate. This $2.3 million includes the cost of excavation for installation of poles on the outside plant scope and certified contractor testing, sampling, soil removal, and Sonotube installations.

The actual spend by quarter for the Market Street project as compared to the last approved estimate is provided below.

Q4 2019	Q1 2020	Total	Estimate	% of Actuals to Estimate
Actuals				
$251,193	$1,938,713	$2,189,906	$30,000,000	7%

9. Meadow Road

The Meadow Road substation scope calls for replacing the existing five 13kV individual feeder rows that sit below the flood elevation level with new 13kV sheltered aisle switchgear on elevated platforms one foot above the flood elevation level. This will increase the reliability and resiliency of the Meadow Road substation against flooding impacts and increase the lifespan of the station.

Through the end of the first quarter of 2020, $206,074 was spent on the Meadow Road project. The major activities completed to date include:

- Kickoff meeting held;
- Key drawings reviewed;
- Permit compliance matrix completed;
- Scope locked; and,
- Major equipment (13kV sheltered aisle switchgear) purchase order issued.

Upcoming activities in the second quarter of 2020 include locking the scope and issuing the licensing and permitting package. The actual spend by quarter for the Meadow Road project as compared to the last approved estimate is provided below.

Q4 2019	Q1 2020	Total	Estimate	% of Actuals to Estimate
Actuals				
$63,128	$142,946	$206,074	$9,000,000	2%

10. Orange Valley

The Orange Valley substation scope calls for replacing the existing 4kV feeder rows that sit below the flood elevation level with 4kV sheltered aisle switchgear to be installed on elevated platforms one foot above the flood elevation level. This will increase the reliability and resiliency of the substation against flooding impacts and increase the lifespan of the station.

Through the end of the first quarter of 2020, $173,611 was spent on the Orange Valley project, which largely remained in the initial planning and origination stages, with the property acquisition for associated 69kV projects planned at the same sites still being reviewed. The actual spend by quarter for the Orange Valley project as compared to the last approved estimate is provided below.

Q4 2019	Q1 2020	Total	Estimate	% of Actuals to Estimate
Actuals				
$77,029	$96,582	$173,611	$26,600,000	1%

11. Ridgefield 13kV

The Ridgefield 13kV substation scope calls for replacing existing 13kV feeder rows that are currently below the flood elevation level with two 13kV shelter aisle switchgears on an elevated structure one foot above the flood elevation level. This will increase the reliability and resilience of the substation against flooding impacts and increase the lifespan of the station.

The Ridgefield 13kV PEP follows the P&C PMP set of procedures discussed above in **Section C.2.** On this PEP, the IM is providing comments on invoice management and inside plant commissioning.

- Invoice Management: The PMBOK provides that "Control Procurements has a financial management component that involves monitoring payments to the seller."[11] Within the Ridgefield 13kV PEP, invoice management is included as a section of the main PEP. The Ridgefield 13kV invoice management plan notes that the Project Team, interfacing with construction supervision, inside plant leads, and engineering, will ensure that all invoices are submitted based on monthly cycle time to help prevent re-accruals and support forecast accuracy. The PMBOK also notes that invoices are one type of work performance data, adding that "…work performance data on cost may include funds that have been expended. However, to be useful, that data has to be compared to the budget, the work that was performed, the resources used to accomplish the work, and the funding schedule. This additional information provides the context to determine if the project is on budget or if there is a variance…Interpreting work performance data and the additional information as a whole provides a context that provides a sound foundation for project

[11] Project Management Institute, *A Guide to the Project Management Body of Knowledge – PMBOK Guide,* Sixth Edition, p. 494, 2017

decisions."[12] To fully appreciate how this is detailed in the Ridgefield 13kV PEP, the cost management plan must also be taken into consideration. In this section of the PEP, it details the cash flow forecasting efforts to be undertaken by the project team and supporting functional resources. The IM finds the invoice management processes support the industry standards for effective cost forecasting and can be effectively used to monitor and control project costs.

- Inside Plant Commissioning: The CMAA notes in its *Construction Management Standards of Practice* that "…the commissioning plan must be in concert with the project sustainability plan and the sustainability requirements of the owner…The project goals and objectives and the commissioning plan should be coordinated and focus on achieving the same project outcome."[13] The commissioning plan within the Ridgefield 13kV PEP notes that it is based off the requirements established by the inside plant commissioning procedure (PMP-15). It also establishes the roles and responsibilities of the key personnel involved in commissioning, with the PSE&G Project Construction Supervisor responsible for directing the testing, commissioning, and energization of the project in order to provide for seamless turnover of the project systems and equipment to the Division Operations Team. The Commissioning Engineer, while responsible for development of equipment-specific commissioning plans, also is involved in the development of the project scope and design review process in order to ensure constructability, identification of outage requirements, and avoidance of conflicts during startup activities. The IM finds the commissioning plan as described in the PEP and supported by the PMP-15 procedure aligns with industry standards for project commissioning and can be effectively used to ensure the project's commissioning supports the overall project goals and objectives.

Through the end of the first quarter of 2020, $523,271 was spent on the Ridgefield 13kV project. The major activities completed to date include:

- Kickoff meeting held;
- Key drawings reviewed;
- Permit compliance matrix completed;
- Scope locked; and,
- Major equipment (13kV sheltered aisle switchgear) purchase order issued.

Upcoming activities in the second quarter of 2020 include issuing the licensing and permitting package and release of civil and electrical construction design packages for construction. The actual spend by quarter for the Ridgefield 13kV project as compared to the last approved estimate is provided below.

Q4 2019	Q1 2020	Total	Estimate	% of Actuals to Estimate
Actuals				
$205,982	$317,289	$523,271	$25,500,000	2%

12. Ridgefield 4kV

The Ridgefield 4kV substation scope calls for eliminating the 4kV feeder rows that currently sit below the flood elevation level and transferring the load to the 13kV system. This will increase the reliability and resilience of the substation against flooding impacts and increase the lifespan of the station.

[12] Project Management Institute, *A Guide to the Project Management Body of Knowledge – PMBOK Guide,* Sixth Edition, p. 109, 2017
[13] Construction Management Association of America, *Standards of Practice*, p. 121, 2015

The Ridgefield 4kV PEP follows the P&C PMP set of procedures discussed above in **Section C.2.** On this PEP, the IM is providing comments on project construction oversight.

- The PMBOK includes only limited discussion on oversight, essentially just that the project manager has oversight responsibility.[14] Other industry standard publications, such as those from the CMAA take similar stances, noting that the construction manager provides oversight for the entire project to deliver the project on time, at or under budget, and to the expected standard of quality, scope, and function.[15] In essence, oversight takes place within the different project functions (e.g. schedule, cost, scope, etc.). Within the Ridgefield 4kV PEP, it provides that the Project Construction Oversight procedure establishes the requirements for construction oversight and specifically details the unique responsibilities concerning outside plant conversion work on the project. Within the different project functions, additional structure is provided as to the expected oversight and reviews of the project schedule, costs, and other project functions. The IM finds the project construction oversight processes are established to effectively monitor that project goals and objectives are fulfilled.

Through the end of the first quarter of 2020, $836,542 was spent on the Ridgefield 4kV project. The major activities completed to date include:

- Kickoff meeting held;
- Key drawings reviewed;
- Permit compliance matrix completed;
- Detailed engineering commenced; and,
- Outside plant construction started.

Upcoming activities in the second quarter of 2020 include locking the scope, issuing the civil works contract, and commencing civil construction. The actual spend by quarter for the Ridgefield 4kV project as compared to the last approved estimate is provided below.

Q4 2019	Q1 2020	Total	Estimate	% of Actuals to Estimate
Actuals				
$143,414	$693,128	$836,542	$21,100,000	4%

13. State Street

The original State Street substation scope called for replacing the existing 4kV switchgear, feeder rows, and transformers that currently sit below the flood elevation level with new equipment that will be installed one foot above the flood elevation level. This will increase the reliability and resilience of the substation against flooding impacts and increase the lifespan of the station. On April 16, 2020, PSE&G issued to the BPU a notice of change in mitigation method on this substation (and the Academy Street substation). The State Street substation is located within the City of Camden and is both within a flood hazard area and within the City's redevelopment zone. The City and Camden County have informed PSE&G they are strongly opposed to the substation expansion required for flood mitigation work at the current site. PSE&G researched alternatives and with recommendation from the City identified property at Cooper Street that would be suitable for rebuilding the State Street substation. The new property is an

[14] Project Management Institute, *A Guide to the Project Management Body of Knowledge – PMBOK Guide,* Sixth Edition, p. 29, 2017
[15] https://www.cmaanet.org/about-us/what-construction-management

undeveloped parcel located outside the flood hazard area and the redevelopment zone, however, it will require extensive underground installation (duct banks, manholes) that was not part of the original project scope and will result in a significant increase to the project's estimate (from $28.6 million to $45.1 million). On April 22, 2020, Rate Counsel responded to PSE&G's notice indicating it objects to the change (as well as the change to the Academy Street substation) without additional information and clarification on the changes.

The State Street PEP follows the P&C PMP set of procedures discussed above in **Section C.2.** On this PEP, the IM is providing comments on quality assurance and quality control.

- The PMBOK provides that "Plan Quality Management is the process of identifying quality requirements and/or standards for the project and its deliverables, and documentation how the project will demonstrate compliance with quality requirements and/or standards."[16] Within the State Street PEP, quality assurance and quality control steps are included as a section of the main PEP and establishes the strategies to be implemented on the project for effective quality assurance and quality control, including responsibilities for the project team, project manager, contractor, and vendor/supplier. The general quality assurance and quality control plan is provided as an attachment to the PEP and provides additional detail into the quality management actions and responsibilities, including establishing the strategy and requirements for the different project functional areas (e.g. engineering, procurement, construction, etc.). The IM finds the quality management processes support the industry standards for effective quality assurance and quality control and can be effectively used to ensure project-specific requirements are fulfilled.

Through the end of the first quarter, $205,878 was spent on the State Street project. The major activities completed to date include:

- Kickoff meeting held;
- Key drawings reviewed;
- Permit compliance matrix completed;
- Scope locked;
- Licensing and permitting package submitted; and,
- Major equipment (4kV sheltered aisle switchgear) purchase order issued.

Upcoming activities in the second quarter of 2020 include commencing detailed engineering design. The actual spend by quarter for the State Street project as compared to the last approved estimate is provided below.

Q4 2019	Q1 2020	Total	Estimate	% of Actuals to Estimate
Actuals				
$77,590	$128,288	$205,878	$28,600,000	1%

14. Toney's Brook

The Toney's Brook substation scope calls for replacing the existing 4kV switchgear, feeder rows, transformers, and 26kV equipment that sits below the flood elevation level with new equipment to be

[16] Project Management Institute, *A Guide to the Project Management Body of Knowledge – PMBOK Guide,* Sixth Edition, p. 494, 2017

installed one foot above the flood elevation level. This will increase the reliability and resilience of the substation against flooding impacts and increase the lifespan of the station.

The Toney's Brook PEP follows the P&C PMP set of procedures discussed above in **Section C.2.** On this PEP, the IM is providing comments on contract administration.

- Within the Toney's Brook PEP, the contracting strategy and contract administration responsibilities are included as an attachment to the PEP. The contract administration responsibilities detail the specific responsibilities of the PSE&G personnel, covering the contracting process through the development of bid packages, review and awarding of bids, and managing contracts including change control processes. The PMBOK provides that "Defining roles and responsibilities related to procurement should be done early in the Plant Procurement process" and notes typical steps such as preparing scopes of work, preparing bid documents, evaluating proposals, etc.[17] that are included in the Toney's Brook contract administration responsibilities. The IM finds the contract administration processes align with industry standards and can be used to ensure effective contract management practices are utilized.

Through the end of the first quarter of 2020, $327,687 was spent on the Toney's Brook project. The major activities completed to date include:

- Completion of the contingency plan (part of the companion 69kV project);
- Review of key drawings;
- Submittal of the licensing and permitting packages;
- Issuance of the major equipment purchase order (4kV sheltered aisle switchgear);
- Award of the A/E contract; and,
- Locking of the scope.

Upcoming activities in the second quarter of 2020 include design freeze on the switchgear arrangement, mechanical, and controls, and preparation of the civil design package (issued for review). The actual spend by quarter for the Toney's Brook project compared to the last approved estimate is provided below.

Q4 2019	Q1 2020	Total	Estimate	% of Actuals to Estimate
Actuals				
$211,940	$115,747	$327,687	$19,700,000	2%

15. Waverly

The Waverly substation scope calls for rebuilding the 26kV switchgear and transformers and building new 4kV feeder rows, which will be one foot above the flood elevation level, in addition to the demolishing of the existing 26kV yard, the over 80-year old Class A building and associated old 4kV equipment. This will increase the reliability and resilience of the substation against flooding impacts and increase the lifespan of the station.

Through the end of the first quarter, $459,454 was spent on the Waverly project. The major activities completed to date include:

- Kickoff meeting held;

[17] Project Management Institute, *A Guide to the Project Management Body of Knowledge – PMBOK Guide,* Sixth Edition, p. 468, 2017

- Key drawings reviewed; and,
- Geotech services contract awarded.

Upcoming activities in the second quarter of 2020 include issuing the purchase order for major equipment (26kV and 4kV sheltered aisle switchgear), awarding the A/E contract, and locking the scope. The actual spend by quarter for the Waverly project as compared to the last approved estimate is provided below.

Q4 2019	Q1 2020	Total	Estimate	% of Actuals to Estimate
Actuals				
$103,748	$355,706	$459,454	$35,400,000	1%

16. Woodlynne

The Woodlynne substation scope calls for replacing the existing 4kV feeder rows/sheltered aisle switchgear that currently sits below the flood elevation level with new equipment to be installed one foot above the flood elevation level. This will increase the reliability and resilience of the substation against flooding impacts and increase the lifespan of the station.

The Woodlynne PEP follows the P&C PMP set of procedures discussed above in **Section C.2.** On this PEP, the IM is providing comments on risk management.

- The PMBOK provides that risk management "includes the processes of conducting risk management planning, identification, analysis, response planning, response implementation, and monitoring risk on a project. The objectives of project risk management are to increase the probability and or/impact of positive risks and to decrease the probability and/or impact of negative risks, in order to optimize the chances of project success."[18] Within the Woodlynne PEP, it notes that project risks were identified and assessed with corresponding strategies to control the risks identified. The project's risk register is attached as an attachment to the PEP and will be reviewed on a monthly basis during execution. The IM finds the risk register developed for the Woodlynne project aligns with industry standards for risk management, including quantifying the risk impacts and identifying mitigation plans, and can be effectively used to ensure project risks are identified, managed, and controlled.

Through the end of the first quarter of 2020, $351,400 was spent on the Woodlynne project. The major activities completed to date include:

- Kickoff meeting held;
- Key drawings reviewed;
- Permit compliance matrix completed;
- Scope locked;
- Major equipment (4kV sheltered aisle switchgear) purchase order issued; and,
- A/E contract awarded.

Upcoming activities in the second quarter of 2020 include preparing and issuing the licensing and permitting package and commencing detailed engineering design. The actual spend by quarter for the Woodlynne project as compared to the last approved estimate is provided below.

[18] Project Management Institute, *A Guide to the Project Management Body of Knowledge – PMBOK Guide,* Sixth Edition, p. 395, 2017

Q4 2019	Q1 2020	Total	Estimate	% of Actuals to Estimate
Actuals				
$110,982	$240,418	$351,400	$19,400,000	2%

B. Contingency Reconfiguration

The Stipulation identified the Contingency Reconfiguration subprogram to include up to $145 million invested in increasing system resiliency through implementation of contingency reconfiguration strategies that include: increasing sections in present loop designs by utilizing reclosers; converting all existing two-section overhead 13kV circuits to three-section circuits by installing additional three-phase reclosers, and installing single-phase recloser devices on branch lines that operate with only fuses.

The Contingency Reconfiguration organization is led by Donald Gordon, supported by Bob Kirk (Senior Project Manager), Nicole Severt (PMO Manager), and with subprogram leads at each of the Divisions. Under this arrangement, the subprogram is centrally managed, with execution carried out at the Division-level following their own execution processes. As part of the management of the subprogram, monthly unit targets are established for the Divisions, with status calls held weekly with all Divisions. Additionally, direction was given to the Divisions to push engineering out ahead of execution to support maximum flexibility in carrying out the work. This flexibility has assisted in minimizing Covid-19 impacts, as the permitting process has often been extended due to the process now requiring exchange of permitting documents to take place over the mail, rather than in-person.

The selection criteria for projects under the Contingency Reconfiguration subprogram began with a pool of all overhead 13kV circuits (excluding existing three-section circuits) and the worst performing overhead 4kV circuits (excluding existing two-section circuits). The priority is based on highest customer impact and begins with 13kV circuits, then 4kV feeder reclosers, and followed by 4kV tie reclosers. Additional detail on the specific selection criteria is provided as follows:

- 13kV Circuits: each of the two sections are evaluated based on historical customer outage data, if one of the two sections has a much greater customer interruption rate, then a recloser is added to split that section; if the two sections are relatively close in their performance, the circuit is split into thirds. As a result, all 13kV circuits with overhead mileage will be upgraded from 2 to 3 section reclosers.
- 4kV Circuits: these circuits were not originally designed with sectionalizing reclosers, so a customer interruption analysis was performed and concluded there is value to sectionalizing the worst performing 4kV circuits based on the value of lost load improvement expected. This resulted in approximately 500 of the 1,200 circuits on PSE&G's network being selected for sectionalizing through adding a recloser to split the circuit into two sections. Additionally, where it is feasible, PSE&G will add a tie recloser to the tail end of the circuit to provide an additional source to the circuit in the event of a long-term outage on the first circuit section or at the originating source station.
- Branch Reclosers: three-phase branch lines were evaluated to determine the value in installing branch reclosers on the worst performing branches from a customer interruption standpoint. These branch lines are protected with fuses that when blown require a service crew to be sent out to execute the repairs and return the line to service. PSE&G's criteria included that the branch lines serve at least 1,000 customers and that there was a value of lost load improvement expected. As a result, approximately 100 branches were put into the subprogram scope.
- Fuse Savers: all one- and two-phase branch lines fed from 4kV and 13kV circuits were analyzed to determine if adding a Fuse Saver (essentially a single-phase automatic recloser) was warranted.

PSE&G's criteria included that the branch serve at least 80 customers. The result of the evaluation determined that approximately 3,282 one and two-phase branches were included in the subprogram based on the value of lost load improvement expected.

In addition, PSE&G will continue to evaluate the selected circuits through the detailed design process to ensure that they continue to be appropriate for additional reclosers.

The work performed to date includes:

- Divisions performing detailed reviews of the proposed recloser locations;
- Divisions creating work packages;
- Relay Techs testing breakers and programming recloser controls;
- Divisions overhead crews installing poles, framing poles, and completing wire work in preparation of recloser installations; and
- All four Divisions have begun installing reclosers.

Table 10 – ES 2 Program Recloser Status as of March 31, 2020 provides a summary of the recloser aspect of the Contingency Reconfiguration subprogram, indicating the 2020 year end targets and current status of engineering, installation, and commissioning.

Table 10 – ES 2 Program Recloser Status as of March 31, 2020

Type	2020 Year End Total Target	Engineering Packages Complete (1 recloser ea.)	Reclosers Installed	Reclosers Commissioned
13kV	800	549	333	0
4kV	179	163	24	0
Total	979	712	357	0

As shown in **Table 10**, with engineering comfortably ahead of construction, it allows PSE&G flexibility in selecting which projects to initiate construction and allows the subprogram progress to continue.

The IM evaluated PSE&G's equipment selection decision for the single and two-phase recloser devices that are being installed as part of the Contingency Reconfiguration subprogram. Initially, PSE&G identified two potential options for this equipment, the TripSaver-II manufactured by the S&C Electric Company and the Fusesaver manufactured by Siemens. After several meetings and conference calls to review and discuss PSE&G's requirements against the capabilities of this equipment, it was identified that the TripSaver-II lacked the capability to remotely communicate via supervisory control and data acquisition (SCADA), and thus did not meet PSE&G's requirement to have the equipment able to document and capture the momentary outages on the electric distribution system. Therefore, the Siemens Fusesaver device was selected as it was capable of meeting PSE&G's operating requirements.

The single-phase recloser device installation plan contemplates 2,307 single-phase and 980 two-phase devices over the course of the ES 2 Program. Pole locations and circuits have been verified for the installation of these devices, with individual maps of all fuse saver pole locations provided to the Divisions. Initially, PSE&G anticipated 112 single-phase and 40 two-phase devices as of the end of the first quarter of 2020, however installation of the fuse savers has been delayed due to the lack of radio availability and is now expected to commence in August 2020. The cause of the delay to radio availability was related to component supply delays and certification delays related to Covid-19. In the interim, PSE&G has adjusted its commissioning strategy and is installing additional reclosers to continue to advance the subprogram. PSE&G expects the gap between installation and commissioning will be closed by the end of the year with no overall impact to the subprogram.

The Contingency Reconfiguration subprogram costs through the end of the first quarter of 2020 are presented in **Table 11 – ES 2 Program Contingency Reconfiguration Costs as of March 31, 2020**.

Table 11 – ES 2 Program Contingency Reconfiguration Costs as of March 31, 2020

Scope & Division		Q4 2019	Q1 2020	Total	Forecast	% of Actuals to Forecast
		Actuals				
Reclosers	Central	$2,737,167	$3,918,150	$6,655,317	$27,309,897	24%
	Metro	$2,231,431	$3,576,616	$5,808,047	$23,547,928	25%
	Palisades	$2,515,569	$3,353,246	$5,868,815	$27,460,493	21%
	Southern	$2,081,220	$4,003,537	$6,084,758	$29,657,985	21%
Fuse Savers	Central	$9,970	$29,667	$39,637	$969,760	4%
	Metro	$7,557	$15,498	$23,055	$675,723	3%
	Palisades	$7,468	$15,259	$22,727	$9,245,276	0%
	Southern	$9,792	$21,458	$31,250	$629,503	5%
Total		**$9,609,966**	**$14,933,431**	**$24,533,604**	**$119,496,564**	**21%**

Findings & Observations:

- PSE&G has planned and reviewed resource and installation schedules with the Divisions to ensure they are appropriately prepared to execute the work required for this subprogram.
- Recloser installations advanced ahead of target through the end of the first quarter of 2020, and while radio delays affected the installation of fuse savers and commissioning of reclosers, PSE&G expects to close this gap by the end of 2020. Additionally, by having recloser engineering consistently ahead of the installation plan, it allows PSE&G flexibility in its schedule.
- While early in the subprogram, the IM has found nothing to date that would jeopardize the subprogram being completed on time and/or on budget.

C. Grid Modernization – Communication System

The Stipulation identified the Grid Modernization – Communication System subprogram to include up to $72 million invested in installing a private wireless communications network to eliminate the use of dedicated phone lines for remote communication for both PSE&G and customer equipment. The overall network will provide coverage using both wireless and fiber technologies to all switching devices on the PSE&G system.

The Grid Modernization – Communication System organization is led by Al Balletto (who also leads the other Grid Modernization subprogram) and is supported by communication system leads Jim Yorke (wireless network), Lukasz Kubas (SCADA commissioning), Bob Kirk (fiber – outside plant), and Ayoola Odeyemi (fiber – inside plant), with the latter two leads also a part of the Contingency Reconfiguration subprogram due to the interconnectedness of these subprograms.

The wireless network scope specifically calls for building a robust wireless network across PSE&G's service territory that will support real-time wireless connectivity to all operational asset and redundant communication paths to network devices. Additionally, the network will have robust monitoring and multilayered security, as well as being independent of commercial carriers. PSE&G received bids from multiple vendors for the wireless network, ultimately awarding to FirstNet based on its lower overall cost and better alignment with PSE&G's objectives than other bidders offered. The FirstNet broadband network is built through a private-public partnership between AT&T and the U.S. Federal Government and provides wireless broadband to first responders on dedicated spectrum bands. The PSE&G devices communicating on this network will benefit from overlapping coverage from multiple tower sites and multiple layers of redundancy providing increased reliability.

It is expected that approximately 2,704 routers will be installed in existing reclosers to support the broadened wireless connectivity. Through the end of the first quarter of 2020, there were no retrofitted reclosers installed with activities primarily focused on planning (reviewing resource and installation schedules with the Divisions, completing installation and commissioning procedures, etc.). The recloser retrofitting installation plan is reflected in **Table 12 – ES 2 Program Retrofitting Reclosers Schedule** and contemplates most of the 2020 work occurring during the fourth quarter.

Table 12 – ES 2 Program Retrofitting Reclosers Schedule

Division	2020	2021	2022	2023	Total
Central	33	240	236	265	774
Metro	29	175	163	129	496
Palisades	26	180	182	198	586
Southern	44	284	267	253	848
Total	***132***	***879***	***848***	***845***	***2,704***

The IM evaluated PSE&G's vendor selection decision for the wireless equipment, specifically the routers, antennas, and related accessories and mounting equipment to establish SCADA communication, in addition to the supply, configuration, and implementation a network management system capable of managing the initial deployment of 7,900 routers (with the ability to scale up to over 500,000 end points in the future). Hardware from Sierra Wireless and Nokia represented the two options for the required equipment (from different vendors), with AT&T/Nokia being selected based on the technical solutions, and specifically the IT security requirements, better suiting the needs of PSE&G.

The fiber scope includes installing fiber to electric substations and electric operations centers, in addition to cutting over stations with existing fiber service to the PSE&G fiber network. Execution of this scope is based on a full review of all proposed projects and routes with proposed route maps created and released to engineering to design and build work packages. Asset Strategy performed the first pass in prioritizing the fiber projects, assessing the communication status and the long-term status of the facilities to ensure they are a good fit for the subprogram. The Divisions then performed preliminary review of the fiber routes to identify any potential permitting requirements.

The Grid Modernization – Communication System subprogram costs through the end of the first quarter of 2020 are presented in **Table 13 – ES 2 Program Grid Modernization – Communication System Costs as of March 31, 2020**.

Table 13 – ES 2 Program Grid Modernization – Communication System Costs as of March 31, 2020

Scope & Division		Q4 2019	Q1 2020	Total	Estimate	% of Actuals to Estimate
		Actuals				
Retrofit Reclosers	Central	$0	$50,613	$50,613	$7,819,860	1%
	Metro	$0	$44,164	$44,164	$6,629,143	1%
	Palisades	$0	$44,164	$44,164	$6,854,198	1%
	Southern	$0	$46,901	$46,901	$8,313,084	1%
Fi be	Central	$1,691	$133,115	$134,806	$4,545,000	3%
	Metro	$1,457	$109,382	$110,839	$6,330,000	2%

	Palisades	$1,582	$194,451	$196,033	$3,300,000	6%
	Southern	$4,731	$65,721	$70,452	$2,490,000	3%
	Cutovers	$0	$0	$0	$6,735,000	0%
Wireless Network		$74,306	$1,525,801	$1,600,107	$12,063,705	13%
Total		**$83,767**	**$2,214,312**	**$2,298,078**	**$65,079,990**	**4%**

Findings & Observations:

- The IM finds that selection of FirstNet for the wireless broadband network services was an appropriate selection that will achieve PSE&G's intended objectives, including superior coverage and reliability, at a competitive cost.
- Primary activities to date relate to planning and procurement, including developing detailed schedules and installation and commissioning procedures with the Divisions.
- New reclosers (as Contingency Reconfiguration subprogram) have installation priority of retrofits due to new reclosers providing segregation to the sections they are installed that improves reliability (while retrofits improve communications on the devices).
- While early in the subprogram, the IM has found nothing to date that would jeopardize the subprogram being completed on time and/or on budget.

D. Grid Modernization – ADMS

The Stipulation identified the Grid Modernization – ADMS subprogram to include up to $35 million invested to develop an ADMS that will replace the existing Outage Management System (OMS). The ADMS will incorporate data from Geographic Information System (GIS) and SCADA, intelligent fault indicators, smart meters, and other advanced metering infrastructure (AMI). This will provide enhanced storm damage management including advanced estimated time of restoration calculations and provide AMI capabilities including automated restoration verification, smart detection of nested outages, and visualization of ping results.

The Grid Modernization – ADMS organization is led by Al Balletto (as mentioned above, Mr. Balletto also leads the other Grid Modernization subprogram) and is supported by ADMS leads Steve Zinser (OMS), Francis Frank (Distributed Management System (DMS)/ Distributed Energy Resource Management System (DERMS)), and Ryan Wilson (ADMS platform), as well as Dan Thomsen (Senior Principal Technology Product Consultant) and Mary Jane Jacobson (Performance Measurement Analyst).

The Grid Modernization – ADMS scope is split between three primary sections: DMS/DERMS, the OMS, and ADMS platform upgrades. The primary activities in 2020 are centered on planning activities, with scopes of work developed in the first quarter of 2020. The ADMS is currently forecasted to go live during the second quarter of 2022. The high-level schedule was based on hardware milestones and a goal of getting the equipment in place prior to the summer outage period in 2023. Currently, working with the vendors to incorporate more detail into the subprogram schedule.

The IM evaluated PSE&G's vendor selection decision for the ADMS, which was a sole source award to Open Systems International Inc. (OSII). The sole source decision was based on OSII being the vendor for the SCADA component of the ADMS, utilizing proprietary software of OSII, in addition to the supporting vendor for the operations technology platform. Because there is no other vendor capable of performing these services, it was reasonable and appropriate to award this scope of work to OSII.

The Grid Modernization – ADMS subprogram costs through the end of the first quarter of 2020 are presented in **Table 14 – ES 2 Program Grid Modernization – ADMS Costs as of March 31, 2020**.

Table 14 – ES 2 Program Grid Modernization – ADMS Costs as of March 31, 2020

Q4 2019	Q1 2020	Total	Forecast	% of Actuals to Estimate
Actuals				
$36,213	$925,689	$961,902	$40,375,128	2%

Findings & Observations:

- The primary activities to date on the subprogram are primarily planning activities, including having workshops with the software vendor and operations and finalizing the scope of work.
- Selection of OSII as a vendor through a sole source award was reasonable and appropriate given OSII's unique capabilities in providing the required services.
- While early in the subprogram, the IM has found nothing to date that would jeopardize the subprogram being completed on time and/or on budget.

E. Electric Stipulated Base

The Stipulation identified that the electric portion of the Stipulated Base include $100 million in investments at PSE&G's discretion towards electric outside plant higher design and construction standards and/or electric life cycle subprograms described in the original ES 2 Program filing. The preliminary planning by PSE&G estimates that approximately one-third of the Stipulated Base funds will be used towards the electric life cycle investments and the remaining two-thirds towards outside plant higher design and construction standards.

The outside plan higher design and construction standards scope of work contemplates replacing the traditional open wire and cross-arm type construction on distribution overheard circuits with spacer cable in targeted locations. PSE&G determined that spacer cable provides significant improvement in customer reliability during storm events and other tree-related events as compared to the traditional methods. At present, approximately 45% of PSE&G's 4kV and 13kV overhead distribution system uses spacer cable. The final circuit selection for this effort is still being developed but will be selected from PSE&G's original proposal using historical value of lost load from reportable and major event history.

Through the first quarter of 2020, there was no spend in the electric stipulated base projects as the projects are still being identified, planned, and going through the approval process. Four stations have been identified for life cycle station upgrades and are expected to go before the URB in June 2020 for approval.

Findings & Observations:

- The electric stipulated base projects remain in the planning and approval phases, as such the IM has no additional comments on this component of the ES 2 Program at this time.

F. Gas M&R Station Upgrades

The Stipulation identified that the Gas M&R subprogram will consist of up to $50.5 million in investments through the ES 2 Program Accelerated Rate Recovery Mechanism to rebuild/modernize six gas M&R stations. An additional $50.5 million will be invested through Stipulated Base to be recovered in PSE&G's next base rate case, bringing the total subprogram investment to $101 million. While the current estimates forecast the six identified M&R stations will utilize the full $101 million investment, an additional stipulated base project (Hillsborough M&R) was identified if the total cost of the subprogram comes in under the stipulated amount.

The Gas M&R subprogram is led by Charlie Miracola, with two senior project managers splitting five of the projects (Camden, Mt. Laurel, Westampton, East Rutherford, and Paramus) and a project manager overseeing the other project (Central). The subprogram is also supported by Sonia Zacher-Martini (PMO Manager), Tony Fuhrman (Manager Gas Asset Strategy), and John Fillman (Manager M&R).

The common scope of work at all stations in the Gas M&R subprogram is for installation of new underground piping that is rated for the full pipeline company maximum allowable operating pressure, thus eliminating the need for high pressure relief valves and enhancing safety and environmental performance. Overpressure protection will be provided through series regulators with a working regulator and monitor regulator. Downstream distribution system relief valves will also be installed as a third line of overpressure protection, also enhancing safety and environmental performance. As part of the planning efforts, PSE&G's Asset Management group evaluated the equipment at each station, including performing inspections, examining O&M records, and receiving feedback from the operations personnel to determine the possibility for re-using equipment rather than replacing it. Additional scope elements for each of the specific stations is described in the following subsections on the individual stations.

The IM evaluated PSE&G's selection of the design work for the Mt. Laurel and Westampton projects, which were the first to be awarded in the Gas M&R subprogram. The evaluation included both technical and commercial components, with both projects ultimately awarded to the highest evaluated contractor with the requisite experience and capabilities, which in these cases was also the lowest price bidder. The Camden design work was also initially awarded in this period, but due to the selected contractor not agreeing to the procurement terms and conditions, the work was re-bid, with the Camden design work and the other remaining projects having design contracts awarded in May-June 2020.

Through the end of the first quarter, preliminary design had been initiated on each of the Gas M&R stations. Additionally, the contract design RFP for each station was issued, with recommendations to award completed for the Westampton, Camden, and Mt. Laurel stations. The remaining stations are expected to have recommendations to award for the design services early in the second quarter of 2020. As with other subprograms in the ES 2 Program, the primary Covid-19 related impact has been shifting in-person meetings to a virtual setting. The detailed project schedules are currently under development.

Table 15 – ES 2 Program Gas M&R Summary Status as of March 31, 2020 below provides the currently approved estimates for each project within the Gas M&R subprogram, along with the actuals to date and forecasted in-service dates. As indicated in **Table 15**, there has been minimal spend to date on the subprogram, primarily related to initial planning efforts.

Table 15 – ES 2 Program Gas M&R Summary Status as of March 31, 2020

Project	Estimate Level	Base	Risk & Contingency	Total	Actuals	% of Actuals to Estimate	Forecasted In-Service
1. Camden*	Office	$10,000,000	$5,400,000	$15,400,000	$60,017	0%	Jan 2023
2. Central*	Office	$12,800,000	$6,900,000	$19,700,000	$51,917	0%	Jan 2023
3. East Rutherford	Office	$10,300,000	$5,600,000	$15,900,000	$46,757	0%	Jan 2023

Project	Estimate Level	Base	Risk & Contingency	Total	Actuals	% of Actuals to Estimate	Forecasted In-Service
4. Mount Laurel	Office	$11,300,000	$6,100,000	$17,400,000	$33,769	0%	Jan 2022
5. Paramus*	Office	$12,900,000	$7,000,000	$19,900,000	$46,634	0%	Jul 2023
6. Westampton	Office	$8,300,000	$4,400,000	$12,700,000	$49,234	0%	Jul 2021
Subprogram Total		**$65,600,000**	**$35,400,000**	**$101,000,000**	**$288,328**	**0%**	**Jul 2023**
**-Included in the Stipulated Base.*							

Findings & Observations:

- The primary efforts to date on the subprogram are initial planning efforts, including the preparation of bid material and awarding of bids for the design services on the projects (with two awarded in the first quarter of 2020 and the remaining awarded in the second quarter of 2020).
- While early in the subprogram, the IM has found nothing to date that would jeopardize the subprogram being completed on time and/or on budget.

1. Camden

The Camden M&R station scope includes construction of a new station to support buildings and critical equipment being installed one foot above the flood elevation level. The major equipment at this station that is not near the end of life condition and operationally can be relocated will be re-installed to the appropriate elevation at the new station.

As noted above, the primary work to date on the Gas M&R subprogram has been commencing preliminary engineering, awarding of the A/E contract (in June 2020), and other planning activities. The actual spend by quarter for the Camden project as compared to the last approved estimate is provided below.

Q4 2019	Q1 2020	Total	Estimate	% of Actuals to Estimate
Actuals				
$13,326	$46,691	$60,017	$15,400,000	0%

2. Central

The Central M&R station scope includes consolidating the three existing stations at this site into a new building. The major equipment at this station that is not near the end of life condition and operationally can be relocated will be re-installed to the appropriate elevation at the new station.

As noted above, the primary work to date on the Gas M&R subprogram has been commencing preliminary engineering, awarding of the A/E contract, and other planning activities. The actual spend by quarter for the Central project as compared to the last approved estimate is provided below.

Q4 2019	Q1 2020	Total	Estimate	% of Actuals to Estimate
Actuals				
$6,869	$45,048	$51,917	$19,700,000	0%

3. East Rutherford

The East Rutherford M&R station scope includes construction of a new station to support buildings and critical equipment being installed one foot above the flood elevation level. The major equipment at this station that is not near the end of life condition and operationally can be relocated will be re-installed to the appropriate elevation at the new station.

As noted above, the primary work to date on the Gas M&R subprogram has been commencing preliminary engineering, awarding of the A/E contract, and other planning activities. The actual spend by quarter for the East Rutherford project as compared to the last approved estimate is provided below.

Q4 2019	Q1 2020	Total	Estimate	% of Actuals to Estimate
Actuals				
$9,010	$37,747	$46,757	$15,900,000	0%

4. Mount Laurel

The Mount Laurel M&R station scope includes installation of new underground piping that is rated for the full pipeline company maximum allowable operating pressure, thus eliminating the need for high pressure relief valves and enhancing safety and environmental performance. Overpressure protection will be provided through series regulators with a working regulator and monitor regulator. Downstream distribution system relief valves will also be installed as a third line of overpressure protection, also enhancing safety and environmental performance. The major equipment at this station that is not near the end of life condition and operationally can remain in service will not be replaced.

As noted above, the primary work to date on the Gas M&R subprogram has been commencing preliminary engineering, awarding of the A/E contract, and other planning activities. The actual spend by quarter for the Mount Laurel project as compared to the last approved estimate is provided below.

Q4 2019	Q1 2020	Total	Estimate	% of Actuals to Estimate
Actuals				
$5,965	$27,804	$33,769	$17,400,000	0%

5. Paramus

The Paramus M&R station scope includes installation of new underground piping that is rated for the full pipeline company maximum allowable operating pressure, thus eliminating the need for high pressure relief valves and enhancing safety and environmental performance. Overpressure protection will be provided through series regulators with a working regulator and monitor regulator. Downstream distribution system relief valves will also be installed as a third line of overpressure protection, also enhancing safety and environmental performance. The major equipment at this station that is not near the end of life condition and operationally can remain in service will not be replaced.

As noted above, the primary work to date on the Gas M&R subprogram has been commencing preliminary engineering, awarding of the A/E contract, and other planning activities. The actual spend by quarter for the Paramus project as compared to the last approved estimate is provided below.

Q4 2019	Q1 2020	Total	Estimate	% of Actuals to Estimate
Actuals				
$8,842	$37,793	$46,634	$19,900,000	0%

6. *Westampton*

The Westampton M&R station scope includes installation of new underground piping that is rated for the full pipeline company maximum allowable operating pressure, thus eliminating the need for high pressure relief valves and enhancing safety and environmental performance. Overpressure protection will be provided through series regulators with a working regulator and monitor regulator. Downstream distribution system relief valves will also be installed as a third line of overpressure protection, also enhancing safety and environmental performance. The major equipment at this station that is not near the end of life condition and operationally can remain in service will not be replaced.

As noted above, the primary work to date on the Gas M&R subprogram has been commencing preliminary engineering, awarding of the A/E contract, and other planning activities. The actual spend by quarter for the Westampton project as compared to the last approved estimate is provided below.

Q4 2019	Q1 2020	Total	Estimate	% of Actuals to Estimate
Actuals				
$8,395	$40,839	$49,234	$12,700,000	0%

ENERGY STRONG 2 PROGRAM INDEPENDENT MONITOR 2020 FIRST QUARTER REPORT

APPENDIX A – DRAFT REPORT COMMENTS AND RESPONSES

18 SEPTEMBER 2020

PEGASUS GLOBAL HOLDINGS, INC. ®

Appendix A – Draft Report Comments and Responses

ID #	Question/Comment	IM Response	Report Changes
RCR-INF-1	Has the Company identified comparable projects base spend projects for both electric and gas?	The IM scope includes the Energy Strong 2 Program Accelerated Rate Recovery investments (the core ES 2 Program) and the Stipulated Base expenditures. The Baseline capital expenditures are outside the IM scope.	No change
RCR-INF-2	Comment: Table 2 Total Estimate should be labeled to either reflect current estimate or Stipulated amount just to clarify distinction. For example, new Academy and State Street substation estimates are not incorporated in Table 9 as well.	Both Table 2 and Table 9 reflect the current approved estimates as of the end of the first quarter of 2020. At that time, the new Academy and State Street estimates had not gone through the formal estimate approval process as the approval of the mitigation change was still pending.	No change
RCR-INF-3	Page 6, are there updates to the two projects (Academy and State)?	The IM will continue to provide updates on the Academy and State Street projects in future reports as new information is received.	No change
RCR-INF-4	Page 7, for the following substations (Woodlynne, State Street, Academy Street, Clay Street, Hasbrouck Heights, Meadow Road, Lakeside Avenue, Toney's Brook, and Orange Valley), is the A/E firm conducting the Transmission component (upgrade from 26 to 69 kV) also conducting the Energy Strong 2 A/E work?	Yes, those projects have the same A/E for the ES 2 Program and Transmission components, with the exception of State Street where PSE&G is performing the ES 2 Program A/E work.	No change
RCR-INF-5	What are the three firms selected to do the A/E work?	Black & Veatch and Burns & McDonnell have currently been assigned to Electric Station Flood Mitigation projects (based on their associated 69kV work); additionally Black & Veatch, Sargent & Lundy, and Mesa Associates were approved through the competitive bid process and may be awarded work on other projects as it is released.	Future reports will call out the A/E on each project
RCR-INF-6	Page 7, do any of the remaining seven substations have any transmission upgrade work associated? If so, which ones?	No	No change
RCR-INF-7	Page 8, please identify which stations that are not in-house and not associated with the 69kV transmission upgrade would be competitively bid for A/E services.	The 69kV-associated projects and those that were not assigned to PSE&G internal resources were all competitively bid.	No change
RCR-INF-8	With reference to Page 9, how much experience with ES 1 is there with the listed PSEG personnel and Pegasus personnel.	During the ES 1 Program, the IM interfaced with each of the individuals listed as providing overall	No change

ID #	Question/Comment	IM Response	Report Changes
		direction and oversight on the ES 2 Program except for Danny Nembhard.	
RCR-INF-9	Comment on pages 10 through 12, what is the significance of bracketed substation associated with each heading?	As indicated on page 10, the brackets next to the procedure name identify the specific project where the implementation of the procedure was reviewed and discussed by the IM.	No change
RCR-INF-10	Page 10, is the feasibility/turnover stage the same as the office level estimate presented in Table 9?	Yes.	Clarified in **Section II.C.2.**
RCR-INF-11	Page 13, are there current plans to perform a project audit similar to what was conducted in ES 1?	Yes, initial conversations with PSEG's Internal Audit group have indicated an audit on the Program is expected to commence early in 2021. The IM will continue to provide updates on the audit status as new information is confirmed.	No change
RCR-INF-12	Page 18, the five-year baseline level estimate would exclude Superstorm Sandy. Presumably, this should not be an issue since these stations and feeders were not damaged in Superstorm Sandy.	The five-year baseline circuit performance was intended to help establish how the current/future circuit performance can be evaluated.	No change
RCR-INF-13	Page 19, please describe how the ES 2 planning is more integrated than ES 1 and what role planning plays in the process.	On the ES 2 Program there was centralized work planning and scheduling, including a more thorough stakeholder review process (based on more robust front-end planning and design). Enhanced planning typically results in the ability to better plan and forecast work, including reducing the likelihood of unexpected issues being identified later in the process.	Added information to **Section III.A.**
RCR-INF-14	Table 8, with the scope locked, have the Company's estimates changed for the five substations, excluding Academy and State.	Each would be expected to change as the projects continue to work through detailed engineering at the different estimate phases. The locking of the scope is part of the design process that is an input to the estimating process.	No change
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RCR-INF-20	Page 36, please elaborate on the lack of radio availability.	The radio availability was impacted by certification and component supply delays related to Covid-19. This has now been resolved.	Added additional detail in **Section III.B.**
RCR-INF-21	Page 37, is the installed communication system compatible with current and future systems? Would the system be compatible with an AMI system if the BPU were to approve AMI?	The wireless network will provide real-time wireless connectivity to all operational assets and redundant communication paths to network devices.	No change
RCR-INF-22	Page 38, is the 500,000 endpoint the current limit to the installed communications system?	As noted, the initial deployment is for 7,900 routers with the ability to scale up to <u>over</u> 500,000 end points in the future.	No change
RCR-INF-23	Page 39, was the ADMS vendor selection competitively bid? Is OSII a current vendor for PSEG?	As noted, the ADMS vendor selection was a sole source award to OSII base on OSII being the existing vendor for the SCADA component of AMDS, which utilizes a proprietary software of OSII, in addition to being the supporting vendor for the operations technology platform.	No change
S-INF-1	As noted in the report, the Grid Modernization – ADMS subprogram is now forecasted to cost approximately $40 million (<u>See</u> Page 1, Table 1) – over its original budget of $35 million. What does the Company attribute to this cost increase, and is it related to the Company's decision to select a sole-source vendor for the ADMS? (<u>See</u> Page 39).	The primary variances between the initial forecast (done at the time of the ES 2 Program filing) and the current forecast (at the 70% estimate level) is related to increased levels of vendor support needed to address additional complexities identified in the application landscape (primarily related to integration of new and/or upgraded PSE&G operational technology platforms) and additional hardware (e.g. servers) required after a review of the system identified the significant growth in the number of distribution assets on the network since the time of the filing.	Added additional detail in **Section III.D.**
S-INF-2	**<u>Contingency Reconfiguration Subprogram - COR Charges</u>** a. Please provide additional details about the work comprising the cost of removal charges (<u>See</u> Page 16, Table 5) within the Contingency Reconfiguration subprogram. b. In regard to the statement "Contingency Reconfiguration COR charges reflect work on the recloser replacement efforts in all districts", is the Company replacing existing reclosers in order to facilitate the subprogram?	(a) COR charges reflect removal of existing infrastructure to install new reclosers in all districts. (b) No existing reclosers are being replaced; in some case existing reclosers are being reprogrammed as a SCADA Switch Inline in	No change

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		instances where two reclosers are installed to balance a circuit into three sections.	
S-INF-3	Please describe any other factors (besides SCADA) considered by the Company when choosing between TripSaver-II reclosers and Fusesaver reclosers. Please indicate if the TripSaver-II reclosers have any capabilities that are not possessed by the Fusesaver reclosers selected by the Company.	Remote communications via SCADA is an operational requirement for PSE&G, this was the primary driver.	No change
S-INF-4	In regard to the Grid Modernization – Communications System subprogram, the report states that AT&T/Nokia hardware was selected over Sierra Wireless based on the technical solutions better suiting the needs of PSE&G. (See Page 38). a. Please provide additional details about these technical solutions that better suit the needs of PSE&G. b. Please describe any other factors considered by the Company, including costs, when selecting a vendor.	(a) PSE&G completed a detailed IT security architecture requirements review of both vendors and found the responses from Sierra Wireless were not in compliance with the IT security requirements of PSE&G. (b) Non-technical factors feature cost as a primary factor, typically broken out into key components for evaluation purposes; other factors include related work a vendor may have (simplifies coordination efforts compared to multiple vendors, lowers execution risk and cost).	Added additional detail in **Section III.C.**

ENERGY STRONG 2 PROGRAM INDEPENDENT MONITOR 2020 FIRST QUARTER REPORT

APPENDIX A – DRAFT REPORT COMMENTS AND RESPONSES

18 SEPTEMBER 2020

PEGASUS GLOBAL HOLDINGS, INC. ®

Appendix A – Draft Report Comments and Responses

ID #	Question/Comment	IM Response	Report Changes
RCR-INF-1	Has the Company identified comparable projects base spend projects for both electric and gas?	The IM scope includes the Energy Strong 2 Program Accelerated Rate Recovery investments (the core ES 2 Program) and the Stipulated Base expenditures. The Baseline capital expenditures are outside the IM scope.	No change
RCR-INF-2	Comment: Table 2 Total Estimate should be labeled to either reflect current estimate or Stipulated amount just to clarify distinction. For example, new Academy and State Street substation estimates are not incorporated in Table 9 as well.	Both Table 2 and Table 9 reflect the current approved estimates as of the end of the first quarter of 2020. At that time, the new Academy and State Street estimates had not gone through the formal estimate approval process as the approval of the mitigation change was still pending.	No change
RCR-INF-3	Page 6, are there updates to the two projects (Academy and State)?	The IM will continue to provide updates on the Academy and State Street projects in future reports as new information is received.	No change
RCR-INF-4	Page 7, for the following substations (Woodlynne, State Street, Academy Street, Clay Street, Hasbrouck Heights, Meadow Road, Lakeside Avenue, Toney's Brook, and Orange Valley), is the A/E firm conducting the Transmission component (upgrade from 26 to 69 kV) also conducting the Energy Strong 2 A/E work?	Yes, those projects have the same A/E for the ES 2 Program and Transmission components, with the exception of State Street where PSE&G is performing the ES 2 Program A/E work.	No change
RCR-INF-5	What are the three firms selected to do the A/E work?	Black & Veatch and Burns & McDonnell have currently been assigned to Electric Station Flood Mitigation projects (based on their associated 69kV work); additionally Black & Veatch, Sargent & Lundy, and Mesa Associates were approved through the competitive bid process and may be awarded work on other projects as it is released.	Future reports will call out the A/E on each project
RCR-INF-6	Page 7, do any of the remaining seven substations have any transmission upgrade work associated? If so, which ones?	No	No change
RCR-INF-7	Page 8, please identify which stations that are not in-house and not associated with the 69kV transmission upgrade would be competitively bid for A/E services.	The 69kV-associated projects and those that were not assigned to PSE&G internal resources were all competitively bid.	No change
RCR-INF-8	With reference to Page 9, how much experience with ES 1 is there with the listed PSEG personnel and Pegasus personnel.	During the ES 1 Program, the IM interfaced with each of the individuals listed as providing overall	No change

ID #	Question/Comment	IM Response	Report Changes
		direction and oversight on the ES 2 Program except for Danny Nembhard.	
RCR-INF-9	Comment on pages 10 through 12, what is the significance of bracketed substation associated with each heading?	As indicated on page 10, the brackets next to the procedure name identify the specific project where the implementation of the procedure was reviewed and discussed by the IM.	No change
RCR-INF-10	Page 10, is the feasibility/turnover stage the same as the office level estimate presented in Table 9?	Yes.	Clarified in **Section II.C.2.**
RCR-INF-11	Page 13, are there current plans to perform a project audit similar to what was conducted in ES 1?	Yes, initial conversations with PSEG's Internal Audit group have indicated an audit on the Program is expected to commence early in 2021. The IM will continue to provide updates on the audit status as new information is confirmed.	No change
RCR-INF-12	Page 18, the five-year baseline level estimate would exclude Superstorm Sandy. Presumably, this should not be an issue since these stations and feeders were not damaged in Superstorm Sandy.	The five-year baseline circuit performance was intended to help establish how the current/future circuit performance can be evaluated.	No change
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ENERGY STRONG 2 PROGRAM INDEPENDENT MONITOR CORRECTED 2020 SECOND QUARTER REPORT

PREPARED AND SUBMITTED BY

PEGASUS GLOBAL HOLDINGS, INC. ®

CONFIDENTIAL

11 MAY 2021

Table of Contents

Appendices

List of Acronyms and Abbreviations

Advanced Distribution Management Systems .... ADMS

Allowance for Funds Used During Construction .... AFUDC

Architectural and Engineering .... A/E

Board of Public Utilities .... BPU

Chief Financial Officer .... CFO

Construction Work In Progress .... CWIP

Costs of Removal .... COR

Distribution Management System .... DMS

Distributed Energy Resource Management System .... DERMS

Energy Strong 2 .... ES 2

Gas Metering & Regulating .... Gas M&R

Independent Monitor .... IM

Issued for Construction .... IFC

Issued for Review .... IFR

Open Systems International Inc. .... OSII

Outage Management System .... OMS

Potential Transformer .... PT

Projects & Construction .... P&C

Public Service Electric & Gas .... PSE&G

Public Service Enterprise Group .... PSEG

PSEG Internal Audit .... PSEGIA

Record of Decision .... ROD

Risk and Contingency .... R&C

Utility Review Board .... URB

I. Executive Summary

Public Service Electric & Gas's (PSE&G's) Energy Strong 2 (ES 2) Program was established from a Stipulation that the involved parties agreed to in August 2019, as approved by a Board of Public Utilities (BPU) Order dated September 11, 2019 with an effective date of September 21, 2019. The Stipulation provided the ES 2 Program would be comprised of five primary subprograms: Electric Station Flood Mitigation; Contingency Reconfiguration; Grid Modernization – Communications; Grid Modernization – Advanced Distribution Management Systems (ADMS); and Gas Metering & Regulating (Gas M&R) Station Upgrades. In addition, a Stipulated Base spend was established that includes both an electric component (higher outside plant design standards and station lifecycle upgrades) and a gas component (overlapping with the Gas M&R subprogram).

During the second quarter of 2020, the bulk of the work within the ES 2 Program continued to be in the two largest subprograms, Electric Station Flood Mitigation with three projects now in construction and Contingency Reconfiguration that continues to advance the installation and commissioning of reclosers. Within the other subprograms, the two Grid Modernization subprograms continued to advance with the Communications piece primarily focusing on readying the new network and preparing for the selected fiber projects and the ADMS piece continuing to plan and scope the platform and necessary hardware equipment, while the Gas M&R subprogram largely remains in preliminary planning and early engineering activities. **Table 1 – ES 2 Subprogram & Stipulated Base Status as of June 30, 2020** below provides the spend to date on the subprograms within the ES 2 Program and Stipulated Base compared to the total forecast and forecasted completion for each.

Table 1 – ES 2 Subprogram & Stipulated Base Status as of June 30, 2020

Subprogram	2019 Spend	Q1 2020 Spend	Q2 2020 Spend	Total Spend to Date*	Total Forecast*	% of Actuals to Forecast	Forecasted Completion**	Stipulation Funding Amount
Electric Station Flood Mitigation	**$1,977,398**	**$5,118,886**	**$10,325,107**	**$17,421,391**	**$332,662,596**	**5%**	**Dec 2023**	**$389M**
Contingency Reconfiguration	**$9,600,174**	**$14,933,431**	**$8,662,536**	**$33,196,141**	**$150,876,803**	**22%**	**Jul 2023**	**$145M**
Grid Modernization – Communications	**$83,766**	**$2,214,312**	**$4,159,420**	**$6,457,497**	**$64,863,452**	**10%**	**Dec 2023**	**$72M**
Grid Modernization – ADMS	**$36,213**	**$925,689**	**$4,430,542**	**$5,392,444**	**$39,707,462**	**14%**	**Oct 2022**	**$35M**
Electric Stipulated Base	**$0**	**$0**	**$0**	**$0**	**$100,000,000**	**N/A**	**Under Development**	**$100M**
Gas M&R Station Upgrades^	**$52,406**	**$235,922**	**$651,513**	**$939,841**	**$65,600,000**	**1%**	**Jul 2023**	**$110M**
Total*	**$11,749,957**	**$23,428,239**	**$28,229,119**	**$63,407,315**	**$746,975,315**	**8%**	**Dec 2023**	**$851M**

-Note: total figures may not fully align due to rounding. Additionally, the total forecast includes only the base cost for the Electric Station Flood Mitigation and Gas M&R subprograms as PSE&G does not include risk and contingency (R&C) in its forecasts for these projects. See **Table 11 and **Table 17** for the Electric Station Flood Mitigation and Gas M&R project estimates, respectively, with base costs and R&C shown.*
***-Final in-service date.*
^-Includes both the ES 2 projects and the Stipulated Base gas projects.

As shown in **Table 1**, the Electric Stipulated Base component remained largely in the planning stage as of the end of the second quarter of 2020. However, the four stations comprising the lifecycle upgrades portion of the Electric Stipulated Base were approved at a Study level estimate in a Utility Review Board (URB) meeting in June 2020 with a total current estimate of $79.7 million.[1] Additionally, the Contingency Reconfiguration subprogram saw its forecast increase from $119.5 million at the end of the first quarter of 2020 to $150.9 million at the end of the second quarter of 2020 as the Fuse Saver scope was fully forecasted during this quarter. It is expected that the forecast will continue to fluctuate as the scope is refined. Similarly, the forecasted completion date for the Grid Modernization – ADMS subprogram advanced from December 2023 as of the end of the first quarter of 2020 to October 2022 as of the end of the second quarter. This advancement was driven by additional schedule detail and development from what the high-level milestone schedule in place during the first quarter.

Given the prominence of the Electric Station Flood Mitigation subprogram, which represents over half of the total ES 2 Program spending, a summary of the projects within this subprogram is provided below in **Table 2 – ES 2 Electric Station Flood Mitigation Status as of June 30, 2020**.

Table 2 – ES 2 Electric Station Flood Mitigation Status as of June 30, 2020

Project	Total Estimate	Actuals to Date	% of Actuals to Estimate	Forecasted In-Service Date*
1. Academy Street	$17,000,000	$650,226	4%	10/25/2021
2. Clay Street	$42,000,000	$619,335	1%	12/27/2022
3. Constable Hook	$5,300,000	$101,960	2%	TBD
4. Hasbrouck Heights	$18,000,000	$531,773	3%	11/18/2022
5. Kingsland	$10,000,000	$255,665	3%	10/4/2023
6. Lakeside Avenue	$36,100,000	$442,176	1%	TBD
7. Leonia	$32,200,000	$713,897	2%	11/30/2022
8. Market Street	$30,000,000	$7,334,176	24%	9/22/2021
9. Meadow Road	$9,000,000	$310,637	3%	9/21/2023
10. Orange Valley	$26,600,000	$294,300	1%	TBD
11. Ridgefield 13kV	$25,500,000	$1,023,746	4%	10/19/2022
12. Ridgefield 4kV	$21,100,000	$2,971,169	14%	6/30/2021
13. State Street	$28,600,000	$378,656	1%	9/23/2023
14. Toney's Brook	$19,700,000	$414,002	2%	4/21/2023
15. Waverly	$35,400,000	$814,790	2%	12/4/2023
16. Woodlynne	$19,400,000	$564,882	3%	9/26/2023
**-Reflects the in-service date of the last major asset (e.g. switchgear), certain activities may take place after this date to support the final in-service date (i.e. when all customers are cutover).*				

[1] As noted in the Stipulation, the electric life cycle upgrades are part of the electric Stipulated Base to be recovered in the Company's next base rate case provided the investments are found to be prudent. The Stipulation also notes that should the 16 stations that comprise the Electric Station Flood Mitigation subprogram be completed for under the $389 million allocated for that subprogram, PSE&G may reallocate such unused funds to stations identified in the life cycle station upgrade portion of PSE&G's petition for accelerated recovery.

As indicated in **Table 2**, the Market Street and Ridgefield 4kV projects continue to have the highest percentage of spend, which is reflective of these two projects advancing further into construction. Additionally, three of the stations (Academy Street, Kingsland, and State Street) had internally approved new estimates at the end of June 2020 that went to approval before the URB in July 2020 and as such will be reported in the 2020 third quarter Independent Monitor (IM) report.

While early in the subprogram, the IM has found nothing to date that would jeopardize the ES 2 Program being completed on time and/or on budget.

As noted in the IM 2020 First Quarter Report, the IM conducts its assessment in accordance with Generally Accepted Government Auditing Standards (GAGAS, or more commonly referred to as the "Yellow Book" standards). The Yellow Book provides a framework for conducting performance management reviews/audit engagements with competence, integrity, objectivity, and independence that result in information used for oversight, accountability, transparency, and improvements of the audited programs and operations. On November 16, 2020, a draft report was presented and submitted to PSE&G, BPU Staff, and Rate Counsel. Per the Yellow Book, the transmittal of a draft report is intended to allow for review and comment by the audited entity and others to develop a fair, complete, and objective report. A summary of the comments on the draft report and the IM's responses are provided in **Appendix A – Draft Report Comments and Responses**. This **Appendix A** also identifies specific sections within this IM 2020 Second Quarter Report that have been edited, supplemented with additional information, or otherwise revised in response to the comments received.

II. Program Status

A. Key Decisions

In order to capture formalized key decisions regarding the ES 2 Program, PSE&G completes a "Record of Decision" (ROD) that includes a description of the decision; alternatives considered; the decision made; and, rationale for the decision. The RODs are assessed by the IM as they are completed to review their impact to the Program. In addition, the IM may request PSE&G complete a ROD to formalize a decision if such a decision has not yet been formalized through the ROD process.

The current and pending RODs as of the date of this IM 2020 Second Quarter Report are presented below in **Table 3 – ES 2 Records of Decisions**.

Table 3 – ES 2 Records of Decisions

Subprogram	Record of Decision	IM Comments
Electric Station Flood Mitigation	Academy Street & State Street Change in Mitigation Method	Reasonable and appropriate *(See Section B.1. in the IM 2020 First Quarter Report)*
Electric Station Flood Mitigation	Engineering Support for Energy Strong Program Projects	Reasonable and appropriate *(See Section B.2. in the IM 2020 First Quarter Report)*

There were no formal RODs issued during the second quarter of 2020, however, PSE&G has proposed mitigation method changes driven by transmission project upgrade needs at three additional substations in the Electric Station Flood Mitigation subprogram, these are the Lakeside Avenue, Orange Valley, and Constable Hook substations. The IM is still in discussion with PSE&G with respect to these proposed mitigation methods and has not yet completed its evaluation, which will be discussed in the IM's next quarterly report.

The IM will continue to monitor the status of these proposed changes and include additional discussions on these projects as new information is available.

B. Program Management

Beginning in July 2020, the IM began participating in a bi-weekly call with PSE&G to review its bi-weekly ES 2 Program Dashboard. As with ES 1, the Dashboard provides a mechanism for PSE&G to monitor and control activities to be completed in order to achieve key near-term milestones, including a focus on recently completed activities, any key issues, and other key metrics (e.g. installation targets) as appropriate. These calls have proven to be an effective way for the IM to stay informed on current and upcoming activities and to allow a venue for discussions between the IM and PSE&G on these activities and status updates.

C. Cost Assignments

1. Costs of Removal (COR)

Costs of Removal (COR) generally include costs for such activities as environmental removal, removal of inside station equipment, structures, foundations, towers and fixtures, conductors and other electrical devices, poles and fixtures, transformers, plant demolition, foundations, and removal of underground conduit and other wiring. Generally, COR are charged to Accumulated Depreciation and are amortized and recovered through a component of depreciation expense. The specific method and amount of recovery is determined in gas and electric rate cases before the BPU.

Table 4 – ES 2 Costs of Removal as of June 30, 2020 below itemizes the charges to COR for the second and first quarters of 2020, the fourth quarter of 2019 and total ES 2 COR to date. These amounts do not reflect any salvage value reductions, which have been de minimis in the ES 2 Program through June 30, 2020.

Table 4 – ES 2 Costs of Removal as of June 30, 2020

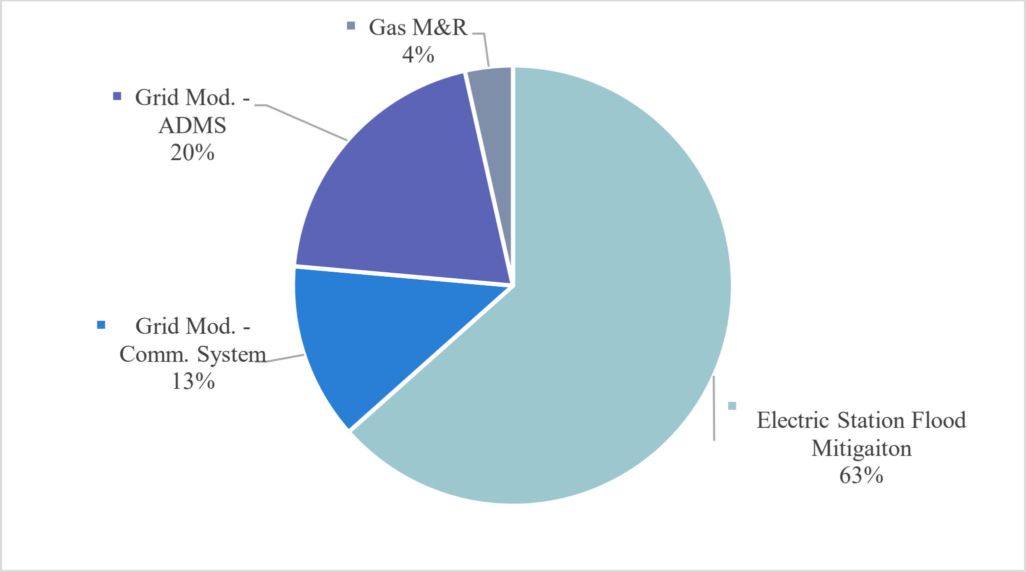
Subprogram	Q4 2019 COR	Q1 2020 COR	Q2 2020 COR	Total COR
Electric Station Flood Mitigation	**$0**	**$67,332**	**$468,989**	**$536,321**
Contingency Reconfiguration	**$431,030**	**$616,752**	**$624,595**	**$1,672,377**
Grid Modernization – Communications	**$0**	**$0**	**$1,495**	**$1,495**
Grid Modernization - ADMS	**$0**	**$0**	**$0**	**$0**
Electric Stipulated Base	**$0**	**$0**	**$0**	**$0**
Gas M&R Station Upgrades	**$0**	**$0**	**$0**	**$0**
Total	**$431,030**	**$684,084**	**$1,095,079**	**$2,210,193**

For the second quarter of 2020, the increase in COR charges is attributed to the removal of poles, insulators and transformers at Ridgefield and Market Street for the conversion of the 4kV circuits to 13kV. Contingency Reconfiguration COR charges reflect continued work involving removal of pole fixtures and conductors for the installation of new reclosers.

2. Construction Work-in-Progress (CWIP) & In-Service Transfers

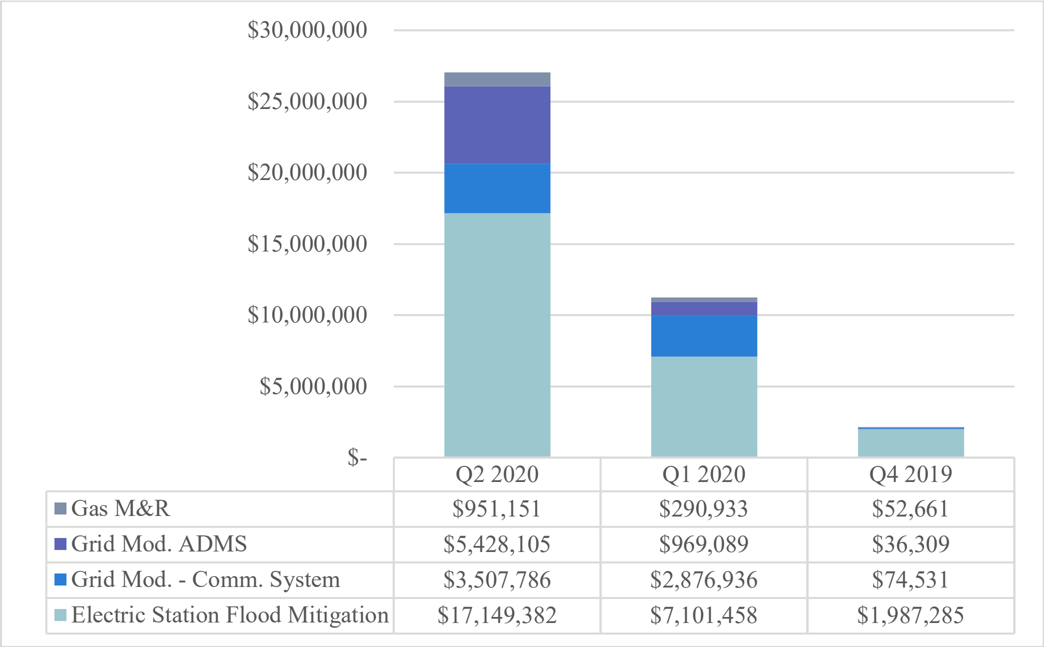
As of June 30, 2020, the Energy Strong CWIP balance was $27.0 million, compared to $10.3 million as of March 30, 2020. The largest components of June 30, 2020 CWIP were the elimination and conversion of the 4kV circuits at Market Street and Ridgefield substations, and work associated with the Advanced Distribution and Management System. The Electric Station Flood Mitigation subprogram comprises the largest component of total end of period CWIP outstanding, as depicted in **Figure 1 – ES 2 CWIP as of June 30, 2020** below.

Figure 1 – ES 2 CWIP as of June 30, 2020



In addition, **Figure 2 – ES 2 CWIP Balances by Subprogram as of June 30, 2020** below depicts the composition of end-of-quarter CWIP balances by subprogram for the second and first quarters of 2020, and the fourth quarter of 2019.

Figure 2 – ES 2 CWIP Balances by Subprogram as of June 30, 2020



Transfers from CWIP to plant in service have totaled $1.8 million as of June 30, 2020, which was comprised of Grid Modernization computer hardware. It should be noted that work related to certain assets, such as the reclosers under the Contingency Reconfiguration subprogram, generally can be completed without being recorded through CWIP. The changes to CWIP from the first quarter to the second quarter of 2020 are shown in **Table 5 – ES 2 CWIP Q1 to Q2 2020**.

Table 5 – ES 2 CWIP Q1 to Q2 2020

	Electric Station Flood Mitigation	Grid Modernization – Communication System	Grid Modernization – ADMS	Gas M&R
CWIP Balance as of Q1 2020	$7,101,458	$1,907,846	$969,089	$290,933
CWIP Additions during Q2 2020	$10,047,924	$3,427,230	$4,459,016	$660,218
CWIP Transfers to Plant In-Service during Q2 2020	$0	$1,827,290	$0	$0
CWIP Balance as of Q2 2020	$17,149,382	$3,507,786	$5,428,105	$951,151

3. Allowance for Funds Used During Construction (AFUDC)

The amount of quarterly AFUDC recorded by the Company for each ES 2 subprogram during the second and first quarters of 2020, the fourth quarter of 2019, and total ES 2 AFUDC accrued to date, is shown below in **Table 6 – ES 2 AFUDC as of June 30, 2020**.

Table 6 – ES 2 AFUDC as of June 30, 2020

Subprogram	Q4 2019	Q1 2020	Q2 2020	Total AFUDC
Electric Station Flood Mitigation	**$9,887**	**$62,618**	**$191,807**	**$264,312**
Contingency Reconfiguration	**$0**	**$0**	**$0**	**$0**
Grid Modernization – Communications	**$225**	**$14,752**	**$60,073**	**$75,050**
Grid Modernization - ADMS	**$96**	**$7,092**	**$28,474**	**$35,662**
Electric Stipulated Base	**$0**	**$0**	**$0**	**$0**
Gas M&R Station Upgrades	**$254**	**$2,590**	**$8,465**	**$11,309**
Total	**$10,462**	**$87,052**	**$288,819**	**$386,333**

During the first quarter of each year, the AFUDC rate is reviewed for possible reset as it applies the current year based on updated capital structure and component cost data. For the year 2020, the new AFUDC rate was calculated to be 6.95%, using the capital structure and component costs as of January 31, 2020. This rate is higher than the 2019 rate of 6.34%, primarily due to a significantly lower average short-term debt balance during the first quarter of 2020, with its lower associated component cost relative to cost of equity and embedded cost of long-term debt. In calculating the 2020 AFUDC rate, the Company used (i) a 4.02% embedded cost of long-term debt, (ii) a short-term debt rate of 1.86%, and (iii) a cost of equity of 9.60%.

Subsequent to the annual reset calculation referred to above, and during the course of each year, the AFUDC rate is also recalculated as it applies to each fiscal quarter. If the recalculated rate changes by 25 basis points from the rate then in effect, the rate is reset and retroactively applied to January 1 of that year. For the second quarter of 2020, based on data as of June 30, 2020, the recalculated weighted average AFUDC accrual rate (6.93%) did not meet this criterion to warrant changing from the annual rate (6.95%) in effect. Therefore, AFUDC was accrued during the first quarter of 2020 at the calculated rate of 6.95%.

AFUDC accrued for ES 2 projects during the second quarter of 2020 increased significantly over AFUDC accrued during the first quarter of 2020 as the result of the increases in total average CWIP balances across all subprograms.

The IM observes that the Company's calculation of the AFUDC rate and its application is in accordance with both PSE&G's accounting policy and Plant Instruction 3(17) of the Federal Energy Regulatory Commission's Uniform Systems of Accounts prescribed for public utilities.

The IM also notes that the relevant AFUDC information as it relates to second quarter 2020 ES 2 project costs is consistent with the applicable dictates of the Stipulation entered into with respect to these ES 2 projects. The IM will continue to review future ES 2 AFUDC accruals for consistency with relevant provisions of the Stipulation for accounting and reporting purposes only, and not as a party to, or in expressing an opinion concerning, any rate proceedings.

4. Allocated Overheads

PSE&G follows a philosophy of allocating overhead costs, whether at the Service Company or from utility support organizations, to the operating company or unit receiving the benefit, and ultimately, if appropriate, settling costs to individual assets. Where possible, services are charged directly to the entity receiving the benefit, but where direct charging of costs is not feasible, cost allocations from the Service Company to operating companies are prescribed pursuant to the methodology, as revised in the Company's December 15, 2008 notice to the Board, which included one multi-factor formula that equally weights the PSEG Operating Company values of Net Fixed Assets, Headcount, and Operations & Maintenance.

For ES 2 electric and gas distribution projects, allocated overhead costs should primarily come from utility-related labor costs associated with administrative and supervisory personnel, labor and other costs associated with bargaining unit personnel, fringe benefits, materials handling costs, payroll taxes and depreciation expense. Shown below in **Table 7 – ES 2 Overhead Allocations as of June 30, 2020** are the allocated overhead costs charged to ES 2 projects for the second and first quarters of 2020, the fourth quarter of 2019, and total allocated overheads to date.

Table 7 – ES 2 Overhead Allocations as of June 30, 2020

Subprogram	Q4 2019	Q1 2020	Q2 2020	Total Overhead Allocations
Electric Station Flood Mitigation	**$286,953**	**$1,648,117**	**$3,560,216**	**$5,495,286**
Contingency Reconfiguration	**$3,415,460**	**$4,692,085**	**$3,055,700**	**$11,163,245**
Grid Modernization – Communications	**$12,074**	**$345,720**	**$548,017**	**$905,811**
Grid Modernization – ADMS	**$10,603**	**$116,442**	**$91,786**	**$218,831**
Electric Stipulated Base	**$0**	**$0**	**$0**	**$0**
Gas M&R Station Upgrades	**$15,287**	**$52,836**	**$68,257**	**$136,380**
Total	**$3,740,376**	**$6,855,199**	**$7,323,975**	**$17,919,550**

The overwhelming majority of overhead costs allocated to ES 2 projects during the second quarter of 2020 are costs allocated from areas that support all utility distribution and transmission projects, including ES 2 projects. More specifically, most of the second quarter allocated costs reflect labor costs of supervisory, administrative and operations planning personnel, labor and other costs from bargaining unit personnel, and fringe benefits associated with these labor costs.

The IM believes these allocations represent no change in the Company's normal methodology of allocating overhead costs.

5. ES 2 Program Internal Audit

In large companies such as Public Service Enterprise Group (PESG), parent company of PSE&G, the Internal Audit department's objective is to systematically evaluate the firm's management control and governing processes, specifically as they relate to the integrity of financial reporting and compliance with applicable regulations.

PSEG's Internal Audit (PSEGIA) department reports functionally to the Audit Committee of the Board of Directors and administratively to the Chief Financial Officer (CFO), which is to ensure both an atmosphere of independence and a degree of objectivity and prominence, such that its findings and recommendations can be fully vetted with the appropriate corporate audience.

Shortly after its engagement as monitor for the ES 2 Program, the IM held preliminary discussions with PSEGIA personnel regarding a potential audit of the ES 2 Program, similar to the audits it conducted during the first Energy Strong Program. Following these discussions, PSEGIA has indicated that it intends to: (i) conduct a full-scope audit, likely of the Electric Station Flood Mitigation and Contingency Reconfiguration subprograms, beginning in the second quarter of 2021, (ii) in 2022, conduct a full-scope audit of the ES 2 subprograms not covered in the first audit, and (iii) conduct a review of the ES 2 Program in 2023, the scope and depth of which will depend on the results of the previous audits. The IM and PSEGIA will have continued discussions prior to and during the audits to ensure the audits cover those areas specific to cost accumulation as required by the Stipulation. The IM will report on the progress and conclusions of the audits as information is available, and in similar fashion as it did with the audits conducted in the first Energy Strong Program.

D. System Performance

During the second quarter of 2020, PSE&G experienced a Major Event on June 3-7, 2020 stemming from a derecho and severe thunderstorms that primarily affected its Southern Division. This series of storms first entered PSE&G's service territory in the afternoon of June 3, 2020, bringing wind gusts of over 70 miles per hour. By the June 3, 2020 1:00pm operations conference call, the Southern Division reported that it experienced multiple sub-transmission and distribution circuit lockouts and crews were dispatched from the other PSE&G Divisions and from its Projects & Construction (P&C) group to aid in recovery efforts. During this afternoon call, PSE&G's weather service indicated that a second line of storms with similar wind speeds and possible tornadoes was expected that evening. Conference calls later in the day continued to analyze the outages experienced thus far and prepared for upcoming weather impacts. On the June 4, 2020 8:00am operations conference call, the Southern Division reported the evening storms on June 3, 2020 caused additional plant damage and more tree damage, while PSE&G's weather service predicted yet another round of severe thunderstorms was expected later that day and did cause additional damage.

These series of storms led to 257,209 PSE&G customers experiencing service interruptions, with 246,075 of those customers located in the Southern Division. 45% of the customers interrupted were restored within one day, 81% within two days, 97% within three days, and full restoration in just over four days. The IM calls attention specifically to the Woodlynne substation that was shut down during these storms due to both 26kV supply lines being interrupted due to tree/vegetation issues, affecting service to 11,319 customers. An emergency tie line installed under the original Energy Strong Program allowed the substation to return to service in less than three hours.

The IM received PSE&G's report on the performance of its Energy Strong 2 Program investments from this Major Event and has reproduced the results as follows:

Circuit	5 Year Baseline SAIDI	Report Quarter SAIDI
ALD 8015	0.12276	
ALD 8026	0.07735	
BAO 8003	0.00096	
BAO 8006		
BEN 8012	0.15243	
BEN 8015	0.00623	
BEN 8021	0.00143	

Circuit	5 Year Baseline SAIDI	Report Quarter SAIDI
BRU 8011	0.04127	0.00363
BRU 8012	0.01236	
BUS 8011	0.13129	0.04924
CED 8011	0.05594	
CED 8021	0.03575	
CED 8022	0.05071	
CIN 8032	0.32648	1.13907

Circuit	5 Year Baseline SAIDI	Report Quarter SAIDI
CIN 8043	0.18459	0.16269
CLF 8012	0.00401	
CLF 8013	0.00064	
CLF 8023	0.00895	
CLK 8022	0.06677	0.21086
CLK 8024	0.01526	
CON 8001		
COR 8042	0.02723	
CRX 8003	0.07703	0.00467
DAY 8002	0.03617	
DVB 8013	0.00455	
EAT 8011	0.09890	0.01689
FAW 8014	0.21021	
FAW 8022	0.03342	
FAW 8026	0.00902	
FRA 8021		
GBK 8021	0.06208	
GBK 8023	0.02487	
GBK 8025	0.31504	
HAT 8023	0.01869	
HAT 8035	0.04291	
HAW 8032	0.07658	0.00000
HID 8043	0.06432	
HID 8044	0.08229	
HNC 8015	0.10285	
HNC 8021	0.02280	
HNC 8024	0.21727	
HOE 8047	0.05561	
HOM 8001	0.06027	
HOM 8012	0.00000	
HOM 8014	0.00115	
HOM 8041	0.00000	
JAC 8021	0.00318	
JAC 8023	0.05394	
JAC 8043	0.04897	
KIL 8023		
KIL 8024	0.01504	
KIL 8041	0.02511	
KIL 8044	0.03622	
KIN 8015	0.00194	
KUL 8012	0.02022	
KUL 8022	0.00186	0.00206
KUL 8023	0.00582	
KUS 8004	0.00500	0.03236
KUS 8042	0.07830	0.02334

Circuit	5 Year Baseline SAIDI	Report Quarter SAIDI
KUS 8045	0.02505	
LAF 8013	0.00125	0.00126
LAF 8015	0.00354	
LAU 8021	0.22050	
LAU 8023	0.82844	
LAU 8034	0.40130	
LAU 8035	0.29567	
LAW 8014	0.03705	1.01225
LCE 8003	0.15926	0.01544
LCE 8032	0.30801	0.03039
LCE 8043	0.10606	
LCE 8046	0.01692	
LEO 8042		
LEV 8006	0.23842	
LOC 8012		0.04313
LOC 8033		
MAD 8015	0.15514	0.95230
MAD 8031	0.45221	0.01856
MAI 8013	0.05318	
MAR 8004	0.02404	
MAR 8017	0.45014	
MAY 8014	0.03470	0.00505
MAY 8024	0.00558	
MDF 8012	0.58371	0.18948
MDF 8023	0.26488	0.54601
MEA 8013	0.04040	0.00365
MIN 8024		
MON 8003	0.27132	
NBS 8011	0.01516	
NBS 8013	0.00000	
NBS 8023	0.00057	
NED 8022	0.02419	0.00773
NEW 8014	0.01839	
NIT 8007	0.00000	
NRB 8014	0.03116	
PIE 8011		
PIE 8023	0.04636	
PLI 8003	0.00215	
PLI 8005	0.16440	0.01832
POH 8024	0.12643	
RFL 8034	0.02787	
RVR 8031	0.02752	
SAD 8045	0.00284	
SDH 8034	0.00000	
SMV 8013	0.00000	

Circuit	5 Year Baseline SAIDI	Report Quarter SAIDI
SMV 8021		
SMV 8022	0.01681	
SMV 8023	0.01943	
SPF 8012	0.52501	
SUN 8021		
SWT 8001		

Circuit	5 Year Baseline SAIDI	Report Quarter SAIDI
SWT 8002		
WEW 8011	0.18034	
WEW 8033	0.03506	
WEW 8041		
WFL 8041	0.07197	
WOR 8021		

Following receipt of this data, the IM has followed-up with requests for additional information on this data to establish additional context for these results. This additional information has yet to be received as of the date of this final IM 2020 Second Quarter Report and will be discussed in the next IM report following receipt of that information.

III. Project Status

A. Electric Station Flood Mitigation

A summary of the subprogram plan as of June 30, 2020 is provided below in **Table 8 – ES 2 Electric Station Flood Mitigation Subprogram Milestone Schedule as of June 30, 2020**.

Table 8 – ES 2 Electric Station Flood Mitigation Milestone Schedule as of June 30, 2020

Project	Plan Status Point	2019		2020				2021				2022				2023				2024
		Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	
1. Academy Street	Dec. 2019		KO					C					IS		CO					
	Jun. 2020		KO		C						IS			CO						
2. Clay Street	Dec. 2019	*Schedule Under Development*																		
	Jun. 2020			KO							C				IS					CO (Q2)
3. Constable Hook	Dec. 2019	*Schedule Under Development*																		
	Jun. 2020	*Schedule Under Development*																		
4. Hasbrouck Heights	Dec. 2019		KO						C						IS		CO			
	Jun. 2020		KO						C						IS		CO			
5. Kingsland	Dec. 2019			KO				C			IS		CO							
	Jun. 2020			KO										C					IS	CO (Q2)
6. Lakeside Avenue	Dec. 2019				KO				C										IS	CO (Q2)
	Jun. 2020	*Schedule Under Development**																		
7. Leonia	Dec. 2019	*Schedule Under Development*																		
	Jun. 2020			KO		C									IS				CO	
8. Market Street	Dec. 2019			KO				C	OS		CO									
	Jun. 2020			KO						OS/C			CO							
9. Meadow Road	Dec. 2019	*Schedule Under Development*																		
	Jun. 2020			KO											C			IS		CO (Q2)
10. Orange Valley	Dec. 2019	*Schedule Under Development*																		
	Jun. 2020	*Schedule Under Development*																		

December 31, 2023 - ES 2 Program End Date

Project	Plan Status Point	2019 Q3	2019 Q4	2020 Q1	2020 Q2	2020 Q3	2020 Q4	2021 Q1	2021 Q2	2021 Q3	2021 Q4	2022 Q1	2022 Q2	2022 Q3	2022 Q4	2023 Q1	2023 Q2	2023 Q3	2023 Q4		2024
11. Ridgefield 13kV	Dec. 2019			KO	C										IS		CO			Dec. 31, 2023 - ES 2 Program End Date	
	Jun. 2020			KO	C										IS		CO				
12. Ridgefield 4kV	Dec. 2019			KO						C	OS			CO							
	Jun. 2020			KO	C				OS				CO								
13. State Street	Dec. 2019		KO					C								IS					CO (Q1)
	Jun. 2020		KO						C					IS							CO (Q1)
14. Toney's Brook	Dec. 2019			KO						C									IS		CO (Q2)
	Jun. 2020			KO										C			IS				CO (Q4)
15. Waverly	Dec. 2019	*Schedule Under Development*																			
	Jun. 2020			KO			C												IS		CO (Q3)
16. Woodlynne	Dec. 2019		KO												C				IS		CO (Q2)
	Jun. 2020		KO												C			IS			CO (Q2)

Legend: KO = Kickoff; C = Construction; IS = Fully In-Service (major assets in-service); OS = Out-of-Service (if eliminated); CO = Closeout
-Actuals are indicated with an underline (Note: for the Market Street and Ridgefield 4kV projects, outside plant construction began in the first quarter of 2020, the construction milestone indicated on this chart reflects inside plant construction).
***-The Lakeside Avenue project had a schedule previously developed, but due to the proposed mitigation method change that contemplates relocating the substation, the schedule is now being revised and updated.**

A summary of the subprogram status as of the end of the second quarter of 2020 is provided below **Table 9 – ES 2 Electric Station Flood Mitigation Summary Status as of June 30, 2020**.

Table 9 – ES 2 Electric Station Flood Mitigation Summary Status as of June 30, 2020

Activity	Total # of Projects	Specific Projects
Kickoff Meeting	13	Academy Street; Clay Street; Hasbrouck Heights; Kingsland; Leonia; Market Street; Meadow Road; Ridgefield 13kV; Ridgefield 4kV; State Street; Toney's Brook; Waverly; Woodlynne
Key Drawing Review	13	Academy Street; Clay Street; Hasbrouck Heights; Kingsland; Leonia; Market Street; Meadow Road; Ridgefield 13kV; Ridgefield 4kV; State Street; Toney's Brook; Waverly; Woodlynne
Scope Locked	13	Academy Street; Clay Street; Hasbrouck Heights; Kingsland; Leonia; Market Street; Meadow Road; Ridgefield 4kV; Ridgefield 13kV; State Street; Toney's Brook; Waverly; Woodlynne
Major Equipment POs	14*	Academy Street; Clay Street; Hasbrouck Heights; Kingsland; Leonia*; Meadow Road; Ridgefield 13kV*; State Street; Toney's Brook; Waverly*; Woodlynne
A/E Contract Award (or selection of PSE&G internal engineering)	14	Academy Street[1]; Clay Street[1]; Hasbrouck Heights[1]; Lakeside Avenue[3]; Leonia[2]; Kingsland[2]; Market Street[2]; Meadow Road[2]; Ridgefield 13kV[2]; Ridgefield 4kV[2]; State Street[2]; Toney's Brook[3]; Waverly[3]; Woodlynne[1]
Construction Start	3	Academy Street; Market Street; Ridgefield 4kV

**-Three of the listed projects (Leonia, Ridgefield 13kV, and Waverly) have two switchgears, thus the current count reflects 14 switchgears at 11 substations.*
[1]-Indicates Burns & McDonnell is serving as the A/E.
[2]-Indicates PSE&G internal resources are serving as the A/E.
[3]-Indicates Black & Veatch is serving as the A/E.

Beyond the key activities summarized in **Table 9** above, **Table 10 – ES 2 Electric Station Flood Mitigation Upcoming Activities for Q3 2020** summarizes the planned activities for each project during the third quarter of 2020, including any carryover of activities from earlier periods.

Table 10 – ES 2 Electric Station Flood Mitigation Upcoming Activities for Q3 2020

Station	Upcoming Activities for Q3 2020	Carryover Activities from Q2 2020
1. Academy Street	• 70% estimate completion • Electrical contractor purchase order issued • Major license and permit issued	• None
2. Clay Street	• License and permit package submitted • Design freeze on switchgear arrangement and controls	• None
3. Constable Hook	• Remains in planning/origination stages	• Planning/origination stages with property acquisition still being reviewed for 69kV project at same site
4. Hasbrouck Heights	• Design freeze on switchgear arrangement and controls • Civil and electrical drawings Issued For Review (IFR)	• License and permit package submitted
5. Kingsland	• 50% estimate submittal (revised)	• None
6. Lakeside Avenue	• Remains in planning/origination stages	• Planning/origination stages with property acquisition still being reviewed for 69kV project at same site
7. Leonia	• Major licenses and permits issued • Civil construction start	• None
8. Market Street	• 70% estimate completion • License and permit package submitted	• None
9. Meadow Road	• License and permit package submitted	• None
10. Orange Valley	• Remains in planning/origination stages	• Planning/origination stages with property acquisition still being reviewed for 69kV project at same site
11. Ridgefield 13kV	• Civil contingency construction completion • Major equipment (13kV contingency switchgear) delivered • Start electrical construction (temporary switchgear)	• Civil mechanical and duct bank construction
12. Ridgefield 4kV	• 70% estimate completed	• Civil underground construction
13. State Street	• Major license and permit received (site plan) • Civil and electrical drawings Issued For Construction (IFC)	• License and permit package submitted
14. Toney's Brook	• Civil and electrical drawings IFR • Vendor submittal of final arrangement mechanical drawings to PSE&G for controls IFR	• None

Station	Upcoming Activities for Q3 2020	Carryover Activities from Q2 2020
15. Waverly	• Phase 1 civil and layout drawings IFC • Phase 2 civil and electrical drawings IFR • Major permits submitted • Phase 2 constructability review	• License and permit package submitted
16. Woodlynne	• Major regional licenses and permits received • Contingency drawings IFR and IFC • Civil and electrical drawings IFC •	• License and permit package submitted

The current project estimates, including base and R&C amounts, is shown below in **Table 11 – ES 2 Electric Station Flood Mitigation Project Cost Status as of June 30, 2020**. **Table 11** also shows the current estimate level based on PSE&G's estimating processes and as approved by the URB, the actual spend and percentage of actuals to estimate as of the end of the second quarter of 2020, and the forecasted in-service date.

Table 11 – ES 2 Electric Station Flood Mitigation Project Cost Status as of June 30, 2020

Project	Estimate Level	Base	Risk & Contingency	Total	Actuals to Date	% of Actuals to Estimate
1. Academy Street	Office	$12,600,000	$4,400,000	$17,000,000	$650,226	4%
2. Clay Street	Study	$34,800,000	$7,200,000	$42,000,000	$619,335	1%
3. Constable Hook	Office	$3,900,000	$1,400,000	$5,300,000	$101,960	2%
4. Hasbrouck Heights	Study	$14,900,000	$3,100,000	$18,000,000	$531,773	3%
5. Kingsland	Study	$7,100,000	$2,900,000	$10,000,000	$255,665	3%
6. Lakeside Avenue	Office	$26,800,000	$9,400,000	$36,100,000	442,176	1%
7. Leonia	Study	$27,700,000	$4,500,000	$32,200,000	$713,897	2%
8. Market Street	Study	$24,200,000	$5,800,000	$30,000,000	$7,334,176	24%
9. Meadow Road	Study	$7,200,000	$1,800,000	$9,000,000	$310,637	3%
10. Orange Valley	Office	$19,700,000	$6,900,000	$26,600,000	$294,300	1%
11. Ridgefield 13kV	Study	$19,600,000	$5,900,000	$25,500,000	$1,023,746	4%
12. Ridgefield 4kV	Study	$16,800,000	$4,300,000	$21,100,000	$2,971,169	14%
13. State Street	Office	$21,200,000	$7,400,000	$28,600,000	$378,656	1%
14. Toney's Brook	Study	$14,300,000	$5,400,000	$19,700,000	$414,002	2%

Project	Estimate Level	Base	Risk & Contingency	Total	Actuals to Date	% of Actuals to Estimate
15. Waverly	Study	$29,400,000	$6,000,000	$35,400,000	$814,790	2%
16. Woodlynne	Study	$15,800,000	$3,600,000	$19,400,000	$564,882	3%
Subprogram Total		**$309,000,000**	**$80,000,000**	**$389,000,000**	**$17,421,931**	**4%**

Findings & Observations

- The projects that comprise the Electric Station Flood Mitigation subprogram continue at various phases of execution, with three projects in construction as of the end of the second quarter of 2020, three projects remaining in the planning/origination phases (the three with proposed mitigation changes discussed in **Section II.A.**), and the remaining projects continuing to advance in design and pre-construction activities.
- While early in the subprogram, the IM has found nothing to date that would jeopardize the subprogram being completed on time and/or on budget.

1. Academy Street

During the second quarter of 2020, approximately $400,000 was spent on the Academy Street project towards its revised mitigation method compared to a forecast of approximately $435,000, which brought the total spend to approximately $650,000. Notable activities completed during the second quarter of 2020 include:

- Civil and electrical drawings IFR and IFC;
- Inside plant constructability review;
- Civil construction purchase order issued;
- Study level estimate internally approved and prepared for URB approval.

The actual spend by quarter for Academy Street as compared to the last URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals					
$150,398	$99,893	$399,935	$650,226	$17,000,000	4%

As mentioned in the Executive Summary, Academy Street had its Study level estimate internally approved at the end of June 2020, which went to the URB for approval in July 2020. The new estimate, which will be detailed in the IM 2020 Third Quarter Report, is $12,800,000, or $4.2 million lower than the prior estimate and driven by the change in mitigation method from raise and rebuild to relocate.

2. Clay Street

During the second quarter of 2020, approximately $283,000 was spent on the Clay Street project compared to a forecast of approximately $344,000, which brought the total spend to approximately $619,000. Notable activities completed during the second quarter of 2020 include:

- Preliminary engineering design freeze;
- License and permit package design commencement;
- Scope document signed off; and

- 4kV sheltered aisle switchgear purchase order issued.

The actual spend by quarter for Clay Street as compared to the last URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals					
$116,409	$219,707	$283,219	$619,335	$42,000,000	1%

3. *Constable Hook*

Through the end of the second quarter of 2020, the Constable Hook project continued to remain in the initial planning and origination stages, with the property acquisition for associated 69kV projects planned at the same area still being reviewed. The actual spend by quarter for Constable Hook as compared to the last URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals					
$17,889	$51,758	$32,313	$101,690	$5,300,000	2%

4. *Hasbrouck Heights*

During the second quarter of 2020, approximately $188,000 was spent on the Hasbrouck Heights project compared to a forecast of approximately $179,000, which brought the total spend to approximately $532,000. Notable activities completed during the second quarter of 2020 include:

- Detailed design started; and,
- License and permit package submitted.

The actual spend by quarter for Hasbrouck Heights as compared to the URB last approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals					
$149,848	$193,879	$188,045	$531,773	$18,000,000	3%

5. *Kingsland*

During the second quarter of 2020, approximately $43,000 was spent on the Kingsland project compared to a forecast of approximately $23,000, which brought the total spend to approximately $256,000. Notable activities completed during the second quarter of 2020 include:

- Final vendor switchgear arrangement, mechanical, and control drawings were submitted to PSE&G.

The actual spend by quarter for Kingsland as compared to the last URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals					
$104,112	$108,286	$43,268	$255,665	$10,000,000	3%

As mentioned in the Executive Summary, Kingsland had a revised Study level estimate internally approved at the end of June 2020, which went to the URB for approval in July 2020. The new estimate, which will be detailed in the IM 2020 Third Quarter Report, is $8,300,000, or $1.7 million lower than the prior estimate and driven by a reduction in the switchgear procurement commitment.

6. Lakeside Avenue

Through the end of the second quarter of 2020, the Lakeside Avenue project continued to remain in the initial planning and origination stages, with the property acquisition for associated 69kV projects planned at the same area still being reviewed. The actual spend by quarter for Lakeside Avenue as compared to the last URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals					
$148,943	$172,224	$121,009	$442,176	$36,100,000	1%

7. Leonia

During the second quarter of 2020, approximately $425,000 was spent on the Leonia project compared to a forecast of approximately $405,000, which brought the total spend to approximately $714,000. Notable activities completed during the second quarter of 2020 include:

- Preliminary design frozen and commencement of detail design;
- Scope document signed off;
- License and permit package submitted; and,
- Contingency plan civil and temporary switchgear drawings IFC.

The actual spend by quarter for Leonia as compared to the last URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals					
$44,792	$244,323	$424,783	$713,897	$32,200,000	2%

8. Market Street

During the second quarter of 2020, approximately $5,144,000 was spent on the Market Street project compared to a forecast of approximately $5 million, which brought the total spend to approximately $7.3 million. Notable activities completed during the second quarter of 2020 include:

- Outside plant construction on overhead poles and 4kV associated pole top equipment to upgrade to 13kV.
- Civil demolition/yard work drawings, control drawings, and electrical demolition drawings IFC.

The actual spend by quarter for Market Street as compared to the last URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals					
$251,193	$1,938,713	$5,144,270	$7,334,176	$30,000,000	24%

9. Meadow Road

During the second quarter of 2020, approximately $105,000 was spent on the Meadow Road project compared to a forecast of approximately $108,000, which brought the total spend to approximately $311,000. Notable activities completed during the second quarter of 2020 include:

- Design freeze on switchgear arrangement, mechanical, and controls;
- Scope document signed off; and,
- License and permit package design commencement.

The actual spend by quarter for Meadow Road as compared to the last URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals					
$63,128	$142,946	$104,563	$310,637	$9,000,000	3%

10. Orange Valley

Through the end of the second quarter of 2020, the Orange Valley project continued to remain in the initial planning and origination stages, with the property acquisition for associated 69kV projects planned at the same area still being reviewed. The actual spend by quarter for Orange Valley as compared to the last URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals					
$77,029	$96,582	$120,690	$294,300	$26,600,000	1%

11. Ridgefield 13kV

During the second quarter of 2020, approximately $500,000 was spent on the Ridgefield 13kV project compared to a forecast of approximately $483,000, which brought the total spend to approximately $1.02 million. Notable activities completed during the second quarter of 2020 include:

- Civil and electrical drawings for contingency switchgear IFC;
- License and permit package submitted;
- Major county licenses and permits received;
- Pre-work performed (138kV monopole relocated and foundation removed);
- Civil mechanical and duct bank construction start.

The actual spend by quarter for Ridgefield 13kV as compared to the last URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals					
$205,982	$317,289	$500,475	$1,023,476	$25,500,000	4%

12. Ridgefield 4kV

During the second quarter of 2020, approximately $2.1 million was spent on the Ridgefield 4kV project compared to a forecast of approximately $2.9 million. The variance in actual versus forecasted spend for the second quarter was predominantly the result of less test pit work required (originally expected to have to dig 12 feet to verify conditions for manhole expansions, however in some place only had to dig three feet deep). This brought the total spend to approximately $3.0 million. Notable activities completed during the second quarter of 2020 include:

- Scope document signed off;
- Railroad agreement received; and,
- Outside plant underground manholes/duct bank civil construction start.

The actual spend by quarter for Ridgefield 4kV as compared to the last URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals					
$143,414	$693,128	$2,134,627	$2,971,169	$21,100,000	14%

13. State Street

During the second quarter of 2020, approximately $173,000 was spent on the State Street project towards its revised mitigation method compared to a forecast of approximately $245,000, which brought the total spend to approximately $379,000. Notable activities completed during the second quarter of 2020 include:

- License and permit package submitted; and,
- Detailed engineering commenced.

Additionally, the property purchase for this project was completed (which is funded and executed under the associated 69kv project). The actual spend by quarter for State Street as compared to the last URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals					
$77,950	$128,288	$172,777	$378,656	$28,600,000	1%

As mentioned in the Executive Summary, State Street had its Study level estimate internally approved at the end of June 2020, which went to the URB for approval in July 2020. The new estimate, which will be detailed in the IM 2020 Third Quarter Report, is $45,100,000, or $16.5 million higher than the prior estimate and driven by the change in mitigation strategy from raise and rebuild to relocate.

14. Toney's Brook

During the second quarter of 2020, approximately $86,000 was spent on the Toney's Brook project compared to a forecast of approximately $128,000, which brought the total spend to approximately $414,000. Notable activities completed during the second quarter of 2020 include:

- Design freeze on switchgear arrangement, mechanical, and controls; and, Additionally, two of the three property parcels for this project closed during the second quarter of 2020 (which is funded and executed under the associated 69kv project), with the third parcel closing in the third quarter of 2020.The actual spend by quarter for Toney's Brook as compared to the last URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals					
$211,940	$115,747	$86,315	$414,002	$19,700,000	2%

15. Waverly

During the second quarter of 2020, approximately $355,000 was spent on the Waverly project compared to a forecast of approximately $270,000, which brought the total spend to approximately $815,000. Notable activities completed during the second quarter of 2020 include:

- Major equipment (switchgear) purchase order issued;
- Detailed engineering commenced;
- Scope document signed off; and,
- Phase 1 constructability review.

The actual spend by quarter for Waverly as compared to the last URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals					
$103,748	$355,706	$355,335	$814,790	$35,400,000	2%

16. Woodlynne

During the second quarter of 2020, approximately $213,000 was spent on the Woodlynne project compared to a forecast of approximately $284,000, which brought the total spend to approximately $565,000. Notable activities completed during the second quarter of 2020 include:

- License and permit package submitted;
- Site plan approved (county); and,
- Detailed engineering commenced.

The actual spend by quarter for Woodlynne as compared to the last URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals					
$110,982	$240,418	$213,482	$564,882	$19,400,000	3%

B. Contingency Reconfiguration

During the second quarter of 2020, work continued to advance in the Contingency Reconfiguration subprogram with all four Divisions installing reclosers. However, due to failure of a B-phase potential transformer (PT) on a recloser being energized, all recloser installations were temporarily suspended on May 7, 2020 to allow PSE&G to conduct a root cause analysis of the issue. The root cause analysis, conducted by a third party, determined a pinched wire in the PT junction box caused a secondary fault that led to the PT failure. The short was grounded before the fuse, which meant the fuse was not blown and could not provide protection to the PT. PSE&G revised its testing procedures to limit the number of times required to be in the PT junction box and to test for ground faults before going to the field. Recloser installations resumed the week of June 22, 2020. While the recloser installation suspension caused the second quarter target of 204 installed reclosers to be missed, during this suspension pole installations continued, and PSE&G also shifted resources to install Hm radios and commission reclosers that were already installed without radios to allow other work in the subprogram to continue to advance. **Table 12 – ES 2 Recloser Status as of June 30, 2020** provides a summary of the recloser aspect of the Contingency Reconfiguration subprogram, indicating the 2020 yearend targets and current status of engineering, installation, and commissioning.

Table 12 – ES 2 Recloser Status as of June 30, 2020

Type	2020 Year End Total Target	Engineering Packages Complete (1 recloser ea.)		Reclosers Installed		Reclosers Commissioned	
		Q2 Qty.	*Total*	*Q2 Qty.*	*Total*	*Q2 Qty.*	*Total*
13kV	800	45	594	84	417	130	130
4kV	179	100	263	14	38	11	11
Total	979	145	857	98	455	141	141

As shown in **Table 12**, engineering continues to stay comfortably ahead of construction, allowing PSE&G flexibility in selecting which projects to initiate construction on and allows the subprogram progress to continue.

The Fuse Saver installations is planned to begin later in 2020 with a pilot program that installs Hmc radios in the Fuse Savers to support communication on the device when there is an event. PSE&G's Asset Management group determined a pilot program would be initiated prior to the full scope to ensure the devices work as intended, with the pilot program contemplating installation of 57 single-phase units and 18 two-phase units. The pilot program is expected to be completed by the end of 2020.

The Contingency Reconfiguration subprogram costs through the end of the second quarter of 2020 are presented in **Table 13 – ES 2 Contingency Reconfiguration Costs as of June 30, 2020**.

Table 13 – Contingency Reconfiguration Costs as of June 30, 2020

Scope & Division		Q4 2019	Q1 2020	Q2 2020	Total to Date	Forecast	% of Actuals to Forecast
		Actuals					
Reclosers	Central	$2,737,167	$3,918,150	$2,238,132	$8,893,449	$25,257,404	35%
	Metro	$2,231,431	$3,576,616	$1,946,751	$7,754,798	$21,745,230	36%
	Palisades	$2,515,569	$3,353,246	$2,263,303	$8,132,118	$29,244,631	28%
	Southern	$2,081,220	$4,003,537	$2,098,258	$8,183,015	$27,398,087	30%
Fuse Savers	Central	$9,970	$29,667	$48,444	$88,081	$13,694,230	1%
	Metro	$7,557	$15,498	$28,339	$51,394	$10,537,153	0%
	Palisades	$7,468	$15,259	$16,336	$39,063	$10,834,460	0%
	Southern	$9,792	$21,458	22,973	$54,223	$12,165,607	0%
Total		**$9,600,174**	**$14,933,431**	**$8,662,536**	**$33,196,141**	**$150,876,803**	**22%**

Findings & Observations:

- Recloser installations fell behind the second quarter target due to the suspension of installations following the PT failure and corresponding root cause analysis. However, PSE&G continued to advance work particularly through pole installations and commissioning of recloser installed earlier with Hm radios.
- It was appropriate for PSE&G to suspend installations in order to determine the cause of the PT failure so it could determine the cause of the failure and protect the safety of the workers.
- It was reasonable for PSE&G to introduce a pilot program on the Fuse Saver/Hmc radio installations to ensure the devices work as intended prior to commencement of the full scope.
- While still early in the subprogram, the IM has found nothing to date that would jeopardize the subprogram being completed on time and/or on budget.

C. Grid Modernization – Communication System

In June 2020, the permanent PSE&G Wireless Network infrastructure solution for connecting to the First Net LTE Network was officially placed in-service and is being utilized to manage all traffic from the field routers. Also during the second quarter of 2020, the first shipment of field routers and accessory hardware and Hm radios were delivered to the Divisions and installation commenced. By the end of the second quarter, six retrofit reclosers had been installed, in line with the target quantity for the quarter. PSE&G has made the strategic decision to focus on new recloser installations and has delayed the ramp-up in retrofit installations from August 2020 to January 2021 due to resource constraints. No overall impacts are expected from this decision and PSE&G plans to regain the planned retrofit installations by the middle of 2021 as it shifts focus from new recloser installations to the retrofit reclosers.

On the fiber scope, which includes installing fiber to electric substations and electric operations centers, in addition to cutting over stations with existing fiber service to the PSE&G fiber network, 41 installation projects and 12 cutover have been identified, with the first batch of installations expected to be placed in-service during the fourth quarter of 2020 and the cutovers to be completed early in 2021.

The Grid Modernization – Communication System subprogram costs through the end of the second quarter of 2020 are presented in **Table 14 – ES 2 Grid Modernization – Communication System Costs as of June 30, 2020**.

Table 14 – ES 2 Grid Modernization – Communication System Costs as of June 30, 2020

Scope & Division		Q1 2019	Q1 2020	Q2 2020	Total to Date	Forecast	% of Actuals to Forecast
		Actuals					
Retrofit Reclosers	Central	$0	$50,613	$150,958	$201,571	$7,389,617	3%
	Metro	$0	$44,164	$139,069	$183,233	$6,357,784	3%
	Palisades	$0	$44,164	$138,485	$182,649	$6,445,616	3%
	Southern	$0	$46,901	$145,479	$192,380	$7,953,623	2%
Fiber	Central	$1,691	$133,115	$272,307	$407,113	$6,990,081	6%
	Metro	$1,457	$109,382	$299,876	$410,715	$4,544,079	8%
	Palisades	$1,582	$194,451	$520,068	$716,101	$3,148,835	23%
	Southern	$4,731	$65,721	$139,575	$210,027	$3,233,586	6%
	Cutovers	$0	$0	$0	$0	$6,735,000	0%
Wireless Network		$74,306	$1,525,801	$2,353,604	$3,953,710	$12,065,231	33%
Total		**$83,767**	**$2,214,312**	**$4,159,421**	**$6,457,500**	**$64,863,452**	**10%**

Findings & Observations:

- Retrofit recloser installations began in the second quarter of 2020, but PSE&G made a strategic decision for new reclosers (as part of the Contingency Reconfiguration subprogram) continue to have installation priority of retrofits due to new reclosers providing segregation to the sections they are installed that improves reliability (while retrofits improve communications on the devices, but no segregation).
- While still early in the subprogram, the IM has found nothing to date that would jeopardize the subprogram being completed on time and/or on budget.

D. Grid Modernization – ADMS

The Grid Modernization – ADMS scope is split between three primary sections: Distribution Management System (DMS)/Distributed Energy Resource Management System (DERMS), the Outage Management System (OMS), and ADMS platform upgrades. The primary activities in 2020 are centered on planning activities, with the notable milestone completed in the second quarter of 2020 being the signing of the Open Systems International Inc. (OSII) contract (with the vendor selection discussed in the IM 2020 First Quarter Report). The ADMS team continues to use remote meetings with the vendor in response to the ongoing Covid-19 issues and continues to conduct design workshops to further develop the application. The final ADMS release is currently forecasted to go live during the fourth quarter of 2022.

The Grid Modernization – ADMS subprogram costs through the end of the second quarter of 2020 are presented in **Table 15 – ES 2 Grid Modernization – ADMS Costs as of June 30, 2020**.

Table 15 – ES 2 Grid Modernization – ADMS Costs as of June 30, 2020

Q4 2019	Q1 2020	Q2 2020	Total to Date	Forecast	% of Actuals to Forecast
Actuals					
$36,213	$925,689	$4,430,542	$5,392,444	$39,707,462	14%

Findings & Observations:

- The activities to date on the subprogram continue to be primarily planning activities, including continuing to have workshops with the software vendor and operations.
- While still early in the subprogram, the IM has found nothing to date that would jeopardize the subprogram being completed on time and/or on budget.

E. Electric Stipulated Base

The Stipulation identified that the electric portion of the Stipulated Base include $100 million in investments at PSE&G's discretion towards electric outside plant higher design and construction standards and/or electric stations life cycle subprograms described in the original ES 2 filing.[2] As reported in the IM 2020 First Quarter Report, the preliminary planning by PSE&G estimated that approximately one-third of the Stipulated Base funds will be used towards the electric stations life cycle investments and

[2] As noted in the Stipulation, the electric life cycle upgrades are part of the electric Stipulated Base to be recovered in the Company's next base rate case provided the investments are found to be prudent. The Stipulation also notes that should the 16 stations that comprise the Electric Station Flood Mitigation subprogram be completed for under the $389 million allocated for that subprogram, PSE&G may reallocate such unused funds to stations identified in the life cycle station upgrade portion of PSE&G's petition for accelerated recovery.

the remaining two-thirds towards outside plant higher design and construction standards. Based on the current study level estimate for the life cycle upgrades (detailed below), the current view shows that approximately 80% of these funds will be applied towards life cycle upgrades, with the remainder going towards the electric outside plant higher design and construction standards. This current ratio is driven by the approval of the four life cycle stations, including risk and contingency funds, to allow their completion within the ES 2 Program window. PSE&G has confirmed with the IM that it intends to maintain the ratio at approximately one-third of funding to life cycle upgrades and two-thirds to outside plant higher design and construction schedules. In accordance with what the Stipulation provides, PSE&G plans to fund some of the lifecycle station upgrades from the electric program accelerated investment, subject to funds available, after all Electric Station Flood Mitigation projects are funded at their final costs.

The outside plan higher design and construction standards scope of work contemplates replacing the traditional open wire and cross-arm type construction on distribution overheard circuits with spacer cable in targeted locations. PSE&G determined that spacer cable provides significant improvement in customer reliability during storm events and other tree-related events as compared to the traditional methods. At present, approximately 45% of PSE&G's 4kV and 13kV overhead distribution system uses spacer cable. As reported in the IM 2020 First Quarter Report, the final circuit selection for this effort was still being developed but has now been completed and was selected from PSE&G's original proposal using historical value of lost load from reportable and major event history. The value of lost load was based on tree-related outages for reportable results and all outages for storm events. The rationale for using all outages in storms was that tree-related damage represents the large majority of outages during storms and the stronger poles, metal hardware and steel messenger cable all provide higher strength to resist high winds. This work is currently anticipated to commence in January 2022.

The projects identified from the pool of eligible substations are generally located in congested urban/suburban areas with a small property footprint that makes replacing the equipment while maintaining service a challenge. PSE&G has developed a standardized approach for these life cycle upgrades that should result in efficiencies in design, equipment standardization, and construction, as well as eliminating the need for additional property. Essentially, the approach calls for setting concrete footings and columns between and next to existing feeder rows to support new breaker buildings and switchgear being installed on elevated platforms above the existing feeder rows. Following installation of the new equipment, the service is transferred from the old equipment and the old equipment is demolished.

To prioritize and select the stations receiving investments through the life cycle upgrades efforts, PSE&G performed a study of asset demographics, failure curves, and risk scoring for all its Distribution Assets. PSE&G's ES 2 filing indicated it proposed to replace or retire substations with 4kV assets that are either at or close to end-of-life, with 96 stations identified with these assets. PSE&G evaluated each identified station to determine if the station is still required or if its circuits can be cost effectively converted to 13kV operation (generally those with low customer counts and/or peak loads are best candidates to eliminate with a 13kV circuit upgrade). For remaining stations, Class C stations are prioritized due to the significantly higher risk scores present compared with Class A/B stations, in part due to the fact that the 4kV equipment is in outdoor switchgear and exposed to the elements. The prioritization noted in the ES 2 filing was:

1. Class C stations located where 69kV upgrades are completed or in progress. (15 stations)
2. Class C stations identified for elimination. (13 stations)
3. Class C stations where a full station upgrade is required. (10 stations)

4. Class A & B stations where 69kV upgrades are completed or are in progress or 26kV upgrades are planned. (26 stations)
5. Remaining Class A, B, & C stations not candidates to be completed within the proposed 5-year subprogram. (21 stations)

Of those 15 stations in the top priority, Plainfield, Hamilton, Paramus, and Woodbury were initially selected. These four stations PSE&G selected for life cycle station upgrades went before the URB in June 2020 for Study level estimate approval and received approval for full funding. These four stations and their current estimate are provided in **Table 16 – ES 2 Life Cycle Station Upgrade Projects**.

Table 16 – ES 2 Life Cycle Station Upgrade Projects

Project	Estimate Level	Base	Risk & Contingency	Total
1. Hamilton	Study	$14,500,000	$3,700,000	$18,200,000
2. Paramus	Study	$14,800,000	$5,400,000	$20,200,000
3. Plainfield	Study	$18,400,000	$4,200,000	$22,600,000
4. Woodbury	Study	$15,400,000	$3,300,000	$18,700,000

Additional information on each of these life cycle stations is provided as follows:

1. Hamilton: The Hamilton substation was originally constructed in 1953 with a significant portion of its current 4kV equipment being the original equipment at the substation. The station currently consists of three 69kV lines, two 69/4kV transformers, and eight 4kV feeders. From 2008-2017, the 4kV supply circuits at Hamilton have experienced 67 extended outages and seven momentary outages, for a total duration of nearly 308 hours. The life cycle upgrades contemplate upgrading equipment and protection schemes including replacing the old electromechanical relays with modern digital relays to increase the reliability, resiliency, and life span of the substation.

2. Paramus: The Paramus substation was originally constructed in 1958 with a significant portion of its current 4kV equipment being the original equipment at the substation. The station currently consists of three 69kV lines supplying a six-breaker ring bus, with three 69/4kV transformers, and 12 4kV feeder rows. From 2008-2017, the 4kV supply circuits at Paramus have experienced 116 extended outages and 20 momentary outages, for a total duration of nearly 1,044 hours. Black & Veatch was awarded the A/E scope for this project. The life cycle upgrades contemplate upgrading equipment and protection schemes including replacing the old electromechanical relays with modern digital relays to increase the reliability, resiliency, and life span of the substation.

3. Plainfield: The 4-kV Switchgear at the Plainfield substation is in poor condition. A significant portion of the 4-kV equipment at the station is still original and the metal clad switchgear has rusted and must be addressed. In addition, all of the 4-kV distribution feeders and Tie Feeder currently run through the same manhole and conduit system, which presents the possibility of extended outages to the customers supplied from Plainfield Substation in the event of a cable or splice failure that results in collateral damage to adjacent feeders. This station currently consists of three (3) 69-kV lines supplying a Six (6) - Breaker GIS Ring Bus, with three (3) 69 / 4-kV transformers, twelve (12) 4-kV feeders, one (1) 4-kV Tie Feeder, and two (2) 2.7MVA. Black & Veatch was awarded the A/E scope for this project.

4. Woodbury: The Woodbury substation was originally constructed in 1954 with a significant portion of its current 4kV equipment being the original equipment at the substation. The station currently consists of four 26kV lines, three 26kV bus section breakers, three 26/4kV transformers, three transformer 4kV breakers, and 12 4kV feeders with voltage regulators and reactors. From 2008-2017, the 4kV supply circuits at Woodbury have experienced 153 extended outages and eight momentary outages, for a total duration of nearly 883 hours. Burns & McDonnell was awarded the A/E scope for this project. The life cycle upgrades contemplate replacing the old electromechanical relays with modern digital relays to increase the reliability, resiliency, and life span of the substation.

The four life cycle stations identified above also completed their key drawing review and initiated the major equipment procurement bid events in June 2020.

Findings & Observations:

- The four selected life cycle stations appears to be following a process consistent with how PSE&G has planned and managed the projects within the Electric Stations Flood Mitigation subprogram.
- The standardized approach PSE&G developed for these life cycle stations is an appropriate approach based on the common aspects of these substations (e.g. small footprint, common scope, etc.) and should provide an effective method for updating these substations while also benefiting from efficiencies through using a standardized approach across the projects.
- The IM agrees with the rationale applied by PSE&G for its circuit prioritization for the outside plant higher design standards, including the value of lost load for tree-related outages on reportable events and all outages for storm events, particularly given that tree/vegetation damage accounts for a majority of the outages during storm events and that the criteria also included tree-related outages for reportable results, further emphasizing this prioritization.
- The electric stipulated base projects remain largely in the planning phase, as such the IM has no additional comments on this component of the ES 2 Program at this time.

F. Gas M&R Station Upgrades

Through the end of the second quarter of 2020, preliminary design continued on each of the Gas M&R stations. **Table 17 – ES 2 Gas M&R Summary Status as of June 30, 2020** below provides the currently approved estimates for each project within the Gas M&R subprogram, along with the actuals to date and forecasted in-service dates. As indicated in **Table 16**, there continues to have been minimal spend to date on the subprogram, with the actual spend primarily related to initial planning efforts.

Table 17 – ES 2 Gas M&R Summary Status as of June 30, 2020

Project	Estimate Level	Base	Risk & Contingency	Total to Date	Actuals	% of Actuals to Estimate	Forecasted In-Service
1. Camden*	Office	$10,000,000	$5,400,000	$15,400,000	$143,516	1%	Jan 2023
2. Central*	Office	$12,800,000	$6,900,000	$19,700,000	$161,474	1%	Jan 2023
3. East Rutherford	Office	$10,300,000	$5,600,000	$15,900,000	$158,283	1%	Jan 2023
4. Mount Laurel	Office	$11,300,000	$6,100,000	$17,400,000	$108,507	1%	Jan 2022
5. Paramus*	Office	$12,900,000	$7,000,000	$19,900,000	$137,881	1%	Jul 2023

Project	Estimate Level	Base	Risk & Contingency	Total to Date	Actuals	% of Actuals to Estimate	Forecasted In-Service
6. Westampton	Office	$8,300,000	$4,400,000	$12,700,000	$230,181	2%	Jul 2021
Subprogram Total		**$65,600,000**	**$35,400,000**	**$101,000,000**	**$939,841**	**1%**	**Jul 2023**
**-Included in the Stipulated Base.*							

Findings & Observations:

- The primary efforts to date on the subprogram continue to be initial planning efforts, including the preparation of bid material and awarding of bids for the design services on the projects (with all now awarded).
- While still early in the subprogram, the IM has found nothing to date that would jeopardize the subprogram being completed on time and/or on budget.

1. Camden

As noted above, the primary work to date on the Gas M&R subprogram has been continuing with preliminary engineering and other planning activities. For the remainder of 2020, planned activities include continued engineering development, with all drawings (civil, electrical, instrumentation, and mechanical) expected to be IFR in November 2020, and the issuance of purchase orders for the major equipment (building, heaters, pipes, scrubber, valves and regulators) in December 2020. Construction is currently anticipated to begin in September 2021 and be completed in July 2022 (with demolition work continuing through October 2022).

The actual spend by quarter for Camden as compared to the last approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals					
$13,326	$46,691	$83,499	$143,516	$15,400,000	1%

2. Central

As noted above, the primary work to date on the Gas M&R subprogram has been continuing with preliminary engineering, including the prior award of the A/E contract to Odin EPC, LLC, and other planning activities. For the remainder of 2020, engineering efforts are planned to continue with electrical and instrumentation drawings being IFR in November 2020 (and civil and mechanical in January 2021). Construction is currently anticipated to begin in February 2022 and be completed in September 2022 (with demolition work continuing through January 2023).

The actual spend by quarter for Central as compared to the last approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals					
$6,869	$45,048	$109,557	$161,474	$19,700,000	1%

3. East Rutherford

As noted above, the primary work to date on the Gas M&R subprogram has been continuing preliminary engineering, including the prior award of the A/E contract to EN Engineering, LLC, and other planning activities. For the remainder of 2020, engineering efforts are planned to continue with all drawings (civil, electrical, instrumentation, and mechanical) expected to be IFR in January 2021. Construction is currently anticipated to begin in February 2022 and be completed in December 2022 (with demolition activities planned for completion in June 2022).

The actual spend by quarter for East Rutherford as compared to the last approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals					
$9,010	$37,747	$111,526	$158,283	$15,900,000	1%

4. *Mount Laurel*

As noted above, the primary work to date on the Gas M&R subprogram has been continuing preliminary engineering, including the prior award of the A/E contract to J.F. Kiely Service Co., LLC, and other planning activities. For the remainder of 2020, engineering efforts are planned to continue with all drawings (civil, electrical, instrumentation, and mechanical) expected to be IFR in September 2020, followed by the issuance of purchase orders for major equipment (building, instrumentation, pipes, scrubber, valves and regulators) in October 2020. Construction is currently anticipated to begin in May 2021 and be completed in October 2021 (with demolition activities continuing through January 2022).

The actual spend by quarter for Mount Laurel as compared to the last approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals					
$5,965	$27,804	$74,737	$108,507	$17,400,000	1%

5. *Paramus*

As noted above, the primary work to date on the Gas M&R subprogram has been continuing preliminary engineering, including the prior award of the A/E contract to EN Engineering, LLC, and other planning activities. For the remainder of 2020, engineering efforts are planned to continue with electrical and instrumentation drawings being IFR in November 2020 (followed by civil and mechanical in January 2021). Construction is currently anticipated to begin in August 2022 and be completed in June 2023 (with demolition activities continuing through September 2023).

The actual spend by quarter for Paramus as compared to the last approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals					
$8,842	$37,793	$91,247	$137,881	$19,900,000	1%

6. *Westampton*

As noted above, the primary work to date on the Gas M&R subprogram has been continuing preliminary engineering, including the prior award of the A/E contract to NVS, Inc., and other planning activities. For the remainder of 2020, engineering efforts are planned to continue with all drawings (civil, electrical, instrumentation, and mechanical) expected to be IFR in August 2020, followed by the issuance of purchase orders for major equipment (building, instrumentation, pipes, pipe fittings, scrubber, valves and regulators) in September 2020. Construction is currently anticipated to begin in December 2020 and be completed in March 2021 (with demolition activities continuing through May 2021).

The actual spend by quarter for Westampton as compared to the last approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals					
$8,395	$40,839	$180,947	$230,181	$12,700,000	1%

ENERGY STRONG PROGRAM

INDEPENDENT MONITOR

2020 SECOND QUARTER REPORT

APPENDIX A – DRAFT REPORT COMMENTS AND RESPONSES

30 DECEMBER 2020

PEGASUS GLOBAL HOLDINGS, INC. ®

Questions & Comments to the IM 2020 Second Quarter Report Formally Submitted to the IM

ID #	Question/Comment	IM Response	Report Changes
RCR-INF-1	With reference to page 9 of the ES2 Q2 2020 Report, please provide any additional details regarding the outage at the Woodlynne substation.	The Woodlyne substation experienced 26kV supply line interruptions, similar to other 26kV outages during this Major Event. Each of these interruptions stemmed from tree/vegetation issues.	**Section D.**
RCR-INF-2	With reference to page 9 of the ES2 Q2 2020 Report, did the Company experience any outages with respect to the other ES 1 or ES 2 substations?	As noted in PSE&G's Major Event report, Bordentown, Collingswood, Ewing, and Woodlynne substations were each shut down during the June 2020 Major Event. Each shutdown stemmed from interruptions to the 26kV or 69kV supply lines to the substations. The Ewing substation was part of Energy Strong 1 and Woodlynne is part of Energy Strong 2, however, the nature of these outages was not a water intrusion event, but tree/vegetation interruptions to the supply lines.	No change
RCR-INF-3	With reference to page 9 of the ES2 Q2 2020 Report, when does the Company plan to have preliminary results of the performance of ES 2 circuits relative to unimproved circuits impacted by the June 3-7, 2020 thunderstorms?	The initial information was provided to the IM in early December, which is reflected through the new material added to **Section D** of this IM 2020 Second Quarter Report. The IM has also requested additional information from PSE&G based on its review of the initial data provided, which is expected to be discussed in the next IM report.	**Section D.**
RCR-INF-4	With reference to page 9 of the ES2 Q2 2020 Report, does the Company have results of the performance of ES 1 circuits relative to unimproved circuits impacted by the June 3-7, 2020 thunderstorms?	The initial information was provided to the IM in early December, which is reflected through the new material added to **Section D** of this IM 2020 Second Quarter Report. The IM has also requested additional information from PSE&G based on its review of the initial data provided, which is expected to be discussed in the next IM report.	**Section D.**
RCR-INF-5	With reference to Table 9 of the ES2 Q2 2020 Report, is the Company getting pricing discounts or preferential deliveries with suppliers for equipment given the scope of the substation work?	PSE&G has indicated to the IM that it has not received discounts or preferential deliveries relating to the substation work. All pricing and delivery dates originated from the competitive bid process.	No change
RCR-INF-6	With reference to page 13 of the ES2 Q2 2020 Report, please confirm that the $399,935 spent on the Academy Street substation was associated with the change in design strategy discussed during the 2nd quarter.	These funds were spent entirely on the new/current mitigation method.	**Section III.A.1.**

ID #	Question/Comment	IM Response	Report Changes
RCR-INF-7	With reference to page 17 of the ES2 Q2 2020 Report, please confirm that the $172,777 spent on the State Street substation was associated with the change in design strategy discussed during the 2nd quarter.	These funds were spent entirely on the new/current mitigation method.	**Section III.A.13.**
RCR-INF-8	With reference to page 18 of the ES2 Q2 2020 Report, please provide an update on the status of the root cause analysis. Has the Company experienced equipment failures associated with earlier recloser installations?	The root cause analysis from the May 2020 PT failure was provided to the IM in December 2020. Based on the IM's review of this analysis, additional information has been provided on this event in **Section III.B.** of this IM 2020 Second Quarter Report. PSE&G has informed the IM there has been one other recloser PT failure that occurred in October 2019.	**Section III.B.**
RCR-INF-9	With reference to page 21 of the ES2 Q2 2020 Report, has the ongoing remote working sessions impacted the schedule of ADMS implementation?	The Covid-19 protocols including the remote working sessions with the ADMS vendor, while not the original plan, this approach has not impacted the ADMS implementation schedule.	No change
RCR-INF-10	With reference to page 22 of the ES2 Q2 2020 Report, has the Company developed evaluation criteria to identify spacer cable installations?	Circuit selection has been completed. The value of lost load was based on tree related outages for reportable results and all outages for storm events. The rationale for using all outages in storms was that tree related damage represents the large majority of outages during storms and the stronger poles, metal hardware and steel messenger cable all provide higher strength to resist high winds.	**Section III.E.**
RCR-INF-11	With reference to page 22 of the ES2 Q2 2020 Report, please provide details of the four lifecycle upgrade projects for the Electric Stipulated Base component.	Additional information on these four lifecycle upgrade projects has been incorporated into this report.	**Section III.E.**
S-INF-1	Reference Page 1, Table 1 – ES 2 Subprogram & Stipulated Base Status as of June 30, 2020 What can be attributed to the significant increase in the forecasted cost of the Contingency Reconfiguration subprogram from the Q1 2020 Update ($119,496,564) to the Q2 2020 Update ($150,876,803)?	Driven in part by the full forecasting of the Fuse Saver scope of the subprogram, which as of Q1 2020 had only been partially forecasted. The IM further notes that while this is report covers the second quarter, as of the third quarter of 2020 the Contingency Reconfiguration subprogram forecast decreased to $131.9 million.	**Section I.**
S-INF-2	Reference Page 1, Table 1 – ES 2 Subprogram & Stipulated Base Status as of June 30, 2020 What can be attributed to the change in the forecasted completion date of the Grid Modernization – ADMS subprogram from the Q1 2020 Update (Dec. 2023) to the Q2 2020 Update (Oct. 2022)?	Primarily attributed to additional schedule development from the initial high-level schedule that was in place as of Q1 2020 to a more detailed schedule in place as of Q2 2020.	**Section I.**
S-INF-3	Reference Page 10, Table 9 – ES 2 Electric Station Flood Mitigation Summary Status as of June 30, 2020 a. Regarding the Electric Station Flood Mitigation projects, please confirm that all A/E contracts were awarded based on bid price.	a. All A/E contracts were awarded through a competitive bid process. b. Driven by the capabilities and availability of in-house resources.	No change

ID #	Question/Comment	IM Response	Report Changes
	b. Please describe the circumstances under which PSE&G internal resources would serve as the A/E.		
S-INF-4	Reference Page 13 (Academy Street) Regarding the statement "Academy Street had its Study level estimate internally approved at the end of June 2020, which went to the [Utility Review Board] for approval in July 2020", please confirm that construction began on Academy Street in Q2 2020 (See Page 9, Table 8), before approval was received from the Utility Review Board.	The civil construction PO was issued in June 2020, along with the release of civil IFC drawings and a constructability review. Actual construction commenced in July 2020. The Office level estimate for Academy Street (and all other Electric Station Flood Mitigation projects) was approved before the URB in September 2019. The July 2020 URB approval for Academy Street related to the project transitioning from an Office level to a Study level estimate.	No change
S-INF-5	Reference Page 19 (Contingency Reconfiguration) Regarding the statement "The Fuse Saver installations is planned to begin later in 2020 with a pilot program that installs Hmc radios in the Fuse Savers to support communication on the device when there is an event. PSE&G's Asset Management group determined a pilot program would be initiated prior to the full scope to ensure the devices work as intended, with the pilot program contemplating installation of 57 single-phase units and 18 two-phase units." a. What is the approximate timeline of the pilot program? b. Will the pilot program delay the anticipated completion date of the Contingency Reconfiguration subprogram?	a. November-December b. No expected impact to the overall completion of the subprogram; in fact, intent of pilot program is to identify potential equipment/installations issues to avoid impacts during full implementation of the Fuse Saver devices.	**Section III.B.**
S-INF-6	Reference Page 21 (Electric Stipulated Base) Please provide additional details describing the Company's decision to now spend approximately 80% of the Electric Stipulated Base on life cycle upgrades, rather than approximately 33% as previously estimated in the IM 2020 Q1 Report.	While the Stipulation provided that the $100M in electric stipulated base "will be spent at the Company's discretion toward electric outside plant higher design and construction standards ('outside plant') and/or electric life cycle subprograms identified in the June 8, 2018 ES II filing." PSE&G's intent remains to allocate approximately 1/3 of the Electric Stipulated Based funding to lifecycle station upgrades. The current ratio roughly allocates 4/5 of this funding to the lifecycle station upgrades is reflective of the funding approval for the initial four substations (Hamilton, Plainfield, Paramus, and Woodbury) including the risk and contingency allowance for each substation. The funding approval allows these projects to be initiated in alignment with the ES 2 Program duration. In accordance with what the Stipulation provides, PSE&G plans to fund some of the lifecycle station upgrades from the electric program accelerated investment, subject to funds available, after all Electric Station Flood Mitigation projects are funded at their final costs.	**Section III.E.**

ID #	Question/Comment	IM Response	Report Changes
S-INF-7	Reference Page 22 (Electric Stipulated Base) Regarding the statement "At present, approximately 45% of PSE&G's 4kV and 13kV overhead distribution system uses spacer cable. As reported in the IM 2020 First Quarter Report, the final circuit selection for this effort is still being developed but will be selected from PSE&G's original proposal using historical value of lost load from reportable and major event history." a. Please confirm that the historical value of lost load reflects all outages, rather than only tree-related outages. b. If so, please discuss if the IM believes it is appropriate to select circuits for spacer cable installation based on the historical value of lost load, rather than the circuit's tree-related outage history.	The value of lost load utilized by PSE&G was based on tree related outages for reportable results and all outages for storm events. PSE&G's rationale for using all outages in storms was that tree related damage represents the large majority of outages during storms and the stronger poles, metal hardware and steel messenger cable all provide higher strength to resist high winds. The IM agrees with this rationale, particularly given that tree/vegetation damage accounts for a majority of the outages during storm events and that the criteria also included tree-related outages for reportable results, further emphasizing this prioritization.	**Section III.E.**
S-INF-8	Reference Page 22, Table 16 – ES 2 Life Cycle Station Upgrade Projects Please describe the factors considered by the Company in selecting the four (4) life cycle station projects in Table 16 for inclusion within the Program.	PSE&G performed a study of asset demographics, failure curves, and risk scoring for all its Distribution Assets. PSE&G's filing indicated it proposed to replace or retire substations with 4kV assets that are either at or close to end-of-life, with 96 stations identified with these assets. PSE&G evaluated each identified station to determine if the station is still required or if its circuits can be cost effectively converted to 13kV operation (generally those with low customer counts and/or peak loads are best candidates to eliminate with a 13kV circuit upgrade). For remaining stations, Class C stations are prioritized due to the significantly higher risk scores present compared with Class A/B stations, in part due to the fact that the 4kV equipment is in outdoor switchgear and exposed to the elements. The prioritization noted in the ES 2 filing was: 1. Class C stations located where 69kV upgrades are completed or in progress. (15 stations) 2. Class C stations identified for elimination. (13 stations) 3. Class C stations where a full station upgrade is required. (10 stations) 4. Class A & B stations where 69kV upgrades are completed or are in progress or 26kV upgrades are planned. (26 stations)	**Section III.E.**

ID #	Question/Comment	IM Response	Report Changes
		5. Remaining Class A, B, & C stations not candidates to be completed within the proposed 5-year subprogram. (21 stations) Of those 15 stations in the top priority, Plainfield, Hamilton, Paramus, and Woodbury were initially selected.	
S-INF-9	Reference Page 23 (Gas M&R Station Upgrades) Regarding the Gas M&R Station Upgrades: a. Please confirm that all A/E contracts were awarded based on bid price. b. Please identify the entity that was awarded the A/E contract for the Camden M&R project.	a. All awarded on bid pricing. b. Burns & McDonnell was awarded the contract in July 2020 after the work was re-bid following the initially selected firm not agreeing to PSE&G's terms and conditions regarding material procurement.	No change
PSE&G-1	Table 6, Grid Modification – Communications Total AFUDC should be $38,148.	The correct total has been added to **Table 6.**	**Table 6**
PSE&G-2	Table 6, Grid Modification – ADMS Total AFUDC should be $22,926.	The correct total has been added to **Table 6**.	**Table 6**
PSE&G-3	Academy and State were at Study estimates though URB approval was pending. The estimate phase and numbers should be updated to Study data. Academy Base - $9,900,000 R&C - $2,900,000 State Street Base - $39,000,000 R&C - $6,100,000 Kingsland – Phase shows Study phase which is right but the number is office data. Number should be updated to Study numbers Kingsland Base - $5,400,000 R&C - $2,900,000	As noted in the discussion on the estimates for these projects, the values displayed are reflective of the current estimate approved by the URB. While Academy Street, State Street, and Kingsland had updated estimates approved internally in June, these estimates were not approved by the URB until July, as such, the IM reported the previously approved URB estimates for these projects (while also noting the URB approval was pending).	No change
Rate Counsel 12/7/2020 Letter to IM	Rate Counsel also notes that the budget for Electric stipulated base has been set to $100 million, but that Pegasus states that the subprogram's projects "remained largely in the planning stage."	The $100 million budget for the electric component of the Stipulated Based was established by the Stipulation. This component of the ES 2 Program has largely remained in the planning stage, as evidenced by the selection of the initial life cycle stations reported in this report and the establishment of criteria for higher design standards.	No change
Rate Counsel 12/7/2020 Letter to IM	The Electric Flood mitigation program increased from $309,160,283 in the First Quarter Report to $332,662,596 in the Second Quarter Report, not including risk and contingency estimates. However, Table 11 – ES 2 Electric Station Flood Mitigation Project Cost Status as of June 30, 2020, states that the base spending amount for the subprogram is $309,000,000 in budgeted base project costs and $80,000,000 allocated to risk and contingency.	The $309,160,283 figure reported in the IM 2020 First Quarter Report and the $332,662,596 figure reported in this IM 2020 Second Quarter Report reflect PSE&G's <u>current forecasted</u> spend for the Electric Station Flood Mitigation subprogram. The figures presented in Table 11 depict the <u>latest estimate</u> for each of the substations within this subprogram, including designation of the current estimate level.	No change

ID #	Question/Comment	IM Response	Report Changes
		It is common for the current forecast to differ from the latest estimate based on the forecast including trends and other more current metrics (which would be captured by the next revision to the project estimate).	
Rate Counsel 12/7/2020 Letter to IM	The Independent Monitor notes that no formal RODs were issued during the second quarter of 2020, however, PSE&G has proposed additional mitigation method changes at three substations in the Electric Station Flood Mitigation subprogram: the Lakeside Avenue, Orange Valley, and Constable Hook substations.	The IM concurs that no formal RODs were issued during the second quarter of 2020. The IM also notes that while these mitigation changes were raised during the second quarter, as noted in this IM 2020 Second Quarter Report, the formal notification was not submitted by PSE&G until the third quarter of 2020 and will be discussed in more detail in the IM 2020 Third Quarter Report.	No change
Rate Counsel 12/7/2020 Letter to IM	Similarly, the Contingency Reconfiguration subprogram total forecast increased to $150,876,803 from $119,496,564 in the First Quarter Report. The stipulated budget for the subprogram is $145 million. Nonetheless. Pegasus concludes that "[w]hile still early in the subprogram, the IM has found nothing to date that would jeopardize the subprogram being completed on time and/or on budget."	The IM notes that it is still early in the subprogram and as the planning and forecasting becomes more solidified based on the initial efforts it is expected the forecast will be less volatile. This second quarter forecast increase to the Contingency Reconfiguration subprogram was driven in part by the full forecasting of the Fuse Saver scope of the subprogram, which as of Q1 2020 had only been partially forecasted. The IM further notes that while this is report covers the second quarter, as of the third quarter of 2020 the contingency reconfiguration subprogram forecast decreased to $131.9 million.	**Section I.**
Rate Counsel 12/7/2020 Letter to IM	The amounts set forth in the Second Quarter Report Tables should be amended so that the stipulated amounts for the ESII program are clearly stated.	This information has been added to **Table 1**.	**Table 1**

ENERGY STRONG 2 PROGRAM INDEPENDENT MONITOR 2020 THIRD QUARTER REPORT

PREPARED AND SUBMITTED BY

PEGASUS GLOBAL HOLDINGS, INC. ®

CONFIDENTIAL

11 MAY 2021

Table of Contents

Appendices

List of Acronyms and Abbreviations

Advanced Distribution Management Systems .... ADMS

Air Insulated Substation.. AIS

Allowance for Funds Used During Construction .... AFUDC

Architectural and Engineering .... A/E

Board of Public Utilities .... BPU

Construction Work In Progress .... CWIP

Costs of Removal.. COR

Distribution Management System .... DMS

Distributed Energy Resource Management System .... DERMS

Energy Strong 2 .... ES 2

Gas Insulated Substation... GIS

Gas Metering & Regulating .... Gas M&R

Independent Monitor.. IM

Infrastructure Investment Program.. IIP

Issued for Construction .... IFC

Issued for Review .... IFR

Open Systems International Inc. .... OSII

Operations & Maintenance .... O&M

Outage Management System... OMS

Plain Old Telephone Service... POTS

Public Service Electric & Gas .... PSE&G

Record of Decision .... ROD

Risk and Contingency .... R&C

State of New Jersey Division of Rate Counsel.. Rate Counsel

Supervisory Control And Data Acquisition.. SCADA

System Average Interruption Duration Index .... SAIDI

Underground Storage Tanks .... USTs

Utility Review Board .... URB

I. Executive Summary

Public Service Electric & Gas's (PSE&G's) Energy Strong 2 (ES 2) Program was established from a Stipulation that the involved parties agreed to in August 2019, as approved by a Board of Public Utilities (BPU) Order dated September 11, 2019 with an effective date of September 21, 2019. The Stipulation provided the ES 2 Program would be comprised of five primary subprograms: Electric Station Flood Mitigation; Contingency Reconfiguration; Grid Modernization – Communications; Grid Modernization – Advanced Distribution Management Systems (ADMS); and Gas Metering & Regulating (Gas M&R) Station Upgrades. In addition, a Stipulated Base spend was established that includes both an electric component (higher outside plant design standards and station life cycle upgrades) and a gas component (overlapping with the Gas M&R subprogram).

During the third quarter of 2020, the bulk of the spend within the ES 2 Program continued to be in the two largest subprograms: Electric Station Flood Mitigation with six projects now in construction, up from three in the prior quarter; and Contingency Reconfiguration that continues to advance the installation and commissioning of reclosers, despite encountering weather-related impacts and minor inventory issues. Within the other subprograms, the two Grid Modernization subprograms continued to advance with the Communications piece primarily focusing on readying the new network and preparing for the selected 2020 fiber projects that were initiated in the fourth quarter of 2020 and the ADMS piece continuing to plan and scope the platform and necessary hardware equipment, while the Gas M&R subprogram largely remains in preliminary planning and early engineering activities. As noted in the Independent Monitor's (IM's) 2020 Second Quarter Report, four stations within the life cycle upgrades portion of the Electric Stipulated Base were approved by the Utility Review Board (URB) in July 2020, which initiated the initial spend on these projects during the third quarter of 2020 as design and permitting efforts began. **Table 1 – ES 2 Subprogram & Stipulated Base Status as of September 30, 2020** below provides the spend to date on the subprograms within the ES 2 Program and Stipulated Base compared to the total forecast and forecasted completion for each.

Table 1 – ES 2 Subprogram & Stipulated Base Status as of September 30, 2020

Subprogram	Q3 Spend	Total Spend to Date*	Total Forecast*	% of Actuals to Forecast	Forecasted Completion**	Stipulation Funding Amount
Electric Station Flood Mitigation	$16,058,679	$33,480,071	$327,092,250	10%	Jan 2024	$389M
Contingency Reconfiguration	$10,289,616	$43,485,758	$131,898,033	33%	Jul 2023	$145M
Grid Modernization – Communications	$5,106,396	$11,563,893	$59,120,939	20%	Dec 2023	$72M
Grid Modernization – ADMS	$6,970,572	$12,363,016	$40,374,822	31%	Oct 2022	$35M
Electric Stipulated Base	$1,473,779	$1,473,779	$100,103,160	1%	Under Development	$100M
Gas M&R Station Upgrades^	$1,178,542	$2,118,383	$76,200,001	3%	Jul 2023	$101M
*Total**	$41,077,584	$104,484,899	$734,789,205	14%	Dec 2023	$842M

-Note: total figures may not fully align due to rounding. Additionally, the total forecast includes only the base cost for the Electric Station Flood Mitigation and Gas M&R subprograms as PSE&G does not include risk and contingency (R&C) in its forecasts for these projects. See **Table 20 and **Table 19** for the Electric Station Flood Mitigation and Gas M&R project estimates, respectively, with base costs and R&C shown.*
***-Final in-service date.*
^-Includes both the ES 2 projects and the Stipulated Base gas projects.

From the second quarter of 2020, the overall ES 2 Program forecast decreased from approximately $747 million to $734.8 million. This was largely driven by an approximate $18 million decrease in the Contingency Reconfiguration subprogram forecast, which was slightly offset by an approximate $10.6 million increase in the Gas M&R subprogram forecast. The change in the Contingency Reconfiguration subprogram forecast from the second to third quarter of 2020 was predominantly driven by the removal of 117 13kV reclosers and 109 4kV reclosers. This was the result of a detailed assessment of each circuit to determine the current status reflecting updated system plans and changes or other work done subsequent to the ES 2 filing. The change in the Gas M&R forecast was predominantly driven by an increase to the forecast for the Central M&R project from $12.8 million as of the second quarter of 2020 to $23.9 million as of the third quarter of 2020. This forecast was validated and incorporated into the project's Study level estimate that was approved at $30.0 million (including R&C) in December 2020. The increase was driven by higher construction costs based on the engineer's 50% estimate, additional buildings and equipment required for the refined design, and additional project management, engineering, and licensing and permitting support not included in the prior estimate.

Given the prominence of the Electric Station Flood Mitigation subprogram, which represents over half of the total ES 2 Program spending, a summary of the projects within this subprogram is provided below in **Table 2 – ES 2 Electric Station Flood Mitigation Status as of September 30, 2020**.

Table 2 – ES 2 Electric Station Flood Mitigation Status as of September 30, 2020

Project	Total Estimate	Actuals to Date	% of Actuals to Estimate	Forecasted In-Service Date*
1. Academy Street	$11,800,000	$1,962,997	17%	10/25/2021
2. Clay Street	$42,000,000	$853,506	2%	1/12/2023 (↓)
3. Constable Hook	$5,300,000	$110,380	2%	TBD
4. Hasbrouck Heights	$18,000,000	$857,466	5%	12/2/2022 (↓)
5. Kingsland	$8,300,000	$283,143	3%	10/4/2023
6. Lakeside Avenue	$36,100,000	$529,588	1%	12/29/2023 (↓)
7. Leonia	$32,200,000	$1,785,365	6%	12/2/2022 (↓)
8. Market Street	$30,000,000	$12,273,747	41%	9/22/2021
9. Meadow Road	$9,000,000	$483,601	5%	9/21/2023
10. Orange Valley	$26,600,000	$358,732	1%	1/22/2024
11. Ridgefield 13kV	$25,500,000	$3,997,876	16%	10/7/2022 (↑)
12. Ridgefield 4kV	$20,200,000	$6,745,564	33%	6/30/2021
13. State Street	$45,100,000	$596,495	1%	9/23/2022
14. Toney's Brook	$19,700,000	$510,253	3%	4/21/2023
15. Waverly	$35,400,000	$1,465,452	4%	11/16/2023 (↑)
16. Woodlynne	$19,400,000	$665,906	3%	9/26/2023
**-Reflects the in-service date of the last major asset (e.g., switchgear), certain activities may take place after this date to support the final in-service date (i.e., when all customers are cutover).* (↑)-*Indicates the forecasted in-service date advanced from the prior quarter.* (↓)-*Indicates the forecasted in-service date slipped from the prior quarter.*				

As indicated in **Table 2**, the Market Street and Ridgefield 4kV projects continue to have the highest percentage of spend, which is reflective of these two projects advancing further into construction. Additionally, three of the stations (Academy Street, Kingsland, and State Street) had new estimates approved by the URB in July 2020. **Table 2** also shows that six of the sixteen projects in this subprogram had movement in the forecasted in-service date, with two advancing and four slipping. Of these six projects, only one (Lakeside Avenue) had movement more than 60 days, which is the threshold the IM applied during the original Energy Strong Program for evaluating the project schedules. Lakeside Avenue's delay is driven by the original property purchase location for the corresponding 69kV project falling through while a new potential property purchase is underway.

While early in the subprogram, the IM has found nothing to date that would jeopardize the ES 2 Program being completed on time and/or on budget.

As noted in the IM 2020 First Quarter Report, the IM conducts its assessment in accordance with Generally Accepted Government Auditing Standards (GAGAS, or more commonly referred to as the "Yellow Book" standards). The Yellow Book provides a framework for conducting performance management reviews/audit engagements with competence, integrity, objectivity, and independence that result in information used for oversight, accountability, transparency, and improvements of the audited programs and operations. On March 11, 2021, a draft report was presented and submitted to PSE&G, BPU Staff, and Rate Counsel. Per the Yellow Book, the transmittal of a draft report is intended to allow for review and comment by the audited entity and others to develop a fair, complete, and objective report. A summary of the comments on the draft report and the IM's responses are provided in **Appendix A – Draft Report Comments and Responses**. This **Appendix A** also identifies specific sections within this IM 2020 Third Quarter Report that have been edited, supplemented with additional information, or otherwise revised in response to the comments received.

II. Program Status

A. Key Decisions

In order to capture formalized key decisions regarding the ES 2 Program, PSE&G completes a "Record of Decision" (ROD) that includes a description of the decision; alternatives considered; the decision made; and rationale for the decision. The RODs are assessed by the IM as they are completed to review their rationale and any impact to the Program. In addition, the IM may request PSE&G complete a ROD to formalize a decision if such a decision has not yet been formalized through the ROD process.

The current and pending RODs as of the date of this IM 2020 Third Quarter Report are presented below in **Table 3 – ES 2 Records of Decisions**.

Table 3 – ES 2 Records of Decisions

Subprogram	Record of Decision	IM Comments
Electric Station Flood Mitigation	Academy Street & State Street Change in Mitigation Method	Reasonable and appropriate *(See Section II.B.1. in the IM 2020 First Quarter Report)*
Electric Station Flood Mitigation	Engineering Support for Energy Strong Program Projects	Reasonable and appropriate *(See Section II.B.2. in the IM 2020 First Quarter Report)*
Grid Modernization – Communication System	Wireless Communication Network	Reasonable and appropriate *(See **Section II.A.1**. below)*
Grid Modernization – Communication System	Substation Communication Cutover	Reasonable and appropriate *(See **Section II.A.2**. below)*

Subprogram	Record of Decision	IM Comments
Electric Station Flood Mitigation	Constable Hook, Lakeside, & Orange Valley Change in Mitigation Method	Pending review of additional information *(See **Section II.A.3**. below and **Section IV.B.**)*
Grid Modernization – Communication System	Fiber Scope	Reasonable and appropriate *(See **Section IV.A.** below)*
Grid Modernization – Communication System	Communication Retrofit of Replacement and non-ES-2 Units	Under initial review

1. Grid Modernization – Wireless Communication Network

The initial proposal for a wireless network solution included a self-contained network not reliant on any third-party carriers. On July 6, 2020, PSE&G recorded a ROD to detail why this was not a component of the selected FirstNet solution (this selection was initially discussed in the IM 2020 First Quarter Report).

One of the major components of the Grid Modernization subprogram is to create a high-speed wireless network across the PSE&G service territory. The network will be leveraged to communicate with a broad range of electric distribution field assets. PSE&G considers reliability, redundancy, and resilience to be key characteristics required for the communication platform. In order to achieve these objectives, required capabilities of the network include high-bandwidth transmission, minimal latency, industry standard encryption and authentication, and the ability to prioritize traffic based on hierarchical classification. In addition, PSE&G has determined that the communication network must communicate wirelessly with PSE&G's underground electric distribution network through manholes and vaults. PSE&G has further noted to the IM that full coverage in underground residential developments where there is no overhead electric construction is also required.

Alternatives considered include:

1. ABB Mesh Network – operating in unlicensed public spectrum;
2. Nokia LTE Network – operating based on a 2.5 GHz spectrum band;
3. AT&T LTE Network – operating based on a 2.3 GHz spectrum band;
4. Hybrid Solution: Multiple Vendors – proposing operating on proposed re-banding of 900 MHz spectrum; and
5. FirstNet: Public/Private Partnership with the Federal Government – operating on a 700 MHz spectrum band.

The initial proposal for how to create a high-speed wireless network across the PSE&G territory stated that the network would be completely self-contained and not reliant on any third-party public commercial communication carriers. The decision as discussed herein, determined this not to be a component of the selected alternative.

The total vendor costs including the network construct and the cost to purchase the spectrum (and not including the annual operating and maintenance costs) ranged from $28.7 million to $238 million, with the FirstNet being the lowest cost.

FirstNet is a nationwide wireless broadband network for first responders being built and deployed through a public-private partnership between the federal government and AT&T. FirstNet offers first responders a dedicated communications network built and customized to meet their needs. As a corporation in the utility industry that works with public safety and first responders during emergency responses, PSE&G qualifies as an Extended Primary FirstNet User.

As the Federal Government's choice to be the exclusive FirstNet network provider, AT&T is uniquely positioned to provide these services. AT&T is the only vendor that can properly configure, provision, and optimize the routers for use on their FirstNet network. Utilizing another vendor for these services was not considered due to AT&T's exclusive agreement with the Federal Government for management and oversight of the FirstNet network.

In its decision-making process, PSE&G, after an evaluation and analysis, determined that building a solely owned and operated communication network would not be prudent. The evaluation and analysis concluded that the cost to construct a privately owned network and the purchase of the required spectrum for LTE solutions was much higher than anticipated (with an estimated cost of $87 million to purchase spectrum up front or an estimated cost of $156 million to lease spectrum over 20 years). In addition, PSE&G's evaluation found that the time to obtain the proper permitting and network construction would add risk to the project timelines. While the ABB mesh solution operated on unlicensed frequencies the total number of network devices (30k), the cost to construct and maintain were determined by PSE&G not to be practical or easily maintainable.

Findings and Observations

- The IM finds that PSE&G conducted the appropriate due diligence, evaluation, and analysis in determining its solution to create a high-speed wireless network across the PSE&G electric service territory.
- While the FirstNet is the lowest cost solution, the solution also provides a network that is already being used by First Responders nationwide and was already vetted and chosen by the Federal Government.
- The decision will provide the required reliability, redundancy, and resiliency for the communication platform.

2. Grid Modernization – Substation Communication Cutover

On October 29, 2020, PSE&G recorded a ROD to cutover primary SCADA communications at substations where PSE&G's fiber backbone is installed but not yet connected and to install Nokia Hmc radios and cutover backup Substation communications to the new FirstNet Wireless Network (see related discussion in **Section II.A.1**).

Alternatives were considered which included:

1. Do nothing and maintain 3rd party fiber, "plain old telephone service" (POTS) lines and/or Verizon 4G as the primary and backup communication for SCADA at PSE&G's substations, and
2. Cutover primary SCADA communications to existing PSE&G fiber and backup communications to the new FirstNet Wireless Network.

The PSE&G 2018 filing included provisions to effectively eliminate PSE&G's reliance on POTS or Verizon 4G for critical operational communications. POTS lines were predominately provided by copper wire, which is unreliable during major weather events. In addition, Verizon no longer maintains POTS lines and is in the process of upgrading its network to fiber. PSE&G has noted that while the Verizon upgrade is expected to improve reliability, PSE&G would incur costs to connect the communication equipment and would still be reliant on a third-party provider.

The primary communication for the SCADA system at substations will be PSE&G's Fiber Backbone. Twelve substations that currently have the fiber backbone but have not yet been connected to the network will be cutover. The backup communication inside approximately 218 substations will have Nokia Hmc radios installed and will be cutover to the FirstNet solution, a public safety network dedicated, built, and customized for First Responders.

12 substations are currently included in the Fiber Cutover initiative including: Delair, East Riverton 2, Elizabeth Sub, Fairview, Henry Street, Mount Holly, Polk Street, Riverside-13kV, Spring Valley Rd, Tonnelle Avenue, Union City and West Orange Sub. The substation division where FirstNet wireless communication will be leveraged include: Central (61), Metro (61), Palisades (21) and Southern (75).

The IM inquired with PSE&G as to whether there is an estimate of the anticipated operational cost savings from the elimination of POTS lines and 4G. PSE&G responded that the estimated savings from the Substation Cutover program from disconnecting third party POTS lines and 4G are as follows:

- Annual O&M Communication Plan savings (218 substations): $17,668/year.
- One-time avoided O&M costs from eliminating the requirement of transitioning existing POTS lines over to Verizon Fiber (205 Substations): $773,670.

Findings and Observations

- By leveraging the existing PSE&G Fiber Backbone for primary communication to substations with SCADA will effectively eliminate PSE&G's reliance on POTS lines or Verizon 4G for any critical operational communications inside substations that contain SCADA.
- Transitioning all backup SCADA communications for 218 substation RTUs to the new FirstNet Wireless Network will ensure ruggedized communication redundancy to PSE&G substations in the event of a hardware or infrastructure failure.
- By making the changes, PSE&G will incur lower operational costs achieved by the elimination of the POTS lines and 4G and improved reliability of communication during storm events.
- The IM finds that PSE&G appropriately investigated the alternatives and making its decision focusing on the long-term reliability for customers while at the same time evaluating the operational cost for that long-term reliability.
- The IM further finds that PSE&G's decision will have both a one-time cost benefit as well as an annual savings benefit to customers.

3. Electric Station Flood Mitigation – Lakeside Avenue, Orange Valley, and Constable Hook Change in Mitigation Method

Following the previous change in mitigation method to the Academy Street and State Street substations (discussed in the IM 2020 First Quarter Report), PSE&G indicated that it continuously assesses and reassess it transmission and distribution projects to consider overall systems needs and scheduled improvements. From these reviews, PSE&G determined that the Lakeside Avenue, Orange Valley, and Constable Hook projects in the Electric Station Flood Mitigation subprogram presented opportunities to combine transmission and distribution work to gain project and cost efficiencies. On September 24, 2020, PSE&G formally notified the BPU and other parties of the proposed change in mitigation method for certain the Lakeside Avenue, Orange Valley and Constable Hook projects. The information presented within this **Section II.A.3.** is intended to convey the status of this decision as of the end of the third quarter of 2020, additional information reviewed by the IM as of the date of this report, but outside of the third quarter of 2020, is provided in **Section IV** and will also be discussed as appropriate in the next IM report.

In regard to the proposed mitigation changes at Lakeside and Orange Valley, from an overall perspective, PSE&G is upgrading network supply to Lakeside, Orange Valley, Toney's Brook, and South Orange (future) by establishing a 69kV transmission path in Essex County. PSE&G identified that it could combine transmission and distribution work at Lakeside and Orange Valley to gain project efficiencies and reduce the costs of these projects compared to if they were performed separately. The proposed change at Constable Hook is similar in regard to combining the project with other work, but instead of combining the flood mitigation distribution work with a transmission project, the distribution work is being combined with new capacity needs in the area and life cycle replacement needs at the neighboring Bergen Point substation.

Lakeside Avenue

For Lakeside Avenue, PSE&G originally contemplated constructing the distribution and transmission projects at the Lakeside Avenue location noted in the ES 2 filing, which included a rebuild at the existing location. Since the ES 2 filing, PSE&G determined that moving sites to a new property is a better option for several reasons as discussed below including that it would be more costly to perform the ES 2 project and the 69kV transmission project separately.

PSE&G learned in March 2018 that the adjacent property planned for purchase was not available, thus requiring a more complicated construction sequence and the need to temporarily relocate the 4kV switchgear. Further, due to the size of the Lakeside site, a customized design to accommodate both the distribution and transmission facilities on the property would be required as well as the use of contingencies and cutovers to increase safety, environmental and reliability risks.

Prior to the 101 N. Park alternative, PSE&G first considered a property at 338 Washington Street. However, in October 2019, PSE&G deemed that the Washington Street site was not viable due to environmental conditions. PSE&G continued to also consider the existing Lakeside Substation and at this time began to consider 101 N. Park as an option. PSE&G has noted that it expects to acquire the property at 101 N. Park Street in December 2021.

PSE&G has determined that since there is no existing utility operation on the new property located at 101 N. Park Street, the use of contingencies is not required and would allow the substation to be build based on a standard PSE&G design, which PSE&G notes would be better from an operational and maintenance standpoint.

The initial cost estimate of ES 2 project and the 69kV project were $36.1 million and $106 million, respectively. The current estimate, based on the refined study level estimates at the 101 N. Park Street location are $47.9 million and $93.6 million respectively, or an estimated combined savings on the projects of approximately $0.6 million.

PSE&G, in its response to RCR-INF-0001, provided the estimates for the ES 2 and 69kV Lakeside Avenue projects, including the estimate at filing, the Office Level estimate, and the current Study Level estimate, which has been reproduced below in **Table 4 – Lakeside Avenue Project Estimates**.

Table 4 – Lakeside Avenue Project Estimates

Estimate	69kV Project	ES 2 Project	Total
Initial Filing Estimate	$106.0 million	$36.1 million	$142.1 million
Office Level (existing site)	$120.4 million	$47.9 million	$168.3 million
Study Level (101 N. Park Street site)	$93.6 million	$47.9 million	$141.5 million

As shown in **Table 4**, while the combined total is a slight decrease of $0.6 million from the total authorized, the Lakeside Avenue Office Level estimate at the existing site showed an estimate of $47.9 million versus a Stipulation Filing estimate of $36.1 million. The updated Study Level estimate does not change the prior Office Level estimate for the Lakeside Avenue, thus resulting in an $11.8 million increase from the initial estimate for the ES 2 project regardless of site location.

PSE&G described the existing location design noting that the 4kV in the building is a unique design resulting in higher construction and operating costs. The proposed location at 101 N. Park would result in a 4kV standard switchgear arrangements that would have lower construction and operating costs. PSE&G in its response to RCR-INF-0001 described the design of the 101 N. Park Street substation and noted that it would not incorporate loads from other PSE&G substations.

While there is an approximate $11 million increase in the ES 2 Lakeside project estimate from the filing estimate, this increase is not directly tied to the change in mitigation method as it also was realized in the Office Level estimate for the original site. The bulk of the anticipated cost savings are in the 69kV transmission project, which shows a cost reduction of approximately $26 million to perform the work at 101 N. Park versus the original site.

Findings and Observations

- The IM finds that the proposed mitigation mitigates the impacts stemming from the unavailability of the adjacent property as originally planned (complexities to design and construction sequencing due to small site.)
- Construction risk (i.e., no buildings to remove or abatement necessary at new site) is reduced.
- The need for service contingencies is eliminated.
- The new substation at 101 N. Park Street would be a traditional design, thus improving operations and maintenance aspects of the station.
- While there is only marginal cost savings of approximately $0.6 million from the filing estimate by the joint execution of distribution and transmission projects, the mitigation measure avoids costlier option of performing these projects at the existing site-$168.3 million combined estimate at existing site versus $141.5 million combined estimate at the new site.

Orange Valley

With respect to Orange Valley, as with Lakeside Avenue, PSE&G identified transmission upgrades in the same area and determined that it would be less costly to perform both the ES 2 project and the transmission project jointly.

In the ES 2 filing, PSE&G contemplated rebuilding the substation on the existing location. PSE&G proposes to move from the existing Orange Valley site to a larger property approximately 120 feet from the existing station. The adjacent property is a larger property, close to the 230kV and will result in less operational risks as no service contingencies are required. By combining the work, PSE&G has determined that it will be able to avoid the need for a 7-Breaker 69 kV Ring Bus Switchgear that would be required if PSE&G proceeded with the construction at two separate stations. The proposed change thus consolidates the 230kV/69/4kV on a single property.

PSE&G, in its response to S-INF-0002, provided the estimates at filing and the current Office Level estimate for the ES 2 and 69kV Orange Valley projects, which has been reproduced below in **Table 5 – Orange Valley Project Estimates**.

Table 5 – Orange Valley Project Estimates

Estimate	69kV Project	ES 2 Project	Total
Initial Filing Estimate (original site)	$328.0 million	$26.6 million	$354.6 million
Office Level (new site)	$205.3 million	$21.0 million	$226.3 million

Due to the close proximity of the new Orange Valley Substation site and a simpler construction concept, PSE&G expects to complete the ES 2 project work with an expected savings of approximately $5 million from the original estimate. The original concept was based on an over/under design, where the new equipment needed to be constructed at the existing Orange Valley substation site, around and over the old equipment, while the old equipment remained in service. PSE&G noted that this required an intricate design of the foundations, additional steel, and also a detailed, possibly daily, outage schedule for the existing circuits during construction that greatly added to the cost and timing of the construction. The contemplated project and involves construction of the standard sheltered aisle switchgear on a previously cleared property. The cost of the switchgear is purported by PSE&G to be more accurate because it is based on recent switchgear purchases. Further, that recent information reduces the R&C estimate as the only outages will be for the cutover of the circuits, reducing the time spent coordinating construction. PSE&G noted that the common site costs (drainage, security, grading, fencing, etc.) are being shared, with 15% going towards the ES 2 project and 85% towards the larger transmission project. This ratio of common site costs between the ES 2 and 69kV Orange Valley projects was determined by PSE&G based on the ratio of each project's Study level estimated cost of station equipment and structures to the total estimate cost of station equipment and structures for both projects, which was then rounded to the nearest 5%.

PSE&G explained that in order to construct the 69kV network, PSE&G needs a 230/69kV switching station as a source station for the 69kV system. PSE&G discussed the alternatives considered including building Orange Valley on the existing property at 69/4kV and a separate 230/69kV switching station to supply the 69kV network. However, that alternative would require the construction of two separate stations as well as 69kV ring bus at Orange Valley. Building the two stations independently was noted to also require the construction of three new transmission circuits from the 230/69kV switching station to the 69/4kV station at Orange Valley. The elimination of the 69kV ring bus and the extension of three 69kV lines was further noted to be conservatively estimated at savings of $15-$20 million by consolidating the Orange Valley site.

PSE&G responded to RCR-INF-0002 providing a description of the design proposed for the new Orange Valley substation. Further, the Company noted in response to S-INF-0002 that it expected to acquire the nearby property in April 2021, and as of the date of this report PSE&G is still in purchase negotiations regarding the new property. PSE&G confirmed that the Orange Valley substation will not incorporate loads from other PSE&G substations and that the ES 2 distribution work is included in the $26.6 million estimate for the substation. Further, the land costs are also included in the Company's estimate of the combined cost savings of these transmission and distribution projects.

In response to RCR-INF-5 asking for an explanation as to whether the preliminary and/or phase 1 environmental assessment(s) have identified the presence of Underground Storage Tanks (USTs) associated with the current property owners, PSE&G responded that the Phase 1 assessment did identify USTs and that the seller will be responsible to remove all USTs present at the property.

Findings and Observations

- The IM finds that PSE&G conducted its due diligence in its evaluation of whether there would be benefits to customers in combing both the transmission and distribution projects with both consolidation of 230kV/69/4kV on a single property and less operational risk.
- The proposed mitigation also eliminates the need for service contingencies.
- PSE&G has identified savings of approximately $5 million to the Orange Valley ES 2 project resulting from this mitigation change from what was originally contemplated in the ES 2 filing.

Constable Hook

The original ES 2 filing contemplated rebuilding the substation on the existing location. The original project did not have associated transmission costs. Existing units were to be raised above the flood zone under the original project. PSE&G identified an opportunity to combine the flood mitigation work at Constable Hook with new capacity needed in the area based on ongoing development. The proposed change further would eliminate the existing station and construct at new station in the area of Constable Hook and supply the new load at the former Military Ocean Terminal. The new station would serve the existing Constable Hook customers with a storm-hardened facility. By consolidating into a single location, PSE&G determined there would be a better source of 69kV vs. 26kV for storms as well as lower long term operating costs. The existing circuits are very close to the new site and rearrangements can improve reliability at low cost.

The need for additional capacity in the area served by Constable Hook was determined in the spring of 2020 when new residential and electric vehicle growth was identified. The estimated load growth on the Bayonne Peninsula in the areas served by Constable Hook is 25-30MW.

In response to RCR-INF-0003, PSE&G described the design of the new Bergen Point substation noting that Bergen Point is an existing 26/4kV station and that there is no plan for a new station at that location. PSE&G discussed the alternative which was to upgrade the station to 69/13kV but that after evaluation, the alternative had higher costs versus the option of constructing a new Constable Hook station and retiring Bergen Point (approximately $203 million to upgrade the existing Bergen Point station versus approximately $187 million under the new Constable Hook option). The new Constable Hook proposed station to be located on Route 440 was noted to be a 69/13kV station including a 69kV ring bus, two 69/13kV transformers and 13kV sheltered isle switchgear and will eventually allow for the retirement of the Bergen Point substation at some point in the future. However, PSE&G noted that the new Route 440 property has not yet been acquired. Once acquired and upon completion of the new Constable Hook Station, the load will be gradually transferred over by approximately 2028.

PSE&G's Life Cycle subprogram in the ES 2 filing identified Class C stations as a priority over Class A/B stations due to Class C stations being outdoor facilities with metal-clad switchgear, which results in a higher associated risk and poorer performance. The Bergen Point substation is a Class A station where the 4kV equipment is enclosed in a masonry building and thus is a lower risk station per the Company's risk model assessment. However, the station was constructed in 1929 and thus is considered a lifecycle station as PSE&G noted in its ES 2 filing that the majority of the 4kV equipment at these facilities is the original equipment.

The Bergen Point substation and the new Constable Hook substation proposed to be built at the Route 440 property have the same electrical configuration. However, the primary cost difference in the projects is the requirement for a Gas Insulated Substation (GIS) at Bergen Point compared to an Air Insulated Substation (AIS) at the Route 440 property. The GIS station has a much smaller footprint required at the

Bergen Point location but is more expensive while the Route 440 property has the land needed to support an AIS configuration. This proposed change results in approximately $16 million in cost savings compared to upgrading the existing Bergen Point substation to a 69/13kV station ($202.9 million at original site versus $186.9 million at the new Route 440 site, including land and retirement at Bergen Point).

The IM sent a document request to PSE&G requesting 1) the detail of the new identified growth as compared to the prior capacity assumptions, 2) what prompted the review of the area capacity in the spring of 2020 and 3) were the PJM presentations planned for December 2020 and January 2021 conducted. While outside this IM 2020 Third Quarter Report, PSE&G's response to the IM's request confirmed that the new load growth is for the ongoing development on the Bayonne Military Ocean Terminal peninsula. PSE&G further stated that the new load expected to be served on the new substation is estimated at 20-30MW. The review of the area capacity and the new load identified was based on published information regarding development in the area. Regarding PJM, PSE&G noted that the December 2020 Needs Presentation was actually presented in November 2020 although the PJM Solutions presentation planned for January 2021 had not yet been presented as of the date of the response to the IM's questions.

PSE&G has also indicated that the proposed change also offers a planning system for future needs. The proposed change will also support the life cycle replacement needs at the neighboring Bergen Point. As discussed above, PSE&G found in its evaluation that the future elimination of Bergen Point would provide significant cost savings for both transmission and distribution upgrades.

PSE&G, in its response to S-INF-0002, provided the estimates at filing and the new estimate for the proposed new Constable Hook project, which has been reproduced below in **Table 6 – Constable Hook Project Estimates**.

Table 6 – Constable Hook Project Estimates

Estimate	Transmission Cost	Distribution Cost	Total
Initial Filing Estimate (original site)	N/A	$5.3 million	$5.3 million
Proposed Mitigation Change (new site)	$110.77 million	$11.1 million*	$121.87 million*
**-Includes $5.3 million related to the ES 2 flood mitigation project and $5.8 million associated with new substation load growth that is outside the ES 2 Program.*			

<u>Findings and Observations</u>

- The proposed relocation has several benefits including:
  - No change to the planned ES 2 costs in the original filing.
  - Reduction in long term costs of approximately $16 million.
  - Building for the future.
  - Reduced project risk as there is no need for service contingencies.
  - Flood risk is mitigated for Constable Hook Customers.
- The new station addresses identified new load growth, station age/condition at Bergen Point, and flood risk.
- As the existing Constable Hook circuits are very close to the new site, rearrangements can improve reliability at low cost.

- The IM Finds that PSE&G conducted the appropriate due diligence once it determined that by combing both the transmission and distribution projects that there would be multiple benefits to customers in addition to no change in the ES 2 proposed cost for Constable Hook and a reduction in the transmission project cost along with long term operating cost reductions.

Overall Initial Findings and Observations for the Mitigation Changes at Lakeside, Orange Valley, and Constable Hook

While additional information on these mitigation changes has been requested by the IM, based on the current available information the IM identified the pros and cons for each of these three substation mitigation changes in **Table 7 – Evaluation of Substation Mitigation Methods for Lakeside, Orange Valley, and Constable Hook ES 2 Projects** below.

Table 7 – Evaluation of Substation Mitigation Methods for Lakeside, Orange Valley, and Constable Hook ES 2 Projects

Substation & Mitigation Method	Pros	Cons
Lakeside Original Proposal: Raise & rebuild at existing location New Proposal: Relocate to new site	• Mitigates impacts stemming from unavailability of adjacent property as originally planned (complexities to design and construction sequencing due to small site). • Reduces construction risk (no buildings to remove or abatement necessary at new site). • Eliminates need for service contingencies. • New substation at 101 N. Park Street would be a traditional design, improving operations and maintenance aspects of the station. • Marginal cost savings from filing estimate with joint execution of distribution and transmission projects (approx. $0.6M), however avoids costlier option of performing these projects at existing site ($168.3M combined estimate at existing site vs. $141.5M combined estimate at new site).	• Adds some complexity due to integration of distribution and transmission projects.
Orange Valley Original Proposal: Raise & rebuild at existing location New Proposal: Relocate and consolidate 69kV/4kV on a single property	• ES 2 Project cost decreased from initial estimate of $26.6M to $21M. • Eliminates need for 69kV ring bus and 69kV transmission lines by consolidating to single site, resulting in savings of $15M-$20M. • Eliminates need for service contingencies.	• Adds some complexity due to integration of distribution and transmission projects.

Substation & Mitigation Method	Pros	Cons
	• Sharing of common site costs (fencing, grading, etc.) split between ES 2 Project (15%) and 69kV Project (85%) results in cost efficiencies.	
Constable Hook Original Proposal: Raise & rebuild at existing location New Proposal: Eliminate existing station and construct new station that supports new capacity needs in area and allows future elimination of Bergen Point substation	• New station addresses identified new load growth, station age/condition at Bergen Point, and flood risk at Constable Hook. • Existing Constable Hook circuits are very close to the new site, rearrangements can improve reliability at low cost. • No service contingencies required. • For Bergen Point, saves an estimated $16.2M compared with alternative of rebuilding and converting the existing Bergen Point substation from 26/4kV to 69/13kV.	• Adds some complexity due to integration of distribution and transmission projects.

As indicated in **Table 7**, there are multiple benefits identified for each of the mitigation changes proposed at Lakeside, Orange Valley, and Constable Hook, including offering cost efficiencies by combining work and reducing the risk of execution for each project by eliminating the requirement for service contingencies. The common downside to the mitigation changes across these projects was the marginal increase of complexity encountered with projects that have both distribution and transmission components. While having jointly executed transmission and distribution projects can gain cost efficiencies (e.g., having a common project management team for both projects, cost sharing among common site costs, etc.), it naturally adds a layer of complexity from the interdependencies on the separate projects (e.g., if work on the transmission project must be completed prior to certain distribution project work, or vice-versa, it presents the risk to the latter activities that the predecessor activities are not completed in time to support the overall project schedule). A well-planned project with a capable project management team can avoid or mitigate these risks associated with executing two interrelated projects, while also realizing the cost efficiency opportunities available.

B. Program Management

Beginning in July 2020, the IM began participating in a bi-weekly call with PSE&G to review its bi-weekly ES 2 Program Dashboard. As with the original Energy Strong Program, the Dashboard provides a mechanism for PSE&G to monitor and control activities to be completed in order to achieve key near-term milestones, including a focus on recently completed activities, any key issues, and other key metrics (e.g., installation targets) as appropriate. These calls have proven to be an effective way for the IM to stay informed on current and upcoming activities and to allow a venue for discussions between the IM and PSE&G on these activities and status updates and continue to be held on a recurring basis.

C. Cost Assignments

1. Costs of Removal (COR)

Costs of Removal (COR) generally include costs for such activities as environmental removal, removal of inside station equipment, structures, foundations, towers and fixtures, conductors and other electrical devices, poles and fixtures, transformers, plant demolition, foundations, and removal of underground conduit and other wiring. Generally, COR are charged to Accumulated Depreciation and are amortized and recovered through a component of depreciation expense. The specific method and amount of recovery is determined in gas and electric rate cases before the BPU.

Table 8 – ES 2 Costs of Removal as of September 30, 2020 below itemizes the charges to COR for the third, second and first quarters of 2020, the fourth quarter of 2019 and total Energy Strong COR to date. These amounts do not reflect any salvage value reductions, which have been de minimis in the Energy Strong program through September 30, 2020.

Table 8 – ES 2 Costs of Removal as of September 30, 2020

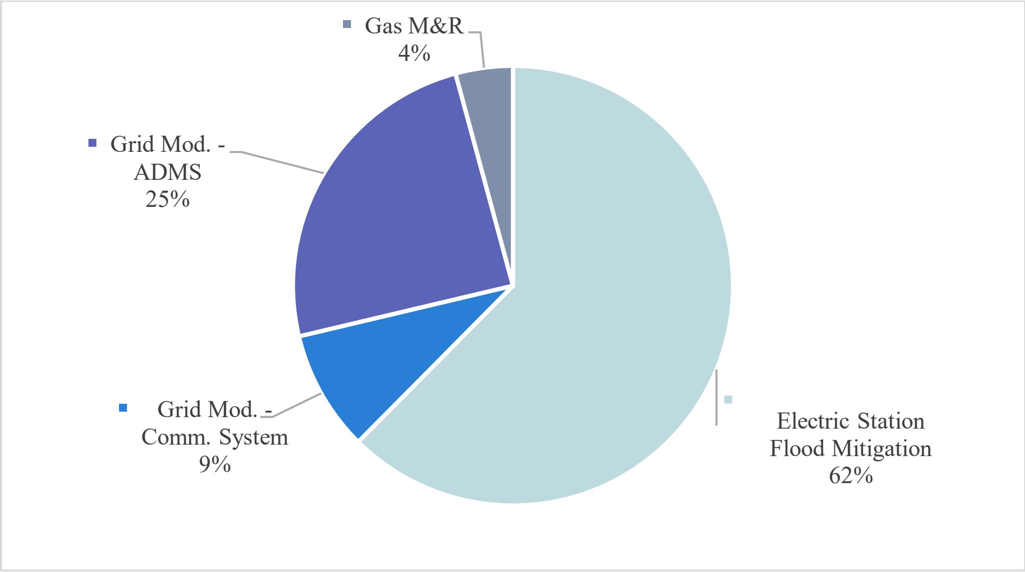
Subprogram	Q4 2019 COR	Q1 2020 COR	Q2 2020 COR	Q3 2020 COR	Total COR
Electric Station Flood Mitigation	**$0**	**$67,332**	**$468,989**	**$294,089**	**$830,410**
Contingency Reconfiguration	**$431,030**	**$616,752**	**$624,595**	**$250,228**	**$1,922,605**
Grid Modernization – Communications	**$0**	**$0**	**$1,495**	**$3,384**	**$4,879**
Grid Modernization - ADMS	**$0**	**$0**	**$0**	**$0**	**$0**
Electric Stipulated Base	**$0**	**$0**	**$0**	**$0**	**$0**
Gas M&R Station Upgrades	**$0**	**$0**	**$0**	**$0**	**$0**
Total	**$431,030**	**$684,084**	**$1,095,079**	**$547,701**	**$2,757,894**

COR charges during the third quarter of 2020 decreased from the second quarter by 50%. Electric Station Flood Mitigation COR decreased by 37% due to the removal of a significant portion of the wiring for the Market Street project during the second quarter. Contingency Reconfiguration COR for the third quarter decreased 60% from the second quarter as a result of correspondingly more preparation work (removing poles, conductors, etc.) done in the second quarter than in the third quarter in support of recloser installation and commissioning.

2. Construction Work-in-Progress (CWIP) & In-Service Transfers

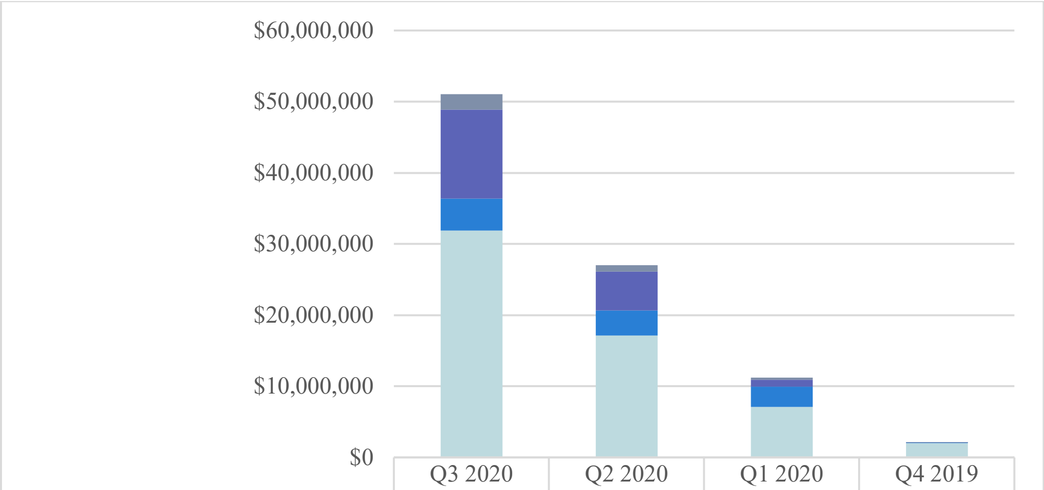
As of September 30, 2020, the Energy Strong CWIP balance was $51.0 million, compared to $27.0 million as of June 30, 2020. The largest components of September 30, 2020 CWIP were the elimination and conversion of the 4kV circuits at Market Street ($10.7 million) and Ridgefield substations ($6.5 million), and work associated with the ADMS ($12.5 million). The Electric Station Flood Mitigation subprogram comprises the largest component of total end of period CWIP outstanding, as depicted in **Figure 1 – ES 2 CWIP as of September 30, 2020** below.

Figure 1 – ES 2 CWIP as of September 30, 2020



In addition, **Figure 2 – ES 2 CWIP Balances by Subprogram as of September 30, 2020** below depicts the composition of end-of-quarter CWIP balances by subprogram for the third, second and first quarters of 2020, and the fourth quarter of 2019.

Figure 2 – ES 2 CWIP Balances by Subprogram as of September 30, 2020



	Q3 2020	Q2 2020	Q1 2020	Q4 2019
Gas M&R	2,149,077	951,151	290,933	52,661
Grid Mod. - ADMS	12,501,905	5,428,105	969,089	36,309
Grid Mod. - Comm. System	4,529,142	3,507,786	2,876,936	74,531
Electric Station Flood Mitigation	31,859,982	17,149,382	7,101,458	1,987,285

Transfers from CWIP to plant in service have totaled $3.6 million as of September 30, 2020, which came from Grid Modernization projects. It should be noted that work related to certain assets, such as the reclosers under the Contingency Reconfiguration subprogram, generally can be completed without being recorded through CWIP.

3. Allowance for Funds Used During Construction (AFUDC)

The amount of quarterly AFUDC recorded by the Company for each Energy Strong subprogram during the third, second and first quarters of 2020, the fourth quarter of 2019, and total Energy Strong AFUDC accrued to date, is shown below in **Table 9 – ES 2 AFUDC as of September 30, 2020**.

Table 9 – ES 2 AFUDC as of September 30, 2020

Subprogram	Q4 2019	Q1 2020	Q2 2020	Q3 2020	Total AFUDC
Electric Station Flood Mitigation	$9,887	$62,618	$191,807	$377,009	$641,321
Contingency Reconfiguration	$0	$0	$0	$0	$0
Grid Modernization – Communications	$225	$14,752	$60,073	$43,496	$118,546
Grid Modernization - ADMS	$96	$7,092	$28,474	$103,228	$138,890
Electric Stipulated Base	$0	$0	$0	$11,413	$11,413
Gas M&R Station Upgrades	$254	$2,590	$8,465	$19,385	$30,694
Total	$10,462	$87,052	$288,819	$554,531	$940,864

During the first quarter of each year, the AFUDC rate is reviewed for possible reset as it applies the current year based on updated capital structure and component cost data. For the year 2020, the new AFUDC rate was calculated to be 6.95%, using the capital structure and component costs as of January 31, 2020. In calculating the 2020 AFUDC rate, the Company used (i) a 4.02% embedded cost of long-term debt, (ii) a short-term debt rate of 1.86%, and (iii) a cost of equity of 9.60%.

Subsequent to the annual reset calculation referred to above, and during the course of each year, the AFUDC rate is also recalculated as it applies to each fiscal quarter. If the recalculated rate changes by 25 basis points from the rate then in effect, the rate is reset and retroactively applied to January 1 of that year. For the third quarter of 2020, based on data as of September 30, 2020, the recalculated weighted average AFUDC accrual rate (6.96%) did not meet this criterion to warrant changing from the annual rate (6.95%) in effect. Therefore, AFUDC was accrued during the third quarter of 2020 at the calculated rate of 6.95%.

AFUDC accrued for Energy Strong projects during the third quarter of 2020 increased significantly over AFUDC accrued during the second quarter of 2020 as the result of the increases in total average CWIP balances across all subprograms.

The IM observes that the Company's calculation of the AFUDC rate and its application is in accordance with both PSE&G's accounting policy and Plant Instruction 3(17) of the Federal Regulatory Commission's Uniform Systems of Accounts prescribed for public utilities.

The IM also notes that the relevant AFUDC information as it relates to third quarter 2020 Energy Strong project costs is consistent with the applicable dictates of the Stipulation entered into with respect to these Energy Strong projects. The IM will continue to review future Energy Strong AFUDC accruals for consistency with relevant provisions of the Stipulation for accounting and reporting purposes only, and not as a party to, or in expressing an opinion concerning, any rate proceedings.

4. Allocated Overheads

PSE&G follows a philosophy of allocating overhead costs, whether at the Service Company or from utility support organizations to the operating company or unit receiving the benefit, and ultimately, if appropriate, settling costs to individual assets. Where possible, services are charged directly to the entity receiving the benefit, but where direct charging of costs is not feasible, cost allocations from the Service Company to operating companies are prescribed in a BPU-approved schedule issued pursuant to a BPU order in July 2003. The Stipulation requires the Company to follow its current practices with regard to capitalized overheads.

For ES 2 electric and gas distribution projects, allocated overhead costs should primarily come from utility-related labor costs associated with administrative and supervisory personnel, labor and other costs associated with bargaining unit personnel, fringe benefits, materials handling costs, payroll taxes and depreciation expense. Shown below in **Table 10 – ES 2 Overhead Allocations as of September 30, 2020** are the allocated overhead costs charged to ES 2 projects for the third, second and first quarters of 2020, the fourth quarter of 2019, and total allocated overheads to date.

Table 10 – ES 2 Overhead Allocations as of September 30, 2020

Subprogram	Q4 2019	Q1 2020	Q2 2020	Q3 2020	Total Overhead Allocations
Electric Station Flood Mitigation	$286,953	$1,648,117	$3,560,216	$3,890,087	$9,385,373
Contingency Reconfiguration	$3,415,460	$4,692,085	$3,055,700	$3,350,239	$14,513,484
Grid Modernization – Communications	$12,074	$345,720	$548,017	$561,011	$1,466,822
Grid Modernization – ADMS	$10,603	$116,442	$91,786	$105,563	$324,394
Electric Stipulated Base	$0	$0	$0	$155,112	$155,112
Gas M&R Station Upgrades	$15,287	$52,836	$68,257	$78,452	$214,832
*Total**	$3,740,376	$6,855,199	$7,323,975	$8,140,465	$26,060,015

**-Note: total figures may not fully align due to rounding.*

The overwhelming majority of overhead costs allocated to ES 2 projects during the third quarter of 2020 were costs allocated from areas that support all utility distribution and transmission projects, including ES 2 projects. More specifically, most of the third quarter allocated costs reflect labor costs of supervisory, administrative and operations planning personnel, labor and other costs from bargaining unit personnel, and fringe benefits associated with these labor costs.

The IM believes these allocations represent no change in the Company's normal methodology of allocating overhead costs.

D. System Performance

1. Current Reporting Quarter Major Events

During the third quarter of 2020, PSE&G experienced a Major Event on August 4-13, 2020 stemming from a State of Emergency that was declared immediately ahead of Tropical Storm Isaias crossing the region and bringing heavy winds and rain to the area. Tropical Storm Isaias resulted in significant impacts to PSE&G's service territory, including over 800,000 customers experiencing extended service interruptions. **Table 11 – August 4-13, 2020 Major Event** indicates the restoration progress made on these service interruptions during the recovery efforts.

Table 11 – August 4-13, 2020 Major Event

Date (status as of 9AM)	Cumulative Customers Restored	Percentage of Customers Restored
August 5, 2020	377,709	49%
August 6, 2020	576,615	72%
August 7, 2020	666,990	83%
August 8, 2020	727,780	91%
August 9, 2020	751,464	94%
August 10, 2020	757,633	94%
August 11, 2020	766,748	96%
August 12, 2020	778,584	97%
August 13, 2020	797,077	99%
Total	803,026	100%

The outside plant damage resulting from Tropical Storm Isaias included over 12,000 locations comprised of tree damage, pole damage, transformer damage, line damage, and related impacts. This Major Event also resulted in 10 substations being shut down (one of which was shut down a second time during restoration efforts), none of these substations is part of the Electric Station Flood Mitigation subprogram of either the original Energy Strong Program or the current ES 2 Program, additionally none of these substations experienced damage or flood intrusions as a result of Tropical Storm Isaias. The IM received PSE&G's report on the performance of its Energy Strong and ES 2 Program investments from this Major Event, which shows the System Average Interruption Duration Index (SAIDI) for the affected circuits. This information is reproduced as follows in **Table 12 – Q3 2020 Major Event Performance of Energy Strong/ES 2 Investments**.

Table 12 – Q3 2020 Major Event Performance of Energy Strong/ES 2 Investments

Circuit	5 Year Baseline SAIDI*	Report Quarter SAIDI*
ALD 8015	0.12276	**0.53760**
ALD 8026	0.07735	0.05740
BAO 8003	0.00193	**0.24119**
BEF 8013	0.02065	**0.75490**
BEF 8015	0.00433	**0.10078**
BEF 8016	0.01430	**0.79704**
BEM 8001	0.00675	**0.01779**
BEN 8012	0.22864	0.15087
BEN 8015	0.01246	**0.09879**
BEN 8016	0.01934	0.00153
BRU 8011	0.04127	**0.17136**
BRU 8012	0.01648	**0.29860**
CAS 8001	0.02438	**0.83779**
CED 8011	0.05594	**2.00873**

Circuit	5 Year Baseline SAIDI*	Report Quarter SAIDI*
CED 8016	0.07119	**2.65822**
CED 8021	0.10724	**0.25793**
CIN 8005	0.04256	**0.15680**
CIN 8032	0.32648	**1.21326**
CIN 8033	0.14578	0.06644
CIN 8043	0.18459	0.00432
CLF 8012	0.00401	**0.29500**
CLF 8013	0.00064	**0.18687**
CLF 8023	0.00895	**0.10659**
CLK 8022	0.06677	**0.20949**
CLK 8024	0.01526	**0.26509**
CON 8001		0.00000
CRX 8003	0.07703	0.02497
CUT 8006	0.59550	0.06186

Circuit	5 Year Baseline SAIDI*	Report Quarter SAIDI*
CUT 8010	0.49117	0.00000
DAY 8002	0.03617	**0.24408**
DFD 8041	0.20440	**0.28663**
DVB 8013	0.00455	0.00016
EAT 8011	0.09890	**2.20796**
EAT 8022	0.08703	**0.14950**
FAW 8022	0.03342	0.02998
FAW 8026	0.00902	**0.83953**
FED 4004		**0.00577**
GBK 8021	0.06208	0.02153
GBK 8022	0.01054	**0.27631**
GET 4009	0.08973	**0.09359**
HAT 8012		**0.10390**
HAT 8023	0.01869	**0.09183**
HAT 8035	0.04291	**0.11367**
HAW 8032	0.22973	**0.33843**
HID 8043	0.06432	**0.11773**
HID 8044	0.08229	**1.21633**
HNC 8015	0.15427	**0.09234**
HNC 8021	0.02280	0.00358
HNC 8024	0.43454	0.01301
HOM 8001	0.06027	0.01298
JAC 8021	0.00477	**0.08572**
JAC 8023	0.05394	**0.65765**
JAC 8043	0.09794	**0.15996**
KIL 8023		0.00000
KIL 8024	0.01504	0.00244
KIL 8031		**0.11829**
KIL 8034	0.44870	0.03134
KIL 8041	0.02511	0.00000
KIL 8044	0.03622	**0.04250**
KIN 8015	0.00194	**1.39884**
KIN 8022	0.01206	**0.56080**
KUL 8022	0.00371	**1.84145**
KUL 8023	0.00582	**0.23170**
KUS 8004	0.00500	**0.32039**
KUS 8042	0.07830	**0.15411**
KUS 8045	0.02505	**0.06255**
LAF 8013	0.00125	**0.07663**
LAU 8021	0.44101	0.13512
LAU 8023	0.82844	0.01479
LAU 8025	0.02009	0.01410
LAU 8034	0.60195	0.04268
LAU 8035	0.29567	0.14706
LAW 8014	0.03705	**0.48862**

Circuit	5 Year Baseline SAIDI*	Report Quarter SAIDI*
LAW 8016	0.14895	0.01929
LCE 8003	0.15926	0.05434
LCE 8032	0.30801	0.13079
LCE 8043	0.10606	**0.45190**
LCE 8046	0.01692	0.00753
LEO 8006	0.07368	**0.14976**
LEO 8032	0.00287	**0.72771**
LEO 8043	0.07891	**2.20942**
LEV 8002	0.06064	0.05044
LEV 8006	0.23842	**0.57946**
LEV 8012	0.25318	**0.32241**
MAD 8015	0.15514	0.00167
MAD 8031	0.45221	0.08238
MAI 8013	0.05318	**0.84551**
MAR 8006	0.06359	0.00000
MAR 8017	0.45014	**0.68220**
MAY 8024	0.00558	**0.09533**
MDF 8012	0.58371	**0.88377**
MDF 8023	0.26488	0.09510
MEA 8012		**0.04784**
MON 8003	0.27132	0.10203
MTL 8013	0.02134	**0.24147**
NBS 8011	0.01516	0.08749
NED 8015	0.09467	**0.13141**
NED 8024		0.00000
NEW 8014	0.01839	**0.05537**
OAK 4004	0.05636	**0.20790**
OAK 4008		**0.24635**
PLI 8003	0.00215	**1.26948**
POH 8021	0.07655	0.00619
RFL 8032	0.12446	**0.15639**
RFL 8034	0.04180	**0.97069**
SDH 8023	0.00860	**0.03903**
SDH 8026	0.01685	**0.15920**
SDH 8031	0.01726	0.01387
SDH 8034		**0.07454**
SMV 8013		**0.00592**
SMV 8021		0.00000
SMV 8023	0.01943	0.00120
SPF 8012	0.78752	**1.81747**
SUN 8022		**0.02479**
TNY 4001	0.02964	0.00638
TUR 8015	0.00704	**0.33184**
WAV 4018	0.02277	**0.79233**
WEW 8011	0.18034	**3.48139**

Circuit	5 Year Baseline SAIDI*	Report Quarter SAIDI*
WEW 8025	0.00255	**0.00665**
WEW 8033	0.03506	**0.08274**
WFL 8041	0.14394	**0.76889**

Circuit	5 Year Baseline SAIDI*	Report Quarter SAIDI*
WOR 8021		0.00000
**-SAIDI calculations are in minutes.*		

In the circuit data above, the bolded figures designate the circuits where performance during this Major Event was worse than the 5-year Major Event average SAIDI for the circuit; in addition, blank cells indicate no outage in the 5-year window, while "0.00000" indicates an outage, but the value is beyond five decimal points. As indicated above, a substantial amount of the affected circuits experienced outages beyond the 5-year Major Event average. This performance is reflective of the severity of the storm, which in terms of the 803,026 customers impacted was the third largest storm in PSE&G's history (behind only Hurricane Sandy, with 2,012,612 customers impacted, and Hurricane Irene with 872,942 customers impacted).

In response to comments received on the IM's draft 2020 Third Quarter Report, a comparison of the average CAIDI and SAIFI of circuits impacted by Tropical Storm Isaias is provided in **Table 13 – Tropical Storm Isaias Average Circuit Performance**. This **Table 13** compares the affected circuits from this Major Event by circuits improved during the original Energy Strong Program, circuits improved during ES 2 prior to this Major Event, and circuits not improved by either the original Energy Strong Program or ES 2.

Table 13 – Tropical Storm Isaias Average Circuit Performance

	Average SAIFI during Tropical Storm Isaias	Average CAIDI during Tropical Storm Isaias
Circuits Improved as part of the original Energy Strong Program	0.0005	1,231.47
Circuits Improved as part of the ES 2 Program*	0.0004	1,633.75
Other Circuits not part of either Energy Strong Program	0.0004	1,550.23
**-Circuits improved prior to the start of this Major Event on August 4, 2020*		

This Tropical Storm Isaias Major Event is compared to prior Major Events with similar numbers of customers impacted in **Table 14 – Tropical Storm Isaias Comparable Major Events**.

Table 14 – Tropical Storm Isaias Comparable Major Events

Storm End Date	Major Event Description	Customers Impacted	SAIDI*
9/3/2011	Hurricane Irene	872,492	454.51
8/13/2020	Tropical Storm Isaias	803,026	313.01
11/6/2011	Wet Snowstorm	636,898	380.52
3/19/2010	Nor'easter Storm	607,403	300.01
**-SAIDI calculations are in minutes.*			

As shown in **Table 14**, the SAIDI results from Tropical Storm Isaias compared to similar pre-Energy Strong Major Events demonstrate improved restoration times. This is particularly evident in the relatively close SAIDI results from Tropical Storm Isaias and the March 2010 Nor'easter Storm, despite Tropical Storm Isaias affecting nearly 200,000, or 32%, more customers.

In response to comments received on the IM's draft 2020 Third Quarter Report, additional information on the circuit-level performance of Energy Strong/ES 2 investments in the Major Events compared in **Table 14** has been included in **Table 15 – Tropical Storm Isaias Comparable Major Events Circuit-Level Performance**. Note that many of the circuits listed in **Table 15** were not impacted by each of these four Major Events, with the blanks in the table reflect no outage for a given circuit in the corresponding Major Event.

Table 15 – Tropical Storm Isaias Comparable Major Events Circuit-Level Performance

Circuit	Mar. 2020 Nor'Easter	Sep. 2011 Hurricane Irene	Nov. 2011 Wet Snow Storm	Aug. 2020 Tropical Storm Isaias
	*Major Event SAIDI**			
ALD 8015	0.0004	0.1056	0.0963	0.53760
ALD 8026	-	0.8265	0.9628	0.05740
BEM 8001	-	0.0555	-	0.01779
BEN 8012	0.0344	1.7619	0.0252	0.15087
BEN 8015	0.0326	0.9115	-	0.09879
BRU 8011	-	-	0.012	0.17136
BRU 8012	0.4574	0.2228	0.2629	0.29860
CAS 8001	-	1.4604	-	0.83779
CED 8011	0.8668	0.0379	1.754	2.00873
CED 8016	0.8873	0.029	0.4095	2.65822
CED 8021	0.3964	-	-	0.25793
CIN 8032	0.0007	-	-	1.21326
CIN 8043	0.1052	0.0618	-	0.00432
CLF 8012	-	0.0838	0.3021	0.29500
CLF 8013	0.048	0.0198	0.0482	0.18687
CLF 8023	-	0.048	-	0.10659
CLK 8022	-	0.2108	-	0.20949
CON 8001	0.0052	-	-	0.00000
CRX 8003	0.0041	-	-	0.02497
CUT 8006	0.0069	-	-	0.06186
DAY 8002	0.0753	0.2237	-	0.24408
DFD 8041	-	0.5275	-	0.28663
EAO 4023	-	0.0585	0.2581	0.81003
EAT 8011	0.2677	0.1536	0.5189	2.20796
EAT 8022	0.0859	-	0.1279	0.14950
FAR 4006	-	-	0.8247	0.12767
FAW 8022	-	0.0459	0.4234	0.02998
GBK 8021	-	1.4263	-	0.02153
GBK 8022	-	0.0252	0.0432	0.27631
HAT 8012	0.4581	0.1317	0.1638	0.10390
HAT 8023	0.0733	-	0.0219	0.09183

Circuit	Mar. 2020 Nor'Easter	Sep. 2011 Hurricane Irene	Nov. 2011 Wet Snow Storm	Aug. 2020 Tropical Storm Isaias
	Major Event SAIDI*			
HAT 8035	0.255	1.7015	0.0885	0.11367
HAW 8032	0.0171	0.1088	0.245	0.33843
HNC 8015	-	0.0174	-	0.09234
HNC 8021	-	-	0.0172	0.00358
HNC 8024	-	0.21	0.8303	0.01301
HOM 8032	-	0.2088	0.3644	0.01298
JAC 8021	0.0357	-	-	0.08572
JAC 8023	0.0288	0.0072	0.1368	0.65765
JAC 8043	-	-	0.4851	0.15996
KIL 8023	-	0.0872	-	0.00000
KIL 8024	0.0538	0.0618	-	0.00244
KIL 8034	-	0.0799	-	0.03134
KIL 8041	-	0.0676	-	0.00000
KIL 8044	-	0.1195	-	0.04250
KIN 8015	-	1.3535	0.178	1.39884
KIN 8022	2.0138	0.1997	1.2249	0.56080
KUL 8023	0.0014	-	0.0884	0.23170
KUS 8004	-	0.1003	0.0199	0.32039
KUS 8042	0.0002	0.8528	-	0.15411
KUS 8045	1.6032	0.3397	0.1158	0.06255
LAU 8021	0.0046	0.0114	4.3783	0.13512
LAU 8023	-	-	0.7065	0.01479
LAU 8025	0.0257	1.2566	0.1612	0.01410
LAU 8034	-	0.1055	0.9157	0.04268
LAU 8035	-	-	0.2887	0.14706
LAW 8016	0.0998	1.266	0.0014	0.01929
LCE 8003	0.0213	0.0657	-	0.05434
LCE 8032	0.1052	0.1621	0.0438	0.13079
LCE 8043	-	0.0231	0.0206	0.45190
LCE 8046	-	0.9558	-	0.00753
LEO 8006	0.0848	0.1848	0.2159	0.14976
LEO 8032	0.6277	0.6999	2.0718	0.72771
LEO 8043	0.1952	0.6377	2.5768	2.20942
LEV 8002	0.0811	-	-	0.05044
LEV 8006	0.2888	0.2704	0.0043	0.57946
LEV 8012	0.0929	0.1373	-	0.32241
MAD 8015	0.0864	-	-	0.00167
MAD 8031	0.0014	-	-	0.08238
MAI 8013	0.9225	0.1033	0.4569	0.84551

Circuit	Mar. 2020 Nor'Easter	Sep. 2011 Hurricane Irene	Nov. 2011 Wet Snow Storm	Aug. 2020 Tropical Storm Isaias
	Major Event SAIDI*			
MAR 8017	-	1.6707	-	0.68220
MAY 8024	0.2847	-	0.15	0.09533
MDF 8012	-	0.125	-	0.88377
MDF 8023	-	0.3549	-	0.09510
MEA 8012	0.0045	0.0672	-	0.04784
MNT 4010	0.0232	0.7827	1.0713	0.06828
MON 8003	-	0.364	-	0.10203
MTL 8013	-	0.0339	0.0073	0.24147
NBS 8011	-	0.5399	0.1007	0.08749
NED 8015	0.0822	0.7023	0.5621	0.13141
NED 8024	-	1.1162	0.3146	0.00000
NEW 8014	0.2358	0.8618	2.0776	0.05537
OAK 4004	0.0052	-	0.4166	0.20790
OAK 4008	-	-	0.5203	0.24635
PLI 8003	-	-	0.0094	1.26948
RFL 8032	0.0134	0.0158	0.7329	0.15639
RFL 8034	-	-	0.0482	0.97069
SDH 8023	-	0.3303	-	0.03903
SDH 8026	1.8938	1.8557	0.0426	0.15920
SDH 8031	0.0135	0.4626	-	0.01387
SDH 8034	0.0008	0.3125	-	0.07454
SMV 8013	-	1.7671	0.0198	0.00592
SMV 8021	-	0.4698	-	0.00000
SMV 8024	-	2.0881	-	0.00120
SPF 8012	-	1.527	0.1048	1.81747
SPF 8022	0.0522	0.0842	2.4832	0.02479
TNY 4001	-	-	0.0968	0.00638
TUR 8015	-	0.0522	2.606	0.33184
WAV 4018	-	0.3968	-	0.79233
WEW 8011	-	2.5084	2.4866	3.48139
WEW 8025	0.0264	0.1207	-	0.00665
WEW 8033	1.6317	-	2.5859	0.08274
WFL 8041	-	-	0.1619	0.76889
WOR 8021	0.0163	-	-	0.00000
**-SAIDI calculations are in minutes.*				

2. *Prior Major Events*

As noted in the IM's 2020 Second Quarter Report, PSE&G experienced a Major Event on June 3-7, 2020 stemming from a derecho and severe thunderstorms that primarily affected its Southern Division. These series of storms led to 257,209 PSE&G customers experiencing service interruptions, with 246,075 of those customers located in the Southern Division. The IM 2020 Second Quarter Report provided the detailed circuit-level performance during this Major Event and in response to questions raised by the IM, PSE&G has provided the IM with additional information on the performance of Energy Strong/ES 2 investments. **Table 16 – Performance of Energy Strong/ES 2 Investments in Q2 2020 Major Event** below reproduces parts of the information originally provided in the IM 2020 Second Quarter Report, specifically identifying those circuits involved in the Major Event that were improved through investments made in either the original Energy Strong Program or the current ES 2 Program.

Table 16 – Performance of Energy Strong/ES 2 Investments in Q2 2020 Major Event

Circuit	5-Year Major Event Average SAIDI*	Q2 2020 Major Event SAIDI*	Q2 2020 Major Event SAIDI Explanation
CIN 8032	0.32648	1.13907	The history for CIN 8032 is spread over eight different events with an average storm SAIDI (34) approximately one-third of the June 2020 event (90). As such, response to these individual events on average would be shorter. In addition to the significantly larger scale of the June 2020 event, the outage was caused by a whole tree failure, which takes longer to restore due to the tree clearing required before service can be restored.
CLK 8022	0.06677	0.21086	The history for CLF 8022 is three low customer count fuse jobs (<70 customers) along with one tree related outage. The June 2020 event SAIDI was driven by a tree related outage on the mainline (578 customers) which required a tree crew to remove the tree before restoration.
KUS 8004	0.00500	0.03236	KUS 8004 experienced three fuse events (average customers of 60) over the course of three smaller storm events. The June 2020 outage was a fuse event (110 customers) caused by a tree failure. Given the scale of the event, this 110-customer job would have been lower priority as compared to jobs with higher customer counts, and thus the outage would have a longer duration. Tree removal would have increased restoration time as well.
LAW 8014	0.03705	1.01225	The history for LAW 8014 is based primarily on a tree limb on the mainline during a much smaller storm event. June 2020 event had five different tree damage locations including one with a broken pole. Scale of the damage significantly higher when compared to history.
MAD 8015	0.15514	0.95230	The history for MAD 8015 includes eight events, five lower count fuse jobs and three mainline jobs of various causes. The June 2020 event SAIDI was primarily due to a section three outage. The scale of the storm event would have delayed this restoration as jobs with higher customer counts (i.e., full circuit lockouts) would have gone first.
MDF 8023	0.26488	0.54601	The history for MDF 8023 is comprised of seven events over three different storms with tree issues being the primary outage driver. The June 2020 events was two whole tree failures. The five-year average history lowers the SAIDI result compared to the single event.
**-SAIDI calculations are in minutes.*			

As indicated in **Table 16**, the circuits with Major Event performance worse than the five-year average from the June 2020 Major Event were primarily the result of lengthier outages during this Major Event resulting from downed trees along with a couple of the circuits having low customer counts and thus had lower priority in the restoration efforts over higher customer circuits that were impacted.

III. Project Status

A. Electric Station Flood Mitigation

A summary of the subprogram plan as of September 30, 2020 is provided below in **Table 17 – ES 2 Electric Station Flood Mitigation Subprogram Milestone Schedule as of September 30, 2020**.

Table 17 – ES 2 Electric Station Flood Mitigation Milestone Schedule as of September 30, 2020

Project	Plan Status Point	2019		2020				2021				2022				2023					2024
		Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4		
1. Academy Street	Dec. 2019		KO					C					IS		CO					*December 31, 2023 - ES 2 Program End Date*	
	Sep. 2020		KO		C						IS		CO								
2. Clay Street	Dec. 2019	*Schedule Under Development*																			
	Sep. 2020			KO							C					IS					CO (Q2)
3. Constable Hook	Dec. 2019	*Schedule Under Development*																			
	Sep. 2020	*Schedule Under Development*																			
4. Hasbrouck Heights	Dec. 2019		KO						C						IS		CO				
	Sep. 2020		KO							C					IS		CO				
5. Kingsland	Dec. 2019			KO				C			IS		CO								
	Sep. 2020			KO										C					IS		CO (Q2)
6. Lakeside Avenue	Dec. 2019				KO				C										IS		CO (Q2)
	Sep. 2020	*Schedule Under Development**																			
7. Leonia	Dec. 2019	*Schedule Under Development*																			
	Sep. 2020			KO		C									IS			CO			
8. Market Street	Dec. 2019			KO				C	OS		CO										
	Sep. 2020			KO					C	OS		CO									
9. Meadow Road	Dec. 2019	*Schedule Under Development*																			
	Sep. 2020			KO											C			IS			CO (Q2)
10. Orange Valley	Dec. 2019	*Schedule Under Development*																			
	Sep. 2020					KO										C					IS (Q1); CO (Q3)
11. Ridgefield 13kV	Dec. 2019			KO	C										IS		CO				
	Sep. 2020			KO	C										IS		CO				
12. Ridgefield 4kV	Dec. 2019			KO						C	OS			CO							
	Sep. 2020			KO	C				OS		CO										
13. State Street	Dec. 2019		KO					C								IS					CO (Q1)
	Sep. 2020		KO						C					IS							CO (Q1)
14. Toney's Brook	Dec. 2019			KO						C									IS		CO (Q2)
	Sep. 2020			KO										C			IS				CO (Q2)
15. Waverly	Dec. 2019	*Schedule Under Development*																			
	Sep. 2020			KO			C												IS		CO (Q2)
16. Woodlynne	Dec. 2019		KO												C				IS		CO (Q2)
	Sep. 2020		KO												C			IS			CO (Q2)

Project	Plan Status Point	2019		2020				2021				2022				2023				2024
		Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	

Legend: KO = Kickoff; C = Construction; IS = Fully In-Service (major assets in-service); OS = Out-of-Service (if eliminated); CO = Closeout
-Actuals are indicated with an underline (Note: for the Market Street and Ridgefield 4kV projects, outside plant construction began in the first quarter of 2020, the construction milestone indicated on this chart reflects inside plant construction).
***-The Lakeside Avenue project had a schedule previously developed, but due to the proposed mitigation method change that contemplates relocating the substation, the schedule is now being revised and updated.**

A summary of the subprogram status as of the end of the third quarter of 2020 is provided below **Table 18 – ES 2 Electric Station Flood Mitigation Summary Status as of September 30, 2020**.

Table 18 – ES 2 Electric Station Flood Mitigation Summary Status as of September 30, 2020

Activity	Total # of Projects	Specific Projects
Kickoff Meeting	13	Academy Street; Clay Street; Hasbrouck Heights; Kingsland; Leonia; Market Street; Meadow Road; Ridgefield 13kV; Ridgefield 4kV; State Street; Toney's Brook; Waverly; Woodlynne
Key Drawing Review	13	Academy Street; Clay Street; Hasbrouck Heights; Kingsland; Leonia; Market Street; Meadow Road; Ridgefield 13kV; Ridgefield 4kV; State Street; Toney's Brook; Waverly; Woodlynne
Scope Locked	13	Academy Street; Clay Street; Hasbrouck Heights; Kingsland; Leonia; Market Street; Meadow Road; Ridgefield 4kV; Ridgefield 13kV; State Street; Toney's Brook; Waverly; Woodlynne
Major Equipment POs	14*	Academy Street; Clay Street; Hasbrouck Heights; Kingsland; Leonia*; Meadow Road; Ridgefield 13kV*; State Street; Toney's Brook; Waverly*; Woodlynne
A/E Contract Award (or selection of PSE&G internal engineering)	14	Academy Street[1]; Clay Street[1]; Hasbrouck Heights[1]; Kingsland[2]; Lakeside Avenue[3]; Leonia[2]; Market Street[2]; Meadow Road[2]; Ridgefield 13kV[2]; Ridgefield 4kV[2]; State Street[2]; Toney's Brook[3]; Waverly[3]; Woodlynne[1]
Construction Start^	6	Academy Street; Leonia; Market Street; Ridgefield 4kV; Ridgefield 13kV; Waverly

**-Three of the listed projects (Leonia, Ridgefield 13kV, and Waverly) have two switchgears, thus the current count reflects 14 switchgears at 11 substations.*
[1]-Indicates Burns & McDonnell is serving as the A/E.
[2]-Indicates PSE&G internal resources are serving as the A/E.
[3]-Indicates Black & Veatch is serving as the A/E.
^-Includes inside plant and/or outside plant construction.

Beyond the key activities summarized in **Table 18** above, **Table 19 – ES 2 Electric Station Flood Mitigation Upcoming Activities for Q4 2020** summarizes the planned activities for each project during the fourth quarter of 2020, including any carryover of activities from earlier periods.

Table 19 – ES 2 Electric Station Flood Mitigation Upcoming Activities for Q4 2020

Station	Upcoming Activities for Q4 2020	Carryover Activities from Q3 2020
1. Academy Street	• Electrical construction start • Switchgear delivery to site • 90% estimate completion	• None
2. Clay Street	• Vendor drawings received for final switchgear arrangement • Detailed engineering start	• License and permit package submitted

Station	Upcoming Activities for Q4 2020	Carryover Activities from Q3 2020
3. Constable Hook	• Remains in planning/origination stages	• Remains in planning/origination stages
4. Hasbrouck Heights	• Constructability review • Civil and electrical drawings issued for construction (IFC)	• None
5. Kingsland	• Switchgear delivery to Ridgefield 13kV site (as contingency switchgear, planned to be used for Kingsland following Ridgefield 13kV completion)	• None
6. Lakeside Avenue	• Project kickoff • A/E purchase order issued • License and permit design start	• Transitioning from planning/origination stages
7. Leonia	• Switchgear delivery to site • Phase 1/contingency electrical purchase order issued • Phase 3 civil and electrical drawings IFC	• None
8. Market Street	• Civil demolition construction purchase order issued • 90% estimate completion	• License and permit package submitted
9. Meadow Road	• No major activities	• None
10. Orange Valley	• Release key drawings for detailed engineering design	• Transitioning from planning/origination stages
11. Ridgefield 13kV	• Phase 1 civil, controls, and electrical drawings IFC	• Civil contingency construction completion
12. Ridgefield 4kV	• Railroad permission to proceed received • Complete outside plant underground civil construction	• None
13. State Street	• Civil construction purchase order issued	• None
14. Toney's Brook	• 70% estimate completion • Civil construction purchase order issued	• None
15. Waverly	• Civil and electrical drawings IFC • Vendor drawings received for final switchgear controls • Civil construction out for bid • Major licenses and permits issued	• None
16. Woodlynne	• Constructability review • Civil and electrical construction purchase orders issued	• Civil and electrical drawings IFC

The current project estimates, including base and R&C amounts, is shown below in **Table 20 – ES 2 Electric Station Flood Mitigation Project Cost Status as of September 30, 2020**. **Table 20** also shows the current estimate level based on PSE&G's estimating processes and as approved by the URB, the actual spend and percentage of actuals to estimate as of the end of the third quarter of 2020, and the forecasted in-service date.

Table 20 – ES 2 Electric Station Flood Mitigation Project Cost Status as of September 30, 2020

Project	Estimate Level	Base	Risk & Contingency	Total	Current Forecast	Actuals to Date	% of Actuals to Estimate
1. Academy Street	Conceptual	$9,900,000	$1,900,000	$11,800,000	$9,972,315	$1,962,997	17%
2. Clay Street	Study	$34,800,000	$7,200,000	$42,000,000	$36,589,865	$853,505	2%
3. Constable Hook	Office	$3,900,000	$1,400,000	$5,300,000	$3,894,313	$110,379	2%
4. Hasbrouck Heights	Study	$14,900,000	$3,100,000	$18,000,000	$17,894,211	$857,466	5%
5. Kingsland	Study	$5,400,000	$2,900,000	$8,300,000	$6,418,540	$283,143	3%
6. Lakeside Avenue	Office	$26,800,000	$9,400,000	$36,100,000	$26,800,000	$529,587	2%
7. Leonia	Study	$27,700,000	$4,500,000	$32,200,000	$30,442,204	$1,785,366	6%
8. Market Street	Conceptual	$26,700,000	$3,300,000	$30,000,000	$26,658,817	$12,273,747	41%
9. Meadow Road	Study	$7,200,000	$1,800,000	$9,000,000	$7,298,686	$483,601	5%
10. Orange Valley	Office	$19,700,000	$6,900,000	$26,600,000	$15,967,714	$358,732	1%
11. Ridgefield 13kV	Study	$19,600,000	$5,900,000	$25,500,000	$23,086,520	$3,997,875	16%
12. Ridgefield 4kV	Study	$17,600,000	$2,600,000	$20,200,000	$17,320,551	$6,745,565	33%
13. State Street	Study	$39,000,000	$6,100,000	$45,100,000	$38,928,940	$596,494	1%
14. Toney's Brook	Study	$14,300,000	$5,400,000	$19,700,000	$15,256,600	$510,253	3%
15. Waverly	Study	$29,400,000	$6,000,000	$35,400,000	$32,274,121	$1,465,452	4%
16. Woodlynne	Study	$15,800,000	$3,600,000	$19,400,000	$18,308,852	$665,906	3%
Subprogram Total		**$311,900,000**	**$73,700,000**	**$385,500,000**	**$327,092,250**	**$33,480,069**	**9%**

<u>Findings & Observations</u>

- The projects that comprise the Electric Station Flood Mitigation subprogram continue at various phases of execution, with six projects now in construction as of the end of the third quarter of 2020 (up from three at the end of the second quarter of 2020), and the remaining projects continuing to advance in design and pre-construction activities with the exception of Constable Hook which largely remains in the planning/origination stage.

- While early in the subprogram, the IM has found nothing to date that would jeopardize the subprogram being completed on budget. The status of the later projects in this subprogram, and in particular Orange Valley and Constable Hook, will have to closely be followed to ensure the projects are completed within the ES 2 Program window. At this time, the Orange Valley project shows an in-service date of January 2024, however subsequent to the third quarter of 2020, PSE&G has informed the IM that the project team will be examining the potential to shorten durations and/or work activities concurrently to pull the in-service date back into 2023.

1. Academy Street

During the third quarter of 2020, approximately $1.3 million was spent on the Academy Street project compared to a forecast of approximately $860,000, which brought the total spend to approximately $2 million. The variance in third quarter spend was largely driven by earlier permit approval and land clearing that supported construction starting earlier than forecasted. Notable activities completed during the third quarter of 2020 include:

- State permits received;
- Controls drawings IFC; and,
- Electrical construction purchase order issued.

As noted in the IM 2020 Second Quarter Report, the Study level estimate was approved internally at the end of June 2020 with $9.9 million in base, $2.9 million in R&C, for a total estimate of $12.8 million. The prior Office level estimate for Academy Street was $17.0 million in total, with the majority of the $4.2 million reduction to the current estimate attributed to the change in mitigation method from raise and rebuild to relocate. In July 2020, this Study level estimate was approved before the URB.

In September 2020, the Conceptual level estimate was submitted and approved before the URB. This Conceptual level estimate lowered the total Academy Street project estimate from the previously approved $12.8 million to $11.8 million, with the reduction driven by a $1.0 million reduction to R&C based on the current risk register for the project.

Construction at Academy Street, which started in July 2020 for non-permit work, has advanced to 25% complete inside plant (100% complete outside plant) as of the end of the third quarter of 2020. The actual spend by quarter for Academy Street as compared to the current approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals						
$150,398	$99,893	$399,935	$1,312,771	$1,962,997	$11,800,000	17%

2. Clay Street

During the third quarter of 2020, approximately $234,000 was spent on the Clay Street project compared to a forecast of approximately $248,000, which brought the total spend to approximately $854,000. Notable activities completed during the third quarter of 2020 include:

- License and permit package issued;
- Project execution plan completed; and,
- Civil and electrical inside plant construction POs issued.

The actual spend by quarter for Clay Street as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals						
$116,409	$219,707	$283,219	$234,171	$853,505	$42,000,000	2%

3. *Constable Hook*

Through the end of the third quarter of 2020, the Constable Hook project continued to remain in the initial planning and origination stages, with the property acquisition for associated 69kV projects planned at the same area still being reviewed (see related discussion in **Section II.A.3.** and **Section IV.B.**). The actual spend by quarter for Constable Hook as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals						
$17,889	$51,758	$32,313	$8,419	$110,379	$5,300,000	2%

4. *Hasbrouck Heights*

During the third quarter of 2020, approximately $326,000 was spent on the Hasbrouck Heights project compared to a forecast of approximately $346,000, which brought the total spend to approximately $532,000. Notable activities completed during the third quarter of 2020 include:

- Site plan administrative approval received;
- NJDEP approval received; and,
- Vendor drawings received (final switchgear arrangement).

A Covid-19 related delay on the associated Hasbrouck Heights 69kV project has resulted in a delay to the Hasbrouck Heights ES 2 project. This delay shifts the planned start of construction from June to August 2021 and the forecasted in-service date from November to December 2022. The actual spend by quarter for Hasbrouck Heights as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals						
$149,848	$193,879	$188,045	$325,694	$857,466	$18,000,000	5%

5. *Kingsland*

During the third quarter of 2020, approximately $27,000 was spent on the Kingsland project compared to a forecast of approximately $42,000, which brought the total spend to approximately $283,000. There were minimal activities performed on this project during the third quarter of 2020.

As noted in the IM 2020 Second Quarter Report, a revised Study level estimate was approved internally at the end of June 2020 with $5.4 million in base, $2.9 million in R&C, for a total estimate of $8.3 million. The prior Study level estimate for Kingsland was $10.0 million in total, with the $1.7 million reduction to the current estimate attributed to a reduction in the switchgear commitment on the project. The current plan and estimate are based on Kingsland utilizing a contingency switchgear from another project that will be available once construction is completed. In July 2020, this revised Study level estimate was approved before the URB. The actual spend by quarter for Kingsland as compared to the current approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals						
$104,112	$108,286	$43,268	$27,477	$283,143	$8,300,000	3%

6. Lakeside Avenue

The Lakeside Avenue project continued to advance the planning efforts, with the key plans and conceptual drawings progressing during the third quarter of 2020. The forecasted in-service date for this project slipped from May 2023, as of the end of the second quarter of 2020, to December 2023, as of the end of the third quarter. This delay was driven by the original property location for the 69kV and ES 2 projects having contamination risks that resulted in a new potential property location, for which the purchase process is underway (see related discussion in **Section II.A.3.** and **Section IV.B.**). The actual spend by quarter for Lakeside Avenue as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals						
$148,943	$172,224	$121,009	$87,411	$529,587	$36,100,000	2%

7. Leonia

During the third quarter of 2020, approximately $1.07 million was spent on the Leonia project compared to a forecast of approximately $1.02 million, which brought the total spend to approximately $$1.8 million. Notable activities completed during the third quarter of 2020 include:

- Vendor drawings received (final switchgear controls for switchgear 1 and 2);
- Civil construction commenced; and,
- Electrical construction (contingency) out for bid.

Construction at Leonia, which started in August 2020, has advanced to 15% complete inside plant as of the end of the third quarter of 2020. The actual spend by quarter for Leonia as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals						
$44,792	$244,323	$424,783	$1,071,468	$1,785,366	$32,200,000	6%

8. Market Street

During the third quarter of 2020, approximately $4.9 million was spent on the Market Street project compared to a forecast of approximately $5 million, which brought the total spend to approximately $12.2 million. Notable activities completed during the third quarter of 2020 include:

- County road crossing permit received;
- Outside plant construction advanced to 45% complete.

In September 2020, the Conceptual level estimate was submitted and approved before the URB. This Conceptual level estimate did not change the total Market Street project estimate from the previously approved $30.0 million, however, it did result in an increase to the base estimate (from $24.2 million to $26.7 million) with the primary changes to the base estimate being attributed to:

- Change in T&D surcharge methodology, approved by PSE&G Accounting, +$2.5 million;
- Outside plant soil remediation, +$1.2 million; and,
- Estimate refinement, ($1.2 million).

This net $2.5 million increase in the base estimate was offset by a $2.5 million reduction to R&C based on the current risk register for the project.

The actual spend by quarter for Market Street as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals						
$251,193	$1,938,713	$5,144,270	$4,939,571	$12,273,747	$30,000,000	41%

9. Meadow Road

During the third quarter of 2020, approximately $173,000 was spent on the Meadow Road project compared to a forecast of approximately $141,000, which brought the total spend to approximately $484,000. Notable activities completed during the third quarter of 2020 included the issuance of the license and permit package.

The actual spend by quarter for Meadow Road as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals						
$63,128	$142,946	$104,563	$172,964	$483,601	$9,000,000	5%

10. Orange Valley

Through the end of the third quarter of 2020, the Orange Valley project advanced past the initial planning and origination stages (see related discussion in **Section II.A.3.** and **Section IV.B.**), with the kickoff meeting taking place in September 2020 and Burns & McDonnell being awarded the A/E scope. The actual spend by quarter for Orange Valley as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals						
$77,029	$96,582	$120,690	$64,432	$358,732	$26,600,000	1%

11. Ridgefield 13kV

During the third quarter of 2020, approximately $3.0 million was spent on the Ridgefield 13kV project compared to a forecast of approximately $2.9 million, which brought the total spend to approximately $4.0 million. Notable activities completed during the third quarter of 2020 include:

- Vendor drawings received (final switchgear controls for switchgear 1 and 2);
- Electrical construction purchase order issued (temporary switchgear);
- The temporary 13kV sheltered aisle switchgear was delivered to the site; and,
- The temporary switchgear was set.

Construction at Ridgefield 13kV, which started in June 2020, has advanced to 23% complete inside plant as of the end of the third quarter of 2020. The actual spend by quarter for Ridgefield 13kV as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals						
$205,982	$317,289	$500,475	$2,974,130	$3,997,875	$25,500,000	16%

12. Ridgefield 4kV

During the third quarter of 2020, approximately $3.8 million was spent on the Ridgefield 4kV project compared to a forecast of approximately $6.6 million. The variance in actual versus forecasted spend for the third quarter was predominantly the result of Division accruals not captured by the Division's accrual system in July, the postponement of jack and bore installation under the railway tracks due to not receiving CSX approval and needed permits in time (this work was performed in October 2020). This brought the total spend to approximately $6.7 million.

In September 2020, the Conceptual level estimate was submitted and approved before the URB. This Conceptual level estimate lowered the total Ridgefield 4kV project estimate from the previously approved $21.1 million to $20.2 million. The base estimate increased from $16.8 million to $17.6 million, largely driven by the underground work costs being higher than previously estimated, while the R&C decreased from $4.3 million to $2.6 million based on the current risk register for the project.

Construction at Ridgefield 4kV, which started in June 2020, has advanced to 47% complete. The actual spend by quarter for Ridgefield 4kV as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals						
$143,414	$693,128	$2,134,627	$3,774,395	$6,745,565	$20,200,000	33%

13. State Street

During the third quarter of 2020, approximately $218,000 was spent on the State Street project compared to a forecast of approximately $190,000, which brought the total spend to approximately $596,000. Notable activities completed during the third quarter of 2020 include:

- Site plan submitted and approved by the planning board;
- Civil and electrical drawings IFC;
- State Conservation District permit approved;
- Vendor drawings received (final switchgear controls); and,
- Civil and electrical construction out for bid.

As noted in the IM 2020 Second Quarter Report, the Study level estimate was approved internally at the end of June 2020 with $39.0 million in base, $6.1 million in R&C, for a total estimate of $45.1 million.

The prior Office level estimate for Academy Street was $28.6 million in total, with the majority of the $16.5 million increase to the current estimate attributed to the change in mitigation method from raise and rebuild to relocate. In July 2020, this Study level estimate was approved before the URB. The actual spend by quarter for State Street as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals						
$77,950	$128,288	$172,777	$217,839	$596,494	$45,100,000	1%

14. Toney's Brook

During the third quarter of 2020, approximately $96,000 was spent on the Toney's Brook project compared to a forecast of approximately $151,000, which brought the total spend to approximately $510,000. Notable activities completed during the third quarter of 2020 include:

- Vendor drawings received (final switchgear arrangement); and,
- Received planning board approval for site plan.

The actual spend by quarter for Toney's Brook as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals						
$211,940	$115,747	$86,315	$96,251	$510,253	$19,700,000	3%

15. Waverly

During the third quarter of 2020, approximately $651,000 was spent on the Waverly project compared to a forecast of approximately $429,000, which brought the total spend to approximately $1.5 million. The third quarter forecast to actual variance was driven largely by Pre-Phase 1 construction work (place-install cast in place hand holes) starting in September to support Phase 1 construction in October 2020. Notable activities completed during the third quarter of 2020 include:

- Civil and electrical drawings IFC;
- License and permitting package submitted; and,
- Start of Pre-Phase 1 construction.

The actual spend by quarter for Waverly as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals						
$103,748	$355,706	$355,335	$650,662	$1,465,452	$35,400,000	4%

16. Woodlynne

During the third quarter of 2020, approximately $101,000 was spent on the Woodlynne project compared to a forecast of approximately $153,000, which brought the total spend to approximately $666,000. Notable activities completed during the third quarter of 2020 include:

- Received planning board approval for the site plan;
- Contingency plan completed; and,
- Vendor drawings received (final switchgear arrangement).

The actual spend by quarter for Woodlynne as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals						
$110,982	$240,418	$213,482	$101,024	$665,906	$19,400,000	3%

B. Contingency Reconfiguration

During the third quarter of 2020, work continued to advance in the Contingency Reconfiguration subprogram with all four Divisions continuing to install reclosers. However, severe weather in July and August (including Tropical Storm Isaias) resulted in approximately half a month of work being missed. PSE&G has worked with the Divisions to identify resources to recover these delays and was able to resume work quickly after the restoration efforts were completed with the current expectation that installation and commissioning of reclosers will regain the planned progress in 2021. The third quarter of 2020 also saw minor inventory issues, with the receipt of 4kV reclosers delayed due to Covid-19 impacts to the manufacturer. To mitigate any potential impacts from that delay, PSE&G reallocated its recloser inventory such that the Metro Division (with the largest 4kV population and smallest 13kV population of the Divisions) received all the 4kV reclosers in PSE&G's inventory until additional equipment was received in September. There is no overall impact anticipated from this temporary inventory shortage as PSE&G was able to adjust its plan to continue to advance the work in the subprogram. **Table 21 – ES 2 Recloser Status as of September 30, 2020** provides a summary of the recloser aspect of the Contingency Reconfiguration subprogram, indicating the 2020 year-end targets and current status of engineering, installation, and commissioning.

Table 21 – ES 2 Recloser Status as of September 30, 2020

Type	2020 Year End Total Target	Engineering Packages Complete (1 recloser ea.)		Reclosers Installed		Reclosers Commissioned	
		Q3 Qty.	*Total*	*Q3 Qty.*	*Total*	*Q3 Qty.*	*Total*
13kV	800	44	638	129	546	283	413
4kV	179	37	300	27	65	44	55
Total	979	81	938	156	611	327	468

As shown in **Table 21**, engineering continues to stay comfortably ahead of construction, allowing PSE&G flexibility in selecting which projects to initiate construction on and allows the subprogram progress to continue, while the commissioned units more than doubled during the third quarter as previously installed units were completed. Compared to the 2020 year-end targets, as of the end of the third quarter of 2020, the engineering was near the year-end target, approximately two-thirds of the targeted reclosers have been installed and approximately half have been commissioned.

The Fuse Saver installations are planned to begin later in 2020 with a pilot program that installs Hmc radios in the Fuse Savers to support communication on the device when there is an event. PSE&G's Asset Management group determined a pilot program would be initiated prior to the full scope to ensure the devices work as intended, with the pilot program contemplating installation of 57 single-phase units and 18 two-phase units by the end of 2020. PSE&G's initial plan was to commence the pilot program in September 2020, however it encountered firmware issues from the vendor that delayed the start of this pilot program until the fourth quarter of 2020.

The current forecasted completion date for the primary components that make up the Contingency Reconfiguration subprogram are provided in **Table 22 – ES 2 Contingency Reconfiguration Forecasted Completion Dates as of September 30, 2020**.

Table 22 – ES 2 Contingency Reconfiguration Forecasted Completion Dates as of September 30, 2020

Scope & Division		Forecasted Completion Date
Reclosers	Central	11/30/2021
	Metro	11/30/2021
	Palisades	12/31/2021
	Southern	12/31/2021
Fuse Savers	Central	7/31/2023
	Metro	7/31/2023
	Palisades	7/31/2023
	Southern	7/31/2023

The Contingency Reconfiguration subprogram costs through the end of the third quarter of 2020 are presented in **Table 23 – ES 2 Contingency Reconfiguration Costs as of September 30, 2020**.

Table 23 – Contingency Reconfiguration Costs as of September 30, 2020

Scope & Division		Q4 2019	Q1 2020	Q2 2020	Q3 2020	Total to Date	Forecast	% of Actuals to Forecast
		Actuals						
Reclosers	Central	$2,737,167	$3,918,150	$2,238,132	$2,801,328	$11,694,777	$21,497,603	54%
	Metro	$2,231,431	$3,576,616	$1,946,751	$1,950,122	$9,704,920	$21,087,215	46%
	Palisades	$2,515,569	$3,353,246	$2,263,303	$2,602,224	$10,734,341	$20,250,897	53%
	Southern	$2,081,220	$4,003,537	$2,098,258	$2,764,372	$10,947,387	$23,561,179	46%
Fuse Savers	Central	$9,970	$29,667	$48,444	$73,176	$161,258	$13,118,198	1%
	Metro	$7,557	$15,498	$28,339	$41,921	$93,315	$10,863,516	1%
	Palisades	$7,468	$15,259	$16,336	$20,878	$59,941	$9,243,291	1%
	Southern	$9,792	$21,458	22,973	$35,596	$89,818	$12,276,134	1%
Total		**$9,600,174**	**$14,933,431**	**$8,662,536**	**$10,289,616**	**$43,485,758**	**$131,898,033**	**33%**

The current forecast of approximately $131.9 million shown in **Table 23** for the Contingency Reconfiguration subprogram represents an approximate $18 million reduction from the forecast as of the end of the second quarter of 2020. The change in the Contingency Reconfiguration subprogram forecast was predominantly driven by the removal of 117 13kV reclosers and 109 4kV reclosers. This was the result of a detailed assessment of each circuit to determine the current status reflecting updated system plans and changes or other work done subsequent to the ES 2 filing.

<u>Findings & Observations</u>:

- Recloser installations fell behind the third quarter target primarily due to weather-related impacts. However, PSE&G continued to advance work particularly through pole installations and commissioning of recloser installed earlier with Hm radios.

- PSE&G was able to mitigate the impacts from the delayed reclosers shipment through adjusting near-term plans to reallocate the available inventory in a way that allowed the Divisions to continue to progress the installations.
- While the Fuse Saver pilot program had its start delayed due to vendor firmware issues, this is an example of why the pilot program was developed as it allows minor issues like these firmware issues to be resolved prior to commencing the full effort.
- While still early in the subprogram, the IM has found nothing to date that would jeopardize the subprogram being completed on time and/or on budget.

C. Grid Modernization – Communication System

As reported in the IM 2020 Second Quarter Report, in June 2020, the permanent PSE&G Wireless Network infrastructure solution for connecting to the First Net LTE Network was officially placed in-service and is being utilized to manage all traffic from the field routers. During the third quarter of 2020, PSE&G conducted a service territory coverage assessment of the network, which found less than 1/10 of 1% of the service territory to have service below the coverage threshold. This assessment also identified four of 30 in-building partitions were below the service threshold, as a result PSE&G boosted the in-building signal at these locations, which had no cost impact to the subprogram.

As also reported in the IM 2020 Second Quarter Report, PSE&G made the strategic decision to focus on new recloser installations and has delayed the ramp-up in retrofit installations from August 2020 to January 2021 due to resource constraints. No overall impacts are expected from this decision and PSE&G plans to regain the planned retrofit installations by the middle of 2021 as it shifts focus from new recloser installations to the retrofit reclosers. During the third quarter of 2020, 34 retrofit installations took place against a forecast of 35 installations. The installations were specifically targeted by PSE&G and the Divisions based on a prioritization of the devices that have the most communication problems, once the majority of these identified devices are retrofitted, the prioritization will switch to by circuit. The initial retrofit reclosers prioritized also includes those that PSE&G's IT department was working with Verizon to replace existing copper lines with fiber. By prioritizing these devices, it allows PSE&G to gain cost efficiencies by retrofitting these devices in conjunction with the other work and avoids the need to return to these devices at a later time.

On the fiber scope, which includes installing fiber to electric substations and electric operations centers, in addition to cutting over stations with existing fiber service to the PSE&G fiber network, 41 installation projects and 12 cutovers have been identified, with the first batch of installations expected to be placed in-service during the fourth quarter of 2020 and the cutovers to be completed early in 2021. During the third quarter of 2020, the initial six fiber projects commenced construction while an additional five had design packages issued. These 11 fiber projects represent the projects selected by PSE&G for 2020, an additional 14 projects have been preliminarily identified for the 2021 efforts.

The Grid Modernization – Communication System subprogram costs through the end of the third quarter of 2020 are presented in **Table 24 – ES 2 Grid Modernization – Communication System Costs as of September 30, 2020**.

Table 24 – ES 2 Grid Modernization – Communication System Costs as of September 30, 2020

Scope & Division		2019	Q1 2020	Q2 2020	Q3 2020	Total to Date	Forecast	% of Actuals to Forecast
		Actuals						
R	Central	$0	$50,613	$150,958	$201,053	$402,264	$7,959,730	5%

Scope & Division		2019	Q1 2020	Q2 2020	Q3 2020	Total to Date	Forecast	% of Actuals to Forecast
		Actuals						
	Metro	$0	$44,164	$139,069	$214,848	$398,081	$6,795,675	6%
	Palisades	$0	$44,164	$138,485	$216,524	$399,173	$6,943,433	6%
	Southern	$0	$46,901	$145,479	$198,307	$390,687	$8,475,961	5%
Fiber	Central	$1,691	$133,115	$272,307	$660,034	$1,067,147	$7,479,617	14%
	Metro	$1,457	$109,382	$299,876	$419,162	$829,877	$5,792,227	14%
	Palisades	$1,582	$194,451	$520,068	$403,443	$1,119,544	$4,087,557	27%
	Southern	$4,731	$65,721	$139,575	$120,011	$330,038	$3,266,163	10%
	Cutovers	$0	$0	$0	$40,869	$40,869	$930,560	4%
Wireless Network		$74,306	$1,525,801	$2,353,604	$1,508,075	$5,461,786	$7,390,016	74%
Total		**$83,767**	**$2,214,312**	**$4,159,421**	**$5,106,396**	**$11,563,896**	**$59,120,939**	**20%**

Findings & Observations:

- Retrofit recloser installations continued in the third quarter of 2020, but as previously noted PSE&G made a strategic decision for prioritizing radio installations on new reclosers (being installed as part of the Contingency Reconfiguration subprogram). PSE&G is also prioritizing the retrofit installations for locations where cost efficiencies can be gained by scheduling the radio retrofit work to be performed with related non-ES 2 work.
- The first six fiber projects commenced during the third quarter of 2020, with the other five fiber projects that comprise the 2020 scope having design underway in advance of construction starting in the fourth quarter of 2020.
- While still early in the subprogram, the IM has found nothing to date that would jeopardize the subprogram being completed on time and/or on budget.

D. Grid Modernization – ADMS

The Grid Modernization – ADMS scope is split between three primary sections: Distribution Management System (DMS)/Distributed Energy Resource Management System (DERMS), the Outage Management System (OMS), and ADMS platform upgrades. The primary activities in 2020 are centered on planning activities, including as previously reported in the second quarter of 2020, the signing of the Open Systems International Inc. (OSII) contract. The ADMS team continues to use remote meetings with the vendor in response to the ongoing Covid-19 issues and continues to conduct design workshops to further develop the application. During the third quarter of 2020, kickoff meetings were held on the OMS scope and six business process workshops, 10 initial interface design workshops, and 24 requirements review workshops were conducted. Other activities during the third quarter of 2020 included the delivery of the first phase of hardware to OSII and the purchase of additional platform hardware (Dell servers and storage devices for Newark and Edison). This additional hardware has an overall cost impact of approximately $1.2 million, however, PSE&G has reviewed the current ADMS estimate and the forecast remains at $40.4 million. The final ADMS release is currently forecasted to go live during the fourth quarter of 2022.

The Grid Modernization – ADMS subprogram costs through the end of the third quarter of 2020 are presented in **Table 25 – ES 2 Grid Modernization – ADMS Costs as of September 30, 2020**.

Table 25 – ES 2 Grid Modernization – ADMS Costs as of September 30, 2020

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Total to Date	Forecast	% of Actuals to Forecast
Actuals						
$36,213	$925,689	$4,430,542	$6,970,572	$12,363,016	$40,374,822	31%

Findings & Observations:

- The activities to date on the subprogram continue to be primarily planning activities, including continuing to have workshops with the software vendor and operations.
- Several workshops occurred during the third quarter, which despite the challenges posed by Covid-19 restrictions, were completed without issue.
- Despite the Covid-19 related challenges, the IM has found nothing to date that would jeopardize the subprogram being completed on time. The current forecast, including the $1.2 million in additional hardware purchased during the third quarter of 2020, exceeds the Stipulation amount allocated for this subprogram by approximately $5.4 million. While this subprogram on its own would likely exceed the Stipulation budget, per the Stipulation, PSE&G has the ability to reallocate funds amongst the electric subprograms of the ES 2 Program in part to address the *"many variables associated with this type of work that make it difficult to precisely budget each subprogram project initiative."*[1] With the overall electric portion of the ES 2 Program under budget, this mechanism may be implemented by PSE&G in the future to address the currently forecasted overrun in this Grid Modernization – ADMS subprogram. The IM will continue to closely monitor the costs in this regard.

E. Electric Stipulated Base

The Stipulation identified that the electric portion of the Stipulated Base include $100 million in investments at PSE&G's discretion towards electric outside plant higher design and construction standards and/or electric stations life cycle subprograms described in the original ES 2 filing.[2] As reported in the IM 2020 First Quarter Report, the preliminary planning by PSE&G estimated that approximately one-third of the Stipulated Base funds will be used towards the electric stations life cycle investments and the remaining two-thirds towards outside plant higher design and construction standards. Based on the current study level estimate for the life cycle upgrades (detailed below), the current view shows that approximately 80% of these funds will be applied towards life cycle upgrades, with the remainder going towards the electric outside plant higher design and construction standards. As noted in the IM 2020 Second Quarter Report, this current ratio is driven by the approval of the four life cycle stations, including risk and contingency funds, to allow their completion within the ES 2 Program window. PSE&G has confirmed with the IM that it intends to maintain the ratio at approximately one-third of funding to life cycle upgrades and two-thirds to outside plant higher design and construction standards. The outside plant higher design and construction standards work is planned to commence in January 2022. In accordance with what the Stipulation provides, PSE&G plans to fund some of the life cycle station upgrades from the

[1] Energy Strong 2 Stipulation, paragraph 22, September 11, 2019

[2] As noted in the Stipulation, the electric life cycle upgrades are part of the electric Stipulated Base to be recovered in the Company's next base rate case provided the investments are found to be prudent. The Stipulation also notes that should the 16 stations that comprise the Electric Station Flood Mitigation subprogram be completed for under the $389 million allocated for that subprogram, PSE&G may reallocate such unused funds to stations identified in the life cycle station upgrade portion of PSE&G's petition for accelerated recovery.

electric program accelerated investment, subject to funds available, after all Electric Station Flood Mitigation projects are funded at their final costs.

As reported in the IM 2020 Second Quarter Report, the initial four stations PSE&G selected for life cycle station upgrades went before the URB in June 2020 for Study level estimate approval and received approval for full funding. These four stations and their current estimate compared to the actuals to date are provided in **Table 26 – ES 2 Life Cycle Station Upgrade Project Status as of September 30, 2020**.

Table 26 – ES 2 Life Cycle Station Upgrade Project Status as of September 30, 2020

Project	Estimate Level	Base	Risk & Contingency	Total	Actuals to Date	% of Actuals to Estimate	Forecasted In-Service Date*
1. Hamilton	Study	$14,500,000	$3,700,000	$18,200,000	$177,808	1%	11/2/2022
2. Paramus	Study	$14,800,000	$5,400,000	$20,200,000	$408,931	2%	9/28/2022
3. Plainfield	Study	$18,400,000	$4,200,000	$22,600,000	$503,189	2%	10/6/2022
4. Woodbury	Study	$15,400,000	$3,300,000	$18,700,000	$383,581	2%	12/16/2022
**-Reflects the in-service date of the last major asset (e.g., switchgear), certain activities may take place after this date to support the final in-service date (i.e., when all customers are cutover).*							

Details on each of these life cycle station upgrade projects is provided in the individual subsections that follow.

1. Hamilton

The Hamilton substation was originally constructed in 1953 with a significant portion of its current 4kV equipment being the original equipment at the substation. The station currently consists of three 69kV lines, two 69/4kV transformers, and eight 4kV feeders. From 2008-2017, the 4kV supply circuits at Hamilton have experienced 67 extended outages and seven momentary outages, for a total duration of nearly 308 hours. The life cycle upgrades contemplate upgrading equipment and protection schemes including replacing the old electromechanical relays with modern digital relays to increase the reliability, resiliency, and life span of the substation. Notable activities conducted during the third quarter of 2020 included:

- Project kickoff meeting held.
- License and permitting design commenced.
- Detailed engineering commenced.
- Major equipment purchase order issued.

The actual spend by quarter for Hamilton as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals						
$0	$0	$0	$177,808	$177,808	$18,200,000	1%

2. Paramus

The Paramus substation was originally constructed in 1958 with a significant portion of its current 4kV equipment being the original equipment at the substation. The station currently consists of three 69kV lines supplying a six-breaker ring bus, with three 69/4kV transformers, and 12 4kV feeder rows. From

2008-2017, the 4kV supply circuits at Paramus have experienced 116 extended outages and 20 momentary outages, for a total duration of nearly 1,044 hours. Black & Veatch was awarded the A/E scope for this project. The life cycle upgrades contemplate upgrading equipment and protection schemes including replacing the old electromechanical relays with modern digital relays to increase the reliability, resiliency, and life span of the substation. Notable activities conducted during the third quarter of 2020 included:

- Project kickoff meeting held.
- Major equipment purchase order issued.
- License and permitting design commenced.

The actual spend by quarter for Paramus as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals						
$0	$0	$0	$408,931	$408,931	$20,200,000	2%

3. Plainfield

The 4-kV Switchgear at the Plainfield substation is in poor condition. A significant portion of the 4-kV equipment at the station is still original from when the substation constructed in 1958 and the metal clad switchgear has rusted and must be addressed. In addition, all of the 4-kV distribution feeders and Tie Feeder currently run through the same manhole and conduit system, which presents the possibility of extended outages to the customers supplied from Plainfield Substation in the event of a cable or splice failure that results in collateral damage to adjacent feeders. This station currently consists of three (3) 69-kV lines supplying a Six (6) - Breaker GIS Ring Bus, with three (3) 69 / 4-kV transformers, twelve (12) 4-kV feeders, one (1) 4-kV Tie Feeder, and two (2) 2.7MVA. Black & Veatch was awarded the A/E scope for this project. Notable activities conducted during the third quarter of 2020 included:

- Project kickoff meeting held.
- License and permitting design commenced.
- Detailed engineering commenced.
- Major equipment purchase order issued.

The actual spend by quarter for Plainfield as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals						
$0	$0	$0	$503,189	$503,189	$22,600,000	2%

4. Woodbury

The Woodbury substation was originally constructed in 1954 with a significant portion of its current 4kV equipment being the original equipment at the substation. The station currently consists of four 26kV lines, three 26kV bus section breakers, three 26/4kV transformers, three transformer 4kV breakers, and 12 4kV feeders with voltage regulators and reactors. From 2008-2017, the 4kV supply circuits at Woodbury have experienced 153 extended outages and eight momentary outages, for a total duration of nearly 883 hours. Burns & McDonnell was awarded the A/E scope for this project. The life cycle upgrades contemplate replacing the old electromechanical relays with modern digital relays to increase the reliability, resiliency, and life span of the substation. Notable activities conducted during the third quarter of 2020 included:

- Major equipment purchase order issued.
- License and permitting design commenced.

The actual spend by quarter for Woodbury as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals						
$0	$0	$0	$383,851	$383,851	$18,700,000	2%

Findings & Observations:

- The four electric stipulated base substation life cycle projects progressed in planning and preparation efforts during the third quarter of 2020 with activities such as permitting preparation and issuance of purchase orders for major equipment.
- While the current four electric substation life cycle projects comprise approximately 80% of the electric stipulated base funding, PSE&G anticipates that the final ratio will be closer to one-third of funding to the electric substation life cycle projects and two-thirds to the outside plant higher design and construction standards. Funding these four projects fully allows them to be completed within the ES 2 Program window, in addition PSE&G excepts excess funds from the Electric Station Flood Mitigation subprogram (currently forecasted approximately $60 million under its Stipulation amount) to be reallocated to the life cycle station upgrades as provided in the Stipulation.

F. Gas M&R Station Upgrades

Through the end of the third quarter of 2020, preliminary design continued on each of the Gas M&R stations. **Table 27 – ES 2 Gas M&R Summary Status as of September 30, 2020** below provides the currently approved estimates for each project within the Gas M&R subprogram, along with the actuals to date and forecasted in-service dates. As indicated in **Table 16**, there continues to have been minimal spend to date on the subprogram, with the actual spend primarily related to initial planning and preliminary design efforts.

Table 27 – ES 2 Gas M&R Summary Status as of September 30, 2020

Project	Estimate Level	Base	Risk & Contingency	Total Estimate	Actuals	% of Actuals to Estimate	Forecasted In-Service
1. Camden*	Office	$10,000,000	$5,400,000	$15,400,000	$351,353	2%	Jan 2023
2. Central*	Office	$12,800,000	$6,900,000	$19,700,000	$356,592	2%	Jan 2023
3. East Rutherford	Office	$10,300,000	$5,600,000	$15,900,000	$317,447	2%	Jan 2023
4. Mount Laurel	Study	$9,400,000	$2,400,000	$11,800,000	$241,187	2%	Dec 2022
5. Paramus*	Office	$12,900,000	$7,000,000	$19,900,000	$307,130	2%	Jan 2022
6. Westampton	Study	$8,300,000	$2,100,000	$10,400,000	$544,675	5%	Dec 2021
Subprogram Total		**$65,600,000**	**$35,400,000**	**$101,000,000**	**$2,118,383**	**2%**	**Jan 2023**

Project	Estimate Level	Base	Risk & Contingency	Total Estimate	Actuals	% of Actuals to Estimate	Forecasted In-Service
**-Included in the Stipulated Base.*							

Findings & Observations:

- The primary efforts to date on the subprogram continue to be initial planning efforts, including the prior awarding of bids for the design services on the projects and current activities such as preparing for issuing the major equipment POs, site surveys, and preparation of permitting packages.
- While still early in the subprogram, the IM has found nothing to date that would jeopardize the subprogram being completed on time and/or on budget.

1. Camden

As noted above, the primary work to date on the Gas M&R subprogram has been continuing with preliminary engineering and other planning activities, including the award of the A/E contract to Burns & McDonnell in July 2020 following the re-bid of this scope after the original selected firm did not agree with PSE&G's terms and conditions for material procurement. For the remainder of 2020, planned activities include continued engineering development, including a 3D model review in October 2020 and preparation and issuance of the licensing and permitting package in November 2020, and the issuance of purchase orders for the major equipment (building, heaters, pipes, scrubber, valves, and regulators) in December 2020. The Study level estimate for the Camden project is planned to be submitted to the URB in December 2020.

The actual spend by quarter for Camden as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals						
$13,326	$46,691	$83,499	$207,837	$351,353	$15,400,000	2%

2. Central

As noted above, the primary work to date on the Gas M&R subprogram has been continuing with preliminary engineering, including the prior award of the A/E contract to Odin EPC, LLC, and other planning activities. During the third quarter of 2020, a site survey was completed, and a coordination meeting conducted with IT and Security. For the remainder of 2020, engineering efforts are planned to continue with detailed design commencing in October 2020 to support the licensing and permitting packages being submitted in January 2021. The Study level estimate for the Central project is planned to be submitted to the URB in December 2020.

The actual spend by quarter for Central as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals						
$6,869	$45,048	$109,557	$195,119	$356,592	$19,700,000	2%

3. East Rutherford

As noted above, the primary work to date on the Gas M&R subprogram has been continuing preliminary engineering, including the prior award of the A/E contract to EN Engineering, LLC, and other planning activities. During the third quarter of 2020, the conceptual design for the project was approved and a coordination meeting was held with IT and Security. For the remainder of 2020, engineering efforts are planned to continue with detailed design commencing in October 2020 to prepare issued for bid drawings to be issued in January 2021. The Study level estimate for the East Rutherford project is planned to be submitted to the URB in December 2020.

The actual spend by quarter for East Rutherford as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals						
$9,010	$37,747	$111,526	$159,165	$317,447	$15,900,000	2%

4. Mount Laurel

As noted above, the primary work to date on the Gas M&R subprogram has been continuing preliminary engineering, including the prior award of the A/E contract to J.F. Kiely Service Co., LLC, and other planning activities. During the third quarter of 2020, detailed schedule development resulted in the initially planned in-service date on the milestone schedule changing from January 2022 to October 2022. In September 2020, the Study level estimate for Mount Laurel was approved by the URB. This updated estimate decreased the total project estimate from $17.4 million to $11.8 million (including a $1.9 million reduction in the base estimate and a $3.7 million reduction in risk and contingency) and was based upon a further refined plan and scope and updated risk evaluation. For the remainder of 2020, engineering efforts are planned to continue with detailed design commencing in October 2020 and all drawings (civil, electrical, instrumentation, and mechanical) expected to be issued for review (IFR) in November 2020. Construction is currently anticipated to begin in March 2022.

The actual spend by quarter for Mount Laurel as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals						
$5,965	$27,804	$74,737	$132,680	$241,187	$11,800,000	2%

5. Paramus

As noted above, the primary work to date on the Gas M&R subprogram has been continuing preliminary engineering, including the prior award of the A/E contract to EN Engineering, LLC, and other planning activities. During the third quarter of 2020, the conceptual design was approved for the project and a 3D drawing review was held in September 2020. A coordination meeting with IT and Security was also conducted during the third quarter of 2020. For the remainder of 2020, engineering efforts are planned to continue with the preparation of issued for review drawings in December 2020 to support their release in January 2021. The Study level estimate for the Paramus project is planned to be submitted to the URB in December 2020.

The actual spend by quarter for Paramus as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals						
$8,842	$37,793	$91,247	$169,249	$307,130	$19,900,000	2%

6. Westampton

As noted above, the primary work to date on the Gas M&R subprogram has been continuing preliminary engineering, including the prior award of the A/E contract to NVS, Inc., and other planning activities. During the third quarter of 2020, detailed schedule development resulted in the initially planned in-service date on the milestone schedule changing from July 2021 to October 2021. In September 2020, geotechnical borings were completed at the site and the Study level estimate for Westampton was approved by the URB. This updated estimate reduced the total project estimate from $12.7 million to $10.4 million (including a $2.3 million reduction of risk and contingency) and was based on a further refinement of the scope and an updated risk evaluation. For the remainder of 2020, engineering efforts are planned to continue in support of the issuance of the major equipment POs in November 2020 and the submittal of the licensing and permitting package. Construction is currently anticipated to begin in January 2021 and be completed in October 2021.

The actual spend by quarter for Westampton as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals						
$8,395	$40,839	$180,947	$314,493	$544,675	$10,400,000	5%

IV. Additional Information Following the End of the Third Quarter of 2020

While the vast majority of this IM report is focused on the activities and status of the ES 2 Program during the third quarter of 2020, the timing of certain Program elements and information provided by PSE&G naturally carried over beyond the end of the calendar quarter. Such information will generally be covered in the next IM quarterly report but given the importance of some of this information as it pertains to the key decisions made on the ES 2 Program, including the related discussion in **Section II.A.**, the IM has provided additional remarks to provide a more complete view of these mitigation changes based on the available information as of the date of this IM 2020 Third Quarter Report.

A. Decisions Recorded After the Third Quarter of 2020

Grid Modernization – Communication System Subprogram: Fiber Scope

On October 29, 2020, PSE&G recorded a Record of Decision to perform a full review of the fiber requirements and the status of all PSE&G substations and operations centers to verify communication needs.

The ES 2 filing included the installation of fiber to approximately 31 distribution substations not currently on the PSE&G transmission fiber system, seven operations centers, and the connection of approximately 133 substations with existing fiber at the substation. PSE&G noted to the IM that as PSE&G has continued to modernize the Distribution system outside of the ES Program, the fiber needs at substations and operations centers have also changed. PSE&G has advised that some locations no longer require fiber due to being scheduled for an upgrade, rebuild, or elimination, others now require fiber, and some have been transitioned to fiber communications.

Alternatives Considered:

1. Install fiber communication to all locations identified in the filing.
2. Perform a full review of the fiber requirements and status of all PSE&G substations and operational centers to verify fiber communication needs.

As PSE&G began to undertake the ES 2 Program, PSE&G noted to the IM that as PSE&G's Distribution grid evolved so did the list of locations that require a high-speed reliable, redundant, and resilient communication network, all a major component of the Grid Modernization subprogram. The overall network will use wireless and fiber technology that will enable communications with a broad range of electric distribution field assets and customer equipment. This ROD is noted to only be for the substation fiber and operations fiber install.

The full review contemplated under this ROD is as follows:

1. Remove Substations and Operation Centers where fiber installation is no longer required or are currently communicating via PSE&G fiber backbone.
2. Place on hold any Substation or Operation Center where the future status of the station is not clearly defined. Once a final determination is made the status will be revised.
3. Identify potential candidates for inclusion in the fiber install program. To be considered, the location needs to meet the following criteria:
    a. Known future status-not subject to being eliminated/upgraded in the near-term
    b. Location is operationally enabled to expand and utilize PSE&G's Fiber Backbone
    c. Operationally Critical (key communication hub during Storm & Emergency Events)

d. Has existing or will support future SCADA [supervisory control and data acquisition] communications.

As of the date of the ROD, eight locations were removed from the scope, six were approved and added to the scope and five proposed locations were under review. Since that time, three additional locations were removed from scope, which PSE&G noted will be reported in a subsequent amendment to the first ROD document.

The IM inquired to PSE&G if the cost of the full review of all PSE&G substation fiber requirements were captured within the subprogram costs. PSE&G responded that the cost of the PSE&G substation fiber requirement review was not directly captured in the subprogram costs. PSE&G noted that these types of scope review activities are part of the standard job function of PSE&G's Asset Management Group. These employees were noted to primarily charge Surcharge or operations & maintenance (O&M) orders depending on the specific activity being performed.

The IM also inquired as to the criteria in which the stations were added or removed from the list provided within the ROD (e.g., which element listed under "Decision Made" contributed to the changes in the table). PSE&G provided the IM with a table of the approved locations, locations removed from the scope, and the reasons for inclusion or elimination.

Five of the approved proposed locations were noted as a station not subject to elimination or upgrade in the near term and is operationally driven to utilize PSE&G's fiber backbone and is SCADA-enabled. The other location was noted to also be operationally critical as a key communication hub during storm and emergency events. For the locations eliminated, nine were noted to be scheduled for upgrade in the near future and the other two noted to have an existing connection to the PSE&G fiber backbone and was moved to the cutover program.

Findings and Observations

- The review and vetting process is being put in place to maximize the value of the ES 2 Program budget allocated to fiber initiatives and to ensure the Program aligns with the current communication needs.
- The IM finds that PSE&G's decision to undertake the review is appropriate and will enable that the projects included in the fiber scope will maximize the efficiency of the network to meet the filing scope of the Grid Modernization subprogram.
- The IM finds the process for determining whether to add or eliminate the location from the scope is reasonable.
- The proposed budget for the scope of work contemplated within the 2018 filing was $24 million (fiber portion of Grid Modernization). The fiber scope to be performed at the approved selected locations is currently forecasted at approximately $21.5 million, suggesting an opportunity to potentially include additional projects.

B. Additional Information on the Constable Hook, Lakeside Avenue, and Orange Valley Mitigation Changes

On October 5, 2020, the State of New Jersey Division of Rate Counsel (Rate Counsel) responded to PSE&G's notice of change in mitigation method by objecting to PSE&G implementing the changes without further clarification, citing to the Stipulation at paragraph 24. Rate Counsel noted that there were remaining questions regarding these PSE&G proposed changes including whether they will likely deliver the same benefits to customers or are appropriate under the circumstances. Rate Counsel requested that all activities cease related to these changes in mitigation until such time as additional information and clarification is provided by PSE&G.

The IM received and reviewed the discovery requests and responses relating to this issue (including BPU Staff requests S-INF-0001 through S-INF-0003 and Rate Counsel requests RCR-INF-0001 through RCR-INF-0006). The responses provide requested information concerning the original and revised transmission and distribution project costs (including whether land and demolition costs are captured in the estimates), timing of when specific factors leading to the decision to change the mitigation method at these substations were identified by PSE&G, and other related information such as the environmental status of the proposed new Orange Valley site and if the new Lakeside/101 N. Park Street substation will incorporate loads from other substations.

The IM also received a presentation on the proposed mitigation method changes at Constable Hook, Lakeside Avenue, and Orange Valley from PSE&G dated October 22, 2020. This presentation provided additional information on the proposed changes including maps of the current and newly proposed sites and the drivers and benefits offered by the proposed changes.

On January 6, 2021, PSE&G wrote to both the BPU and Rate Counsel stating that the plans and estimates provided in the Company's initial ES 2 filing were based on the "best information available at the time" noting that as projects shift into the implementation phase, changes in project estimates and "as-filed" mitigation methods may be necessary as contemplated in the Stipulation. Relative to the prior change in mitigation method at State Street, PSE&G stated that in this limited circumstance, the Company will seek recovery of additional cost over the filing estimate in its next rate case as opposed to through the ES 2 accelerated recovery mechanism. With respect to Lakeside Avenue, Orange Valley, and Constable Hook, PSE&G stated that all requested information regarding the changes have been identified and provided to both the BPU Staff and Rate Counsel. PSE&G also stated that it is moving forward with the changes as discussed in part to benefit from the identified efficiencies, which will result in savings and increased reliability for customers.

On January 19, 2021, Rate Counsel responded to PSE&G's January 6, 2021 letter indicating Rate Counsel did not oppose PSE&G's decision to seek recovery of the increased cost for State Street in its next rate case as opposed to ES 2. Rate Counsel also stated that it cautioned PSE&G that the Company would be proceeding on the changes to Constable Hook, Lakeside, and Orange Valley at its own risk in accordance with paragraph 39 of the Stipulation noting that prudency of projects undertaken in ES 2 Program "would not take place prior to or in connection with the rate adjustments established herein."

In its January 19, 2021 letter to PSE&G, Rate Counsel noted it had specific concerns regarding the changes in mitigation method to the Constable Hook substation. Rate Counsel believes that the changes to the Constable Hook project should be excluded from the ES 2 Program since based on the information provided by PSE&G, the Company's justification for the change in mitigation method at Constable Hook to accommodate the new load at the former Military Ocean Terminal appears inconsistent with the Board's requirements for an Infrastructure Investment Program (IIP) under N.J.A.C. 14:3-2A.1. Rate Counsel stated that the BPU's regulations limit the use of the IIP to "non-revenue producing utility plant and facilities that enhance safety, reliability, and/or resiliency." Rate Counsel noted that although PSE&G identified Bergen Point as a life cycle station due to its age, that it is not part of the ES2 Program since Class A Stations with indoor 4kV equipment have been classified as lower risk than the Class C outdoor stations. Although combining the substation projects to accommodate the anticipated load growth and addressing life cycle issues will result in lower costs for the Company overall, Rate Counsel believes that it should be undertaken through traditional base recovery and not the ES 2 Program.

On February 19, 2021, PSE&G, Rate Counsel, and BPU Staff participated in a conference call to discuss Rate Counsel's objections. During this call, PSE&G explained the proposed change for the Constable Hook substation as consistent with its response to discovery request S-PSEG-ENG-002, including that any costs associated with addressing load growth would be tracked separately under a base capital project and not recovered through the ES 2 accelerated recovery mechanism. However, due to the complexities associated with this project, it became apparent that PSE&G would not be able to complete the Constable Hook project within the ES 2 Program window. Accordingly, PSE&G informed the parties of its intent to remove the Constable Hook substation from the ES 2 Program and instead perform this flood mitigation work as a base capital project. PSE&G also noted its intent to use the funds allocated for Constable Hook to perform additional life cycle station work in accordance with the terms of the Stipulation.

The IM will report on the status of this change as it becomes formalized through PSE&G's processes and as the additional life cycle station work is identified and selected.

ENERGY STRONG PROGRAM
INDEPENDENT MONITOR
2020 THIRD QUARTER REPORT

APPENDIX A – DRAFT REPORT COMMENTS AND RESPONSES

11 MAY 2021

PEGASUS GLOBAL HOLDINGS, INC. ®

Questions & Comments to the IM 2020 Third Quarter Report Formally Submitted to the IM

ID #	Question/Comment	IM Response	Report Changes
S-INF-1	Reference Page 1, Table 1 – ES 2 Subprogram & Stipulated Base Status as of September 30, 2020 a. What is attributed to the forecasted cost of the Contingency Reconfiguration subprogram decreasing from $150.8 million in the Independent Monitor's ("IM's") Q2 2020 Report to $131.9 million in the IM's Q3 2020 Report? b. What is attributed to the forecasted cost of the Gas Metering and Regulation ("M&R") Station Upgrades subprogram increasing from $65.6 million in the IM's Q2 2020 Report to $76.2 million in the IM's Q3 2020 Report?	a. The change in the Contingency Reconfiguration subprogram forecast from the second to third quarter of 2020 was predominantly driven by the removal the removal of 117 13kV reclosers and 109 4kV reclosers. This was the result of a detailed assessment of each circuit to determine the current status reflecting updated system plans and changes or other work done subsequent to the ES 2 filing. While outside of the third quarter of 2020, the IM also points out that the Contingency Reconfiguration subprogram forecast increased to approximately $162.8 million as of the end of 2020 based on a placeholder for additional reclosers currently being reviewed and an increase in the cost per unit of the fuse savers based on the actual cost trend of the pilot program. b. The change in the Gas M&R forecast was predominantly driven by an increase to the forecast for the Central M&R project from $12.8 million as of the second quarter of 2020 to $23.9 million as of the third quarter of 2020. This forecast was validated and incorporated into the project's Study level estimate that was approved at $30.0 million (including R&C) in December 2020. The increase was driven by higher construction costs based on the engineer's 50% estimate, additional buildings and equipment required for the refined design, and additional project management, engineering, and licensing and permitting support not included in the prior estimate.	**Sections I. and II.B.**
S-INF-2	Reference Page 2, Table 2 – ES 2 Electric Station Flood Mitigation Status as of September 30, 2020 Please provide the total forecasted costs of each Electric Station Flood Mitigation project.	The total forecasted costs for each Electric Station Flood Mitigation project (as of the end of the third quarter of 2020) has been incorporated into **Table 2**.	**Table 2**
S-INF-3	Reference Page 8 Regarding the Orange Valley project scope change, please describe how the allocation of common site costs was	The common site costs allocation between the ES 2 and 69kV Orange Valley projects was determined by PSE&G based on the ratio of each project's Study level estimated cost of station equipment and structures	**Section II A.3.**

ID #	Question/Comment	IM Response	Report Changes
	determined (15% going towards the Energy Strong II project and 85% going towards the transmission project).	to the total estimate cost of station equipment and structures for both projects, which was then rounded to the nearest 5%.	
S-INF-4	Reference Page 15, Table 9 – ES 2 AFUDC as of September 30, 2020 Please reconcile the Allowance for Funds Used During Construction recorded within the Electric Station Flood Mitigation subprogram during Q2 2020 ($191,807) with the same value as reported in the IM's Q2 2020 Report ($83,234).	The IM 2020 Second Quarter Report incorrectly reported the AFUDC for the Electric Station Flood Mitigation subprogram as $83,234 (the June 2020 AFUDC amount) rather than the $191,807 figure shown in this report (which represents the total AFUDC for Q2 2020 on that subprogram). In the IM's review of this item, it was determined other Q2 2020 AFUDC figures had similar issues where the June 2020 amount rather than the full second quarter amount was depicted and the Q1 2020 AFUDC figures were correct for each subprogram, but did not distinguish between the two Grid Modernization subprograms and totaled slightly off the correct amount. A corrected IM 2020 First and Second Quarter Reports are being issued to address these errors in the prior reports.	**Table 9**
S-INF-5	Reference Page 18, Table 12 – Q3 2020 Major Event Performance of Energy Strong/ES 2 Investments Please provide the average System Average Interruption Frequency Index ("SAIFI") and Customer Average Interruption Duration Index ("CAIDI") of circuits improved by Energy Strong and Energy Strong II projects during Tropical Storm Isaias and compare to the average SAIFI and CAIDI of unimproved circuits.	The requested comparison has been incorporated into the discussion on this Major Event in the new **Table 13**.	**Section II.D.1. / Table 13**
S-INF-6	Reference Page 19, Table 13 – Tropical Storm Isaias Comparable Major Events Please compare the System Average Interruption Duration Index ("SAIDI") of circuits improved by Energy Strong and Energy Strong II projects during Tropical Storm Isaias to the SAIDI of these same circuits during Hurricane Irene, Wet Snowstorm (11/6/2011), and the March 2020 Nor'Easter Storm.	The requested comparison has been incorporated into the discussion on this Major Event in the new **Table 14**.	**Section II.D.1. / Table 14**
S-INF-7	Reference Pages 24-25, Table 18 – ES 2 Electric Station Flood Mitigation Project Cost Status as of September 30, 2020 Please confirm that the Electrical Station Flood Mitigation subprogram base spending estimate should total $311.9 million (rather than $309.4 million) and risk and contingency should total $73.7 million (rather than $77.2 million).	Table 18 in the draft report (now **Table 20** in this final draft) had incorrect total amounts for the base and R&C figures, the correct amounts ($311.9 million base, $73.7 million R&C, and $385.5 million total) have been updated in this final report.	**Table 20**
S-INF-8	Reference Page 26, Electric Station Flood Mitigation Projects – Hasbrouck Heights	The associated Hasbrouck Heights 69kV project encountered Covid-19 related delays stemming from an equipment vendor not being able to	No change

ID #	Question/Comment	IM Response	Report Changes
	Regarding the Hasbrouck Heights substation project, pleas provide additional details about the COVID-19 related delay which shifted construction from June 2021 to August 2021.	travel to the site, which delayed installation of equipment on the 69kV project. The Hasbrouck Heights ES 2 project requires installation of the 69kV project first, which resulted in the construction shifting on the ES 2 project from June 2021 to August 2021.	
S-INF-9	Reference Page 28, Electric Station Flood Mitigation Projects – Market Street With respect to the Market Street substation project, what is attributed to the base estimate increasing from $24.2 million in Q2 2020 to $26.7 million in Q3 2020?	As the Market Street substation project advanced from a Study level to Conceptual level estimate, the primary changes to the base estimate were: • Change in T&D surcharge methodology, approved by PSE&G Accounting, +$2.5 million • Outside plant soil remediation, +$1.2 million • Estimate refinement, ($1.2 million) The net $2.5 million increase to the base estimate was offset by a reduction in R&C, resulting in no overall change to the project's estimate.	**Section III.A.8**
S-INF-10	Reference Page 34, Table 22- ES 2 Grid Modernization – Communication System Costs as of September 30, 2020 Regarding the Grid Modernization – Communications subprogram, what is attributed to the forecasted cost of fiber cutovers decreasing from $6,735,000 in the IM's Q2 2020 Report to $930,560 in the IM's Q3 2020 Report?	The difference between the fiber cutover forecast from Q2 2020 to Q3 2020 is attributed to the Q2 2020 forecast ($6,735,000) representing the full cutover funding as approved at the onset of the ES 2 Program. As the subprogram has developed, PSE&G has identified that fiber estimates have come in higher than initially planned and with more projects available than there is funding for, PSE&G is maintaining flexibility in allocating funds within this subprogram and will continue to update its forecast based on the current cutover projects selected by the subprogram.	No change
RCR-IM-1	With reference to pages 1 and 31, please explain the "minor inventory issues" for the Contingency Reconfiguration subprogram.	The lead-time on recloser orders is typically approximately four months. The recloser manufacturer experienced Covid-19 impacts and shipping issues that delayed a shipment of additional 4kV reclosers by approximately one month. To mitigate potential impacts, PSE&G reallocated its existing recloser inventory such that Metro Division with the largest population of 4kV circuits and smallest population of 13kV circuits received all 4kV reclosers in the inventory. During this time, the subprogram was also impacted by weather that limited installations. No overall lasting impacts to the subprogram have resulted from this issue.	No change
RCR-IM-2	With reference to page 2, Table 2, please explain the anticipate slip in schedule for the Clay Street substation and whether the Company experienced permitting delays or project execution plan development delays that contributed to the slip in schedule.	The forecasted in-service date for the Clay Street project changed from December 27, 2022 as of the end of the second quarter of 2020 to January 12, 2023 as of the end of the third quarter of 2020, or a 16-day slip. While this is within the 60-day threshold the IM has used since the original Energy Strong Program to evaluate schedule changes, the IM understands the delay is driven by the development and approval of the	No change

ID #	Question/Comment	IM Response	Report Changes
		licensing and permitting package, including related delays in early 2021 in scheduling a meeting with the Newark planning board due to Covid-19 restrictions.	
RCR-IM-3	With reference to page 2, Table 2, please explain the anticipated slip in schedule for the Kingsland substation and whether this slip is attributable to the change in scope or related to the reduction in switchgear commitment described later on page 27.	The IM draft report incorrectly identified the Kingsland substation has having a Q2 to Q3 schedule slippage, there was no change in the forecasted in-service date for the Kingsland substation during this period. However, the Hasbrouck Heights substation listed above Kingsland in **Table 2** did have a change in the forecasted in-service date from November 18, 2022 as of the end of the second quarter of 2020 to December 2, 2022 as of the end of the third quarter of 2020. While this is within the 60-day threshold the IM has used since the original Energy Strong Program to evaluate schedule changes, the schedule change was the result of Covid-19 related delays to the associated Hasbrouck Heights 69kV project (see **Section III.A.4.**).	**Table 2**
RCR-IM-4	With reference to page 2, Table 2, please explain the anticipated slip in schedule for the Leonia substation and whether this slip is due to delays in construction.	The forecasted in-service date for the Leonia project changed from November 30, 2022 as of the end of the second quarter of 2020 to December 2, 2022 as of the end of the third quarter of 2020, or a 2-day slip. Because of this extremely small variance, the IM considers this to be normal schedule movement and has not performed additional analysis on the schedule.	No change
RCR-IM-5	With reference to page 2, Table 2, please explain the anticipated acceleration in schedule for Ridgefield 13kV.	The forecasted in-service date for the Ridgefield 13kV project changed from October 19, 2022 as of the end of the second quarter of 2020 to October 7, 2022 as of the end of the third quarter of 2020, or a 12-day advancement to the schedule. While this is within the 60-day threshold the IM has used since the original Energy Strong Program to evaluate schedule changes, the IM understands this schedule advancement is the result of PSE&G reviewing the schedule activities and durations, which resulted in a slight improvement to the overall project schedule.	No change
RCR-IM-6	With reference to page 2, Table 2, please explain the anticipated acceleration in schedule for the Waverly substation.	The forecasted in-service date for the Waverly project changed from December 4, 2023 as of the end of the second quarter of 2020 to November 16, 2023 as of the end of the third quarter of 2020, or a 18-day advancement to the schedule. While this is within the 60-day threshold the IM has used since the original Energy Strong Program to evaluate schedule changes, the IM understands this schedule advancement is primarily the result of the Phase 2 and Phase 3 construction activities advancing approximately two weeks, which also pulled the in-service date forward.	No change

ID #	Question/Comment	IM Response	Report Changes
RCR-IM-7	With reference to page 2 and 6 through 8, please provide an explanation to the described property owner issue for the 101 N. Park Location. a. Will this issue cause a change in mitigation strategy for the substation? b. Does the company have another site if the current site location cannot be used?	The 101 N. Park location represents the proposed mitigation change from the original Lakeside Avenue location. There is no present property owner issue at the 101 N. Park site and PSE&G anticipates closing its acquisition of the property in December 2021.	No change
RCR-IM-8	With reference to page 4, please explain why the range in bids is so large for creating a wireless network across the PSE&G service territory.	The primary factor in the range of pricing is based on the spectrum requirements, with the FirstNet option not requiring the purchase of additional spectrum and other vendors having a spectrum cost of up to $156 million. The 5-year estimated O&M costs were also lower with FirstNet.	No change
RCR-IM-9	With reference to page 4, is FirstNet architecture completely separate from the AT&T LTE network also contemplated by the Company?	The FirstNet network is the result of a public-private partnership with AT&T. Essentially, AT&T is responsible for building the network using spectrum dedicated to public safety by the Federal government, which is distinct from AT&T's commercial LTE network.	No change
RCR-IM-10	With reference to page 4, is the $28.7 million the cost for the life of the project? Are there fees to be paid that are not included?	The $28.7 million figure represents the cost to construct the network and does not include operating and maintenance costs.	No change
RCR-IM-11	With reference to page 9, is the transaction still expected to close in April 2021 for the new Orange Valley substation location?	As of the date of this report, the property has not yet closed, but is expected to in April-May 2021.	No change
RCR-IM-12	With reference to page 18, which substations were impacted as a result of Tropical Storm Isaias? What was the damage to those substations?	The substations shut down during this Major Event were: Avenel, Clark, Harts Lane, Hudson Terrace (shut down a second time during restoration efforts), Bordentown, Medford, Montgomery, Mount Holly, Princeton, and, Southampton. None of these substations experienced damage or flood intrusion as a result of Tropical Storm Isaias.	**Section II.D.1.**
RCR-IM-13	With reference to pages 18 and 19, Table 12, please identify the units. Are they minutes or hours?	The SAIDI calculations presented are based on minutes.	**Table 12**
RCR-IM-14	With reference to pages 20 and 21, Table 14, please identify the units. Are they minutes or hours?	The SAIDI calculations presented are based on minutes.	**Tables 14 & 16**
RCR-IM-15	With reference to page 25, will the Orange Valley substation work be completed outside the ES2 timeframe?	As of the end of the third quarter of 2020, the Orange Valley project was forecasted to be completed in January 2024. However, as noted in the report, PSE&G is examining the potential to shorten durations and/or work activities concurrently to pull the in-service date into 2023 (as of	No change

ID #	Question/Comment	IM Response	Report Changes
		the January 2021 schedule, the most recent currently available to the IM, the forecasted in-service date has advanced to December 29, 2023).	
RCR-IM-16	With reference to page 29, please describe the underground work scope increase for Ridgefield 4kV.	There was no scope increase for the underground work; however, following the solicitation of bids from PSE&G's approved list of underground contractors and award going to the lowest bidder after analyzing the technical and commercial bid components, the award of this work was higher than PSE&G initially estimated by approximately $1.0 million.	No change
RCR-IM-17	With reference to page 36, Table 24, are these the worst performing Class A substations? Please confirm that they are all Class A substations.	As discussed in the IM 2020 Second Quarter Report, the four current life cycle station upgrade projects are all Class C substations. In addition, each is one of the 15 stations identified in PSE&G's ES 2 filing as having the highest priority for this scope of work. As part of the planning for the 15 highest priority stations, PSE&G evaluated the project complexity for each location. Given that only a limited number of projects can be completed as part of the Program, PSE&G selected three stations where standard equipment and processes could be utilized to upgrade the stations. The fourth project initially selected (Plainfield) will require special equipment to offload the station due to the property constraints. This equipment and construction process can be utilized for future life cycle projects and this project was selected to develop and refine these procedures.	No change
PSE&G-1	Stipulated Base AFUDC figures are missing from Table 9.	The Electric Stipulated Base AFUDC figures were incorporated into **Table 9**.	**Table 9**
PSE&G-2	The Ridgefield 4kV estimate in Table 18 reflects the Study Level estimate rather than the current Conceptual Level estimate.	The current Conceptual Level estimate for Ridgefield 4kV was incorporated into Table 18 (now **Table 20** in this final draft). The IM also notes that the Ridgefield 4kV discussion in **Section III.A.12.** showed the correct and current $20.2 million estimate.	**Table 20**
PSE&G-3	The Kingsland estimate on page 27 shows the prior Study level estimate rather than the revised Study level estimate.	The revised Study level estimate for Kingsland was incorporated into **Section III.A.5**. The IM also notes that the Kingsland estimate in **Table 20** showed the correct and current $8.3 million estimate.	**Section III.A.5**

ENERGY STRONG 2 PROGRAM INDEPENDENT MONITOR 2020 FOURTH QUARTER REPORT

PREPARED AND SUBMITTED BY

PEGASUS GLOBAL HOLDINGS, INC. ®

CONFIDENTIAL

SEPTEMBER 24, 2021

Table of Contents

Appendices

List of Acronyms and Abbreviations

Advanced Distribution Management Systems..ADMS

Allowance for Funds Used During Construction..AFUDC

Architectural and Engineering..A/E

Board of Public Utilities .... BPU

Construction Work In Progress.. CWIP

Costs of Removal.. COR

Distribution Management System.. DMS

Distributed Energy Resource Management System... DERMS

Energy Strong 2 .... ES 2

Environmental Protection Agency..EPA

Gas-Insulated Switchgear ....GIS

Gas Metering & Regulating...Gas M&R

Hazardous Waste Operations and Emergency Response...............................HAZWOPER

Henkels & McCoy ....H&M

Independent Monitor... IM

Issued for Construction...IFC

Issued for Review ....IFR

Liquid Propane Air ....LPA

Mobile Construction Workforce .... MCW

Open Systems International Inc. .... OSII

Outage Management System .... OMS

Passaic Valley Sewerage Commission .... PVSC

Per- and Polyfluoroalkyl Substances ....PFAS

Plain Old Telephone Service .... POTS

Public Service Electric & Gas .... PSE&G

Purchase Orders .... POs

Record of Decision ....ROD

Risk and Contingency..R&C

System Average Interruption Duration Index.. SAIDI

Transmission & Distribution..T&D

Utility Review Board ....URB

I. Executive Summary

Public Service Electric & Gas's (PSE&G's) Energy Strong 2 (ES 2) Program was established from a Stipulation that the involved parties agreed to in August 2019, as approved by a Board of Public Utilities (BPU) Order dated September 11, 2019, with an effective date of September 21, 2019. The Stipulation provided the ES 2 Program would be comprised of five primary subprograms: Electric Station Flood Mitigation; Contingency Reconfiguration; Grid Modernization – Communications; Grid Modernization – Advanced Distribution Management Systems (ADMS); and Gas Metering & Regulating (Gas M&R) Station Upgrades. In addition, a Stipulated Base spend was established that includes both an electric component (higher outside plant design standards and station life cycle upgrades) and a gas component (overlapping with the Gas M&R subprogram).

During the fourth quarter of 2020, the bulk of the spend within the ES 2 Program continued to be in the two largest subprograms: Electric Station Flood Mitigation with six projects continuing in construction; and, Contingency Reconfiguration that continues to advance the installation and commissioning of reclosers. Within the other subprograms, the Grid Modernization – Communication System subprogram continued to advance with the initiation of the 2020 fiber projects during the fourth quarter and placing three of the fiber installation projects and five of the fiber cutover projects in-service before the end of the year. The Grid Modernization – ADMS subprogram continued to plan and develop the platform and necessary hardware equipment, while the Gas M&R subprogram continued engineering design and other early project activities such as developing licensing and permitting packages and identification of major equipment/long-lead items. The four stations approved within the life cycle upgrades portion of the Electric Stipulated Base initiated detailed design and continued other planning activities. **Table 1 – ES 2 Subprogram & Stipulated Base Status as of December 31, 2020** below provides the spend to date on the subprograms within the ES 2 Program and Stipulated Base compared to the total forecast and forecasted completion for each.

Table 1 – ES 2 Subprogram & Stipulated Base Status as of December 31, 2020

Subprogram	Q4 Spend	Total Spend to Date*	Total Forecast*	% of Actuals to Forecast	Forecasted Completion**	Stipulation Funding Amount
Electric Station Flood Mitigation	**$21,896,101**	**$53,945,172**	**$339,403,267**	**16%**	**Jan 2024**	**$389M**
Contingency Reconfiguration	**$16,150,287**	**$59,636,044**	**$162,806,273**	**37%**	**Jun 2023**	**$145M**
Grid Modernization – Communications	**$7,656,612**	**$19,220,506**	**$59,306,886**	**32%**	**Dec 2023**	**$72M**
Grid Modernization – ADMS	**$4,120,822**	**$16,483,837**	**$40,374,139**	**41%**	**Oct 2022**	**$35M**
Electric Stipulated Base	**$962,284**	**$2,436,062**	**$100,000,000**	**2%**	**Dec 2023**	**$100M**
Gas M&R Station Upgrades^	**$1,843,109**	**$3,961,492**	**$76,815,837**	**5%**	**Dec 2023**	**$101M**
Total*	**$52,629,214**	**$155,683,114**	**$778,706,402**	**20%**	**Jan 2024**	**$842M**

-Note: total figures may not fully align due to rounding. Additionally, the total forecast includes only the base cost for the Electric Station Flood Mitigation and Gas M&R subprograms as PSE&G does not include risk and contingency (R&C) in its forecasts for these projects or placeholders for potential additional projects in these subprograms. See **Table 12 and **Table 20** for the Electric Station Flood Mitigation and Gas M&R project estimates, respectively, with base costs and R&C shown.*
***-Final in-service date.*
^-Includes both the ES 2 projects and the Stipulated Base gas projects.

Given the prominence of the Electric Station Flood Mitigation subprogram, which represents over half of the total ES 2 Program spending, a summary of the projects within this subprogram is provided below in **Table 2 – ES 2 Electric Station Flood Mitigation Status as of December 31, 2020**.

Table 2 – ES 2 Electric Station Flood Mitigation Status as of December 31, 2020

Project	Total Estimate	Actuals to Date	% of Actuals to Estimate	Forecasted In-Service Date*
1. Academy Street	$10,500,000	$4,374,948	42%	10/25/2021
2. Clay Street	$42,000,000	$995,748	2%	2/6/2023 (↓)
3. Constable Hook	$5,300,000	$115,640	2%	TBD
4. Hasbrouck Heights	$18,000,000	$1,279,782	7%	4/12/2023 (↓)
5. Kingsland	$8,300,000	$313,779	4%	10/4/2023
6. Lakeside Avenue	$47,900,000	$602,937	1%	12/13/2023 (↑)
7. Leonia	$32,200,000	$6,078,171	19%	9/30/2022 (↑)
8. Market Street	$26,900,000	$16,330,794	61%	9/22/2021
9. Meadow Road	$9,000,000	$598,209	7%	9/21/2023
10. Orange Valley	$20,200,000	$439,924	2%	1/24/2024 (↓)
11. Ridgefield 13kV	$25,500,000	$6,438,674	25%	10/13/2022 (↓)
12. Ridgefield 4kV	$20,200,000	$11,382,948	56%	5/28/2021 (↑)
13. State Street	$45,100,000	$739,738	2%	9/23/2022
14. Toney's Brook	$19,700,000	$585,036	3%	4/21/2023
15. Waverly	$35,400,000	$2,564,563	7%	11/8/2023 (↑)
16. Woodlynne	$19,400,000	$1,104,280	6%	10/11/2023 (↓)

**-Reflects the in-service date of the last major asset (e.g. switchgear), certain activities may take place after this date to support the final in-service date (i.e. when all customers are cutover).*
(↑)-Indicates the forecasted in-service date advanced from the prior quarter.
(↓)-Indicates the forecasted in-service date slipped from the prior quarter.

As indicated in **Table 2**, the projects that have advanced into construction (Academy Street, Leonia, Market Street, Ridgefield 13kV, Ridgefield 4kV, and Waverly) projects continue to have the highest spend. Additionally, five of the stations (Academy Street, Constable Hook, Lakeside Avenue, Market Street, and Orange Valley) had new estimates approved by the URB in during the fourth quarter of 2020. **Table 2** also shows that nine of the sixteen projects in this subprogram had movement in the forecasted in-service date, with four advancing and five slipping. Of these nine projects, only two (Hasbrouck Heights and Leonia) had movement more than 60 days, which is the threshold the IM applied during the original Energy Strong Program for evaluating changes to the project schedules. The Hasbrouck Heights forecasted in-service date moved from early December 2022 to mid-April 2023 due to Covid-19 related delays on the Siemens Gas-Insulated Switchgear (GIS) installation on the associated Hasbrouck Heights 69kV project, which has resulted in the Hasbrouck Heights ES 2 project delaying the start of construction from July 2021 to January 2022. The Leonia forecasted in-service date moved from early December 2022 to late September 2022 based on review of the durations for circuit cutovers and a resulting improvement in durations that allowed the in-service date to advance approximately two months.

The IM has found nothing to date that would jeopardize the ES 2 Program being completed on budget, while schedule challenges, particularly on the Orange Valley substation, will warrant further monitoring to ensure the Program is completed within the defined timeline.

As noted in the IM 2020 First Quarter Report, the IM conducts its assessment in accordance with Generally Accepted Government Auditing Standards (GAGAS, or more commonly referred to as the "Yellow Book" standards). The Yellow Book provides a framework for conducting performance management reviews/audit engagements with competence, integrity, objectivity, and independence that result in information used for oversight, accountability, transparency, and improvements of the audited programs and operations. On July 15, 2021, a draft report was presented and submitted to PSE&G, BPU Staff, and Rate Counsel. Per the Yellow Book, the transmittal of a draft report is intended to allow for review and comment by the audited entity and others to develop a fair, complete, and objective report. A summary of the comments on the draft report and the IM's responses are provided in **Appendix A – Draft Report Comments and Responses**. This **Appendix A** also identifies specific sections within this IM 2020 Fourth Quarter Report that have been edited, supplemented with additional information, or otherwise revised in response to the comments received.

II. Program Status

A. Key Decisions

In order to capture formalized key decisions regarding the ES 2 Program, PSE&G completes a "Record of Decision" (ROD) that includes a description of the decision; alternatives considered; the decision made; and, rationale for the decision. The RODs are assessed by the IM as they are completed to review their impact to the Program. In addition, the IM may request PSE&G complete a ROD to formalize a decision if such a decision has not yet been formalized through the ROD process.

The current and pending RODs as of the date of this IM 2020 Fourth Quarter Report are presented below in **Table 3 – ES 2 Records of Decisions**.

Table 3 – ES 2 Records of Decisions

Subprogram	Record of Decision	IM Comments
Electric Station Flood Mitigation	Academy Street & State Street Change in Mitigation Method	Reasonable and appropriate *(See Section B.1. in the IM 2020 First Quarter Report)*
Electric Station Flood Mitigation	Engineering Support for Energy Strong Program Projects	Reasonable and appropriate *(See Section B.2. in the IM 2020 First Quarter Report)*
Grid Modernization – Communication System	Wireless Communication Network – ESII-GM-3	Reasonable and appropriate *(See Section II.A.1. in the IM 2020 Third Quarter Report)*
Grid Modernization – Communication System	Substation Communication Center – ESII-GM-4	Reasonable and appropriate *(See Section II.A.2. in the IM 2020 Third Quarter Report)*
Grid Modernization – Communication System	Fiber Scope – ESII-GM-1	Reasonable and appropriate *(See Section IV.A. in the IM 2020 Third Quarter Report)*
Electric Station Flood Mitigation	Constable Hook, Lakeside, & Orange Valley Change in Mitigation Method	Reasonable and appropriate *(See Sections II.A.3. and IV.B. in the IM 2020 Third Quarter Report and additional discussion in **Section II.A.1.** below)*

Subprogram	Record of Decision	IM Comments
Grid Modernization – Communication System	Communication Retrofit of Replacement and non ES-II Units – ESII-GM-2	Reasonable and appropriate *(See **Section II.A.2.** below)*
Electric Station Flood Mitigation	Transfer of Clay Street Wastewater Wall Scope from ES2FM to Clay Street 69kV Project	Reasonable and appropriate *(See **Section II.A.3.** below)*
Electric Station Flood Mitigation	Market Street Radioactive Soil Testing and Handling – ESII-FM-1	Reasonable and appropriate *(See **Section IV.A** below)*

1. *Electric Station Flood Mitigation – Lakeside Avenue, Orange Valley, and Constable Hook Change in Mitigation Method*

As discussed within the IM 2020 Third Quarter Report (Sections II.A.3. and IV.B.), in September 2020, PSE&G formally proposed a change to the mitigation method at Lakeside Avenue, Orange Valley, and Constable Hook from raise and rebuild to relocate. Following an objection from Rate Counsel on the implementation of such mitigation methods changes without further clarification, PSE&G responded to requests from Rate Counsel and BPU Staff for additional information on these proposed changes, which continued to be discussed through the end of 2020. Additional information relative to this decision following the end of 2020 is provided in **Section IV.B.**

2. *Communication Retrofit of Replacement and non ES-II Units*

The Grid Modernization – Communication System subprogram features the implementation of a new wireless communication network to eliminate PSE&G's reliance on dedicated phone lines ("plain old telephone service", or "POTS") for remote communications. To address the existing reclosers that communicate via POTS lines, PSE&G is retrofitting these devices to allow communication on the new wireless network as part of this subprogram. During the normal course of operations, some of the existing reclosers fail and require replacement, the capital replacement units are budgeted and accounted for each year under Distribution Base Capital blankets and moving forward, and recloser will be commissioned via the new wireless network instead of reconnected to POTS lines. Additionally, several of the new reclosers being installed by PSE&G outside the ES 2 Program either were in stock or purchased during the period shortly after Program approval, these devices will be fitted with new wireless network radios to facilitate communication on the new wireless network.

Before reaching this decision, PSE&G considered the following alternatives:

For replacement of failed units:

1. Install replacement recloser with communication equipment required to operate on the new wireless network.
2. Install replacement recloser on POTS lines and retrofit communication to the wireless network at a later date.

For the cost application of new non-ES 2 recloser units:

1. Remove commissioning and radio costs from the ES 2 Program for any non-ES 2 reclosers installed after the filing was approved.
2. Create a cutoff point for the transitional period as year-end 2020 as to when commissioning costs can be attributed to the ES 2 retrofit initiative.
3. Apply commissioning costs for non-ES 2 reclosers to retrofit accounting for the duration of the ES 2 Program.

For both components of this decision, PSE&G's Grid Modernization – Communication System subprogram team in coordination with PSE&G's Asset Management group determined the appropriate course of action. This saves time and resources by eliminating the additional work of installing the new asset on POTS lines and later retrofitting it. It also establishes more reliable communications than existed on these units. For replacement of failed units, the decision was made to install the replacement reclosers with communication equipment required to operate on the new wireless network. For the cost application of new non-ES 2 recloser units, the decision was made to implement a cutoff deadline of year-end 2020 for when commissioning costs of these units can be applied to ES 2. This decision was based on a recognition that while some of these units were already part of an existing installation roadmap and would meet the intent of the ES 2 filing, however there was a need to establish a hard deadline rather than continue this approach indefinitely.

Both of these aspects of the Grid Modernization – Communication subprogram will be tracked as completed "existing retrofit" units and from a cost accounting standpoint, the guidance shown in **Table 4 – Retrofit Recloser Cost Treatment** will be applied to both scenarios:

Table 4 – Retrofit Recloser Cost Treatment

Scope Category	Scope Description	Accountable Project
Material	New Recloser	Distribution Base Capital Blanket
	Radio & Accessories	ES 2 Grid Modernization – Communication System
Labor	Removal of Defective Recloser	Distribution Base Capital Blanket
	Installation of New Recloser	Distribution Base Capital Blanket
	Commissioning of New Recloser	ES 2 Grid Modernization – Communication System

This cost allocation is intended to isolate the ES 2 labor and material costs that are only related to the preparation and commissioning of the asset for the new wireless network, which is consistent with the activities performed on a typical recloser retrofit in the Grid Modernization – Communication System subprogram. All other costs for these reclosers will be attributed to the appropriate Distribution Base Capital blanket or specific project.

Findings and Observations

- The IM finds that this decision reached by PSE&G appropriately addresses aspects of the Grid Modernization – Communication System subprogram that overlap with routine, non-ES 2 Program work.
- By allowing replacement reclosers not planned as part of the ES 2 Program to be connected to the new wireless network, it allows the benefits of the Program investments to be realized on these devices earlier than it otherwise would be.
- PSE&G's decision to segregate the costs elements of this type of work between ES 2 and base capital provides alignment with the standard recloser retrofits that are part of the subprogram.

3. Market Street Radioactive Soil Testing and Handling

On August 20, 2020, PSE&G recorded a ROD to utilize outside contractors/consultants Henkels & McCoy (H&M) as its OSHA Hazardous Waste Operations and Emergency Response Standard (HAZWOPER) contractor along with Kleinfelder for all spoils testing and monitoring of work areas in the Market Street Project area as part of the scope of work on the Market Street ES 2 Project.

During detailed engineering of the Outside Plant area of the Project, PSE&G discovered that the Market Street substation and a large portion of the Outside Plant area to be replaced (poles) are located within the Environmental Protection Agency (EPA) designated "Study Areas" within Gloucester City to address the potential presence of radioactive soil.

OSHA's HAZWOPER is established to protect workers at hazardous sites. To comply with the OSHA standard, PSE&G does not have appropriately trained internal resources to self-perform these tasks.

Alternatives were considered which included:

1. Provide necessary HAZWOPER training and certification to PSE&G personnel as well as provide the necessary tools, equipment, and procedures to be able to execute the work within the Study Areas with internal resources.
2. Hire suitably qualified contractors who are experienced and equipped to perform excavation and testing in the Study Areas within the required project schedule.

The PSE&G Mobile Construction Workforce (MCW) determined that the internal PSE&G resources were not available to handle excavation of radioactive material. The PSE&G Environmental Projects team also indicated that internal PSE&G resources were not available to perform testing of this type and scale. As a result, PSE&G Procurement recommended utilizing H&M to perform HAZWOPER excavations since they were already under contract for this type of work, under a previously competitive bid Master Service Agreement. PSE&G noted that conducting a new bid event for these services would likely result in higher rates than contained in the Master Agreement holding favorable rates to PSE&G and would likely delay the substation project by two to three months.

PSE&G indicated that Kleinfelder was chosen for testing and monitoring due to their experience with radioactive contamination, familiarity with associated EPA and U.S. Army Corp of Engineers projects in the Gloucester City area, along with their reliable service on recent PSE&G contamination projects.

The EPA reviewed and approved PSE&G's project plan for the work in the Study Areas and agreed to dispose of any radioactive material that is removed. PSE&G estimates the incremental cost for soil excavation, testing, and monitoring activities is approximately $1.8 million.

<u>Findings and Observations</u>

- The IM finds that PSE&G appropriately investigated the alternatives and making its decision to retain outside contractor/consultants did so based on obtaining the best pricing for the work to be performed and to reduce the risk of schedule delay.
- By hiring a certified HAZWOPER contractor to perform the excavations for the poles and place sonotubes within the Study Areas, PSE&G MCW crews were able to subsequently install new poles within the sonotubes, avoiding direct exposure to potentially contaminated soils.
- The EPA has already approved PSE&G's plan for the work allowing work to proceed without schedule delay.
- The IM further finds that PSE&G's decision will provide for safety of its own crews and avoid schedule delay that may have resulted if PSE&G had chosen to train its internal personnel for this specific location.

B. Program Management

Beginning in July 2020, the IM began participating in a bi-weekly call with PSE&G to review its bi-weekly ES 2 Program Dashboard. As with ES 1, the Dashboard provides a mechanism for PSE&G to monitor and control activities to be completed in order to achieve key near-term milestones, including a focus on recently completed activities, any key issues, and other key metrics (e.g. installation targets) as appropriate. These calls have proven to be an effective way for the IM to stay informed on current and upcoming activities and to allow a venue for discussions between the IM and PSE&G on these activities and status updates and continue to be held on a recurring basis.

C. Cost Assignments

1. Costs of Removal (COR)

Costs of Removal (COR) generally include costs for such activities as environmental removal, removal of inside station equipment, structures, foundations, towers and fixtures, conductors and other electrical devices, poles and fixtures, transformers, plant demolition, foundations, and removal of underground conduit and other wiring. Generally, COR are charged to Accumulated Depreciation and are amortized and recovered through a component of depreciation expense. The specific method and amount of recovery is determined in gas and electric rate cases before the BPU.

Table 5 – ES 2 Costs of Removal as of December 31, 2020, below itemizes the charges to COR for each quarter of 2020, total 2020, the fourth quarter of 2019 and total Energy Strong COR to date. These amounts do not reflect any salvage value reductions, which have been de minimis in the ES 2 Program through December 31, 2020.

Table 5 – ES 2 Costs of Removal as of December 31, 2020

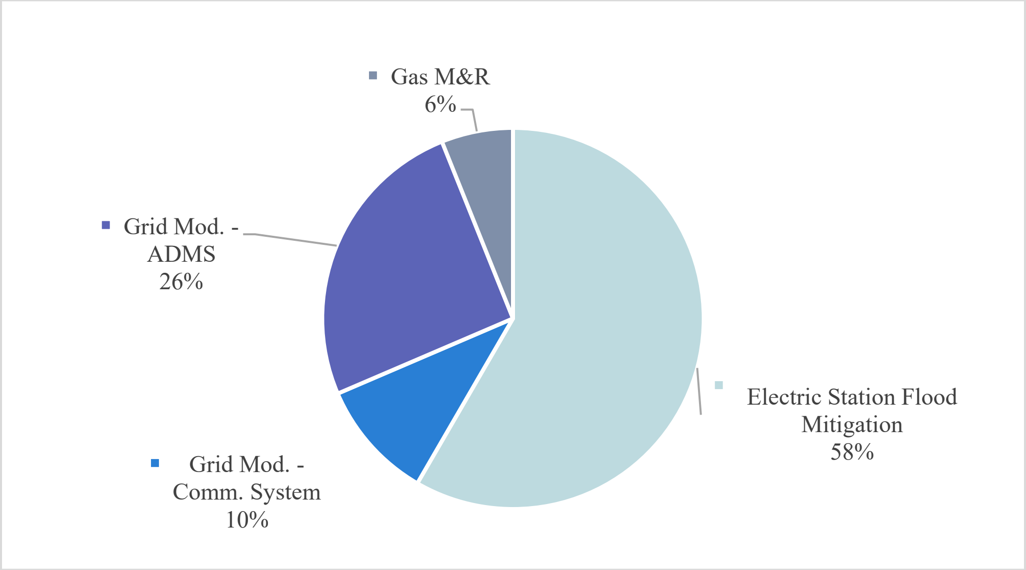
Subprogram	Q4 2020	Q3 2020	Q2 2020	Q1 2020	Total 2020	Q4 2019	Total COR
Electric Station Flood Mitigation	**$190,735**	**$294,089**	**$468,989**	**$67,332**	**$1,021,145**	**$0**	**$1,021,145**
Contingency Reconfiguration	**$707,300**	**$250,228**	**$624,595**	**$616,752**	**$2,198,875**	**$431,030**	**$2,629,905**
Grid Modernization – Communications	**$19,564**	**$3,384**	**$1,495**	**$0**	**$24,443**	**$0**	**$24,443**
Grid Modernization - ADMS	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Electric Stipulated Base	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Gas M&R Station Upgrades	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Total	**$917,599**	**$547,701**	**$1,095,079**	**$684,084**	**$3,244,463**	**$431,030**	**$3,675,493**

COR charges during the fourth quarter of 2020 increased from the third quarter by 68%, primarily due to a higher level of reclosers installations, with the associated pole and conductor removals, in the fourth quarter from the third. The increase in Grid Modernization COR in the fourth quarter of 2020 from the third quarter reflects the removal of existing communications equipment related to the recloser installations, and to removal of equipment in support of the fiber projects.

2. Construction Work-in-Progress (CWIP) & In-Service Transfers

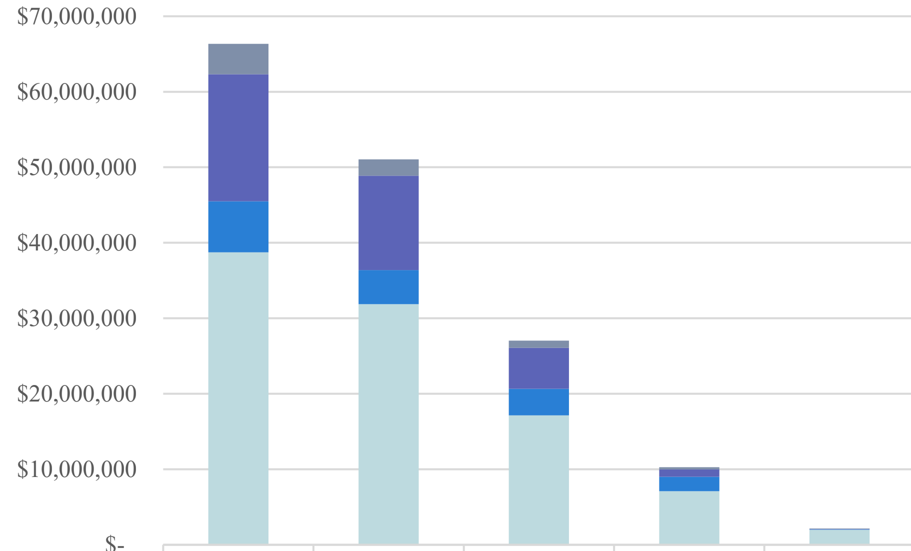
As of December 31, 2020, the ES 2 CWIP balance was $66.4 million, compared to $51.0 million as of September 30, 2020. The largest components of December 31, 2020 CWIP were the work associated with the elimination and conversion of the 4kV circuits at Ridgefield substation ($13.8 million in total), work at Leonia substation ($6.1 million), and work associated with the Advanced Distribution and Management System ($16.8 million). The Electric Flood Mitigation subprogram comprises the largest component of total end of period CWIP outstanding, as depicted in the **Figure 1 – ES 2 CWIP as of December 31, 2020** below.

Figure 1 – ES 2 CWIP as of December 31, 2020



In addition, the **Figure 2 – ES 2 CWIP Balances by Subprogram as of December 31, 2020** below depicts the composition of end-of-quarter CWIP balances by subprogram for each quarter of the year 2020, and the fourth quarter of 2019.

Figure 2 – ES 2 CWIP Balances by Subprogram as of December 31, 2020



	Q4 2020	Q3 2020	Q2 2020	Q1 2020	Q4 2019
Gas M&R	$4,031,780	$2,149,077	$951,151	$290,933	$52,661
Grid Mod. - ADMS	$16,836,599	$12,501,905	$5,428,105	$969,089	$36,309
Grid Mod. - Comm. System	$6,759,807	$4,529,142	$3,507,786	$1,907,846	$74,531
Electric Station Flood Mitigation	$38,726,730	$31,859,982	$17,149,382	$7,101,458	$1,987,285

Transfers from CWIP to plant in-service have totaled $5.2 million as of December 31, 2020, all of which was comprised of Grid Modernization projects. It should be noted that work related to certain assets, such as blanket projects and the reclosers under the Contingency Reconfiguration subprogram, generally can be completed without being recorded through CWIP, and thus, are not recorded as transfers from CWIP. During the fourth quarter of 2020, the company made an adjustment to CWIP to reflect a reversal of about $9.2 million from CWIP to direct in-service. This adjustment was to the Market Street 4kV substation elimination ($7.0 million) and Ridgefield 4kV substation elimination ($2.2 million) to recognize that certain work orders meet the definition of blanket projects and should not have been recorded as CWIP. This adjustment also affected previously recorded amounts for AFUDC (see **Section II.C.3.**).

3. *Allowance for Funds Used During Construction (AFUDC)*

The amount of quarterly AFUDC recorded by the Company for each ES 2 subprogram during each quarter of 2020, total year 2020, the fourth quarter of 2019, and total ES 2 AFUDC accrued to date, is shown below in **Table 6 – ES 2 AFUDC as of December 31, 2020**.

Table 6 – ES 2 AFUDC as of December 31, 2020

Subprogram	Q4 2020	Q3 2020	Q2 2020	Q1 2020	Total 2020	Q4 2019	Total AFUDC
Electric Station Flood Mitigation	$305,014	$377,009	$191,807	$62,618	$936,448	$9,887	$946,335
Contingency Reconfiguration	$0	$0	$0	$0	$0	$0	$0

Subprogram	Q4 2020	Q3 2020	Q2 2020	Q1 2020	Total 2020	Q4 2019	Total AFUDC
Grid Modernization – Communications	**$66,204**	**$43,496**	**$60,073**	**$14,572**	**$184,345**	**$225**	**$184,570**
Grid Modernization - ADMS	**$213,873**	**$103,228**	**$28,474**	**$7,092**	**$352,667**	**$96**	**$352,763**
Electric Stipulated Base	**$32,603**	**$11,413**	**$0**	**$0**	**$44,016**	**$0**	**$44,016**
Gas M&R Station Upgrades	**$39,594**	**$19,385**	**$8,465**	**$2,590**	**$70,034**	**$254**	**$70,288**
Total	**$657,288**	**$554,531**	**$288,819**	**$86,872**	**$1,587,510**	**$10,462**	**$1,597,973**

During the first quarter of each year, the AFUDC rate is reviewed for possible reset as it applies the current year based on updated capital structure and component cost data. For the year 2020, the new AFUDC rate was calculated to be 6.95%, using the capital structure and component costs as of January 31, 2020. In calculating the 2020 AFUDC rate, the Company used (i) a 4.02% embedded cost of long-term debt, (ii) a short-term debt rate of 1.86%, and (iii) a cost of equity of 9.60%.

Subsequent to the annual reset calculation referred to above, and during the course of each year, the AFUDC rate is also recalculated as it applies to each fiscal quarter. If the recalculated rate changes by 25 basis points from the rate then in effect, the rate is reset and retroactively applied to January 1 of that year. For the fourth quarter of 2020, based on data as of November 30, 2020, the recalculated weighted average AFUDC accrual rate (6.96%) did not meet this criterion to warrant changing from the annual rate (6.95%) in effect. Therefore, AFUDC was accrued during the fourth quarter of 2020 at the calculated rate of 6.95%.

AFUDC accrued for ES 2 projects during the fourth quarter of 2020, taking into consideration the reclassification referred to above, increased significantly over AFUDC accrued during the third quarter of 2020 as the result of the increases in total average CWIP balances across all subprograms. The reclassification adjustment related to certain work orders for the Market Street and Ridgefield 4kV substations, referred to in **Section II.C.2.**, resulted in a reduction in fourth quarter AFUDC of $186,260.

The IM observes that the Company's calculation of the AFUDC rate and its application is in accordance with both PSE&G's accounting policy and Plant Instruction 3(17) of the Federal Regulatory Commission's Uniform Systems of Accounts prescribed for public utilities.

The IM also notes that the relevant AFUDC information as it relates to fourth quarter 2020 ES 2 project costs is consistent with the applicable dictates of the Stipulation entered into with respect to these ES 2 projects. The IM will continue to review future ES 2 AFUDC accruals for consistency with relevant provisions of the Stipulation for accounting and reporting purposes only, and not as a party to, or in expressing an opinion concerning, any rate proceedings.

4. Allocated Overheads

PSE&G follows a philosophy of allocating overhead costs, whether at the Service Company or from utility support organizations, to the operating company or unit receiving the benefit, and ultimately, if appropriate, settling costs to individual assets. Where possible, services are charged directly to the entity receiving the benefit, but where direct charging of costs is not feasible, cost allocations from the Service Company to operating companies are prescribed in a BPU-approved schedule issued pursuant to a BPU order in July 2003. The Stipulation requires the Company to follow its current practices with regard to capitalized overheads.

For ES 2 electric and gas distribution projects, allocated overhead costs should primarily come from utility-related labor costs associated with administrative and supervisory personnel, labor and other costs associated with bargaining unit personnel, fringe benefits, materials handling costs, payroll taxes and depreciation expense. Shown below in **Table 7 – ES 2 Overhead Allocations as of December 31, 2020** are the allocated overhead costs charged to ES 2 projects for all four quarters of 2020, total 2020, the fourth quarter of 2019, and total allocated overheads to date.

Table 7 – ES 2 Overhead Allocations as of December 31, 2020

Subprogram	Q4 2020	Q3 2020	Q2 2020	Q1 2020	Total 2020	Q4 2019	Total Overhead Allocations
Electric Station Flood Mitigation	$4,924,531	$3,890,087	$3,560,216	$1,648,117	$14,022,951	$286,953	$14,309,904
Contingency Reconfiguration	$6,010,891	$3,350,239	$3,055,700	$4,692,085	$17,108,915	$3,415,460	$20,524,375
Grid Modernization – Communications	$2,170,097	$561,011	$548,017	$345,720	$3,624,845	$12,074	$3,636,919
Grid Modernization – ADMS	$111,743	$105,563	$91,786	$116,442	$425,534	$10,603	$436,137
Electric Stipulated Base	$104,386	$155,112	$0	$0	$259,498	$0	$259,498
Gas M&R Station Upgrades	$91,988	$78,452	$68,257	$52,836	$291,533	$15,287	$306,820
*Total**	$13,413,636	$8,140,465	$7,323,975	$6,855,199	$35,733,275	$3,740,376	$39,473,651
**-Note: total figures may not fully align due to rounding.*							

The overwhelming majority of overhead costs allocated to ES 2 projects during the fourth quarter of 2020 are costs allocated from areas that support all utility distribution and transmission projects, including ES 2 projects. More specifically, most of the fourth quarter allocated costs reflect labor costs of supervisory, administrative and operations planning personnel, labor and other costs from bargaining unit personnel, and fringe benefits associated with these labor costs. The increase in overheads for the fourth quarter 2020 over the third quarter largely reflects higher ES 2 project activity, and a return to a more normal overhead surcharge pattern from the Isaias storm restoration efforts in August, during which significant bargaining unit labor costs were charged to non-ES 2 projects in connection with service restoration activity.

The IM believes these allocations represent no change in the Company's normal methodology of allocating overhead costs.

D. System Performance

1. Current Reporting Quarter Major Events

During the fourth quarter of 2020, there was one Major Event reported in PSE&G's service territory concerning a State of Emergency declared due to a snowstorm. The State of Emergency was declared by Governor Murphy on December 16, 2020 and was lifted on December 18, 2020. During this Major Event period, 5,108 PSE&G customers experienced extended service interruptions with all returned to service within 29 hours.

The IM has received PSE&G's report on the performance of its investments from this Major Event and has reproduced the results in **Table 8 – Q4 2020 Major Event Performance** below.

Table 8 – Q4 2020 Major Event Performance

Circuit	5 Year Baseline SAIDI*	Report Quarter SAIDI*
ALD 8015	0.12276	0.00000
ALD 8016	0.00654	0.00000
LAU 8014	0.25642	0.00000
LAU 8035	0.29567	0.00400
LAW 8025	0.16759	0.00269
LUM 8014	0.29932	0.00310
MAY 8013		0.00000
MAY 8014	0.03470	0.00000
NEW 8033	0.00571	0.00000
NOT 8013		0.00000
TNY 4001	0.02964	0.00081
**-SAIDI calculations are in minutes.*		

In the circuit data above, the "0.00000" values in the Report Quarter SAIDI data indicates an outage occurred during this Major Event, but the value is beyond five decimal points captured by PSE&G. As indicated above, there were relatively few circuits impacted by this Major Event with the majority of the affected circuits having experienced outages less the 5-year Major Event average (with the only exceptions being two circuits that had extremely minor outages during this Major Event and no other Major Event outage within the 5-year window that forms the reported Major Event average SAIDI).

III. Project Status

A. Electric Station Flood Mitigation

A summary of the subprogram plan as of the end of 2020 is provided below in **Table 9 – ES 2 Electric Station Flood Mitigation Subprogram Milestone Schedule as of December 31, 2020**.

Table 9 – ES 2 Electric Station Flood Mitigation Milestone Schedule as of December 31, 2020

Project	Plan Status Point	2019		2020				2021				2022				2023				2024
		Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	
1. Academy Street	Dec. 2019		KO					C					IS		CO					
	Dec. 2020		KO		C							IS		CO						
2. Clay Street	Dec. 2019	*Schedule Under Development*																		
	Dec. 2020			KO							C								IS	CO (Q2)
3. Constable Hook	Dec. 2019	*Schedule Under Development*																		
	Dec. 2020	*Schedule Under Development*																		
4. Hasbrouck Heights	Dec. 2019		KO						C						IS		CO			
	Dec. 2020		KO									C					IS		CO	
5. Kingsland	Dec. 2019			KO				C			IS		CO							
	Dec. 2020			KO										C					IS	CO (Q2)
6. Lakeside Avenue	Dec. 2019*				KO				C										IS	CO (Q2)
	Dec. 2020						KO							C					IS	CO (Q2)
7. Leonia	Dec. 2019	*Schedule Under Development*																		
	Dec. 2020			KO		C									IS		CO			
8. Market Street	Dec. 2019			KO				C	OS		CO									
	Dec. 2020			KO					C	OS		CO								
9. Meadow Road	Dec. 2019	*Schedule Under Development*																		
	Dec. 2020			KO											C				IS	CO (Q2)
10. Orange Valley	Dec. 2019	*Schedule Under Development*																		
	Dec. 2020					KO										C				IS (Q1); CO (Q3)
11. Ridgefield 13kV	Dec. 2019			KO	C										IS		CO			
	Dec. 2020			KO	C										IS		CO			
12. Ridgefield 4kV	Dec. 2019			KO						C	OS			CO						
	Dec. 2020			KO	C				OS		CO									
13. State Street	Dec. 2019		KO					C								IS				CO (Q1)
	Dec. 2020		KO						C				IS							CO (Q1)
14. Toney's Brook	Dec. 2019			KO						C									IS	CO (Q2)
	Dec. 2020			KO										C			IS			CO (Q2)
15. Waverly	Dec. 2019	*Schedule Under Development*																		
	Dec. 2020			KO			C												IS	CO (Q2)
16. Woodlynne	Dec. 2019		KO												C				IS	CO (Q2)
	Dec. 2020		KO												C				IS	CO (Q2)

December 31, 2023 - ES 2 Program End Date

Legend: KO = Kickoff; C = Construction; IS = Fully In-Service (major assets in-service); OS = Out-of-Service (if eliminated); CO = Closeout
-Actuals are indicated with an underline (Note: for the Market Street and Ridgefield 4kV projects, outside plant construction began in the first quarter of 2020, the construction milestone indicated on this chart reflects inside plant construction).
*-The Dec. 2019 Lakeside Avenue project schedule was based on the original raise and rebuild mitigation strategy; the current schedule reflects the proposed mitigation method change that contemplates relocating the substation.

A summary of the subprogram status as of the end of 2020 is provided below **Table 10 – ES 2 Electric Station Flood Mitigation Summary Status as of December 31, 2020**.

Table 10 – ES 2 Electric Station Flood Mitigation Summary Status as of December 31, 2020

Activity	Total # of Projects	Specific Projects
Kickoff Meeting	15	Academy Street; Clay Street; Hasbrouck Heights; Kingsland; Lakeside Avenue; Leonia; Market Street; Meadow Road; Orange Valley; Ridgefield 13kV; Ridgefield 4kV; State Street; Toney's Brook; Waverly; Woodlynne
Key Drawing Review	15	Academy Street; Clay Street; Hasbrouck Heights; Kingsland; Lakeside Avenue; Leonia; Market Street; Meadow Road; Orange Valley; Ridgefield 13kV; Ridgefield 4kV; State Street; Toney's Brook; Waverly; Woodlynne
Scope Locked	15	Academy Street; Clay Street; Hasbrouck Heights; Kingsland; Lakeside Avenue; Leonia; Market Street; Meadow Road; Orange Valley; Ridgefield 4kV; Ridgefield 13kV; State Street; Toney's Brook; Waverly; Woodlynne
Major Equipment Purchase Orders (POs)	14*	Academy Street; Clay Street; Hasbrouck Heights; Kingsland; Leonia*; Meadow Road; Ridgefield 13kV*; State Street; Toney's Brook; Waverly*; Woodlynne
A/E Contract Award (or selection of PSE&G internal engineering)	15	Academy Street[1]; Clay Street[1]; Hasbrouck Heights[1]; Kingsland[2]; Lakeside Avenue[3]; Leonia[2]; Market Street[2]; Meadow Road[2]; Orange Valley[1]; Ridgefield 13kV[2]; Ridgefield 4kV[2]; State Street[2]; Toney's Brook[3]; Waverly[3]; Woodlynne[1]
Construction Start^	6	Academy Street; Leonia; Market Street; Ridgefield 4kV; Ridgefield 13kV; Waverly

**-Three of the listed projects (Leonia, Ridgefield 13kV, and Waverly) have two switchgears, thus the current count reflects 14 switchgears at 11 substations.*
[1]-Indicates Burns & McDonnell is serving as the A/E.
[2]-Indicates PSE&G internal resources are serving as the A/E.
[3]-Indicates Black & Veatch is serving as the A/E.
^-Includes inside plant and/or outside plant construction.

Beyond the key activities summarized in **Table 10** above, **Table 11 – ES 2 Electric Station Flood Mitigation Upcoming Activities for Q1 2021** summarizes the planned activities for each project during the first quarter of 2021, including any carryover of activities from earlier periods.

Table 11 – ES 2 Electric Station Flood Mitigation Upcoming Activities for Q1 2021

Station	Upcoming Activities for Q1 2021	Carryover Activities from Q4 2020
1. Academy Street	• Continued engineering and construction	• None
2. Clay Street	• Vendor drawings received (final switchgear arrangement) • Planning Board hearing for site plan	• None
3. Constable Hook	• Being removed from the ES 2 Program and replaced with additional Life Cycle projects	• Remains in planning/origination stages
4. Hasbrouck Heights	• Contingency plan – electrical layout complete • Submittal of major state licenses and permits • Control drawings issued for construction (IFC) • Civil construction purchase order issued	• None

Station	Upcoming Activities for Q1 2021	Carryover Activities from Q4 2020
5. Kingsland	• Continued design and engineering	• None
6. Lakeside Avenue	• Major equipment (switchgear) purchase order issued • 50% estimate completion	• None
7. Leonia	• Phase 1 civil construction completed • 70% estimate completion • Phase 2-3 civil and electrical purchase orders issued	• None
8. Market Street	• Major regional and county licenses and permits issued	• None
9. Meadow Road	• Continued engineering and design	• None
10. Orange Valley	• License and permitting package issued • 50% estimate completion	• None
11. Ridgefield 13kV	• Phase 1 control drawings IFC • Phase 2 civil and electrical drawings IFC • Phase 1 electrical purchase order issued	• None
12. Ridgefield 4kV	• Civil and electrical demolition design packages IFC	• None
13. State Street	• Electrical construction purchase order issued	• Civil construction purchase order issued
14. Toney's Brook	• Continued engineering and design	• 70% estimate completion
15. Waverly	• Phase 1 civil construction completed • Planning Board hearing for site plan	• Major licenses and permits issued (Soil Conservation District, others were issued in Q4 2020)
16. Woodlynne	• Release control drawings IFC	• Civil and electrical construction purchase orders issued

The current project estimates, including base and R&C amounts, is shown below in **Table 12 – ES 2 Electric Station Flood Mitigation Project Cost Status as of December 31, 2020**. **Table 12** also shows the current estimate level based on PSE&G's estimating processes and as approved by the URB, the actual spend, and percentage of actuals to estimate as of the end of 2020.

Table 12 – ES 2 Electric Station Flood Mitigation Project Cost Status as of December 31, 2020

Project	Estimate Level	Base	Risk & Contingency	Total	Current Forecast	Actuals to Date	% of Actuals to Estimate
1. Academy Street	Definitive	$9,800,000	$700,000	$10,500,000	$9,704,217	$4,374,948	42%
2. Clay Street	Study	$34,800,000	$7,200,000	$42,000,000	$36,589,553	$995,748	2%
3. Constable Hook	Office	$3,900,000	$1,400,000	$5,300,000	$3,900,000	$115,640	2%
4. Hasbrouck Heights	Study	$14,900,000	$3,100,000	$18,000,000	$17,870,384	$1,279,782	7%
5. Kingsland	Study	$5,400,000	$2,900,000	$8,300,000	$6,418,540	$313,779	4%

Project	Estimate Level	Base	Risk & Contingency	Total	Current Forecast	Actuals to Date	% of Actuals to Estimate
6. Lakeside Avenue	Study	$39,400,000	$8,500,000	$47,900,000	$39,364,023	$602,937	1%
7. Leonia	Study	$27,700,000	$4,500,000	$32,200,000	$30,396,846	$6,078,171	19%
8. Market Street	Definitive	$25,200,000	$1,700,000	$26,900,000	$25,674,480	$16,330,794	61%
9. Meadow Road	Study	$7,200,000	$1,800,000	$9,000,000	$7,310,208	$598,209	7%
10. Orange Valley	Study	$16,000,000	$4,200,000	$20,200,000	$15,854,669	$439,924	2%
11. Ridgefield 13kV	Study	$19,600,000	$5,900,000	$25,500,000	$23,341,969	$6,438,674	25%
12. Ridgefield 4kV	Conceptual	$17,600,000	$2,600,000	$20,200,000	$17,009,752	$11,382,948	56%
13. State Street	Study	$39,000,000	$6,100,000	$45,100,000	$38,928,940	$739,738	3%
14. Toney's Brook	Study	$14,300,000	$5,400,000	$19,700,000	$16,205,042	$585,036	3%
15. Waverly	Study	$29,400,000	$6,000,000	$35,400,000	$32,525,793	$2,564,563	6%
16. Woodlynne	Study	$15,800,000	$3,600,000	$19,400,000	$18,308,852	$1,104,280	6%
Subprogram Total		**$320,000,000**	**$65,500,000**	**$386,500,000**	**$339,403,267**	**$53,945,171**	**14%**

Findings & Observations

- The projects that comprise the Electric Station Flood Mitigation subprogram continue at various phases of execution, with six projects now in construction as of the end of 2020, and the remaining projects continuing to advance in design and pre-construction activities with the exception of Constable Hook which at the end of the fourth quarter largely remained in the planning/origination stage but has since been removed from the ES 2 Program.
- The IM has found nothing to date that would jeopardize the subprogram being completed on budget. The status of the later projects in this subprogram, and in particular Orange Valley, will have to closely be followed to ensure the projects are completed within the ES 2 Program window. As of the end of 2020, the initial project schedule for the Orange Valley project shows an in-service date of January 2024, however PSE&G has informed the IM that the project team will be examining the potential to shorten durations and/or work activities concurrently to pull the in-service date back into 2023.

1. Academy Street

During the fourth quarter of 2020, $2,411,951 was spent on the Academy Street project compared to a forecast of approximately $2.6 million, which brought the total spend to approximately $4.4 million. The variance in fourth quarter spend was largely driven by weather delays and an inability to recover time on weekends that pushed inside plant civil work into early 2021. As noted in the IM 2020 Third Quarter Report, Academy Street had an earlier than anticipated permit approval and land clearing that supported construction starting earlier than forecasted. The earlier start to construction along with adequate float in the schedule resulted in change to the forecasted in-service date, despite some civil construction work slipping into 2021. Notable activities completed during the fourth quarter of 2020 included:

- Major equipment (switchgear) delivered to site;
- Start of electrical construction; and,
- Civil demolition drawings IFC.

Construction at Academy Street, which started in July 2020 for non-permit work, has advanced to 65% complete inside plant as of the end of 2020, up from 25% at the end of the third quarter of 2020.

In December 2020, the Definitive level estimate was submitted and approved before the URB. This Definitive level estimate reduced the total Academy street project estimate to $10.5 million from the previously approved $11.8 million, including a reduction to both the base estimate (-$0.1 million) and R&C (-$1.2 million). The reduction to R&C was driven by the current view of the risk profile on the project while the changes to the base estimate were driven by:

- Electrical construction award lower than estimated (-$0.1 million);
- Inside plant civil time and material cost reduction (-$0.1 million); and slightly offset by,
- Increase in laydown area lease ($0.1 million).

The actual spend by quarter for Academy Street as compared to the current approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020
Actuals				
$150,398	$99,893	$399,935	$1,312,771	$2,411,951

Actuals to Date	Estimate	% of Actuals to Estimate
$4,374,948	$10,500,000	42%

2. Clay Street

During the fourth quarter of 2020, $142,242 was spent on the Clay Street project compared to a forecast of approximately $145,000, which brought the total spend to approximately $1 million. Notable activities completed during the fourth quarter of 2020 included:

- Vendor drawings received for final switchgear arrangement; and,
- Detailed engineering commenced.

The actual spend by quarter for Clay Street as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020
Actuals				
$116,409	$219,707	$283,219	$234,171	$142,242

Actuals to Date	Estimate	% of Actuals to Estimate
$995,748	$42,000,000	2%

3. Constable Hook

Through the end of 2020, the Constable Hook project remained largely in the initial planning and origination stages, with the property acquisition for associated 69kV projects planned at the same area still being reviewed (see discussion in the IM 2020 Third Quarter Report and in **Section II.A.1** in this report).

The actual spend by quarter for Constable Hook as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020
Actuals				
$17,889	$51,758	$32,313	$8,419	$5,261

Actuals to Date	Estimate	% of Actuals to Estimate
$115,640	$5,300,000	2%

As this project is being removed from the ES 2 Program and replaced with additional life cycle stations under the Electric Stipulated Base, this will be the last IM report that includes Constable Hook.

4. Hasbrouck Heights

During the fourth quarter of 2020, $422,316 was spent on the Hasbrouck Heights project compared to a forecast of approximately $439,000, which brought the total spend to approximately $1.3 million. Notable activities completed during the fourth quarter of 2020 included:

- Civil and electrical drawings IFC; and,
- Major state license and permit package submitted.

As reported in the IM 2020 Third Quarter Report, a Covid-19 related delay on the associated Hasbrouck Heights 69kV project resulted in a delay to the Hasbrouck Heights ES 2 project. This delay has been extended as of the fourth quarter of 2020, with the planned start of construction shifting to January 2022 (was previously June-August 2021) and the forecasted in-service date to April 2023 (was previously November-December 2022). The actual spend by quarter for Hasbrouck Heights as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020
Actuals				
$149,848	$193,879	$188,045	$325,694	$422,316

Actuals to Date	Estimate	% of Actuals to Estimate
$1,279,782	$18,000,000	7%

5. Kingsland

During the fourth quarter of 2020, $30,636 was spent on the Kingsland project compared to a forecast of $42,000, which brought the total spend to approximately $314,000. There were minimal activities performed on this project during the fourth quarter of 2020.

The actual spend by quarter for Kingsland as compared to the current approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020
Actuals				
$104,112	$108,286	$43,268	$27,477	$30,636

Actuals to Date	Estimate	% of Actuals to Estimate
$313,779	$8,300,000	4%

6. Lakeside Avenue

During the fourth quarter of 2020, $73,350 was spent on the Lakeside Avenue project compared to a forecast of approximately $82,000. Notable activities completed during the fourth quarter of 2020 included:

- Key drawing review completed;
- Kickoff meeting held;
- Scope document signed off;
- A&E purchase order issued to Black & Veatch; and,
- Commencement of license and permitting design.

As noted in the IM 2020 Third Quarter Report, the Lakeside Avenue forecasted in-service date for this project slipped from May 2023, as of the end of the second quarter of 2020, to December 2023, as of the end of the third quarter. This delay was driven by the initial property relocation identified for the 69kV and ES 2 projects at 338 Washington Street having contamination risks that resulted in a new potential property location at 101 N. Park Street, for which the purchase process is underway. The contamination risks at the 338 Washington Street site related to per- and polyfluoroalkyl substances (PFAS) that are subject to developing federal and state regulations and under increased scrutiny by regulators, increasing the risk exposure at this site. As of the end of 2020, the forecasted in-service date has improved slightly from December 20, 2023 to December 13, 2023 as PSE&G continues to look for opportunities to advance the schedule.

The actual spend by quarter for Lakeside Avenue as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020
Actuals				
$148,943	$172,224	$121,009	$87,411	$73,350

Actuals to Date	Estimate	% of Actuals to Estimate
$602,937	$47,900,000	1%

7. Leonia

During the fourth quarter of 2020, approximately $4.3 million was spent on the Leonia project compared to a forecast of approximately $4.2 million, which brought the total spend to approximately $6.1 million. Notable activities completed during the fourth quarter of 2020 included:

- Contingency switchgear delivered to site;
- Phase 3 civil and electrical drawings and phase 2 control drawings IFC;
- Leonia town council approved the developer agreement (granting permission to proceed with electrical construction of the temporary switchgear).

Construction at Leonia, which started in August 2020, has advanced to 35% complete inside plant as of the end of 2020, up from 15% complete as of the end of the third quarter of 2020. The actual spend by quarter for Leonia as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020
Actuals				
$44,792	$244,323	$424,783	$1,071,468	$4,292,805

Actuals to Date	Estimate	% of Actuals to Estimate
$6,078,171	$32,200,000	19%

8. Market Street

During the fourth quarter of 2020, $5,488,046 was spent on the Market Street project compared to a forecast of approximately $4 million, which brought the total spend to approximately $16.3 million. The forecast to actual variance in the fourth quarter was predominantly the result of an accounting transfer of $1.4 million from September to October. Notable activities completed during the fourth quarter of 2020 included the issuance of the civil construction (demolition) bid and award of the associated purchase order for the work. Construction at Market Street, which started in August 2020, has advanced to 60% complete outside plant as of the end of 2020, up from 45% complete as of the end of the third quarter of 2020. Inside plant construction is anticipated to begin in May 2021.

In December 2020, the Definitive level estimate was submitted and approved before the URB. This Definitive level estimate reduced the total Market Street project estimate to $26.9 million from the previously approved $30.0 million, including a reduction to both the base estimate (-$1.5 million) and R&C (-$1.6 million). The reduction to R&C was driven by the current view of the risk profile on the project while the changes to the base estimate were driven by:

- Reduced milling, paving, and dewatering (-$0.5 million);
- Civil demolition bids lower than estimated (-$1.1 million); and slightly offset by,
- Higher revised environmental abatement estimate ($0.1 million).

The actual spend by quarter for Market Street as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020
Actuals				
$251,193	$1,938,713	$5,144,270	$3,508,572	$5,488,046

Actuals to Date	Estimate	% of Actuals to Estimate
$16,330,794	$26,900,000	61%

9. Meadow Road

During the fourth quarter of 2020, $114,608 was spent on the Meadow Road project compared to a forecast of approximately $108,000, which brought the total spend to approximately $598,000. There were minimal activities on the Meadow Road project during the fourth quarter of 2020, with the bulk of this project's activities planned for 2022-2023.

The actual spend by quarter for Meadow Road as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020
Actuals				
$63,128	$142,946	$104,563	$172,964	$114,608

Actuals to Date	Estimate	% of Actuals to Estimate
$598,209	$9,000,000	7%

10. Orange Valley

During the fourth quarter of 2020, $81,191 was spent on the Orange Valley project compared to a forecast of approximately $194,000, which bought the total spend to approximately $440,000. The variance in fourth quarter forecasted to actual spend was driven by lower labor efforts required versus what was forecasted. There were minimal activities on the Orange Valley project during the fourth quarter of 2020, but a couple notable milestones occurred during the quarter, including the sign off on the approved scope document for the project and the transition from Office level to Study level estimate. The first of six parcel purchases associated with this project closed in December 2020, with four more property closures expected in 2021 and the final parcel expected to close in April 2022.

In December 2020, the Study level estimate was submitted and approved before the URB. This Study level estimate reduced the total Orange Valley project estimate to $20.2 million from the previously approved $26.6 million, including a reduction to both the base estimate (-$3.7 million) and R&C (-$2.7 million). The reduction to R&C was driven by the current view of the risk profile on the project while the changes to the base estimate were driven by the previously discussed change in mitigation method from raise and rebuild to relocate (see IM 2020 Third Quarter Report).

The actual spend by quarter for Orange Valley as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020
Actuals				
$77,029	$96,582	$120,690	$64,432	$81,191

Actuals to Date	Estimate	% of Actuals to Estimate
$439,924	$20,200,000	2%

11. Ridgefield 13kV

During the fourth quarter of 2020, $2,440,799 was spent on the Ridgefield 13kV project compared to a forecast of approximately $2.0 million, which brought the total spend to approximately $6.4 million. Notable activities completed during the fourth quarter of 2020 included:

- Phase 1 civil and electrical drawings IFC;
- Phase 1 controls drawings IFC; and,
- Phase 1 civil construction bid issued.

Construction at Ridgefield 13kV, which started in June 2020, has advanced to 33% complete inside plant as of the end of 2020, up from 23% at the end of the third quarter of 2020. The actual spend by quarter for Ridgefield 13kV as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020
Actuals				
$205,982	$317,289	$500,475	$2,974,130	$2,440,799

Actuals to Date	Estimate	% of Actuals to Estimate
$6,438,674	$25,500,000	25%

12. Ridgefield 4kV

During the fourth quarter of 2020, $4,637,383 was spent on the Ridgefield 4kV project compared to a forecast of approximately $5.5 million. This brought the total spend to approximately $11.4 million. The variance in actual versus forecasted spend for the fourth quarter was predominantly the result of the contractor losing a week due to Covid-19 quarantine and cable pulling postponed due to Division resources working on another emergent project.

Construction at Ridgefield 4kV, which started in June 2020, has advanced to 72% complete, up from 47% at the end of the third quarter of 2020. The actual spend by quarter for Ridgefield 4kV as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020
Actuals				
$143,414	$693,128	$2,134,627	$3,774,395	$4,637,383

Actuals to Date	Estimate	% of Actuals to Estimate
$11,382,948	$20,200,000	56%

13. State Street

During the fourth quarter of 2020, $143,244 was spent on the State Street project compared to a forecast of approximately $154,000, which brought the total spend to approximately $740,000. Notable activities completed during the fourth quarter of 2020 included permit approval from the State Department of Community Affairs.

The actual spend by quarter for State Street as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020
Actuals				
$77,950	$128,288	$172,777	$217,839	$143,244

Actuals to Date	Estimate	% of Actuals to Estimate
$739,738	$45,100,000	2%

14. Toney's Brook

During the fourth quarter of 2020, $74,783 was spent on the Toney's Brook project compared to a forecast of approximately $90,000, which brought the total spend to approximately $585,000. Notable activities completed during the fourth quarter of 2020 included the release of the civil construction work for bid early the quarter and the award of the civil construction work late in the quarter.

The actual spend by quarter for Toney's Brook as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020
Actuals				
$211,940	$115,747	$86,315	$96,251	$74,783

Actuals to Date	Estimate	% of Actuals to Estimate
$585,036	$19,700,000	3%

15. Waverly

During the fourth quarter of 2020, $1,099,112 was spent on the Waverly project compared to a forecast of approximately $1.09 million, which brought the total spend to approximately $2.6 million. Notable activities completed during the fourth quarter of 2020 included:

- Commencement of inside plant civil construction;
- Phase 2 civil and electrical drawings IFC; and
- Major county and federal license and permit packages issued.

Construction at Waverly, which started in October 2020, has advanced to 4% complete as of the end of 2020. The actual spend by quarter for Waverly as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020
Actuals				
$103,748	$355,706	$355,335	$650,662	$1,099,112

Actuals to Date	Estimate	% of Actuals to Estimate
$2,564,563	$35,400,000	7%

16. Woodlynne

During the fourth quarter of 2020, $438,374 was spent on the Woodlynne project compared to a forecast of approximately $468,000, which brought the total spend to approximately $1.1 million. Notable activities completed during the fourth quarter of 2020 included the release of civil and electrical drawings IFC.

The actual spend by quarter for Woodlynne as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020
Actuals				
$110,982	$240,418	$213,482	$101,024	$438,374

Actuals to Date	Estimate	% of Actuals to Estimate
$1,104,208	$19,400,000	6%

B. Contingency Reconfiguration

During the fourth quarter of 2020, work continued to advance in the Contingency Reconfiguration subprogram with all four Divisions continuing to install reclosers with a total of 207 installed during the quarter and 333 commissioned. **Table 13 – ES 2 Recloser Status as of December 31, 2020** provides a summary of the recloser aspect of the Contingency Reconfiguration subprogram, indicating the 2020 year-end targets and current status of engineering, installation, and commissioning.

Table 13 – ES 2 Recloser Status as of December 31, 2020

Type	Subprogram Forecast	2020 Year End Total Target	Engineering Packages Complete (1 recloser ea.)		Reclosers Installed		Reclosers Commissioned	
			Q4 Qty.	*Total*	*Q4 Qty.*	*Total*	*Q4 Qty.*	*Total*
13kV	916	800	61	699	115	661	231	644
4kV	567	179	-46*	254	92	157	102	157
Total	1,483	979	15	953	207	818	333	801
*-During the fourth quarter of 2020, PSE&G's Asset Management team evaluated the reclosers planned for the subprogram and removed 102 4kV reclosers. Of these 102 reclosers, 63 were engineered prior to the decision to remove them from the subprogram, which resulted in an overall fourth quarter reduction of the number of engineering packages completed.								

As shown in **Table 13**, PSE&G ended 2020 slightly below its targets for the year largely the result of weather-related impacts experienced over the course of the year that temporarily delayed installation and commissioning activities. There is no overall subprogram impact from not hitting these targets as PSE&G maintains flexibility within the subprogram, including keeping engineering comfortably ahead of construction, to allow flexibility in selecting which projects to initiate construction on based on resource or inventory availability. Additionally, as noted within **Table 13**, PSE&G revised the quantity of reclosers for the subprogram as part of a routine review of the planned investments to ensure they are still warranted. The types of criteria involved in removing a recloser from the subprogram include: the circuit may be an underground circuit or a short (one-to-two block circuit) where it is not practical to install a recloser device; the circuit may now be planned for elimination or upgrade in the next five years; or other subsequent investments established three section loops on the circuit. All of these factors contributed to the reduction in both 4kV and 13kV reclosers. There is no expected change to the subprogram forecast at this time, as PSE&G subsequently made the decision to identify cost-effective opportunities to include additional circuits in the subprogram to improve reliability to a greater number of customers utilizing the same cost-benefit process performed for the initial selection of reclosers in the ES 2 Program filing.

The Fuse Saver pilot program commenced in November 2020 and was completed in January 2021. In total, this Fuse Saver pilot program included the installation and commissioning of 80 Fuse Saver devices. As noted in the IM 2020 Second Quarter Report, PSE&G's Asset Management group determined a pilot program would be initiated prior to the full scope to ensure these new devices work as intended. During execution of the pilot program, PSE&G observed factors that will help it prepare for execution of the full Fuse Saver scope, including installation specifications (the remote control unit must be placed directly below the Fuse Saver to avoid communications issues), and cost elements for some of the locations (new poles, traffic control, etc.). A comparison of the Fuse Saver costs estimated at the time of the ES 2 filing compared to the actual costs experienced in the pilot program is provided below in **Table 14 – Fuse Saver Cost Per Unit**.

Table 14 – Fuse Saver Pilot Cost Per Unit

Device Type	ES 2 Filing Estimate	Pilot Program Actual Cost	Variance
Single-Phase	$11,721	$35,316	+$23,595
Two-Phase	$18,262	$48,031	+$29,768

While the cost per unit estimated at the ES 2 filing was based on a few prior installations, certain elements experienced in the pilot program drove the actual costs well above the initial estimate. The key drivers to the higher costs in the pilot program included:

- "Other" costs not included in the filing estimate, such as management costs, traffic control, tree trimming, and storage;
- Higher material costs from what was estimated, which was largely driven by 40% of the locations requiring a pole installation (whereas the filing estimate assumed no pole replacements); and,
- Actual average labor hours per unit approximately four times higher than the filing estimate, which was driven by the learning curve with the new technology, initial issues with the installations, shop testing, and increased labor rates since the time of the filing.

Fuse Saver installations are anticipated to resume in September 2021 pending approval by PSE&G's Asset Management group to proceed with the full scope.

The current forecasted completion date for the primary components that make up the Contingency Reconfiguration subprogram are provided in **Table 15 – ES 2 Contingency Reconfiguration Forecasted Completion Dates as of December 31, 2020**. This table also shows the forecasted dates as of the end of the third quarter of 2020 to show movement to the forecast as of the end of the fourth quarter of 2020.

Table 15 – ES 2 Contingency Reconfiguration Forecasted Completion Dates as of December 31, 2020

Scope & Division		Q3 2020 Forecasted Completion Date	Q4 2020 Forecasted Completion Date
Reclosers	Central	11/30/2021	9/30/2021
	Metro	11/30/2021	12/31/2021
	Palisades	12/31/2021	12/31/2021
	Southern	12/31/2021	12/31/2021

Scope & Division		Q3 2020 Forecasted Completion Date	Q4 2020 Forecasted Completion Date
Fuse Savers	Central	7/31/2023	6/30/2023
	Metro	7/31/2023	6/30/2023
	Palisades	7/31/2023	5/31/2023
	Southern	7/31/2023	6/30/2023

As shown in **Table 15**, the forecasted completion for each Division's Fuse Saver program advanced one to two months, which was driven by pulling the planned installations forward in the schedule. The two-month advancement of the Central Division recloser scope was driven by accelerating the 4kV installations during a lull in the 13kV recloser inventory. The one-month slip to the Metro Division recloser was driven by the identification of additional units, which have yet to be finalized and approved by PSE&G, but are assumed within the schedule forecast.

The Contingency Reconfiguration subprogram costs through the end of 2020 are presented in **Table 16 – ES 2 Contingency Reconfiguration Costs as of December 31, 2020**.

Table 16 – Contingency Reconfiguration Costs as of December 31, 2020

Scope & Division		Q4 2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020	Total to Date	Forecast	% of Actuals to Forecast
		Actuals							
Reclosers	Central	$2,737,167	$3,918,150	$2,238,132	$2,801,328	$3,093,210	$14,787,987	$22,767,184	65%
	Metro	$2,231,431	$3,576,616	$1,946,751	$1,950,122	$3,253,121	$12,958,041	$23,255,612	56%
	Palisades	$2,515,569	$3,353,246	$2,263,303	$2,602,224	$3,900,664	$14,635,005	$25,083,532	58%
	Southern	$2,081,220	$4,003,537	$2,098,258	$2,764,372	$3,539,516	$14,486,904	$29,406,939	49%
Fuse Savers	Central	$9,970	$29,667	$48,444	$73,176	$638,650	$799,907	$15,944,726	5%
	Metro	$7,557	$15,498	$28,339	$41,921	$476,157	$569,472	$14,156,700	4%
	Palisades	$7,468	$15,259	$16,336	$20,878	$469,981	$529,922	$11,190,352	5%
	Southern	$9,792	$21,458	22,973	$35,596	$778,987	$868,805	$21,001,227	4%
Total		**$9,600,174**	**$14,933,431**	**$8,662,536**	**$10,289,616**	**$16,150,287**	**$59,636,044**	**$162,806,273**	**37%**

<u>Findings & Observations</u>:

- Recloser installations did not meet PSE&G's 2020 target, largely due to weather-related impacts experienced earlier in the year, but PSE&G has sufficient flexibility in its plan that there is no resulting impact to the subprogram from not achieving this target.
- The Fuse Saver pilot program commenced in November 2020 and was completed in January 2021. While Asset Management has not reached a decision on proceeding with the full scope, PSE&G has already identified elements from the pilot program such as improved installation instruction and cost elements to be aware of that will better prepare PSE&G for executing the full scope should it decide to proceed.
- With over half of the forecasted recloser units installed as of the end of 2020 (54%), PSE&G has spent approximately 56% of both its estimated and currently forecasted recloser costs, suggesting actual costs coming in close to the estimate, but will warrant continued monitoring to ensure the subprogram objectives are completed within the estimated costs.
- The current forecast for the subprogram increased approximately $31 million during the fourth quarter of 2020, driven by an increased in the number of 13kV recloser units (approximately

$12.7 million) and an increase in the forecasted cost per unit for Fuse Savers based on the actual cost trend during the pilot program (approximately $34.4 million).

C. Grid Modernization – Communication System

The Stipulation identified the Grid Modernization – Communication System subprogram to include up to $72 million invested in installing a private wireless communications network to eliminate the use of dedicated phone lines for remote communication for both PSE&G and customer equipment. The overall network will provide coverage using both wireless and fiber technologies to all switching devices on the PSE&G system.

As reported in the IM 2020 Second Quarter Report, in June 2020, the permanent PSE&G Wireless Network infrastructure solution for connecting to the First Net LTE Network was officially placed in-service and is being utilized to manage all traffic from the field routers. Since being placed in-service, PSE&G performed a service territory coverage assessment, which found less than 1/10 of 1% of the service territory had service below the coverage threshold, and initiated actions to boost the signal at these locations at no cost impact to the subprogram.

As also reported in the IM 2020 Second Quarter Report, PSE&G made the strategic decision to focus on new recloser installations and has delayed the ramp-up in retrofit installations from August 2020 to January 2021 due to resource constraints. No overall impacts are expected from this decision and PSE&G plans to regain the planned retrofit installations by the middle of 2021 as it shifts focus from new recloser installations to the retrofit reclosers. During the fourth quarter of 2020, 147 retrofit installations took place against a forecast of 69 installations. Actual installations were well above the fourth quarter forecast due to the planned ramp-up for 2021 immediately seeing results, leading to more resource availability than initially planned for the quarter, in addition to a conservative unit forecast for the quarter. The total forecast for the subprogram contemplates retrofitting 2,601 reclosers, of which 189 have been completed as of the end of 2020.

As previously reported, the fiber scope includes installing fiber to electric substations and electric operations centers, in addition to cutting over stations with existing fiber service to the PSE&G fiber network. PSE&G preliminarily identified 41 installation projects and 12 cutovers for the subprogram, with two of 41 installation projects since removed due to the scheduled elimination of the targeted substations. The list of identified fiber installation and cutover projects is presented in **Table 17 – Fiber Projects by Division**.

Table 17 – Fiber Projects by Division

Division	Fiber Installation	Fiber Cutover
Central	Cranford; Elizabeth Sub HQ; Rahway; Hadley Road HQ; Roselle; Central HQ; Carteret; Edison; Keasby; Mechanic Street; First Street; Lehigh Avenue	Elizabeth; Henry Street
Metro	East Orange; Metro HQ; Bloomfield; Central Avenue; Haldeon; Irvington; Irvington Sub HQ; Montclair; South Orange; Norfolk Street; Waverly	-
Palisades	Bergen Point; Hackensack Sub HQ; Fort Lee; Harrison; Ridgewood; West New York; Palisades HQ; Culver Avenue; Morgan Street; Howell Street	Tonnelle Avenue; Spring Valley Road; Union City; Fairview; Polk Street; West Orange
Southern	Southern HQ; Princeton; Chauncey Street; Bordentown; Haddon Heights; Thirty Second Street	Delair; East Riverton; Riverside; Mount Holly
Total	***39 projects***	***12 projects***

During the fourth quarter of 2020, three of the fiber installation projects (Cranford, Hackensack Sub HQ, and, Southern HQ) and five of the fiber cutover projects (Delair, East Riverton, Mount Holly, Riverside, and Tonnelle) were placed in-service. Eight other projects were in construction as of the end of 2020. Three of the projects that commenced construction in 2020 (Fort Lee, Hadley, and Bloomfield) have had their completion slip to later in 2021 due to Transmission Fiber Infrastructure standards that require fiber communication installations have two active fiber links at all times before putting racks in-service. These stations were designed with a minimum of two links, so there is no expected cost impact from this delay and may actually result in minor cost savings due to not having to return to these sites a second time to place the projects fully in-service.

The Grid Modernization – Communication System subprogram costs through the end of 2020 are presented in **Table 18 – ES 2 Grid Modernization – Communication System Costs as of December 31, 2020**.

Table 18 – ES 2 Grid Modernization – Communication System Costs as of December 31, 2020

Scope & Division		2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020	Total to Date	Forecast	% of Actuals to Forecast
		Actuals							
Retrofit Reclosers	Central	$0	$50,613	$150,958	$201,053	$481,655	$884,278	$7,782,220	11%
	Metro	$0	$44,164	$139,069	$214,848	$420,359	$818,620	$6,726,635	12%
	Palisades	$0	$44,164	$138,485	$216,524	$426,001	$825,174	$6,972,356	12%
	Southern	$0	$46,901	$145,479	$198,307	$538,372	$929,058	$8,429,951	11%
Fiber	Central	$1,691	$133,115	$272,307	$660,034	$1,353,395	$2,420,542	$7,479,720	32%
	Metro	$1,457	$109,382	$299,876	$419,162	$1,038,278	$1,868,154	$5,857,646	32%
	Palisades	$1,582	$194,451	$520,068	$403,443	$928,800	$2,048,344	$4,166,762	49%
	Southern	$4,731	$65,721	$139,575	$120,011	$585,176	$915,214	$3,258,924	28%
	Cutovers	$0	$0	$0	$40,869	$835,633	$876,502	$1,085,671	81%
Wireless Network		$74,306	$1,525,801	$2,353,604	$1,508,075	$647,961	$6,109,747	$7,547,000	81%
Bulk Purchase*		-	-	-	$1,124,072	$400,802	$1,524,874	$0	-
Total		**$83,767**	**$2,214,312**	**$4,159,421**	**$5,106,396**	**$7,656,612**	**$19,220,505**	**$59,306,886**	**30%**

-The Bulk Purchase account contains expenditures for the bulk purchase of materials in the subprogram. As these materials are used and installed in the field, the Bulk Purchase account is credited with the actual spend then assigned to the appropriate Division, thus at the end of the Program, the balance of this Bulk Purchase account is expected to be $0.

Findings & Observations:

- Retrofit recloser installations continued to advance in the fourth quarter of 2020, with installations well above the forecast for the quarter. As previously noted PSE&G made a strategic decision for new reclosers (as part of the Contingency Reconfiguration subprogram) continue to have installation priority. PSE&G's prioritization also has taken advantage of other work performed on the line (replacement of copper telephone wires with fiber) to gain cost efficiencies.
- PSE&G identified 41 potential fiber installation projects for the subprogram, with two stations removed from consideration due to the future elimination of those substations.
- The 11 fiber installation projects that were initiated in 2020 all advanced to at least the construction phase, with three of the projects being placed in-service by the end of the year. Additionally, five of the twelve fiber cutover were placed in-service by the end of the year.

- The IM has found nothing to date that would jeopardize the subprogram being completed on time and/or on budget.

D. Grid Modernization – ADMS

The Grid Modernization – ADMS scope is split between three primary sections: Distribution Management System (DMS)/Distributed Energy Resource Management System (DERMS), the Outage Management System (OMS), and ADMS platform upgrades. The primary activities in 2020 are centered on planning activities, including as previously reported in the second quarter of 2020, the signing of the Open Systems International Inc. (OSII) contract. The ADMS team continues to use remote meetings with the vendor in response to the ongoing Covid-19 issues and continues to conduct design workshops to further develop the application.

The scope for each primary component of the Grid Modernization – ADMS subprogram and notable activities conducted during the fourth quarter of 2020 are presented as follows:

DMS/DERMS

- Scope: Provide software and associated services to deploy a Smart Network in order to meet a subset of the ES 2 Program's objectives and use cases.
- Q4 2020 Activities:
  - Scheduled workshops with OSII for control and estimation design;
  - Scheduled DERMS network optimization design workshop;
  - Developed user stories;
  - Reviewed design documents delivered by OSII;
  - Completed Architecture Design & Epic/Story/Spring Planning (milestone);
  - Inserted review session results in new iterations of OSII design documents;
  - Delivery and installation of software licensing; and,
  - Completed DERMS AMI integration workshop and SCADA linking workshop.
- Forecasted Completion as of the end of 2020: 10/28/2022.

OMS

- Scope: Provide a single user interface for more efficient management of trouble orders and analysis of outage data through an integrated OMS, system interfaces, and geographic view of all integrated outage data through an integrated OMS, system interfaces, and geographic view of all integrated outage data and damage locations. OMS will include tools for dynamic visualization supporting incident management, damage location identification, dashboards, and the as-operated real-time view of PSE&G's network model. Field personnel also will have access to many of these tools as it relates to the incident(s) assigned to them via the Compass mobile crew application. 10 years' worth of existing OMS data will be migrated into the new system as well.
- Q4 2020 Activities:
  - Conducted internal meetings for work/crew management requirements;
  - Shipped laptops to OSI team;
  - Conducted onboarding meetings with Divisions;
  - Conducted configuration and functional training with core team;
  - Conducted data conversion kickoff meeting with OSII, OMS leads, and reporting team;
  - Completed additional user story review sessions, reporting/dashboard workshops, and interfaces sessions;

- Project toolsets approved by Cyber, Security, Risk, and Compliance Team;
- Drafted GIS interface for customers and premises;
- Completed user story review;
- Conducted kickoff meeting with Automated Testing team;
- Completed workshops for four interface designs; and,
- Completed Sprint One with OSII.

- Forecasted Completion as of the end of 2020: 5/20/2022.

ADMS Platform

- Scope: Replace, enhance, and expand the existing DSCADA platform elements inclusive of infrastructure components (servers and workstations) and applications (Monarch, Spectra, and Integra) to create an integrated ADMS platform.
- Q4 2020 Activities:
  - Received delivery of servers;
  - Completed Dell Unity configuration;
  - Completed Windows OS build in production environment; and,
  - Connected workstations to Newark PDS server.
- Forecasted Completion as of the end of 2020: 12/10/2021.

The Grid Modernization – ADMS subprogram costs through the end of 2020 are presented in **Table 19 – ES 2 Grid Modernization – ADMS Costs as of December 31, 2020**.

Table 19 – ES 2 Grid Modernization – ADMS Costs as of December 31, 2020

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020
Actuals				
$36,213	$925,689	$4,430,542	$6,970,572	$4,210,822

Actuals to Date	Forecast	% of Actuals to Forecast
$16,483,837	$40,374,139	41%

Findings & Observations:

- Additional workshops were held during the fourth quarter, which despite the challenges posed by Covid-19 restrictions, continued to be conducted without issue.
- The IM has found no indications to date that would jeopardize the subprogram being completed on time. The current forecast, including the $1.2 million in additional hardware purchased during the third quarter of 2020, exceeds the Stipulation amount allocated for this subprogram by approximately $5.4 million.

E. Electric Stipulated Base

The Stipulation identified that the electric portion of the Stipulated Base include $100 million in investments at PSE&G's discretion towards electric outside plant higher design and construction standards and/or electric stations life cycle subprograms described in the original ES 2 filing.[1] As reported

[1] As noted in the Stipulation, the electric life cycle upgrades are part of the electric Stipulated Base to be recovered in the Company's next base rate case provided the investments are found to be prudent. The Stipulation also notes that should the 16 stations that comprise the Electric Station Flood Mitigation subprogram be completed for under

in the IM 2020 First Quarter Report, the preliminary planning by PSE&G estimated that approximately one-third of the Stipulated Base funds will be used towards the electric stations life cycle investments and the remaining two-thirds towards outside plant higher design and construction standards. PSE&G has confirmed with the IM that it intends to maintain the ratio at approximately one-third of funding to life cycle upgrades and two-thirds to outside plant higher design and construction standards. The outside plant higher design and construction standards work is planned to commence in later in 2021 on the State Street project and ramp-up more fully in 2022. In accordance with what the Stipulation provides, PSE&G plans to fund some of the life cycle station upgrades from the electric program accelerated investment, subject to funds available, after all Electric Station Flood Mitigation projects are funded at their final costs.

As reported in the IM 2020 Second Quarter Report, the initial four stations PSE&G selected for life cycle station upgrades went before the URB in June 2020 for Study level estimate approval and received approval for full funding. These four stations and their current estimate compared to the actuals to date are provided in **Table 20 – ES 2 Life Cycle Station Upgrade Project Status as of December 31, 2020**.

Table 20 – ES 2 Life Cycle Station Upgrade Project Status as of December 31, 2020

Project	Estimate Level	Base	Risk & Contingency	Total	Actuals to Date	% of Actuals to Estimate	Forecasted In-Service Date*
1. Hamilton	Study	$14,500,000	$3,700,000	$18,200,000	$362,372	2%	10/24/2022 (↑)
2. Paramus	Study	$14,800,000	$5,400,000	$20,200,000	$840,200	4%	9/28/2022
3. Plainfield	Study	$18,400,000	$4,200,000	$22,600,000	$682,325	3%	10/6/2022
4. Woodbury	Study	$15,400,000	$3,300,000	$18,700,000	$551,165	3%	12/28/2022 (↓)

**-Reflects the in-service date of the last major asset (e.g. switchgear), certain activities may take place after this date to support the final in-service date (i.e. when all customers are cutover).*
(↑)-*Indicates the forecasted in-service date advanced from the prior quarter.*
(↓)-*Indicates the forecasted in-service date slipped from the prior quarter.*

As shown in **Table 20**, of the four current life cycle station upgrade projects, two had no change in the forecasted in-service date from the third to fourth quarters of 2020 (Paramus and Plainfield), while Hamilton's forecasted in-service date advanced eight days and Woodbury's forecasted in-service date slipped twelve days in this period. Given the small magnitude of these changes, the IM has not performed additional schedule analyses on these projects, but will continue to monitor for potential trends. Additional details on each of these life cycle station upgrade projects is provided in the individual subsections that follow.

1. Hamilton

During the fourth quarter of 2020, $185,564 was spent on the Hamilton project against a forecast of approximately $166,000. This brought total spend through the end of 2020 on the project to $362,372. Notable activities conducted during the fourth quarter of 2020 included:

- Project execution plan completed; and,
- License and permitting package issued.

the $389 million allocated for that subprogram, PSE&G may reallocate such unused funds to stations identified in the life cycle station upgrade portion of PSE&G's petition for accelerated recovery.

The actual spend by quarter for Hamilton as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020
		Actuals		
$0	$0	$0	$177,808	$184,564

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$362,372	$18,200,000	$14,513,934	2%

2. Paramus

During the fourth quarter of 2020, $431,270 was spent on the Paramus project against a forecast of approximately $481,000. This brought total spend through the end of 2020 on the project to $840,200. Notable activities conducted during the fourth quarter of 2020 included:

- License and permitting package issued and submitted;
- Detailed engineering commenced; and,
- Vendor drawings received (final switchgear arrangement).

The actual spend by quarter for Paramus as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020
		Actuals		
$0	$0	$0	$408,931	$431,270

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$840,200	$20,200,000	$16,801,337	4%

3. Plainfield

During the fourth quarter of 2020, $179,136 was spent on the Plainfield project against a forecast of approximately $282,000. This brought total spend through the end of 2020 on the project to $682,325. Notable activities conducted during the fourth quarter of 2020 included:

- License and permitting package issued.

The actual spend by quarter for Plainfield as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020
		Actuals		
$0	$0	$0	$503,189	$179,136

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$682,325	$22,600,000	$18,801,708	3%

4. Woodbury

During the fourth quarter of 2020, $167,341 was spent on the Woodbury project against a forecast of approximately $156,000. This brought the total spend on the project to $551,165. Notable activities conducted during the fourth quarter of 2020 included:

- Project kickoff meeting held;
- A/E purchase order issued;
- Detailed engineering commenced;
- Approval of the project execution plan.

The actual spend by quarter for Woodbury as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020
		Actuals		
$0	$0	$0	$383,851	$167,314

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$551,165	$18,700,000	$14,934,202	3%

Findings & Observations:

- The four electric stipulated base substation life cycle projects continued to progress in planning and preparation efforts during the fourth quarter of 2020 while also advancing engineering in support of the planned release of civil and electrical IFC drawings in the first and second quarters of 2021.
- The electric stipulated base substation life cycle projects are progressing in line with their respective cost and schedule estimates.
- While the current four electric substation life cycle projects comprise approximately 80% of the electric stipulated base funding, PSE&G anticipates that the final ratio will be closer to one-third of funding to the electric substation life cycle projects and two-thirds to the outside plant higher design and construction standards. Funding these four projects fully allows them to be completed within the ES 2 Program window, in addition PSE&G excepts excess funds from the Electric Station Flood Mitigation subprogram (currently forecasted approximately $60 million under its Stipulation amount) to be reallocated to the life cycle station upgrades as provided in the Stipulation.

F. Gas M&R Station Upgrades

Through the end of 2020, primary activities in the Gas M&R subprogram continued to focus on pre-construction activities such as preparing licensing and permitting packages and the continued advancement of engineering on each of the Gas M&R stations. **Table 21 – ES 2 Gas M&R Summary Status as of December 31, 2020** below provides the currently approved estimates for each project within the Gas M&R subprogram, along with the actuals to date and forecasted in-service dates.

Table 21 – ES 2 Gas M&R Summary Status as of December 31, 2020

Project	Estimate Level	Base	Risk & Contingency	Total Estimate	Actuals	% of Actuals to Estimate	Forecasted In-Service
1. Camden*	Office	$10,000,000	$5,400,000	$15,400,000	$872,676	6%	Jan 2023
2. Central*	Study	$23,900,000	$6,100,000	$30,000,000	$677,451	2%	Jan 2023
3. East Rutherford	Study	$13,800,000	$3,200,000	$17,000,000	$530,875	3%	Dec 2022 (↑)
4. Mount Laurel	Study	$9,400,000	$2,400,000	$11,800,000	$368,132	3%	Dec 2022
5. Paramus*	Study	$11,500,000	$2,700,000	$14,200,000	$471,294	3%	Dec 2023 (↓)
6. Westampton	Study	$8,300,000	$2,100,000	$10,400,000	$1,041,065	10%	Dec 2021
Placeholder**	-	$0	$2,200,000	$2,200,000	$0	-	-
Subprogram Total		**$76,900,000**	**$24,100,000**	**$101,000,000**	**$3,961,492**	**4%**	**Dec 2023**

**-Included in the Stipulated Base.*
***-Represents additional funds between the current project estimates and the Stipulation amount for the subprogram.*
(↑)-*Indicates the forecasted in-service date advanced from the prior quarter.*
(↓)-*Indicates the forecasted in-service date slipped from the prior quarter.*

The changes to the East Rutherford (advancing one month) and Paramus (slipping 11 months) project schedules was due to a realignment of the project schedules to avoid the constraint of not being able to have these two stations in construction at the same time (a similar situation exists at the Mt. Laurel and Westampton projects).

Findings & Observations:

- The primary efforts to date on the subprogram continue to be initial planning efforts, including the prior awarding of bids for the design services on the projects, preparing for issuing the major equipment POs, site surveys, and preparation of permitting packages. Continued engineering and design efforts were a main focus of 2020 fourth quarter activities.
- While still early in the subprogram, the IM has found nothing to date that would jeopardize the subprogram being completed on time and/or on budget. Three of the Gas M&R projects had updated estimates approved by the URB during the fourth quarter of 2020, which resulted in two of the projects (Central and East Rutherford) having an increased base estimate, somewhat offset by a reduced R&C, while the other project (Paramus) had a reduction to both the base and R&C estimates, with no change to the overall subprogram estimate.

1. Camden

While the primary work through the end of 2020 on the Gas M&R subprogram has focused largely on preliminary engineering and other planning activities, during the fourth quarter of 2020 notable activities completed on the Camden project included:

- Coordination meeting held with the Audubon District and Remediation;
- 3D preliminary drawings completed;
- Preliminary permitting meeting held with the City; and,
- Permitting package prepared.

The actual spend by quarter for Camden as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020
Actuals				
$13,326	$46,691	$83,499	$207,837	$521,323

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$872,676	$15,400,000	$10,000,000	6%

2. Central

While the primary work through the end of 2020 on the Gas M&R subprogram has focused largely on preliminary engineering and other planning activities, during the fourth quarter of 2020 notable activities completed on the Central project included:

- Completed initial geotechnical review;
- Identified major equipment list and long lead items;
- Completed soft digs to verify tie-in locations and clearances for liquid propane air (LPA) rack foundations; and,
- Permitting package received.

In December 2020, the Study level estimate was submitted and approved before the URB. This Study level estimate increased the total Central project estimate to $30.0 million from the previously approved $19.7 million, which also included a slight reduction to R&C (-$0.8 million). The reduction to R&C was driven by the current view of the risk profile on the project while the changes to the base estimate were driven by:

- Higher construction costs based on the engineer's 50% estimate ($6.9 million);
- Procurement of an additional two buildings and four heaters required for the refined design ($3.0 million); and,
- Additional Project Management, Licensing and Permitting, and Engineering support not included in the Office level estimate ($1.2 million).

The actual spend by quarter for Central as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020
Actuals				
$6,869	$45,048	$109,557	$195,119	$320,858

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$677,451	$30,000,000	$23,900,000	2%

3. East Rutherford

While the primary work through the end of 2020 on the Gas M&R subprogram has focused largely on preliminary engineering and other planning activities, during the fourth quarter of 2020 notable activities completed on the East Rutherford project included:

- Reviewed 3D preliminary drawings;
- Identified major equipment and long lead items; and,
- Issued large equipment specs for internal review.

In December 2020, the Study level estimate was submitted and approved before the URB. This Study level estimate increased the total East Rutherford project estimate to $17.0 million from the previously approved $15.9 million, including a reduction R&C (-$2.4 million). The reduction to R&C was driven by the current view of the risk profile on the project while the changes to the base estimate were driven by:

- Higher construction costs based on the engineer's 50% estimate ($2.7 million); and,
- Additional Project Management support not included in the Office level estimate ($0.8 million).

The actual spend by quarter for East Rutherford as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020
Actuals				
$9,010	$37,747	$111,526	$159,165	$213,428

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$530,875	$17,000,000	$13,739,809	3%

4. Mount Laurel

While the primary work through the end of 2020 on the Gas M&R subprogram has focused largely on preliminary engineering and other planning activities, during the fourth quarter of 2020 notable activities completed on the Mount Laurel project included:

- Received draft site plan package; and,
- Received 70% design drawings for review.

Also during the fourth quarter of 2020, the A/E (J.F. Kiely Service Co.) project manager was replaced following discussions PSE&G had with the A/E on project progress.

The actual spend by quarter for Mount Laurel as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020
Actuals				
$5,965	$27,804	$74,737	$132,680	$126,945

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$368,132	$11,800,000	$9,400,000	3%

5. Paramus

While the primary work through the end of 2020 on the Gas M&R subprogram has focused largely on preliminary engineering and other planning activities, during the fourth quarter of 2020 notable activities completed on the Paramus project included:

- Reviewed 3D preliminary drawings;
- Identified major equipment and long lead items; and,
- Issued large equipment specs for internal review.

In December 2020, the Study level estimate was submitted and approved before the URB. This Study level estimate reduced the total Paramus project estimate to $14.2 million from the previously approved $19.9 million, including a reduction to both the base estimate (-$1.4 million) and R&C (-$4.4 million). The reduction to R&C was driven by the current view of the risk profile on the project while the changes to the base estimate were driven by the cost of using existing building structures rather than building new.

The actual spend by quarter for Paramus as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020
Actuals				
$8,842	$37,793	$91,247	$169,249	$164,163

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$471,294	$14,200,000	$11,476,028	3%

6. Westampton

While the primary work through the end of 2020 on the Gas M&R subprogram has focused largely on preliminary engineering and other planning activities, during the fourth quarter of 2020 notable activities completed on the Westampton project included:

- Completed soft digs to confirm tie-ins;
- Final site plan reviewed;
- Ordered data building (houses equipment for SCADA and other communication/data systems) and regulator buildings;
- Identified major equipment and long lead items; and,
- Submitted municipal/county permit package.

The actual spend by quarter for Westampton as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020
Actuals				
$8,395	$40,389	$180,947	$314,493	$496,390

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$1,041,065	$10,400,000	$8,300,000	10%

IV. Additional Information Following the End of the Fourth Quarter of 2020

While the vast majority of this IM report is focused on the activities and status of the ES 2 Program during the fourth quarter of 2020, the timing of certain Program elements and information provided by PSE&G naturally carried over beyond the end of the calendar quarter. Such information will generally be covered in the next IM quarterly report but given the importance of some of this information as it pertains to the key decisions made on the ES 2 Program, including the related discussion in **Section II.A.**, the IM has provided additional remarks to provide a more complete view of these mitigation changes based on the available information as of the date of this IM 2020 Fourth Quarter Report.

A. Decisions Recorded After the Fourth Quarter of 2020

Transfer of Clay Street Wastewater Wall Scope from ES2FM to Clay Street 69kV Project

The Clay Street ES 2 project and the Clay Street 69kV transmission project are being executed contemporaneously. PSE&G's capital accounting determination established that the wall to be constructed around the Clay Street Substation to prevent wastewater intrusion is a Transmission and Distribution (T&D) asset. PSE&G has determined the primary purpose of the wastewater wall is health and safety and reliability and is not required for flood mitigation, however, the site is located within a flood zone and thus still requires the flood mitigation scope. Thus, PSE&G made the decision on February 2, 2021 to remove the scope of work of the wastewater wall, raising of grade, and pumping system from this ES 2 project and add it instead to the ongoing 69kV project.

Alternatives considered include:

1. Include the wastewater wall as part of ES 2 Program;
2. Do not construct the wastewater wall;
3. Resolve the issue with the City of Newark and the Passaic Valley Sewerage Commission (PVSC) to prevent overflows from combined sewer/storm water events.

In evaluating the alternatives, PSE&G determined constructing the wastewater wall was the only technical solution identified by Stakeholders to effectively keep the site free from combined sewage and storm water inundation. The frequency of incidents of overflowing storm water across the substation site has increased in the past several years, with each occurrence requiring costly remediation and clean-up and delays access to the site and increased risk to reliability.

PSE&G also determined that attempting to resolve the issue with the City of Newark and PVSC to be ineffective based on numerous meetings over the years with minimal improvement to the overflow and storm conditions.

PSE&G further determined that including the wastewater wall as part of the ES 2 Program was not a preferred alternative since the scope of the work was not required to meet the flood mitigation objectives of the Program. As a result of the decision to remove this scope from the Clay Street ES 2 project, the estimate for the project was reduced by approximately $6.8 million.

Findings and Observations

- The IM finds that PSE&G conducted the appropriate due diligence, evaluation and analysis in determining to remove the wastewater wall scope from the ES 2 Program.

- The need for the wastewater wall was approved during 2019 Project Council meetings and in both the Feasibility Assessment Report and the project scope document for the Clay Street ES 2 project were approved to include the wastewater wall and necessary for health, safety, and reliable operation.
- The IM finds PSE&G's decision to include the wastewater wall under the 69kV project consistent with the capital accounting determination.

B. Additional Information on the Constable Hook, Lakeside Avenue, and Orange Valley Mitigation Changes

Relating to the discussion in **Section II.A.1.** in this IM 2020 Fourth Quarter Report and prior discussions within the IM 2020 Third Quarter Report (Sections II.A.3. and IV.B.), in September 2020, PSE&G formally proposed a change to the mitigation method at Lakeside Avenue, Orange Valley, and Constable Hook from raise and rebuild to relocate, which continued to be discussed between PSE&G, Rate Counsel and BPU Staff through the end of 2020. On January 6, 2021, PSE&G informed the parties that all requested information regarding the changes have been identified and provided to both the BPU Staff and Rate Counsel. PSE&G also stated that it is moving forward with the changes as discussed in part to benefit from the identified efficiencies, which will result in savings and increased reliability for customers. Rate Counsel responded to PSE&G on January 19, 2021, noting specific concerns regarding the proposed changes to the Constable Hook substation and opining that the proposed changes to the Constable Hook project should be excluded from the ES 2 Program.

On February 19, 2021, PSE&G, Rate Counsel, and BPU Staff participated in a conference call to discuss Rate Counsel's objections. During this call, PSE&G explained the proposed change for the Constable Hook substation as consistent with its response to discovery request S-PSEG-ENG-002, including that any costs associated with addressing load growth would be tracked separately under a base capital project and not recovered through the ES 2 accelerated recovery mechanism. However, due to the complexities associated with this project, it became apparent that PSE&G would not be able to complete the Constable Hook project within the ES 2 Program window. Accordingly, PSE&G informed the parties of its intent to remove the Constable Hook substation from the ES 2 Program and instead perform this flood mitigation work as a base capital project. PSE&G also noted its intent to use the funds allocated for Constable Hook to perform additional life cycle station work in accordance with the terms of the Stipulation.

Early in the second quarter of 2021, PSE&G proposed the Front Street substation as a candidate for an additional life cycle station project that can utilize funds intended for the Constable Hook under the ES 2 Program. The IM will continue report on the status of this change as it becomes formalized through PSE&G's processes and as the additional life cycle station work is formally selected.

ENERGY STRONG PROGRAM
INDEPENDENT MONITOR
2020 FOURTH QUARTER REPORT

APPENDIX A – DRAFT REPORT COMMENTS AND RESPONSES

SEPTEMBER 24, 2021

PEGASUS GLOBAL HOLDINGS, INC. ®

Questions & Comments to the IM 2020 Fourth Quarter Report Formally Submitted to the IM

ID #	Question/Comment	IM Response	Report Changes
S-INF-1	**Reference Page 2** Regarding the Electric Station Flood Mitigation project "Hasbrouck Heights", please provide additional details about the COVID-related delays on the Siemens GIS installation, which caused the forecasted in-service date of the project to be delayed from December 2022 to April 2023.	This delay stemmed from the GIS equipment manufacturer (Siemens) being delayed from travelling to the U.S. to assist with the installation of the GIS equipment on the Hasbrouck Heights 69kV project. This delay rippled to the ES 2 Hasbrouck Heights project, which requires the 69kV project to be installed first. Additionally, the April 2023 in-service date reported at the end of 2020 was identified by PSE&G as the date the Capacitor bank is scheduled to be placed in-service; as of the end of the first quarter of 2021, PSE&G updated the in-service date on the ES 2 Hasbrouck Heights to reflect the major asset/switchgear in-service date of February 2023.	No change
S-INF-2	**Reference Page 5, Market Street Radioactive Soil Testing and Handling** With respect to radioactive soil testing and handling associated with the Electric Station Flood Mitigation project "Market Street": a. Please clarify if the costs associated with the excavation, testing, and monitoring of hazardous waste are included within the costs of the Energy Strong II program. b. If so, please provide an estimate of these costs.	The scope of work on the Market Street project includes excavation of soil in areas designated by the EPA as potentially hazardous due to radioactivity in order to replace existing poles and related infrastructure. In order to safeguard workers and the general public, the work plan as approved by the EPA includes testing and monitoring of hazardous soil excavations. The estimated incremental cost for soil excavation, testing, and monitoring activities is approximately $1.8 million.	**Section II.A.3.**
S-INF-3	**Reference Page 20, Orange Valley** Regarding the Electric Station Flood Mitigation project "Orange Valley", what is attributed to the variance in actual spending ($81,191) and forecasted spending ($194,000) during the quarter?	The variance in fourth quarter forecasted to actual spend was driven by less than estimated A/E efforts as the project finalized the license and permitting matrix and drawings for site plan approval. PSE&G labor efforts for major equipment procurement were also lower than estimated for the quarter.	**Section III.A.10.**
S-INF-4	**Reference Page 23, Table 13 – "ES 2 Recloser Status as of December 31, 2020"** Regarding the statement "During the fourth quarter of 2020, PSE&G's Asset Management team evaluated the reclosers planned for the subprogram and removed 102 4kV recloser."	PSE&G routinely reviews the reclosers and other investments in the ES 2 Program to ensure the initially planned investments are still warranted. For the reclosers, each circuit was assessed to determine the current status reflective of updated system plans and changes, as well as other work done subsequent to the ES 2 filing, such as poorest performing circuit improvements. The types of criteria involved in	**Section III.B.**

ID #	Question/Comment	IM Response	Report Changes
	a. What is the Company's rationale for removing 102 4kV reclosers from the Contingency Reconfiguration subprogram during the fourth quarter of 2020? b. What is the estimated subprogram budget savings resulting from this decision?	removing a recloser from the subprogram include: the circuit may be an underground circuit or a short (one-to-two block circuit) where it is not practical to install a recloser device; the circuit may now be planned for elimination or upgrade in the next five years; or other subsequent investments established three section loops on the circuit. All of which contributed to a reduction in both 4kV and 13kV reclosers. There is no estimated subprogram budget savings at this time, because subsequent to this review of the initially identified circuits, PSE&G made the decision to conduct a detailed review of 4kV and 13kV circuits to identify cost effective opportunities to include additional circuits in the subprogram in order to improve reliability to a greater number of customers utilizing the same cost-benefit process performed for the initial selection.	
S-INF-5	**Reference Page 25, Contingency Reconfiguration Subprogram** Regarding the statement "The current forecast for the subprogram increased approximately $31 million during the fourth quarter of 2020, driven by an increase in the number of 13kV recloser units (approximately $12.7 million) and an increase in the forecasted cost per unit for Fuse Savers based on the actual cost trend during the pilot program (approximately $34.4 million)." a. Please provide the total number of additional 13kV recloser units included within the subprogram. b. Please provide the Company's rationale for increasing the number of 13kV recloser units within the subprogram. c. Please compare the actual unit cost of Fuse Savers to the originally forecasted cost per unit. d. Does the Company expect to gain any cost savings on Fuse Savers after transitioning from a pilot program to bulk purchasing?	a. The total number of additional 13kV recloser units continues to be under evaluation with 253 13kV opportunities identified by PSE&G as of June 2021 (in addition to 89 additional 4kV opportunities identified). The increase in the fourth quarter forecast reflected additional placeholder units that PSE&G expects to be included in the subprogram based on this evaluation. b. PSE&G decided to identify additional reclosers for the subprogram in order to maximize customer reliability benefits in a cost effective manner. Adding additional reclosers supports faster storm restoration, improved reliability, and reducing the number of customers impacted by a particular outage event. The proposed recloser additions to the subprogram are following the same cost-benefit framework used in the original filing, including having a minimum benefit to cost ratio that is greater than one. c. PSE&G's Fuse Saver unit cost at the time of the ES 2 filing was $11,721 for a single-phase unit and $18,262 for a two-phase unit. The actual average cost per unit experienced in the Fuse Saver pilot program were $35,216 for the single-phase units and $48,031 for the two-phase units. The variance was largely driven by components required that were not part of the initial assumptions (management costs,	**Section III.B.**

ID #	Question/Comment	IM Response	Report Changes
		traffic control, tree trimming, etc.) and higher material and labor costs than what was estimated. d. Yes, PSE&G anticipates that when the Fuse Saver installations fully commence that it will see meaningful improvements in the cost per unit. Specifically, PSE&G expects cost savings due to: 1) higher quantity of units installed, while management costs remain relatively flat; 2) reduction in hours per unit driven by efficiencies gained with the installation of a higher quantity of units; 3) avoidance of extended installation hours seen in the pilot program due to communication issues (modular external antenna assembly being incorporated for trouble locations as needed); and, 4) assumption there will be no additional technical issues that require multiple days/visits to complete an installation.	
S-INF-6	**Reference Page 25, Grid Modernization – Communication System Subprogram** Regarding the statement "During the fourth quarter of 2020, 147 retrofit installation took place against a forecast of 69 installations", what does the Company attribute to the variance in recloser retrofit installations during the fourth quarter of 2020?	The actual installations in the fourth quarter of 2020 were well above the forecast due to the planned ramp-up for 2021 immediately seeing results, leading to more resource availability than planned and coupled with a conservative forecast for the fourth quarter.	**Section III.C.**
S-INF-7	**Reference Page 31, Findings & Observations** Refer the statement "While the current four electric substation life cycle projects comprise approximately 80% of the electric stipulated base funding, PSE&G anticipates that the final ratio will be closer to one-third of funding to the electric substation life cycle projects and two-thirds to the outside plant higher design and construction standards." Has PSE&G incurred any costs for outside plant higher design work to date? If so, please quantify these costs.	No, the outside plant higher design work is anticipated to commence in 2021 (on the State Street project) and ramp-up in 2022.	**Section III.E.**
S-INF-8	**Reference Page 35, Paramus M&R Station** Refer to the statement "the changes to the base estimate were driven by the cost of using existing building structures rather than building new": a. What is the age of the existing building structures that will be used for the Paramus M&R Station project? b. With respect to the Gas M&R Station Upgrade projects, please indicate if PSE&G identified any other existing	Regarding these questions on the Gas M&R subprogram and the Paramus project specifically: a. PSE&G does not have a record of the exact year the Paramus M&R building was originally built as it was built by Transco under an agreement signed on June 6, 1961. PSE&G assumes the station was built within a couple years of that agreement.	No change

ID #	Question/Comment	IM Response	Report Changes
	major equipment that is not near end of life and can be reused within the new M&R stations.	b. PSE&G has identified the following existing equipment to be reused at each site: • Camden: two propane vaporizers. • Central: two Mono Ethylene Glycol units. • East Rutherford: two line heaters. • Mt. Laurel: four line heaters. • Paramus: one scrubber. • Westampton: three line heaters.	
S-INF-9	**Reference Page 36, Transfer of Clay Street Wastewater Wall Scope from ES2FM to Clay Street 69kV Project** Refer to the statement "PSE&G's capital accounting determination established that the wall to be constructed around the Clay Street Substation to prevent wastewater intrusion is a Transmission and Distribution (T&D) asset. PSE&G has determined its primary purpose is health and safety and reliability is not required for flood mitigation. Thus, PSE&G made the decision on February 2, 2021 to remove the scope of work of the wastewater wall, raising of grade, and pumping system from this ES 2 project and add it instead to the ongoing 69kV project." a. Please discuss the cost impact that this adjustments is expected to have on the Clay Street substation project within the Energy Strong II program. b. Please clarify if the shifting of this work scope from the Energy Strong II program to the 69kV project will result in PSE&G reclassifying distribution-related costs as transmission-related costs. c. Please confirm that PSE&G still believes that the raising of the Clay Street substation is required for flood mitigation purposes.	a. The wastewater wall scope change reduces the estimate of the ES 2 Clay Street project by approximately $6.8 million. b. Yes, the costs associated with this scope of work will be transferred to the Clay Street 69kV Project and classified as transmission-related costs. c. Yes, the Clay Street substation is located within a flood zone and the existing regulators/reactors are located on the ground level. Raising and rebuilding the station at least one foot above the flood elevation level will increase the reliability and resiliency of the substation and bring it in compliance with current International Building Code and PSE&G standards.	**Section IV.A.**
S-INF-10	**Reference Page 37, Additional Information on the Constable Hook, Lakeside Avenue, and Orange Valley Mitigation Changes** Refer to the statement "Early in the second quarter of 2021, PSE&G proposed the Front Street substation as a candidate for an additional life cycle station project that can utilize the funds intended for the Constable Hook under the ES 2 Program."	As of the most recent data received by the IM to date, the Front Street life cycle station project has initiated preliminary planning with approximately $190,000 incurred during the second quarter of 2021.	No change

ID #	Question/Comment	IM Response	Report Changes
	Please describe the status and any costs incurred for the Front Street life cycle station project.		
RCR-INF-1	With reference to Table 2- ES-2 Electric Station Flood Mitigation Status as of December 31, 2020 and Table 2- ES-2 Electric Station Flood Mitigation Status as of September 30, 2020, please explain if the proposed change of mitigation strategy estimate of $47.9 million (including risk and contingency) has been updated since December 31, 2020.	As of the most recent data received by the IM to date, there has been no update to the Lakeside Avenue $47.9 million estimate since December 2020. The next estimate (transitioning to the Conceptual level) is expected to be completed in the first quarter of 2022.	No change
RCR-INF-2	With reference to Table 2- ES-2 Electric Station Flood Mitigation Status as of December 31, 2020, please indicate if the Company anticipates that the extended timeline for the Clay Street, Hasbrouck Heights, Orange Valley, Ridgefield 13 kV, and Woodlynne substations will extend beyond current forecasts.	PSE&G updates the Electric Station Flood Mitigation project schedules on a monthly basis based on the actual status and trends observed. The forecasted completion dates commonly change due to a wide variety of factors (weather, productivity, impacts from dependent projects, changing Covid-19 requirements, material/procurement status, permitting status, etc.), with varying impacts to the project schedules as demonstrated by the fourth quarter of 2020 status showing four projects advancing and five projects slipping in their forecasted in-service dates from the prior quarter. In evaluating the actual status and trends, PSE&G regularly looks for opportunities to improve the project schedule, such as by re-sequencing work or identifying activities that can be performed concurrently. Regarding the five projects identified in this comment that saw the forecasted in-service date slip from the third to fourth quarter of 2020, as of the most recent data received by the IM (second quarter 2021) only one project, the Ridgefield 13kV project, has seen the forecasted in-service date slip beyond what the fourth quarter 2020 forecast was, with a second quarter of 2021 forecast of 11/8/2022 vs. the fourth quarter 2020 forecast of 10/13/2022.	No change
RCR-INF-3	With reference to page 4 of the Draft 2020- Fourth Quarter Report, please indicate the number of reclosers, not part of ES II, that were fitted with the ES II wireless communications devices in 2020.	No wireless communication devices (radios) were installed on non-ES 2 reclosers in 2020.	No change
RCR-INF-4	With reference to page 4 of the Draft 2020- Fourth Quarter Report, please indicate the annual number of reclosers, not part of ES II, that are estimated to be fitted with the ES II wireless communications devices through the completion of the Grid Modernization program in December 2023.	During 2021, as of late August 2021, wireless communication devices have been installed on 10 non-ES 2 reclosers with the possibility of three more by the end of the year. For years 2022-2023, there is not an estimate of planned number of radios to be installed in non-ES 2 reclosers. However, PSE&G anticipates that non-ES 2 installations	No change

ID #	Question/Comment	IM Response	Report Changes
		and replacements will continue to be required as part of normal operations and systems build.	
RCR-INF-5	With reference to page 5 of the Draft 2020- Fourth Quarter Report, please provide an update on the status of the Market Street substation and the estimated completion date of September 2021.	During the second quarter of 2021, outside plant 4kV circuits were converted to 13kV. During the summer of 2021, electrical and civil demolition will commence, which will continue after the outside plant 26kV reconfiguration is completed in September 2021 that marks the final asset being placed in-service on this project.	No change
RCR-INF-6	With reference to Table 12- ES-2 Electric Station Flood Mitigation Project Cost Status as of December 31, 2020, please provide an update on the status of the Lakeside property sale and purchase.	PSE&G closed on the Lakeside property (151-155 N. Park Street) on July 14, 2021.	No change
RCR-INF-7	With reference to Table 12-ES-2 Electric Station Flood Mitigation Project Cost Status as of December 31, 2020, please provide an update on the status of the Orange Valley property sale and purchase.	The Orange Valley project contemplates the acquisition of six properties. Three of these properties closed in December 2020, March 2021, and June 2021, respectively. The remaining three property acquisitions are expected to close in September 2021, October 2021, and April 2022.	**Section III.A.10.**
RCR-INF-8	With reference to page 16 of the Draft 2020- Fourth Quarter Report, please explain if weekend work scheduling is currently factored into the cost estimates for the Energy Strong II program. If not please explain the impact of weekend and off-hours work on project costs.	Regarding the specific comment on page 16 of the Draft Report ("The variance in fourth quarter spend was largely driven by weather delays and an inability to recover time on weekends that pushed inside plant civil work into early 2021"), Jersey City, where the project is located, has a moratorium on weekend work. Generally speaking, overtime or weekend work performed by PSE&G crews does not have a cost impact, while contractor performed work may or may not depending on the situation. On the PSE&G performed work, the labor rates do not change with overtime/weekend work. Project management and oversight costs are included in overhead costs that are scheduled in advance to install the planned number of units within the planned timeframe. Thus, project management/oversight costs would have no change from overtime/weekend work provided all units planned for the month are completed. For Outside Plant – Underground/Overhead line work done by the Divisions, resources are planned to meet the project schedule. Outage requirements and other system/operational considerations are primary drivers of the time-of-day and/or day-of week planned for the work. In the event that "schedule recovery"	No change

ID #	Question/Comment	IM Response	Report Changes
		efforts are required to make up for weather or other disruption, the resource cost does not change with overtime/weekend work. On the contractor performed work, each project will make decisions on if and how to execute schedule recovery using overtime/weekend work. Generally, the cause of disruption, contract terms, and critical schedule among other things forms the parameters of such decisions. The project risk registers include schedule impacts and make R&C provisions in project budget to cover estimated schedule impact/recovery cost. If the schedule is constrained by system reliability, safety, environmental, or other operational requirements that would be the determinant of the recovery actions, rather than cost impact. If the impact of the delay can be accommodated, that is, the impacted activity will not extend the critical path nor incur additional cost, weekend/overtime work would not be utilized at additional cost. If the schedule impact extends the critical path (project duration), or there is a cost associated with the delay such as impact time payment to contractor, equipment stand by cost, demobilization and re-mobilization cost, demurrage cost, extended storage cost, etc., then the decision on whether to implement weekend/overtime work is based on a minimum cost.	
RCR-INF-9	With reference to page 18 of the Draft 2020- Fourth Quarter Report, please describe the contamination risks associated with the original property.	The environmental conditions found via investigation at the Washington Street property were Per- and polyfluoroalkyl substances (PFAS). PFAS chemicals are EPA contaminants of emerging concerns currently subject to developing federal and state regulations and standards and increasing scrutiny by regulators. The presence of PFAS represented a significant environmental risk leading to PSE&G no longer considering this site for the Lakeside Avenue project.	**Section III.A.6.**
RCR-INF-10	With reference to Table 15 Contingency Reconfiguration Costs as of December 31, 2020 and Table 11 Contingency Reconfiguration Costs as of March 31, 2020, please explain the increase in the subprograms' estimated cost from \$119.5 million to \$162.8 million.	The fluctuations from quarter to quarter in the Contingency Reconfiguration subprogram forecast have been discussed in prior IM reports, in summary: • In the IM Q2 2020 Report, the forecast as of June 30, 2020 increased approximately \$31 million from the prior quarter, which was driven by the full forecasting of the Fuse Saver scope of the subprogram that had previously only been partially forecasted. • In the IM Q3 2020 Report, the forecast as of September 30, 2020 decreased approximately \$18 million from the prior	No change

ID #	Question/Comment	IM Response	Report Changes
		quarter, which was driven by the removal of over 200 4kV and 13kV reclosers from the scope of the subprogram. • In this IM Q4 2020 Report, the forecast as of December 31, 2020 increased approximately $31 million from the prior quarter, which was driven by an increase in the planned recloser units (placeholders while PSE&G continued to evaluate the circuits) and an increase to the Fuse Saver scope of the subprogram based on the actual cost trend realized in the pilot program. As demonstrated above, the overall change in the Contingency Reconfiguration subprogram forecast from the first to fourth quarter of 2020 was driven predominantly by changes in the scope of the subprogram (i.e. number of reclosers planned) and an evolving forecast of the Fuse Saver scope (initially only partially forecasted, then full forecasted, and more recently updated based on the experience of the pilot program).	
RCR-INF-11	With reference to Table 17 ES 2 Grid Modernization-Communication System Costs as of December 31, 2020 and Table 13 ES 2 Grid Modernization-Communication System Costs as of March 31, 2020, please explain the decrease in the subprograms' estimated cost from $65 million to $59.3 million.	The reduction in the Grid Modernization – Communication System subprogram forecast of approximately $6 million from March 31, 2020 to December 31, 2020 is nearly entirely attributed to lower costs in the wireless network scope of work. These lower costs are driven by the selection of FirstNet, which provided the wireless network at a cost well under what was initially estimated for this scope of work (see the IM Q1 2020 Report and IM Q3 2020 Report for more discussion on the selection of FirstNet).	No change
RCR-INF-12	With reference to page 36 of the Draft 2020- Fourth Quarter Report, please explain if the allocation of the wastewater wall to the ongoing 69 kV project was the primary factor in seeing the estimated project cost drop from $42 million to the current forecast of $36.6 million. If not, please explain.	Yes, the scope change for the wastewater wall resulted in a decrease to the forecast of approximately $6.8 million (which was slightly offset by marginally higher estimates for other scopes of work on the project). The project also transitioned to the Conceptual level estimate in May 2021, which resulted in a new estimate of $33.8 million for the project, reflecting this scope change and other updated cost estimates for the project.	**Section IV.A.**
Rate Counsel 8/4/2020 Letter to IM	As expected, the quarterly spending trends have been accelerating as more projects enter into construction for the ESII program. Also, we note that the trend in Risk and Contingency are moving downward as projects enter the construction phase.	The spend is expected to continue to accelerate as more activity on the ES 2 Program continues to advance. For the projects carrying an R&C balance, those balances naturally are reduced as the projects advance through engineering and into construction in conjunction with advancing through PSE&G's estimating phases. In effect, either the individual risks are realized,	No change

ID #	Question/Comment	IM Response	Report Changes
		shifting the funds from R&C to the base estimate, or the risks are avoided/mitigated and the overall estimate amount is reduced.	
Rate Counsel 8/4/2020 Letter to IM	At the end of the fourth quarter 2020, the Energy Strong II ("ESII") program remains in the early stages. The Independent Monitor reports that spending for the quarter ending December 31, 2020 has been $52,629,214 or 6.7 percent of the forecasted $778,706,402 program (including the $100 million for Electric Stipulated Base and excluding $89.6 million of risk and contingency). Rate Counsel notes that the parties stipulated to $842 million to complete the ES II Program with $641 million for electric, $50.5 million for gas, and $150.5 million within Stipulated Base for electric and gas spending.	The IM adds a point of clarification to this comment that the forecast of $778,706,402 for the ES 2 Program includes the Stipulated Base for both electric and gas spending (with the Stipulated Base gas spend included within the Gas M&R subprogram figures).	No change
Rate Counsel 8/4/2020 Letter to IM	The current forecast for the Electric Flood mitigation program increased from $332,662,596 in the Second Quarter Report to $339,403,267 in the Fourth Quarter Report, not including risk and contingency estimates. However, Table 12 – ES 2 Electric Station Flood Mitigation Project Cost Status as of December 31, 2020, states that the base spending amount for the subprogram is $320,000,000 in budgeted base project costs and $65,500,000 allocated to risk and contingency.	This is correct, the end of fourth quarter 2020 forecast for the Electric Station Flood Mitigation subprogram is also shown in **Table 12** in addition to the current project estimates (as split between base estimate and R&C) shown in the same table.	No change
Rate Counsel 8/4/2020 Letter to IM	The Independent Monitor notes three formal RODs were issued during the fourth quarter of 2020. These three RODs included Communications Retrofit and non-ES-II Units, Transfer of Clay Street Wastewater Wall Scope from ES2FM to Clay Street 69kV Project, and Market Street Radioactive Soil Testing and Handling- ESII-FM-1.	The RODs issued during the fourth quarter included: Grid Modernization – Communication System Subprogram: Fiber Scope (discussed in the IM 2020 Third Quarter Report), Communication Retrofit of Replacement and non ES-II Units, and Transfer of Clay Street Wastewater Wall Scope from ES2FM to Clay Street 69kV Project. This IM 2020 Fourth Quarter Report also discussed the Market Street Radioactive Soil Testing and Handling-ESII-FM-1 decision, which was made early in the first quarter of 2021.	No change
Rate Counsel 8/4/2020 Letter to IM	The Fourth Quarter Report notes: "As noted in the IM 2020 Third Quarter Report, the Lakeside Avenue forecasted in-service date for this project slipped from May 2023, as of the end of the second quarter of 2020, to December 2023, as of the end of the third quarter. This delay was driven by the original property location for the 69kV and ES 2 projects having contamination risks that resulted in a new potential property location, for which the purchase process is underway. As of the end of 2020, the forecasted in-service date has improved slightly from December	The contamination risks were not associated with the original Lakeside Avenue location. This original location had a small site footprint that, due to the unavailability of adjacent property, would require a customized design and complicated construction sequence including the need to temporarily relocate the 4kV switchgear. PSE&G ultimately identified the new property for the Lakeside Avenue substation at the 101 N. Park Street site, as detailed in its September 24, 2020 Change in Mitigation Method letter. This new	**Section III.A.6.**

ID #	Question/Comment	IM Response	Report Changes
	20, 2023 to December 13, 2023 as PSE&G continues to look for opportunities to advance the schedule." Fourth Quarter Report at page 18. The reference to contamination risks at the original property was not mentioned in PSE&G's original Change of Mitigation Strategy letter dated September 24, 2020. Specifically, the September 24th letter stated "[t]he ES II flood mitigation filing assumed acquisition of adjacent property to install the raised switchgear. However, the property was not available, and a more complicated construction sequence requiring temporary relocation of the 4kV switchgear would be necessary. The initial Lakeside site is very small and would require a customized design to accommodate both the distribution and transmission facilities on the property. It would also require use of contingencies and cutovers that will increase safety, environmental and reliability risks, and pose a challenge to mitigate." PSE&G Change In Mitigation Method Letter, page 2. Rate Counsel has concerns that environmental contamination risk on the original property was not disclosed as the reason for the Company's decision to seek to acquire the 101 N. Park Street location.	site offered lower overall costs vs. the existing location, lower construction risk and outage contingencies, and the benefit of allowing a standard PSE&G design. Prior to selecting the 101 N. Park Street site, PSE&G considered property at 338 Washington Street. This site was determined not viable due to environmental concerns with the site (see also the response to RCR-INF-9 above), which drove the delay in the in-service date initially reported in the IM 2020 Third Quarter Report.	
Rate Counsel 8/4/2020 Letter to IM	Additionally, the Fourth Quarter Report noted that the Contingency Reconfiguration subprogram total forecast increased from $131,898,033 in the Third Quarter Report to $162,806,273. The stipulated budget for the subprogram is $145 million. Nonetheless, Pegasus concludes that "PSE&G has spent approximately 56% of both its estimated and currently forecasted recloser costs, suggesting actual costs coming in close to the estimate, but will warrant continued monitoring to ensure the subprogram objectives are completed within the estimated costs."	The overall change in the Contingency Reconfiguration subprogram forecast from the first to fourth quarter of 2020 was driven predominantly by changes in the scope of the subprogram (i.e. number of reclosers planned) and an evolving forecast of the Fuse Saver scope (initially only partially forecasted, then full forecasted, and more recently updated based on the experience of the pilot program). See also the response to RCR-INF-10 above.	No change

ENERGY STRONG 2 PROGRAM INDEPENDENT MONITOR 2021 FIRST QUARTER REPORT

PREPARED AND SUBMITTED BY

PEGASUS GLOBAL HOLDINGS, INC. ®

CONFIDENTIAL

~~NOVEMBER 30, 2021~~

JANUARY 20, 2022

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Appendices

List of Acronyms and Abbreviations

Advanced Distribution Management Systems .... ADMS

Advanced Metering Infrastructure .... AMI

Allowance for Funds Used During Construction .... AFUDC

Architecture/Engineer .... A/E

Board of Public Utilities .... BPU

Construction Work In Progress .... CWIP

Costs of Removal .... COR

Department of Community Affairs .... DCA

Distributed Energy Resource Management System .... DERMS

Distribution Management System .... DMS

Distribution Supervisory Control and Data Acquisition .... DSCADA

Energy Strong 2 .... ES 2

Gas Metering & Regulating .... Gas M&R

Geographic Information System .... GIS

Independent Monitor .... IM

Inside Plant .... IP

Issued for Construction .... IFC

Liquid Propane Air .... LPA

New Jersey Department of Environmental Protection .... NJDEP

New Jersey Sports & Exposition Authority .... NJSEA

Open Systems International Inc. .... OSII

Outage Management System .... OMS

Outside Plant .... OP

Public Service Electric & Gas .... PSE&G

Purchase Orders .... POs

Record of Decision .... ROD

Remote Control Unit .... RCU

Remote Terminal Unit .... RTU

Risk and Contingency .... R&C

Soil Conservation District .... SCD

System Average Interruption Duration Index .... SAIDI

Supervisory Control and Data Acquisition ....SCADA

Transmission & Distribution...T&D

Utility Review Board ....URB

I. Executive Summary

Public Service Electric & Gas's (PSE&G's) Energy Strong 2 (ES 2) Program was established from a Stipulation that the involved parties agreed to in August 2019, as approved by a Board of Public Utilities (BPU) Order dated September 11, 2019, with an effective date of September 21, 2019. The Stipulation provided the ES 2 Program would be comprised of five primary subprograms: Electric Station Flood Mitigation; Contingency Reconfiguration; Grid Modernization – Communications; Grid Modernization – Advanced Distribution Management Systems (ADMS); and Gas Metering & Regulating (Gas M&R) Station Upgrades. In addition, a Stipulated Base spend was established that includes both an electric component (higher outside plant design standards and station life cycle upgrades) and a gas component (overlapping with the Gas M&R subprogram).

During the first quarter of 2021, the bulk of the spend within the ES 2 Program continued to be in the two largest subprograms: Electric Station Flood Mitigation with six projects continuing in construction; and Contingency Reconfiguration that continues to advance the installation and commissioning of reclosers largely in alignment with PSE&G's plan. Within the other subprograms, the Grid Modernization – Communication System subprogram placed five additional fiber installation projects and three additional fiber cutover projects in-service and continued the ramp-up of the retrofit recloser installations, with 749 units completed through the end of the first quarter of 2021 out of a current forecast of 2,449 units. The Grid Modernization – ADMS subprogram continued to plan and develop the platform and necessary hardware equipment, while the Gas M&R subprogram continued advancing the engineering at each station and other pre-construction activities such as reviewing scope and permit documents and performing noise and geotechnical studies. The four stations approved within the life cycle upgrades portion of the Electric Stipulated Base continued design activities, including receipt of vendor drawings and advancing licensing and permitting packages. **Table 1 – ES 2 Subprogram & Stipulated Base Status as of March 31, 2021** below provides the spend to date on the subprograms within the ES 2 Program and Stipulated Base compared to the total forecast and forecasted completion for each.

Table 1 – ES 2 Subprogram & Stipulated Base Status as of March 31, 2021

Subprogram	Q1 Spend	Total Spend to Date*	Total Forecast*	% of Actuals to Forecast	Forecasted Completion**	Stipulation Funding Amount
Electric Station Flood Mitigation	$15,984,038	$69,929,211	$331,509,117	21%	Sep 2024	$389M
Contingency Reconfiguration	$12,503,156	$72,139,201	$148,927,422	48%	Dec 2023	$145M
Grid Modernization – Communications	$6,306,330	$25,526,835	$58,602,845	44%	Dec 2023	$72M
Grid Modernization – ADMS	$2,488,981	$18,972,817	$40,375,507	47%	Oct 2022	$35M
Electric Stipulated Base	$1,350,398	$3,786,460	$100,000,000	4%	Dec 2023	$100M
Gas M&R Station Upgrades^	$2,019,800	$5,981,294	$91,199,999	7%	Dec 2023	$101M
*Total**	$40,652,703	$196,335,818	$770,614,891	22%	Sep 2024	$842M

-Note: total figures may not fully align due to rounding. Additionally, the total forecast includes only the base cost for the Electric Station Flood Mitigation and Gas M&R subprograms as PSE&G does not include risk and contingency (R&C) in its forecasts for these projects. See **Table 12 and **Table 21** for the Electric Station Flood Mitigation and Gas M&R project estimates, respectively, with base costs and R&C shown.*
***-Final in-service date.*
^-Includes both the ES 2 projects and the Stipulated Base gas projects.

Given the prominence of the Electric Station Flood Mitigation subprogram, which represents over half of the total ES 2 Program spending, a summary of the projects within this subprogram is provided below in **Table 2 – ES 2 Electric Station Flood Mitigation Status as of March 31, 2020**.

Table 2 – ES 2 Electric Station Flood Mitigation Status as of March 31, 2020

Project	Total Estimate (rounded)	Actuals	% of Actuals to Estimate	Forecasted In-Service Date*
1. Academy Street	$10,500,000	$4,753,887	45%	10/25/2021
2. Clay Street	$42,000,000	$1,560,778	4%	2/7/2023 (↓)
3. Constable Hook	*Identified for Removal from the ES 2 Program*			
4. Hasbrouck Heights	$18,000,000	$1,830,577	10%	2/7/2023 (↑)
5. Kingsland	$8,300,000	$344,400	4%	10/4/2023
6. Lakeside Avenue	$47,900,000	$781,910	2%	12/13/2023
7. Leonia	$32,200,000	$8,887,799	28%	9/30/2022
8. Market Street	$26,900,000	$20,366,674	76%	9/23/2021 (↓)
9. Meadow Road	$9,000,000	$715,881	8%	9/21/2023
10. Orange Valley	$20,200,000	$447,215	2%	12/12/2023 (↑)
11. Ridgefield 13kV	$25,500,000	$9,654,641	38%	10/28/2022 (↓)
12. Ridgefield 4kV	$19,500,000	$14,191,713	73%	5/28/2021
13. State Street	$45,100,000	$977,153	2%	9/23/2022
14. Toney's Brook	$18,800,000	$673,983	4%	4/21/2023
15. Waverly	$35,400,000	$3,224,135	9%	9/17/2024 (↓)
16. Woodlynne	$19,400,000	$1,386,467	7%	10/10/2023 (↑)

**-Reflects the in-service date of the last major asset (e.g. switchgear), certain activities may take place after this date to support the final in-service date (i.e. when all customers are cutover).*
(↑)-*Indicates the forecasted in-service date advanced from the prior quarter.*
(↓)-*Indicates the forecasted in-service date slipped from the prior quarter.*

As indicated in **Table 2**, the projects that have previously started construction (Academy Street, Leonia, Market Street, Ridgefield 13kV, Ridgefield 4kV, and Waverly) continue to have the highest spend. Additionally, two of the stations (Toney's Brook and Ridgefield 4kV) had new estimates approved by the Utility Review Board (URB) in during the first quarter of 2021. **Table 2** also shows that seven of the fifteen remaining projects in this subprogram (following the removal of Constable Hook) had movement in the forecasted in-service date, with three advancing and four slipping. Of these seven projects, three of the projects (Market Street, Clay Street, and Woodlynne) had forecasted in-service dates change by one day. Only two (Hasbrouck Heights and Waverly) had movement more than 60 days, which is the threshold the Independent Monitor (IM) applied during the original Energy Strong Program for evaluating changes to the project schedules. The Hasbrouck Heights forecasted in-service date previously moved in the fourth quarter of 2020 from early December 2022 to mid-April 2023 due to Covid-19 related delays on the Siemens GIS installation on the associated Hasbrouck Heights 69kV project, which has resulted in the Hasbrouck Heights ES 2 project delaying the start of construction from July 2021 to January 2022, with no expected cost impacts from this schedule shift. The fourth quarter in-service date was based on the capacitor bank in-service date (April 2023), which has now been updated by PSE&G to reflect the switchgear in-service date currently forecasted for February 2023. The Waverly in-service date slipped

314 days from the forecasted in-service date at the end of the prior quarter. This was due to PSE&G being denied approval of the site plan by the Newark Planning Board, which requires PSE&G to address the comments received, coordinate community meetings on the new site plan application, and re-submit to the Newark Planning Board.

The IM has found nothing to date that would jeopardize the ES 2 Program being completed on budget. With schedule challenges, particularly on the Waverly substation and other projects with forecasted in-service dates near the Program end date as discussed in **Section III**, the ES 2 Program Schedule will warrant further monitoring by the IM to ensure the Program is completed within the defined timeline.

As noted in the IM 2020 First Quarter Report, the IM conducts its assessment in accordance with Generally Accepted Government Auditing Standards (GAGAS, or more commonly referred to as the "Yellow Book" standards). The Yellow Book provides a framework for conducting performance management reviews/audit engagements with competence, integrity, objectivity, and independence that result in information used for oversight, accountability, transparency, and improvements of the audited programs and operations. On November 30, 2021, a draft report was presented and submitted to PSE&G, BPU Staff, and Rate Counsel. Per the Yellow Book, the transmittal of a draft report is intended to allow for review and comment by the audited entity and others to develop a fair, complete, and objective report. A summary of the comments on the draft report and the IM's responses are provided in **Appendix A – Draft Report Comments and Responses**. This **Appendix A** also identifies specific sections within this IM 2021 First Quarter Report that have been edited, supplemented with additional information, or otherwise revised in response to the comments received.

II. Program Status

A. Key Decisions

In order to capture formalized key decisions regarding the ES 2 Program, PSE&G completes a "Record of Decision" (ROD) that includes a description of the decision; alternatives considered; the decision made; and rationale for the decision. The RODs are assessed by the IM as they are completed to review their impact to the Program. In addition, the IM may request PSE&G complete a ROD to formalize a decision if such a decision has not yet been formalized through the ROD process.

The current and pending RODs as of the date of this IM 2021 First Quarter Report are presented below in **Table 3 – ES 2 Records of Decisions**.

Table 3 – ES 2 Records of Decisions

Subprogram	Record of Decision	IM Comments
Electric Station Flood Mitigation	Academy Street & State Street Change in Mitigation Method	Reasonable and appropriate *(See Section B.1. in the IM 2020 First Quarter Report)*
Electric Station Flood Mitigation	Engineering Support for Energy Strong Program Projects	Reasonable and appropriate *(See Section B.2. in the IM 2020 First Quarter Report)*
Grid Modernization – Communication System	Wireless Communication Network – ESII-GM-3	Reasonable and appropriate *(See Section II.A.1. in the IM 2020 Third Quarter Report)*
Grid Modernization – Communication System	Substation Communication Center– ESII-GM-4	Reasonable and appropriate *(See Section II.A.2. in the IM 2020 Third Quarter Report)*

Subprogram	Record of Decision	IM Comments
Grid Modernization – Communication System	Fiber Scope – ESII-GM-1	Reasonable and appropriate *(See Section IV.A. in the IM 2020 Third Quarter Report)*
Electric Station Flood Mitigation	Constable Hook, Lakeside, & Orange Valley Change in Mitigation Method	Reasonable and appropriate *(See Sections II.A.3. and IV.B. in the IM 2020 Third Quarter Report and additional discussion in Section II.A.1. and Section IV.B. of the IM 2020 Fourth Quarter Report)*
Grid Modernization – Communication System	Communication Retrofit of Replacement and non-ES-II Units – ESII-GM-2	Reasonable and appropriate *(See Section II.A.2. in the IM 2020 Fourth Quarter Report)*
Electric Station Flood Mitigation	Market Street Radioactive Soil Testing and Handling – ESII-FM-1	Reasonable and appropriate *(See Section II.A.3. in the IM 2020 Fourth Quarter Report)*
Electric Station Flood Mitigation	Transfer of Clay Street Wastewater Wall Scope from ES2FM to Clay Street 69kV Project – ESII-FM-Clay01	Reasonable and appropriate *(See Section IV.A. in the IM 2020 Fourth Quarter Report)*
Contingency Reconfiguration	Energy Strong II Electric Program – Contingency Reconfiguration Subprogram, 13kV and 4kV Reclosers–ESII-CR-1	Reasonable and appropriate *(See **Section IV.A.** in this IM 2021 First Quarter Report)*
Grid Modernization – ADMS	Outage Management System (OMS) Implementation – ESII-GM-5	Under review *(See **Section IV.A.** in this IM 2021 First Quarter Report)*

B. Program Management

Beginning in July 2020, the IM began participating in a bi-weekly call with PSE&G to review its bi-weekly ES 2 Program Dashboard. As with ES 1, the Dashboard provides a mechanism for PSE&G to monitor and control activities to be completed in order to achieve key near-term milestones, including a focus on recently completed activities, any key issues, and other key metrics (e.g. installation targets) as appropriate. These calls have proven to be an effective way for the IM to stay informed on current and upcoming activities and to allow a venue for discussions between the IM and PSE&G on these activities and status updates and continue to be held on a recurring basis.

C. Cost Assignments

1. Costs of Removal (COR)

Costs of Removal (COR) generally include costs for such activities as environmental removal, removal of inside station equipment, structures, foundations, towers and fixtures, conductors and other electrical devices, poles and fixtures, transformers, plant demolition, foundations, and removal of underground conduit and other wiring. Generally, COR are charged to Accumulated Depreciation and are amortized and recovered through a component of depreciation expense. The specific method and amount of recovery is determined in gas and electric rate cases before the BPU.

Table 4 – ES 2 Costs of Removal as of March 31, 2021, below itemizes the charges to COR for the first quarter of 2021, the fourth quarter of 2020, and for comparative purposes, total 2020, total 2019 (which was only the fourth quarter) and total ES 2 COR to date. These amounts do not reflect any salvage value reductions, which have been de minimis in the ES 2 Program through March 31, 2021.

Table 4 – ES 2 Costs of Removal as of March 31, 2021

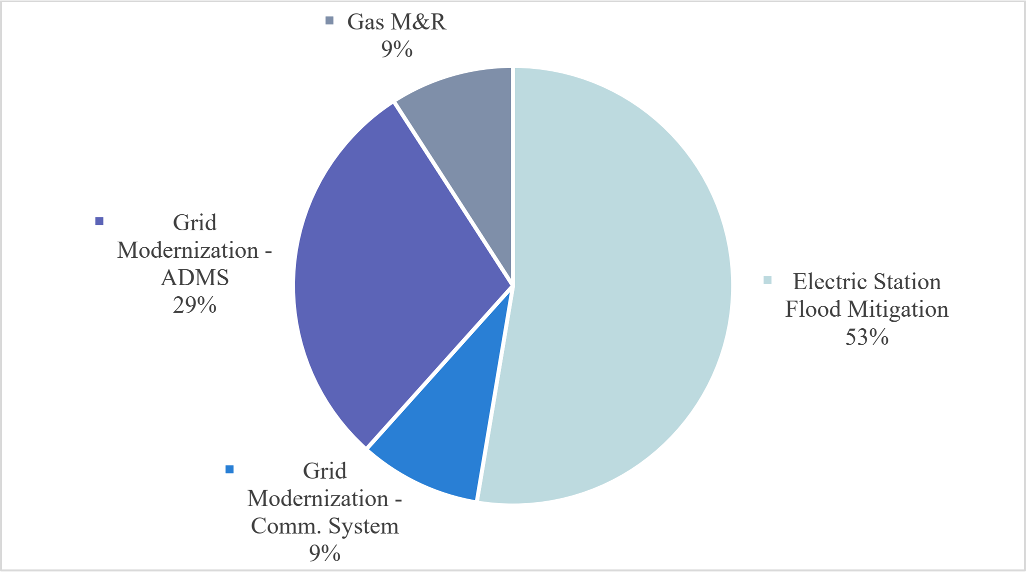
Subprogram	Q1 2021	Q4 2020	Total 2020	Total 2019 (Q4)	Total COR
	(in $ thousands)				
Electric Station Flood Mitigation	**$1,129.5**	**$190.7**	**$1,021.1**	**$0**	**$2,150.6**
Contingency Reconfiguration	**$622.9**	**$707.3**	**$2,198.9**	**$431.0**	**$3,252.8**
Grid Modernization – Communications	**$37.8**	**$19.6**	**$24.4**	**$0**	**$62.2**
Grid Modernization - ADMS	**$0**	**$0**	**$0**	**$0**	**$0**
Electric Stipulated Base	**$0**	**$0**	**$0**	**$0**	**$0**
Gas M&R Station Upgrades	**$0**	**$0**	**$0**	**$0**	**$0**
Total	**$1,790.2**	**$917.6**	**$3,244.4**	**$431.0**	**$5,465.6**

COR charges during the first quarter of 2021 increased substantially from the fourth quarter of 2020 primarily due to the removal of the 4kV overhead circuits and associated equipment at the Market Street substation project (about $1.0 million).

2. *Construction Work-in-Progress (CWIP) & In-Service Transfers*

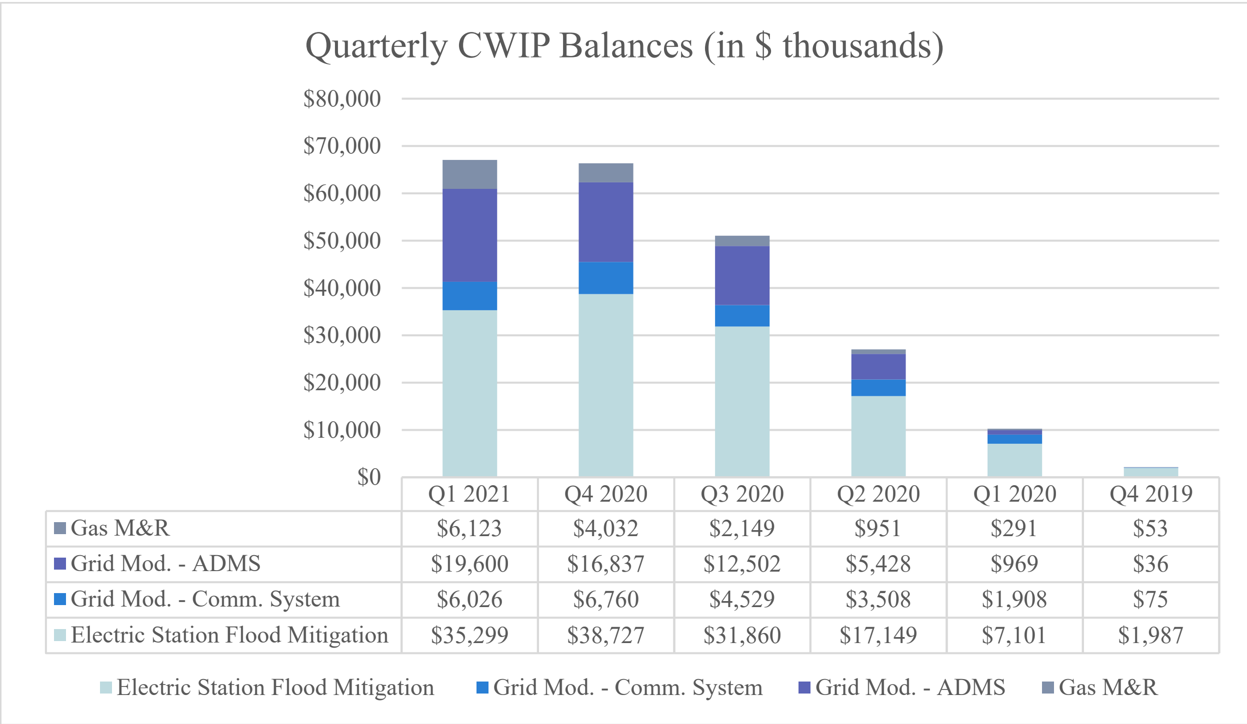
As of March 31, 2021, the ES 2 CWIP balance was $67.0 million, compared to $66.4 million as of December 31, 2020. The largest components of March 31, 2021 CWIP were the elimination and conversion of the 4kV circuits at the Ridgefield ($9.1 million) and Market Street substations ($5.1 million), activity at Academy Street substation ($5.0 million) and work associated with the Grid Modernization – ADMS subprogram ($19.6 million). The Electric Station Flood Mitigation subprogram comprises the largest component of total end of period CWIP outstanding, as depicted in **Figure 1 – ES 2 CWIP as of March 31, 2021** below.

Figure 1 – ES 2 CWIP as of March 31, 2021



In addition, the **Figure 2 – ES 2 CWIP Balances by Subprogram as of March 31, 2021** below depicts the composition of end-of-quarter CWIP balances by subprogram for the first quarter of 2021, each quarter of 2020, and the fourth quarter of 2019.

Figure 2 – ES 2 CWIP Balances by Subprogram as of March 31, 2021



Transfers from CWIP to plant in-service totaled $12.2 million during the first quarter of 2021, mainly comprised of $9.5 million of switchgear assets at the Leonia and Ridgefield 13kV substations. Total ES 2 transfers from CWIP have been $17.4 million through March 31, 2021. It should be noted that work related to certain assets, such as the reclosers under the Contingency Reconfiguration subprogram, generally can be completed without being recorded through CWIP. As such, no AFUDC is recorded on these expenditures. This accounting treatment is fully in accord with generally accepted accounting principles and the Company's accounting policies.

3. Allowance for Funds Used During Construction (AFUDC)

The amount of quarterly AFUDC recorded by the Company for each ES 2 subprogram during the first quarter of 2021, the fourth quarter of 2020 (for comparative purposes), total AFUDC for the years 2020 and 2019 and total ES 2 AFUDC accrued to date, is shown below in **Table 5 – ES 2 AFUDC as of March 31, 2021**.

Table 5 – ES 2 AFUDC as of March 31, 2021

Subprogram	Q1 2021	Q4 2020	Total 2020	Total 2019 (Q4)	Total AFUDC
	(in $ thousands)				
Electric Station Flood Mitigation	**$558.6**	**$305.0**	**$936.5**	**$9.9**	**$1,505.0**
Contingency Reconfiguration	**$0**	**$0**	**$0**	**$0**	**$0**

Subprogram	Q1 2021	Q4 2020	Total 2020	Total 2019 (Q4)	Total AFUDC
	(in $ thousands)				
Grid Modernization – Communications	**$59.0**	**$66.2**	**$184.3**	**$0.2**	**$243.5**
Grid Modernization - ADMS	**$274.2**	**$213.9**	**$352.7**	**$0.1**	**$627.0**
Electric Stipulated Base	**$49.6**	**$32.6**	**$44.0**	**$0**	**$93.6**
Gas M&R Station Upgrades	**$72.2**	**$39.6**	**$70.0**	**$0.2**	**$142.4**
Total	**$1,013.6**	**$657.3**	**$1,587.5**	**$10.4**	**$2,611.5**

During the first quarter of each year, the AFUDC rate is reviewed for possible reset as it applies to the current year based on updated capital structure and component cost data. For the year 2021, the new AFUDC rate was calculated to be 6.81%, using the capital structure and component costs as of January 31, 2021. This rate is lower than the 2020 rate of 6.95%, primarily due to a significantly lower interest rate used for short-term debt in the AFUDC calculation, and also to a reduction in the Company's embedded cost of long-term debt. In calculating the 2021 AFUDC rate, the Company used (i) a 3.85% embedded cost of long-term debt (vs. 4.02% in 2020), (ii) a short-term debt rate of 0.32% (vs. 1.86% in 2020), and (iii) a cost of equity of 9.60% (unchanged from 2020).

Subsequent to the annual reset calculation referred to above, and during the course of each year, the AFUDC rate is also recalculated as it applies to each fiscal quarter. If the recalculated rate changes by 25 basis points from the rate then in effect, the rate is reset and retroactively applied to January 1 of that year. For the first quarter of 2021, based on data as of March 31, 2021, the recalculated weighted average AFUDC accrual rate (6.79%) did not meet this criterion to warrant changing from the annual rate (6.81%) in effect. Therefore, AFUDC was accrued during the first quarter of 2021 at the calculated rate of 6.81%.

AFUDC accrued for ES 2 projects during the first quarter of 2021 increased over AFUDC accrued during the fourth quarter of 2020 as the result of the reclassification made to CWIP and AFUDC during the fourth quarter of 2020 to reflect the reversal of certain costs from CWIP to plant in-service, with the associated effect on fourth quarter 2020 AFUDC (as discussed in the IM's Fourth Quarter 2020 Report), the semiannual AFUDC compounding roll-in to the AFUDC base calculation that occurs in January of each year, and increases in total average CWIP balances for the Grid Modernization – ADMS and Gas M&R subprograms.

The IM observes that the Company's calculation of the AFUDC rate and its application is in accordance with both PSE&G's accounting policy and Plant Instruction 3(17) of the Federal Energy Regulatory Commission's Uniform Systems of Accounts prescribed for public utilities.

The IM also notes that the relevant AFUDC information as it relates to first quarter 2021 ES 2 project costs is consistent with the applicable dictates of the Stipulation entered into with respect to these ES 2 projects. The IM will continue to review future Energy Strong AFUDC accruals for consistency with relevant provisions of the Stipulation for accounting and reporting purposes only, and not as a party to, or in expressing an opinion concerning, any rate proceedings.

4. Allocated Overheads

PSE&G follows a philosophy of allocating overhead costs, whether at the Service Company or from utility support organizations, to the operating company or unit receiving the benefit, and ultimately, if appropriate, settling costs to individual assets. Where possible, services are charged directly to the entity receiving the benefit, but where direct charging of costs is not feasible, cost allocations from the Service Company to operating companies are prescribed in a BPU-approved schedule issued pursuant to a BPU order in July 2003. The Stipulation requires the Company to follow its current practices with regard to capitalized overheads.

For ES 2 electric and gas distribution projects, allocated overhead costs should primarily come from utility-related labor costs associated with administrative and supervisory personnel, labor and other costs associated with bargaining unit personnel, fringe benefits, materials handling costs, payroll taxes and depreciation expense. Shown below in **Table 6 – ES 2 Overhead Allocations as of March 31, 2021** are the allocated overhead costs charged to ES 2 projects for the first quarter of 2021, the fourth quarter of 2020 (for comparative purposes), total 2020, total 2019 and total Energy Strong allocated overheads to date.

Table 6 – ES 2 Overhead Allocations as of March 31, 2021

Subprogram	Q1 2021	Q4 2020	Total 2020	Total 2019 (Q4)	Total Overhead Allocations
	(in $ thousands)				
Electric Station Flood Mitigation	$5,588	$4,925	$14,023	$287	$19,898
Contingency Reconfiguration	$4,215	$6,011	$17,109	$3,415	$24,739
Grid Modernization – Communications	$1,743	$2,170	$3,625	$12	$5,380
Grid Modernization – ADMS	$119	$112	$426	$11	$556
Electric Stipulated Base	$126	$104	$259	$0	$385
Gas M&R Station Upgrades	$131	$92	$291	$15	$437
*Total**	$11,922	$13,414	$35,733	$3,740	$51,395

The overwhelming majority of overhead costs allocated to ES 2 projects during the first quarter of 2021 are costs allocated from areas that support all utility distribution and transmission projects, including ES2 projects. More specifically, most of the first quarter allocated costs reflect labor costs of supervisory, administrative and operations planning personnel, labor and other costs from bargaining unit personnel, and fringe benefits associated with these labor costs. The decrease in overheads for the first quarter 2021 from the fourth quarter of 2020 largely reflects lower overall ES 2 project spend, notably in the Contingency Reconfiguration subprogram.

D. System Performance

1. Current Reporting Quarter Major Events

During the first quarter of 2021, there was one Major Event reported in PSE&G's service territory concerning a State of Emergency declared due to a series of snowstorms. The State of Emergency was declared by Governor Murphy on January 31, 2021 and was lifted on February 23, 2021. During this Major Event period, 104,932 PSE&G customers experienced extended service.

The IM has received PSE&G's report on the performance of its investments from this Major Event and has reproduced the results in **Table 7 – Q1 2021 Major Event Performance** below.

Table 7 – Q1 2021 Major Event Performance

Circuit	5 Year Baseline SAIDI*	Report Quarter SAIDI*
ADA 8026		0.00000
BAO 8006		0.00000
BAO 8008	**0.00005**	**0.00036**
BEF 8015	**0.00433**	**0.01158**
BEN 8012	0.22864	0.00548
BLO 4016	**0.01635**	**0.12393**
BRU 8012	0.01648	0.00000
BRU 8022	0.02954	0.00313
BRU 8023		**0.01247**
BUS 8023	0.03965	0.00000
CAS 8001	0.02438	0.00391
CED 8022	0.05071	0.00646
CIN 8002	0.01418	0.00000
CIN 8043	0.18459	0.00946
CLF 8024	0.01800	0.00000
CLK 8023	0.00019	0.00000
CLK 8024	0.01526	0.00000
COR 8034	0.03335	0.00000
COR 8041	0.05596	0.00000
CRX 8003	0.07703	0.00247
CUT 8006	0.59550	0.00052
CUT 8007	0.67234	0.01577
CUT 8010	0.49117	0.02914
CUT 8031	0.00845	0.00000
DFD 8007	0.06056	0.01571
EAT 8023		**0.00363**
FAW 8023	0.02811	0.00117
FED 4021		**0.02426**
FIT 8003	0.01301	0.00538
FOU 8014	**0.00123**	**0.00690**
FOU 8022	**0.00091**	**0.00180**
FOU 8024		**0.00402**
GBK 8014	0.30784	0.00027
GBK 8025	0.31504	0.00145
HAC 4007		0.00000
HAT 8015	0.02090	0.00181
HAT 8035	0.04291	0.00026
HNC 8015	0.15427	0.00340
HNC 8024	0.43454	0.00282
HOE 8047	0.05561	0.04167
IRO 4003		0.00000
IRO 4005		0.00000
IRO 4011		0.00000
IRO 4012		0.00000

Circuit	5 Year Baseline SAIDI*	Report Quarter SAIDI*
IRO 4014		0.00000
IRV 4013	**0.02207**	**0.03411**
JAC 8021	0.00477	0.00090
JAC 8022	0.04453	0.00030
JAC 8024	0.25423	0.00000
JAC 8033	**0.00350**	**0.00819**
KIL 8014		**0.00821**
KIL 8016	0.01491	0.00000
KIL 8023		**0.02076**
KIL 8024	0.01504	0.00212
KIL 8033	0.01648	0.01115
KIL 8042	0.06155	0.00000
KUS 8009	**0.04178**	**0.05447**
LAW 8016	0.14895	0.00804
LAW 8025	0.16759	0.00894
LAW 8033	0.04306	0.00000
LCU 8051	0.19366	0.01809
LEO 8005	0.61152	0.01045
LEO 8006	0.07368	0.00000
LEV 8002	0.06064	0.05175
LEV 8011	0.25139	0.00457
LEV 8012	0.25318	0.00449
LIB 4007**	0.10880	0.01004
LIT 8001	0.02586	0.00000
LOC 8012		**0.00993**
LUM 8024	0.23063	0.00164
MAD 8018	0.20763	0.00118
MAD 8022	0.41375	0.00156
MAD 8024	0.11054	0.00000
MAI 8013	0.05318	0.01301
MAR 8017	0.45014	0.00683
MAY 8013		**0.00155**
MDF 8012	0.58371	0.00080
MDF 8023	0.26488	0.00110
MEA 8024	0.09438	0.03566
MIN 8024		0.00000
MIN 8025	**0.00515**	**0.01043**
MTL 8015	0.04117	0.00308
NBS 8023	0.00085	0.00000
NED 8013	0.03270	0.00000
NED 8025	0.01640	0.01087
NEW 8014	0.01839	0.00098
NIN 4004	0.03196	0.00131
NOT 8011		**0.00307**

Circuit	5 Year Baseline SAIDI*	Report Quarter SAIDI*
NOT 8013		0.00000
NOT 8014	0.00232	0.00000
NOT 8021		**0.00017**
NOT 8022	**0.00091**	**0.02397**
NRB 8012		**0.00574**
ORA 4001	0.02674	0.02302
PEK 8026	0.04523	0.00101
PIE 8023	0.04636	0.01156
PIN 4002**	0.08187	0.00000
PLI 8005	0.16440	0.00000
POH 8012		**0.00016**
POR 8021**		0.00000
RAV 8003	0.00674	0.00008
RFL 8025		0.00000
RGW 4007		**0.00800**
RUN 8001		**0.01054**
SAD 8002		**0.00115**
SAD 8045	**0.00284**	**0.02276**

Circuit	5 Year Baseline SAIDI*	Report Quarter SAIDI*
SMV 8012		**0.01636**
SPF 8025	0.09408	0.00000
SUN 8045	**0.00066**	**0.00073**
TUR 8001	**0.00248**	**0.00976**
TUR 8015	**0.00704**	**0.04733**
VIL 8001**	0.24055	0.00000
WAD 8011	0.08512	0.02907
WAN 8015		**0.00201**
WAN 8022		**0.00214**
WEW 8014		**0.00093**
WEW 8042	0.01304	0.00249
WOR 8021		0.00000
WOR 8034	0.01023	0.00207
**-SAIDI calculations are in minutes. **-These circuits have not received investments under the Original Energy Strong Program or under the ES 2 Program, all other circuits listed have received investments.*		

In the circuit data above, the "0.00000" indicates an outage, but the value is beyond five decimal points captured by PSE&G; in addition, blank cells indicate no outage in the 5-year window. As indicated above, there were 119 circuits impacted by this Major Event with the majority of the affected circuits having experienced outages less the 5-year Major Event average.

For those circuits with a higher Major Event SAIDI than the 5-year Major Event SAIDI average (shown in bold in **Table 7**), 19 had no outages in the past five years while 14 had a higher report quarter SAIDI average than the 5-year baseline SAIDI. For those 14, additional information on the circuits and the outage experienced is provided below in **Table 8 – Q1 2021 Major Event Additional Information on Selected Circuits** (note that some of these circuits had more than one incident during the Major Event, resulting in a total of 24 incidents from these 14 circuits).

Table 8 – Q1 2021 Major Event Additional Information on Selected Circuits

Circuit	5-Year Baseline SAIDI*	Report Quarter SAIDI*	Customers Impacted	Outage Duration*
BAO 8008	0.00005	0.00036	47	19
BEF 8015	0.00433	0.01158	569	50
BLO 4016	0.01635	0.12393	473	171
BLO 4016	0.01635	0.12393	1,254	171
BLO 4016	0.01635	0.12393	0	356
BLO 4016	0.01635	0.12393	17	171
BLO 4016	0.01635	0.12393	18	171
BLO 4016	0.01635	0.12393	0	171
BLO 4016	0.01635	0.12393	19	171
FOU 8014	0.00123	0.00690	0	168

Circuit	5-Year Baseline SAIDI*	Report Quarter SAIDI*	Customers Impacted	Outage Duration*
FOU 8014	0.00123	0.00690	47	47
FOU 8014	0.00123	0.00690	117	126
FOU 8022	0.00091	0.00180	85	52
IRV 4013	0.02207	0.03411	1,035	81
JAC 8033	0.00350	0.00819	117	172
KUS 8009	0.04178	0.05447	631	154
KUS 8009	0.04178	0.05447	1,930	19
MIN 8025	0.00515	0.01043	39	657
NOT 8022	0.00091	0.02397	1,636	36
SAD 8045	0.00284	0.02276	948	59
SUN 8045	0.00284	0.02276	948	59
TUR 8001	0.00248	0.00976	101	129
TUR 8001	0.00248	0.00976	85	129
TUR 8015	0.00704	0.04733	1,077	108
**-Calculated in minutes.*				

As indicated in **Table 8**, in addition to the original Energy Strong Program and ES 2 investments that increased sectionalizing of circuits to reduce the number of customers impacted by outages, the customer impact from a Major Event is also a function of the nature of the outages (extent of damage) and the location of damage relative to the various interrupting devices on the circuit, that is, reclosers or fuses. For some circuits, the 5-year baseline outage(s) were smaller or affected fewer customers, whether it be different device operations (fuse with 10 customers vs. fuse with 150 customers) than the Major Event being reported. Some circuits had more non-reclosing device operations in this Major Event (more fuse jobs) or more customers served by the circuit due to circuit rearrangements.

III. Project Status

A. Electric Station Flood Mitigation

A summary of the subprogram plan as of the end of the first quarter of 2021 is provided below in **Table 9 – ES 2 Electric Station Flood Mitigation Subprogram Milestone Schedule as of March 31, 2021**.

Table 9 – ES 2 Electric Station Flood Mitigation Milestone Schedule as of March 31, 2021

Project	Plan Status Point	2019		2020				2021				2022				2023				2024
		Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	
1. Academy Street	Dec. 2019		KO					C					IS		CO					
	Dec. 2020		KO		C							IS		CO						
	Mar. 2021		KO		C						IS			CO						
2. Clay Street	Dec. 2019	*Schedule Under Development*																		
	Dec. 2020			KO							C								IS	CO (Q2)
	Mar. 2021			KO							C					IS				CO (Q2)
3. Constable Hook	Dec. 2019	*Schedule Under Development*																		
	Dec. 2020	*Schedule Under Development*																		
	Mar. 2021	*Identified for Removal from the ES 2 Program*																		

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Project	Plan Status Point	2019		2020				2021				2022				2023					2024
		Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4		
4. Hasbrouck Heights	Dec. 2019		KO						C						IS		CO			*Dec. 31, 2023 - ES 2 Program End Date*	
	Dec. 2020		KO									C					IS		CO		
	Mar. 2021		KO									C				IS					CO (Q1)
5. Kingsland	Dec. 2019			KO				C			IS		CO								
	Dec. 2020			KO										C					IS		CO (Q2)
	Mar. 2021			KO											C				IS		CO (Q2)
6. Lakeside Avenue	Dec. 2019*				KO				C										IS		CO (Q2)
	Dec. 2020						KO							C					IS		CO (Q2)
	Mar. 2021						KO							C					IS		CO (Q4)
7. Leonia	Dec. 2019	*Schedule Under Development*																			
	Dec. 2020			KO		C									IS		CO				
	Mar. 2021			KO		C								IS			CO				
8. Market Street	Dec. 2019			KO				C	OS		CO										
	Dec. 2020			KO					C	OS		CO									
	Mar. 2021			KO					C/OS					CO							
9. Meadow Road	Dec. 2019	*Schedule Under Development*																			
	Dec. 2020			KO											C				IS		CO (Q2)
	Mar. 2021			KO										C				IS			CO (Q2)
10. Orange Valley	Dec. 2019	*Schedule Under Development*																			
	Dec. 2020					KO										C					IS (Q1); CO (Q3)
	Mar. 2021					KO								C					IS		CO (Q3)
11. Ridgefield 13kV	Dec. 2019			KO	C										IS		CO				
	Dec. 2020			KO	C										IS		CO				
	Mar. 2021			KO	C										IS			CO			
12. Ridgefield 4kV	Dec. 2019			KO						C	OS			CO							
	Dec. 2020			KO	C				OS		CO										
	Mar. 2021			KO	C				OS		CO										
13. State Street	Dec. 2019		KO					C								IS					CO (Q1)
	Dec. 2020		KO						C				IS								CO (Q1)
	Mar. 2021		KO						C					IS							CO (Q1)
14. Toney's Brook	Dec. 2019			KO						C									IS		CO (Q2)
	Dec. 2020			KO										C			IS				CO (Q2)
	Mar. 2021			KO										C			IS				CO (Q2)
15. Waverly	Dec. 2019	*Schedule Under Development*																			
	Dec. 2020			KO			C												IS		CO (Q2)
	Mar. 2021			KO			C														IS (Q3); CO (Q1 2025)
16. Woodlynne	Dec. 2019		KO												C				IS		CO (Q2)
	Dec. 2020		KO												C				IS		CO (Q2)
	Mar. 2021		KO												C				IS		CO (Q2)

Legend: KO = Kickoff; C = Construction; IS = Fully In-Service (major assets in-service); OS = Out-of-Service (if eliminated); CO = Closeout

-Actuals are indicated with an underline (Note: for the Market Street and Ridgefield 4kV projects, outside plant construction began in the first quarter of 2020, the construction milestone indicated on this chart reflects inside plant construction).

*-The Dec. 2019 Lakeside Avenue project schedule was based on the original raise and rebuild mitigation strategy; the current schedule reflects the proposed mitigation method change that contemplates relocating the substation.

A summary of the subprogram status as of the end of the first quarter of 2021 is provided below **Table 10 – ES 2 Electric Station Flood Mitigation Summary Status as of March 31, 2021**.

Table 10 – ES 2 Electric Station Flood Mitigation Summary Status as of March 31, 2021

Activity	Total # of Projects	Specific Projects
Kickoff Meeting	15	Academy Street; Clay Street; Hasbrouck Heights; Kingsland; Lakeside Avenue; Leonia; Market Street; Meadow Road; Orange Valley; Ridgefield 13kV; Ridgefield 4kV; State Street; Toney's Brook; Waverly; Woodlynne
Key Drawing Review	15	Academy Street; Clay Street; Hasbrouck Heights; Kingsland; Lakeside Avenue; Leonia; Market Street; Meadow Road; Orange Valley; Ridgefield 13kV; Ridgefield 4kV; State Street; Toney's Brook; Waverly; Woodlynne
Scope Locked	15	Academy Street; Clay Street; Hasbrouck Heights; Kingsland; Lakeside Avenue; Leonia; Market Street; Meadow Road; Orange Valley; Ridgefield 4kV; Ridgefield 13kV; State Street; Toney's Brook; Waverly; Woodlynne
Major Equipment Purchase Orders (POs)	15*	Academy Street; Clay Street; Hasbrouck Heights; Kingsland; Lakeside; Leonia*; Meadow Road; Ridgefield 13kV*; State Street; Toney's Brook; Waverly*; Woodlynne
Architecture/Engineer (A/E) Contract Award (or selection of PSE&G internal engineering)	15	Academy Street[1]; Clay Street[1]; Hasbrouck Heights[1]; Kingsland[2]; Lakeside Avenue[3]; Leonia[2]; Market Street[2]; Meadow Road[2]; Orange Valley[1]; Ridgefield 13kV[2]; Ridgefield 4kV[2]; State Street[2]; Toney's Brook[3]; Waverly[3]; Woodlynne[1]
Construction Start^	6	Academy Street; Leonia; Market Street; Ridgefield 4kV; Ridgefield 13kV; Waverly

**-Three of the listed projects (Leonia, Ridgefield 13kV, and Waverly) have two switchgears, thus the current count reflects 15 switchgears at 12 substations.*
[1]-Indicates Burns & McDonnell is serving as the A/E.
[2]-Indicates PSE&G internal resources are serving as the A/E.
[3]-Indicates Black & Veatch is serving as the A/E.
^-Includes inside plant and/or outside plant construction.

Beyond the key activities summarized in **Table 10** above, **Table 11 – ES 2 Electric Station Flood Mitigation Upcoming Activities for Q2 2021** summarizes the planned activities for each project during the second quarter of 2021, including any carryover of activities from earlier periods.

Table 11 – ES 2 Electric Station Flood Mitigation Upcoming Activities for Q2 2021

Station	Upcoming Activities for Q2 2021	Carryover Activities from Q1 2021
1. Academy Street	• Continued engineering and construction	• Continued engineering and construction
2. Clay Street	• 70% estimate completed • Civil, controls, and electrical drawings issued for construction (IFC)	• None
3. Constable Hook	• Identified for Removal from the ES 2 Program	
4. Hasbrouck Heights	• Electrical construction PO issued • Major municipal licenses and permits issued	• None
5. Kingsland	• Continued design and engineering	• Continued design and engineering
6. Lakeside Avenue	• License and permitting packages issued (site plan application)	• None

Station	Upcoming Activities for Q2 2021	Carryover Activities from Q1 2021
7. Leonia	• Phase 3 municipal licenses and permits issued (site plan, construction) • Switchgear delivered • Phase 2 civil construction complete • Phase 2 electrical construction start	• None
8. Market Street	• In-service achieved for 4kV to 13kV circuit conversions and outside plant Deptford street and Locust street extensions	• None
9. Meadow Road	• Continued engineering and design	• Continued engineering and design
10. Orange Valley	• Switchgear PO issued	• License and permitting package issued
11. Ridgefield 13kV	• Switchgear delivered • Major state and municipal licenses and permits issued (piles/foundation) • Phase 1 civil construction start	• None
12. Ridgefield 4kV	• Civil demolition PO issued • Electrical construction completed • In-service achieved for 4kV to 13kV circuit conversions • Start electrical demolition	• None
13. State Street	• 70% estimate completed • Civil PO issued • Controls drawings IFC	• Electrical construction purchase order issued
14. Toney's Brook	• Electrical construction PO issued • Civil and electrical drawings IFC	• None
15. Waverly	• Switchgear delivered • Phase 2 controls drawings IFC	• None
16. Woodlynne	• 70% estimate completed • Civil and electrical POs issued • Major municipal licenses and permits issued (construction)	• None

The current project estimates, including base and R&C amounts, is shown below in **Table 12 – ES 2 Electric Station Flood Mitigation Project Cost Status as of March 31, 2021**. **Table 12** also shows the current estimate level based on PSE&G's estimating processes and as approved by the URB, the actual spend, and percentage of actuals to estimate as of the end of the first quarter of 2021.

Table 12 – ES 2 Electric Station Flood Mitigation Project Cost Status as of March 31, 2021

Project	Estimate Level	Base	Risk & Contingency	Total	Current Forecast	Actuals to Date	% of Actuals to Estimate
1. Academy Street	Definitive	$9,800,000	$700,000	$10,500,000	$9,704,217	$4,753,887	45%
2. Clay Street	Study	$34,800,000	$7,200,000	$42,000,000	$29,796,949	$1,560,778	4%
3. Constable Hook	*Identified for Removal from the ES 2 Program*						

Project	Estimate Level	Base	Risk & Contingency	Total	Current Forecast	Actuals to Date	% of Actuals to Estimate
4. Hasbrouck Heights	Study	$14,900,000	$3,100,000	$18,000,000	$20,474,628	$1,830,577	10%
5. Kingsland	Study	$5,400,000	$2,900,000	$8,300,000	$6,418,541	$344,400	4%
6. Lakeside Avenue	Study	$39,400,000	$8,500,000	$47,900,000	$39,356,278	$781,910	2%
7. Leonia	Study	$27,700,000	$4,500,000	$32,200,000	$25,082,905	$8,887,799	27%
8. Market Street	Definitive	$25,200,000	$1,700,000	$26,900,000	$26,174,479	$20,366,674	76%
9. Meadow Road	Study	$7,200,000	$1,800,000	$9,000,000	$7,325,880	$715,881	8%
10. Orange Valley	Study	$16,000,000	$4,200,000	$20,200,000	$15,703,933	$447,215	2%
11. Ridgefield 13kV	Study	$19,600,000	$5,900,000	$25,500,000	$25,256,853	$9,654,641	38%
12. Ridgefield 4kV	Definitive	$18,500,000	$1,000,000	$19,500,000	$18,829,711	$14,191,713	73%
13. State Street	Study	$39,000,000	$6,100,000	$45,100,000	$38,928,940	$977,153	4%
14. Toney's Brook	Conceptual	$16,200,000	$2,600,000	$18,800,000	$16,205,945	$673,983	4%
15. Waverly	Study	$29,400,000	$6,000,000	$35,400,000	$33,806,170	$3,224,135	9%
16. Woodlynne	Study	$15,800,000	$3,600,000	$19,400,000	$18,308,852	$1,386,467	7%
Subprogram Total		**$318,900,000**	**$59,800,000**	**$378,700,000**	**$331,374,281**	**$69,797,213**	**14%**

Findings & Observations

- Seven Electric Station Flood Mitigation projects had changes to the forecasted in-service date from the end of 2020 to the end of the first quarter of 2021. Of these projects: Market Street, Clay Street, and Woodlynne had a one-day move in the forecasted in-service date; Ridgefield 13kV slipped 15 days; and Orange Valley improved 43 days. Two other projects had forecasted in-service movements greater than 60 days, including Hasbrouck Heights, which improved 64 days based on PSE&G identifying the in-service date as the final major asset (which is consistent with PSE&G's treatment of other Electric Station Flood Mitigation in-service dates across Energy Strong and ES 2) instead of the previously identified date of when the capacitor banks were completed, and Waverly, which slipped 314 days stemming from delays in approval of the site plan application that pushed out construction to 2022 and the last major asset in-service to September 2024, substantially beyond the ES 2 Program completion date of December 31, 2023.

- The Ridgefield 4kV and Toney's Brook projects had new estimates approved during the first quarter of 2021, each resulting in a minor decrease to the overall estimate for the project. The Ridgefield 4kV project advanced from the Conceptual to Definitive estimate phase, with an overall decrease of $0.7 million from the prior estimate for a total estimate of $19.5 million. The Toney's Brook project advanced from the Study to Conceptual estimate phase, with an overall decrease of $0.9 million from the prior estimate for a total estimate of $18.8 million.
- The IM has found nothing to date that would jeopardize the subprogram being completed on budget. However, the IM finds that the Waverly project is currently scheduled beyond the ES 2 Program completion date. The status of the later projects in this subprogram, and in particular Waverly, will have to closely be followed to monitor if the projects can be completed within the ES 2 Program window. As of the end of the first quarter of 2021, the Waverly project shows a final in-service date of September 2024. The Waverly project has multiple major asset in-service dates for the 26kV switchgear, 4kV switchgear, and three transformers. At this time Transformer #3 is the outlier from completing the full scope within the ES 2 Program window. PSE&G has informed the IM that the project team has every intention of improving the in-service dates and will be examining the potential to shorten durations and/or work activities concurrently to pull the final in-service date back into 2023. The IM has increased its monitoring on the projects that are currently forecasted to be completed in the fourth quarter of 2023 and the Waverly project and will continue to discuss with PSE&G actions undertaken to improve schedule, for which updated information will continue to be provided in future IM reports.

1. Academy Street

During the first quarter of 2021, $378,939 was spent on the Academy Street project compared to a forecast of approximately $470,000, which brought the total spend to approximately $4.7 million. The variance in first quarter spend was largely driven by completion of the 69kV underground duct bank pushing out remaining ES 2 work and delivery of substation steel slipping from March to April. The forecasted in-service date for the Academy Street project remains at October 25, 2021, which is unchanged from the previous quarter.

The primary activity conducted during the first quarter of 2021 on the Academy Street project included the commencement of 4kV to 13kV conversion pre-work. Construction, which started in July 2020 for non-permit work on Academy Street, remains at 65% complete inside plant, while the total project is reported at 77% complete as of the end of the first quarter of 2021.

The actual spend by quarter for Academy Street as compared to the current approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals			*Forecast*			
$150,398	$4,224,550	$378,939	$443,324	$738,947	$1,687,021	$2,081,037

Actuals to Date	Estimate	% of Actuals to Estimate
$4,753,887	$10,500,000	45%

2. Clay Street

During the first quarter of 2021, $565,030 was spent on the Clay Street project compared to a forecast of approximately $570,000, which brought the total spend to approximately $1.6 million. At the beginning of the quarter, there was the potential for delay on the site plan approval stemming from the planning board's Covid-19 protocols. However, the project team requested a special meeting to maintain the project's schedule, which was held in March 2021 and resulted in the approval of the site plan.

Also in the first quarter of 2021, PSE&G's accounting group made the determination that the sanitation wall on the Clay Street project is both a transmission and distribution asset. This is resulting in a scope change that will remove this scope of work from the ES 2 project and add it to the 69kV project. The final details have yet to be reported to the IM, but no schedule impacts are expected from this change, while the costs to the ES 2 project will be slightly reduced.

The actual spend by quarter for Clay Street as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2024
Actuals			*Forecast*			
$116,409	$879,339	$565,030	$1,103,119	$205,080	$8,590,291	$18,337,680

Actuals to Date	Estimate	% of Actuals to Estimate
$1,560,778	$42,000,000	4%

3. Constable Hook

As discussed in the IM 2020 Fourth Quarter Report, this project has been identified to be removed from the ES 2 Program and replaced with the Front Street project. Should the Front Street project be approved for inclusion in the ES 2 Program, it will be covered in this section, otherwise a placeholder will remain here to maintain consistency in the project/section numbering throughout future IM reports.

The actual spend for Constable Hook as compared to the URB approved estimate is provided below. PSE&G has informed the IM it will be removing the actual costs associated with the Constable Hook project from ES 2.

Actuals to Date	Estimate	% of Actuals to Estimate
$115,640	$5,300,000	2%

4. Hasbrouck Heights

During the first quarter of 2021, $550,796 was spent on the Hasbrouck Heights project compared to a forecast of approximately $612,000, which brought the total spend to approximately $1.8 million. Notable activities completed during the fourth quarter of 2020 included:

- Civil and electrical construction packages out for bid;
- Contingency plan electrical layout completed; and,
- State Department of Community Affairs (DCA) permit received.

As reported in the IM 2020 Third Quarter Report, a Covid-19 related delay on the associated Hasbrouck Heights 69kV project resulted in a delay to the Hasbrouck Heights ES 2 project. In the IM 2020 Fourth Quarter Report it was reported that this delay shifted the forecasted in-service date to April 2023 (was previously November-December 2022). PSE&G since identified that the April 2023 forecasted in-service date reflected the capacitor bank in-service date, with the project in-service date now updated to February 2023 as that is reflective of the switchgear in-service date.

The actual spend by quarter for Hasbrouck Heights as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project. The total project forecast increased from approximately $17.9 million as of the end of 2020 to $20.5 million as of the end of the first quarter of 2021, which was primarily driven by civil construction bids coming in higher than estimated ($1.2 million) and higher dewatering estimates based on site conditions ($1.3 million).

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals			*Forecast*			
$149,848	$1,129,934	$550,795	$1,146,217	$254,070	$4,584,100	$12,659,663

Actuals to Date	Estimate	% of Actuals to Estimate
$1,830,577	$18,000,000	10%

5. Kingsland

During the first quarter of 2021, $30,621 was spent on the Kingsland project compared to a forecast of $42,000, which brought the total spend to $344,400. There continued to be minimal activities performed on this project during the first quarter of 2021.

The actual spend by quarter for Kingsland as compared to the current approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals			*Forecast*			
$104,112	$209,667	$30,621	$42,000	$83,542	$307,674	$5,640,925

Actuals to Date	Estimate	% of Actuals to Estimate
$344,400	$8,300,000	4%

6. Lakeside Avenue

During the first quarter of 2021, $178,973 was spent on the Lakeside Avenue project compared to a forecast of approximately $73,000. The variance in first quarter spend was largely driven by the early completion of the key drawing package milestone that was previously forecasted for May 2021. Other notable activities completed during the first quarter of 2021 included the issuance of the switchgear PO.

The actual spend by quarter for Lakeside Avenue as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2024
Actuals			*Forecast*			
$148,943	$453,994	$178,973	$190,952	$111,167	$241,028	$38,031,221

Actuals to Date	Estimate	% of Actuals to Estimate
$781,910	$47,900,000	2%

7. Leonia

During the first quarter of 2021, approximately $2.8 million was spent on the Leonia project compared to a forecast of approximately $2.2 million, which brought the total spend to approximately $8.9 million. The variance in first quarter spend was primarily the result of the in-service date of the temporary switchgear advancing and cable and conduit relocation work not forecasted but needed to be completed to prepare the switchgear foundation in advance of the switchgear delivery. Other notable activities completed during the first quarter of 2021 included:

- Civil and electrical construction phases 2/3 out for bid and PO issued;
- State DCA permit (phase 2) received; and,
- Conceptual level estimate completed.

Construction at Leonia, which started in August 2020, has advanced to 38% complete inside plant as of the end of the first quarter of 2021, up from 35% complete as of the end of 2020, with the total project reported at 46% complete.

The actual spend by quarter for Leonia as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project. The total project forecast decreased from approximately $30.4 million as of the end of 2020 to approximately $25.1 million as of the end of the first quarter of 2021, which was driven by civil and electrical construction awards coming in lower than estimated.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals			*Forecast*			
$44,792	$6,033,379	$2,809,628	$4,243,320	$1,475,002	$1,478,341	$8,998,442

Actuals to Date	Estimate	% of Actuals to Estimate
$8,887,799	$32,200,000	27%

8. Market Street

During the first quarter of 2021, $4,035,880 was spent on the Market Street project compared to a forecast of approximately $3.8 million, which brought the total spend to approximately $20.3 million. Notable activities completed during the first quarter of 2021 included the receipt of the Soil Conservation District (SCD) permit.

Construction at Market Street, which started in August 2020, advanced to 75% complete outside plant as of the end of the first quarter of 2021, up from 60% as of the end of 2020. Inside plant construction is anticipated to begin in September 2021 and the overall project is reported at 64% complete as of the end of the first quarter of 2021.

The actual spend by quarter for Market Street as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022
Actuals			*Forecast*			
$251,193	$16,079,601	$4,035,880	$3,064,249	$1,452,036	$1,138,089	$153,432

Actuals to Date	Estimate	% of Actuals to Estimate
$20,366,674	$26,900,000	76%

9. Meadow Road

During the first quarter of 2021, $117,672 was spent on the Meadow Road project compared to a forecast of $94,000, which brought the total spend to approximately $716,000. The New Jersey Department of Environmental Protection (NJDEP) Flood Hazard Area permit was submitted during the first quarter of 2021 and there were minimal other activities on the Meadow Road project during the first quarter of 2020, with the bulk of this project's activities planned for 2022-2023.

The actual spend by quarter for Meadow Road as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2024
Actuals			*Forecast*			
$63,128	$535,081	$117,672	$84,000	$69,000	$79,000	$6,377,998

Actuals to Date	Estimate	% of Actuals to Estimate
$715,881	$9,000,000	8%

10. Orange Valley

During the first quarter of 2021, $7,291 was spent on the Orange Valley project compared to a forecast of approximately $152,000, which bought the total spend to approximately $447,000. The variance in first quarter spend was largely the result of the project re-allocating an engineering invoice between this ES 2 project and the 69kV project that had incorrectly been included in the ES 2 project forecast, along with less project management, engineering, and permitting spend compared to the forecast. There were minimal activities on the Orange Valley project during the first quarter of 2020, with the bulk of this project's activities planned for 2022-2023.

The actual spend by quarter for Orange Valley as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2024
Actuals			*Forecast*			
$77,029	$362,895	$7,291	$125,588	$333,622	$271,428	$14,526,081

Actuals to Date	Estimate	% of Actuals to Estimate
$447,215	$20,200,000	2%

11. Ridgefield 13kV

During the first quarter of 2021, $3,215,967 was spent on the Ridgefield 13kV project compared to a forecast of approximately $2.6 million, which brought the total spend to approximately $9.7 million. The variance in first quarter spend was largely the result of additional work required to support the temporary switchgear going in-service and the Division pulling more cable than anticipated to keep progress on the project and to meet the demolition timeframe requirements. Notable activities completed during the first quarter of 2021 included:

- Temporary switchgear placed in-service;
- Phase 2 civil and electrical drawings IFC; and,
- New Jersey Sports & Exposition Authority (NJSEA) piles/foundation permits received.

Construction at Ridgefield 13kV remained at a reported 33% complete inside plant as of the end of the first quarter of 2021, with the total project at a reported 40% completion.

The actual spend by quarter for Ridgefield 13kV as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals			*Forecast*			
$205,982	$6,232,692	$3,215,967	$3,366,788	$2,326,500	$1,697,213	$8,211,711

Actuals to Date	Estimate	% of Actuals to Estimate
$9,654,641	$25,500,000	38%

12. Ridgefield 4kV

During the first quarter of 2021, $2,808,765 was spent on the Ridgefield 4kV project compared to a forecast of approximately $4.8 million, which brought the total spend to approximately $14.2 million. The variance in first quarter spend was driven by the outside plan manhole rebuilding being delayed due to bids received later than expected and Division cable pulling postponed due to weather and more urgent work performed on the Ridgefield 13kV project that shifted the available resources. With the resources for both the Ridgefield 4kV and Ridgefield 13kV projects limited due to weather impacts, allocating the available resources to the Ridgefield 13kV project maintained that project's critical path with no impact to the Ridgefield 4kV critical path. Activities completed during the first quarter of 2021 on the Ridgefield 4kV project included the civil and electrical demolition drawings IFC.

Construction at Ridgefield 4kV, which started in June 2020, has advanced to 88% complete, up from 72% at the end of 2020. The total project is reported at 81% complete as of the end of the first quarter of 2021.

In March 2021, the Definitive level estimate was submitted and approved before the URB. This Definitive level estimate reduced the total Ridgefield 4kV project estimate to $19.5 million from the previously approved $20.2 million, which included an increase to the base estimate ($0.9 million) that was offset by a reduction to R&C (-$1.6 million). The reduction to R&C was driven by the current view of the risk profile on the project while the changes to the base estimate were driven by:

- Additional manhole rebuild work ($0.8 million);
- Additional underground cable and overhead switching procedures ($0.5 million);

- Higher costs for paving and cable pulling ($0.4 million); and,
- Less Division contractor surcharges (-$0.8 million).

The actual spend by quarter for Ridgefield 4kV as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022
Actuals			*Forecast*			
$143,414	$11,239,534	$2,808,765	$3,036,469	$1,460,530	$81,000	$60,000

Actuals to Date	Estimate	% of Actuals to Estimate
$14,191,713	$19,500,000	73%

13. State Street

During the first quarter of 2021, $237,415 was spent on the State Street project compared to a forecast of approximately $210,000, which brought the total spend to approximately $977,000. The activities performed on State Street during the first quarter of 2021 primarily related to advancing the engineering work in preparation of the start of civil construction in the second quarter.

The actual spend by quarter for State Street as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals			*Forecast*			
$77,590	$662,148	$237,415	$767,376	$6,240,801	$1,119,853	$29,823,756

Actuals to Date	Estimate	% of Actuals to Estimate
$977,153	$45,100,000	2%

14. Toney's Brook

During the first quarter of 2021, $88,947 was spent on the Toney's Brook project compared to a forecast of approximately $89,000, which brought the total spend to approximately $674,000. Notable activities completed during the first quarter of 2021 included the electrical construction work going out for bid.

In February 2021, the Conceptual level estimate was submitted and approved before the URB. This Conceptual level estimate reduced the total Toney's Brook project estimate to $18.8 million from the previously approved $19.7 million, which included an increase to the base estimate ($1.9 million) that was offset by a reduction to R&C (-$2.8 million). The reduction to R&C was driven by the current view of the risk profile on the project while the changes to the base estimate were driven by:

- Higher concrete quantities ($0.9 million);
- Changing in T&D surcharge methodology ($0.6 million); and,
- Switchgear award higher than estimated ($0.4 million).

The change in T&D surcharge methodology caused an increase in Outside Service Electrical construction planned surcharge rate which increased by over 45% from 2019 to 2020. As a result, approximately $587,000 of the $0.6 million increase on Toney's Brook Conceptual level estimate was attributed to increase in electrical construction. The remainder of the $0.6 million increase is associated with Project Management labor.

The actual spend by quarter for Toney's Brook as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2024
Actuals			*Forecast*			
$211,940	$373,096	$88,947	$330,962	$200,548	$207,809	$14,792,644

Actuals to Date	Estimate	% of Actuals to Estimate
$673,983	$18,800,000	4%

15. Waverly

During the first quarter of 2021, $659,572 was spent on the Waverly project compared to a forecast of approximately $490,000, which brought the total spend to approximately $3.2 million. The variance in first quarter spend was largely driven by phase 1 civil construction and environmental progress advancing more than forecasted due to favorable weather conditions. Notable activities completed during the first quarter of 2021 included:

- Vendor drawings received (final switchgear arrangement and controls); and,
- Phase 2 electrical construction out for bid;

As with the Clay Street project, at the beginning of the quarter, there was the potential for delay on the site plan approval stemming from the planning board's Covid-19 protocols. However, the project team requested a special meeting to maintain the project's schedule, which was held in March 2021. The Newark Planning Board denied the site plan application at this meeting, which requires the project team to prepare a new site plan application. The comments received from the Newark Planning Board were generally aesthetic in nature (e.g. comments on why a green roof was not considered, art on exterior fence, height of lightning mast, etc.) and PSE&G is preparing to follow-up with a public workshop and meetings with the City to resolve the comments and prepare a revised site plan. The revised site plan is expected to be submitted in the coming months. Due to the site plan not being approved in the March 2021 meeting, the remaining aspects of the entire project have shifted out, including the commencement of phase 2 construction from May 2021 to a forecasted January 2022, commencement of phase 3 construction from February 2022 to October 2022, and pushing the final in-service date for Transformer #3 from the fourth quarter of 2023 to the third quarter of 2024 (the other in-service dates for the Waverly substation, including the other transformers, the 4kV switchgear, and the 26kV switchgear shifted from December 2022 to November 2023). PSE&G's preliminary estimate on the changes stemming from the revised site plan indicate a resulting cost increase of approximately $2.6 million to the project, which is driven by additional engineering, revised fencing and external façade improvements, and the extended project duration.

Construction at Waverly, with phase 1 having started in October 2020, advanced to 6% complete as of the end of the first quarter of 2021.

The actual spend by quarter for Waverly as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2025
Actuals			*Forecast*			
$103,748	$2,460,815	$659,572	$2,832,258	$562,468	$489,899	$26,697,409

Actuals to Date	Estimate	% of Actuals to Estimate
$3,224,135	$35,400,000	9%

16. Woodlynne

During the first quarter of 2021, $282,187 was spent on the Woodlynne project compared to a forecast of approximately $276,000, which brought the total spend to approximately $1.1 million. Notable activities completed during the fourth quarter of 2020 included the site plan resolution compliance achieved and State DCA permit received.

The actual spend by quarter for Woodlynne as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2024
Actuals			*Forecast*			
$110,982	$993,298	$282,187	$157,336	$1,429,454	$923,989	$14,411,606

Actuals to Date	Estimate	% of Actuals to Estimate
$1,386,467	$19,400,000	6%

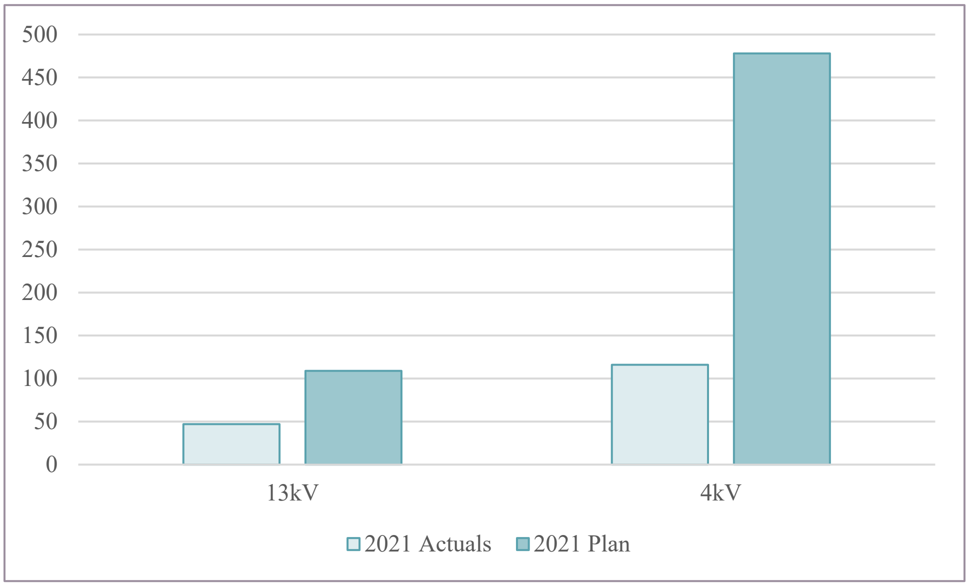
B. Contingency Reconfiguration

During the first quarter of 2021, work continued to progress in the Contingency Reconfiguration subprogram with all four Divisions continuing to install reclosers with a total of 163 installed during the quarter and 167 commissioned. **Table 13 – ES 2 Recloser Status as of March 31, 2021** provides a summary of the recloser aspect of the Contingency Reconfiguration subprogram, indicating the current status of engineering, installation, and commissioning; while **Figure 3 – 2021 Recloser Installations as of March 31, 2021** compares the installed reclosers as of the end of the first quarter of 2021 against PSE&G's 2021 installation plan.

Table 13 – ES 2 Recloser Status as of March 31, 2021

Type	Engineering Packages Completed (1 recloser ea.)			Reclosers Installed			Reclosers Commissioned		
	Q1 Qty.	*2021 Total*	*Program Total*	*Q1 Qty.*	*2021 Total*	*Program Total*	*Q1 Qty.*	*2021 Total*	*Program Total*
13kV	52	52	751	47	47	708	51	51	695
4kV	77	77	331	116	116	273	116	116	273
Total	129	129	1,082	163	163	981	167	167	968

Figure 3 – 2021 Recloser Installations as of March 31, 2021



As also shown in **Figure 3**, the 2021 installation plan shifts the focus primarily to the 4kV reclosers from the 13kV reclosers that were prioritized in 2020. As also shown in **Table 13** and **Figure 3**, PSE&G maintained progress during the first quarter of 2021 and stayed on track for the 2021 plan despite some weather impacts and resource constraints in the Metro Division. The weather impacts were primarily 10 snow days during February and piles of snow at pole locations, which was recovered through the use of overtime and weekend work.[1] The resource constraints in the Metro Division stemmed from attrition at the end of the year and two larger projects in the Division with firm in-service dates, leading to a shortage of approximately 30 full-time equivalents compared to normal. While new hires have been brought on board, they will not be able to work on crews until their training is completed. To mitigate impacts, PSE&G engaged a contractor to perform the pole settings from the recloser scope, which commenced early in the second quarter of 2021 and will continue until the internal resources are available. PSE&G estimates that the cost of outsourcing the pole setting and preparation work in the Metro Division will result in a less than 1% increase to the cost per unit of the reclosers, or a total cost of approximately $784,000. By outsourcing this scope, PSE&G will allow the Metro Division recloser scope to complete earlier than it otherwise would, which avoids an estimated $100,000 in additional carrying costs and avoids additional resource constraints from the Fuse Saver work commencing in 2022 overlapping with the recloser work.~~As also shown in **Figure 3**, the 2021 installation plan shifts the focus primarily to the 4kV reclosers from the 13kV reclosers that were prioritized in 2020.~~

The Fuse Saver pilot program commenced in November 2020 and was primarily completed in January 2021.[2] In total, this phase of the Fuse Saver pilot program included the installation and commissioning of

[1] As discussed in Appendix A to the IM 2020 Fourth Quarter Report (in response to RCR-INF-8), unitized work such as reclosers do not have a labor rate premium associated with weekend/overtime work. The schedule is made in advance and resources are planned accordingly in order to achieve the installation rate necessary to install the planned number of units within the scheduled timeframe, thus the cost per unit does not change provided all units planned for the period are completed.
[2] In the second quarter of 2021, PSE&G decided to install the remaining 34 Fuse Savers in its inventory to capture additional cost and performance data to better inform the planning and execution of the full scope of work. These installations were completed across the second and third quarters of 2021.

80 Fuse Saver devices. As noted in the IM 2020 Second Quarter Report, PSE&G's Asset Management group determined a pilot program would be initiated prior to the full scope to ensure these new devices work as intended. During execution of the pilot program, PSE&G observed factors that will help it prepare for execution of the full Fuse Saver scope, including installation specifications (the remote-control unit must be placed directly below the Fuse Saver to avoid communications issues), and cost elements for some of the locations (new poles, traffic control, etc.). While monitoring performance of the installed Fuse Savers, PSE&G experienced other communication issues between the Fuse Savers and the remote control unit (RCU), wherein the supervisory control and data acquisition (SCADA) communication indicated a false open/close alarm on some of the devices. Siemens has provided a prototype Fuse Saver to address the communication issues, which have affected approximately 10% of the installed devices. The solution to resolve these communication issues includes modifying the external antenna (and modifying the RCU enclosure to accommodate the antenna). PSE&G will monitor the devices to ensure the identified solution~~it~~ addresses the issues prior to placing additional Fuse Saver orders. Because of this, the full Fuse Saver scope is no longer anticipated to commence in 2021, as it awaits approval by PSE&G's Asset Management group to proceed with the full scope, aside from the installation of additional units from existing stock.

The current forecasted completion date for the primary components that make up the Contingency Reconfiguration subprogram are provided in **Table 14 – ES 2 Contingency Reconfiguration Forecasted Completion Dates as of March 31, 2021**. This table also shows the forecasted dates as of the end of 2020 to show movement to the forecast as of the end of the first quarter of 2021.

Table 14 – ES 2 Contingency Reconfiguration Forecasted Completion Dates as of March 31, 2021

Scope & Division		Q4 2020 Forecasted Completion Date	Q1 2021 Forecasted Completion Date
Reclosers	Central	9/30/2021	12/31/2021
	Metro	12/31/2021	12/31/2021
	Palisades	12/31/2021	11/30/2021
	Southern	12/31/2021	12/31/2021
Fuse Savers	Central	6/30/2023	12/30/2023
	Metro	6/30/2023	12/30/2023
	Palisades	5/31/2023	12/30/2023
	Southern	6/30/2023	12/30/2023

As shown in **Table 14**, the forecasted completion for each Division's Fuse Saver program slipped approximately six months, which was driven by a delay to the start of this scope while PSE&G evaluates the performance of the devices installed in the Fuse Saver pilot program. The three-month slippage of the Central Division recloser scope was driven by additional units added to the scope. The one-month advancement in the Palisades Division recloser scope was driven by schedule adjustments that reflected increased monthly installations.

The Contingency Reconfiguration subprogram costs through the end of the first quarter of 2021 are presented in **Table 15 – ES 2 Contingency Reconfiguration Costs as of March 31, 2021**.

Table 15 – Contingency Reconfiguration Costs as of March 31, 2021

Scope & Division		2019	2020	Q1 2021	Total to Date	Forecast	% of Actuals to Forecast
		Actuals					
Re	Central	$2,737,167	$12,050,820	$3,007,686	$17,795,674	$24,596,856	72%

Scope & Division		2019	2020	Q1 2021	Total to Date	Forecast	% of Actuals to Forecast
		Actuals					
	Metro	$2,231,431	$10,726,610	$587,396	$13,545,438	$22,390,145	60%
	Palisades	$2,515,569	$12,119,436	$3,109,037	$17,744,042	$24,889,624	71%
	Southern	$2,081,220	$12,405,684	$5,008,143	$19,495,047	$28,712,956	68%
Fuse Savers	Central	$9,970	$789,937	$375,811	$1,175,719	$12,848,369	9%
	Metro	$7,557	$561,915	$216,511	$785,983	$11,800,845	7%
	Palisades	$7,468	$522,454	$133,552	$663,475	$9,164,257	7%
	Southern	$9,792	$859,014	$65,018	$933,824	$14,524,371	6%
Total		**$9,600,174**	**$50,035,871**	**$12,503,156**	**$72,139,200**	**$148,927,422**	**48%**

Findings & Observations:

- PSE&G maintained progress during the first quarter of 2021 and stayed on track for the 2021 plan despite some weather impacts and resource constraints experienced in the Metro Division.
- 80 Fuse Saver devices have been installed as part of the pilot program for these devices. PSE&G is monitoring the performance of these initial devices and has already gleaned information that will better inform the planning and execution of the full scope, including specific installation requirements and cost elements, such as additional traffic control required, from the actual installations to date.
- The forecasted completion of the recloser and Fuse Saver scopes of this subprogram saw some adjustment during the first quarter of 2021. For the reclosers, the Central Division recloser scope moving three months out to December 2021 based on additional units added to the scope, while the Palisades Division saw a one-month advancement to November 2021 based on schedule adjustment that reflected increased monthly installations. For the Fuse Savers, each Division saw a slip of six to seven months reflective of the delay to the start of the full scope of this work.
- The Contingency Reconfiguration subprogram forecast decreased from $162.8 million at the end of 2020 to $148.9 million as of the end of the first quarter of 2021. This was largely driven by an approximate $14 million reduction to the Fuse Saver scope due to the number of units planned for the Program decreasing from 2,572 to 1,967 due to the higher cost per unit observed in the pilot program.

C. Grid Modernization – Communication System

The Stipulation identified the Grid Modernization – Communication System subprogram to include up to $72 million invested in installing a private wireless communications network to eliminate the use of dedicated phone lines for remote communication for both PSE&G and customer equipment. The overall network will provide coverage using both wireless and fiber technologies to all switching devices on the PSE&G system.

As reported in the IM 2020 Second Quarter Report, PSE&G made the strategic decision to focus on new recloser installations and has delayed the ramp-up in retrofit installations from August 2020 to January 2021 due to resource constraints. No overall impacts are expected from this decision and PSE&G plans to regain the planned retrofit installations by the middle of 2021 as it shifts focus from new recloser installations to the retrofit reclosers. During the first quarter of 2021, retrofit installations ramped up with 557 installations completed during the quarter against a target of 565. The first quarter installations were also impacted by weather, particularly during the month of February where only 71 installations took place. However, the performance in January and March allowed PSE&G to nearly reach its first quarter target. In total, 749 retrofit reclosers have been installed on the Program through the end of the first quarter out of a total program forecast of 2,449 (which is periodically reviewed and updated).

As previously reported, the fiber scope includes installing fiber to electric substations and electric operations centers, in addition to cutting over stations with existing fiber service to the PSE&G fiber network. PSE&G preliminarily identified 41 installation projects and 12 cutovers for the subprogram, with two of 41 installation projects since removed due to the scheduled elimination of the targeted substations. The list of identified fiber installation and cutover projects is presented in **Table 16 – Fiber Projects by Division**.

Table 16 – Fiber Projects by Division

Division	Fiber Installation	Fiber Cutover
Central	Cranford; Elizabeth Sub HQ; Rahway; Hadley Road HQ; Roselle; Central HQ; Carteret; Edison; Keasby; Mechanic Street; First Street; Lehigh Avenue	Elizabeth; Henry Street
Metro	East Orange; Metro HQ; Bloomfield; Central Avenue; Haldeon; Irvington; Irvington Sub HQ; Montclair; South Orange; Norfolk Street; Waverly	-
Palisades	Bergen Point; Hackensack Sub HQ; Fort Lee; Harrison; Ridgewood; West New York; Palisades HQ; Culver Avenue; Morgan Street; Howell Street	Tonnelle Avenue; Spring Valley Road; Union City; Fairview; Polk Street; West Orange
Southern	Southern HQ; Princeton; Chauncey Street; Bordentown; Haddon Heights; Thirty Second Street	Delair; East Riverton; Riverside; Mount Holly
Total	***39 projects***	***12 projects***

During the first quarter of 2021, five additional fiber installation projects (Bergen Point, East Orange, Elizabeth Sub HQ, Metro HQ, and Rahway) and three additional fiber cutover projects (Elizabeth, Spring Valley Road, and Union City) were placed in-service. This brought the total projects in-service as of the end of the first quarter of 2021 to eight for the fiber installation projects and eight for the fiber cutover projects. **Table 17 – Fiber Projects Status as of March 31, 2021** provides a summary of the status of the fiber installation and cutover projects within the subprogram as of the end of the first quarter of 2021.

Table 17 – Fiber Projects Status as of March 31, 2021

Project Name	Q1 2021 Status
Fiber Installation Projects	
Bergen Point	In-Service (Q1 2021)
Bloomfield	Outside Plant (OP) IFC issued; Construction commenced
Bordentown	Preliminary engineering
Carteret	Preliminary engineering
Central Ave	Preliminary engineering
Central HQ	Preliminary engineering
Chauncey Street	OP construction commenced; First OP fiber run completed; TFI rack delivered
Cranford	In-Service (Q4 2020)
Culver Ave	Preliminary engineering
East Orange	In-Service (Q1 2021)
Edison	Preliminary engineering
Elizabeth Sub HQ	In-Service (Q1 2021)
First Street	OP IFC issued
Fort Lee	OP IFC issued; Construction commenced
Hackensack Sub HQ	In-Service (Q4 2020)
Haddon Heights	Preliminary engineering

Project Name	Q1 2021 Status
Hadley Rd HQ	OP IFC issued; Construction commenced
Haledon	Preliminary engineering
Harrison	OP construction commenced; Commenced battery upgrade installation
Howell Street	Preliminary engineering
Irvington	Preliminary engineering
Irvington Sub HQ	Preliminary engineering
Keasbey	Preliminary engineering
Lehigh Avenue	Preliminary engineering
Mechanic Street	Preliminary engineering
Metro HQ	In-Service (Q1 2021)
Montclair	Preliminary engineering
Morgan Street	Preliminary engineering
Norfolk St	Preliminary engineering
Palisades HQ	Inside Plant (IP)/OP IFC; Construction commenced
Princeton	OP construction commenced
Rahway	In-Service (Q1 2021)
Ridgewood	Preliminary engineering
Roselle	OP construction commenced; Completed both OP fiber runs; completed IP IFC; completed battery upgrade installation
So Orange	Preliminary engineering
Southern HQ	In-Service (Q4 2020)
Thirty Second Street	Preliminary engineering
Waverly	Preliminary engineering
West New York	Preliminary engineering
Fiber Cutover Projects	
Delair	In-Service (Q4 2020)
East Riverton	In-Service (Q4 2020)
Elizabeth	In-Service (Q1 2021)
Fairview	Completion dependent upon Fort Lee fiber installation project (tentative start of construction in September 2021)
Henry St	Battery rack installation pending; site visit with Central Division scheduled
Mount Holly	In-Service (Q4 2020)
Polk Street	Completion dependent upon West New York fiber installation project (engineering in progress)
Riverside	In-Service (Q4 2020)
Spring Valley Rd	In-Service (Q1 2021)
Tonnelle Ave	In-Service (Q4 2020)
Union City	In-Service (Q1 2021)
West Orange	Completion dependent upon redundant link to Montclair substation being ready (two redundant fiber links required for each router to support reliability guidelines)

The Grid Modernization – Communication System subprogram costs through the end of the first quarter of 2021 are presented in **Table 18 – ES 2 Grid Modernization – Communication System Costs as of March 31, 2021**.

Table 18 – ES 2 Grid Modernization – Communication System Costs as of March 31, 2021

Scope & Division		2019	2020	Q1 2021	Total to Date	Forecast	% of Actuals to Forecast
		Actuals					
Retrofit	Central	$0	$884,278	$1,067,295	$1,951,572	$7,046,140	28%
	Metro	$0	$818,620	$436,089	$1,254,709	$5,958,867	21%
	Palisades	$0	$825,174	$754,869	$1,580,043	$6,507,561	24%

Scope & Division		2019	2020	Q1 2021	Total to Date	Forecast	% of Actuals to Forecast
		Actuals					
	Southern	$0	$929,058	$956,444	$1,885,502	$7,821,332	24%
Fiber	Central	$1,691	$2,418,851	$796,586	$3,217,128	$7,479,716	43%
Fiber	Metro	$1,457	$1,866,697	$340,713	$2,208,867	$5,857,647	38%
Fiber	Palisades	$1,582	$2,046,762	$248,558	$2,296,902	$4,166,762	55%
Fiber	Southern	$4,731	$910,483	$645,219	$1,560,434	$3,258,924	48%
Fiber	Cutovers*	$0	$876,502	$323,458	$1,199,960	$2,768,762	43%
Wireless Network		$74,306	$6,035,441	$296,946	$6,396,832	$7,737,133	83%
Bulk Purchase**		$0	$1,524,874	$450,013	$1,974,887	$0	-
Total		**$83,767**	**$19,136,741**	**$6,306,330**	**$25,526,835**	**$58,602,845**	**44%**

**-Includes fiber communication cutovers and substation remote terminal unit (RTU) cutovers (the latter of which began having spent in Q1 2021).*
***-The Bulk Purchase account contains expenditures for the bulk purchase of materials in the subprogram. As these materials are used and installed in the field, the Bulk Purchase account is credited with the actual spend then assigned to the appropriate Division, thus at the end of the Program, the balance of this Bulk Purchase account is expected to be $0.*

<u>Findings & Observations</u>:

- During the first quarter of 2021, retrofit installations ramped up as planned with 557 installations completed during the quarter against a target of 565. The first quarter installations were also impacted by weather, particularly during the month of February where only 71 installations took place. However, the performance in January and March allowed PSE&G to nearly reach its first quarter target. In total, 749 retrofit reclosers have been installed on the Program through the end of the first quarter of 2021 out of a total program forecast of 2,449 (which is periodically reviewed and updated).
- Five fiber installation and three fiber cutover projects were placed in-service during the first quarter of 2021, bringing the total number of projects in-service to eight fiber installation projects and eight fiber cutover projects.
- The Grid Modernization – Communication System subprogram forecast remained fairly constant from the end of 2020 to the end of the first quarter of 2021, with an approximate $700,000 decrease to the forecast (or -1%). The cutover forecast increased approximately $1.7 million, which was driven by the substation RTU cutover scope being split off from the retrofit work breakdown structure (which resulted in the retrofit forecast decreasing by a like amount).

D. Grid Modernization – ADMS

The Grid Modernization – ADMS scope is split between three primary sections: Distribution Management System (DMS)/Distributed Energy Resource Management System (DERMS), the Outage Management System (OMS), and ADMS platform upgrades. The primary activities in 2021 are focused on the continued development of the systems and platforms that comprise this subprogram.

The scope for each primary component of the Grid Modernization – ADMS subprogram and notable activities conducted during the first quarter of 2021 are presented as follows:

<u>DMS/DERMS</u>

- <u>Scope</u>: Provide software and associated services to deploy a Smart Network in order to meet a subset of the ES 2 Program's objectives and use cases.
- <u>Q1 2021 Activities</u>:
  - Conducted Monarch demonstration session.
  - Conducted Advanced Metering Infrastructure (AMI) use case follow-up meeting.

  - Completed PSEG application design use case draft document review.
  - Completed out feeder and substation device ID in SCADA document.
  - Populated DERMS workbook items.
  - Discussed DMS data tables in geographic information system (GIS) and their maintenance.
- Forecasted Completion as of the end of the first quarter of 2021: 10/28/2022.

OMS

- Scope: Provide a single user interface for more efficient management of trouble orders and analysis of outage data through an integrated OMS, system interfaces, and geographic view of all integrated outage data through an integrated OMS, system interfaces, and geographic view of all integrated outage data and damage locations. OMS will include tools for dynamic visualization supporting incident management, damage location identification, dashboards, and the as-operated real-time view of PSE&G's network model. Field personnel also will have access to many of these tools as it relates to the incident(s) assigned to them via the Compass mobile crew application. 10 years' worth of existing OMS data will be migrated into the new system as well.
- Q1 2021 Activities:
  - Finalized outage data warehouse architecture.
  - Interviewed SAP architect for SAP design.
  - Conducted design workshops.
  - Conducted Jira training.
  - Attended product showcases for DMS, OMS, and DERMS.
  - Attended AMI planning meetings.
  - Finalized GIS interface design for customer and premises.
  - Conducted Manager OMS overview workshop.
  - Conducted performance testing meetings with Long Island and Quality Assurance teams.
  - Conducted workshops for data conversion and reporting.
  - Conducted initial AMI/OMS interface meetings.
- Forecasted Completion as of the end of the first quarter of 2021: 5/20/2022.

ADMS Platform

- Scope: Replace, enhance, and expand the existing distribution supervisory control and data acquisition (DSCADA) platform elements inclusive of infrastructure components (servers and workstations) and applications (Monarch, Spectra, and Integra) to create an integrated ADMS platform.
- Q1 2021 Activities:
  - Prepared for testing alignment with Quality Assurance team.
- Forecasted Completion as of the end of the first quarter of 2021: 12/10/2021.

The Grid Modernization – ADMS subprogram costs through the end of the first quarter of 2021 are presented in **Table 19 – ES 2 Grid Modernization – ADMS Costs as of March 31, 2021**.

Table 19 – ES 2 Grid Modernization – ADMS Costs as of March 31, 2021

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals			*Forecast*			
$36,213	$16,447,624	$2,488,980	$2,518,103	$2,800,945	$3,428,855	$12,654,786

Actuals to Date	Forecast	% of Actuals to Forecast
$18,972,817	$40,375,507	47%

Findings & Observations:

- Resource constraints remain an area of focus on the subprogram due to the limited number and availability of the specific resources needed to support the subprogram. This has caused some activities to shift, but with no overall impact to the subprogram completion.
- The ADMS forecast remained essentially unchanged at the end of the first quarter of 2021 from the end of 2020 (an increase of $1,368). Likewise, the forecasted completion dates for the primary scopes of DMS/DERMS, OMS, and ADMS Platform remained unchanged from the end of 2020.
- As initially reported in the IM 2020 Third Quarter Report, additional hardware needed for the subprogram resulted in the cost forecast exceeding the Stipulation amount by approximately $5.4 million. While the forecast has remained steady since then, in July 2021, PSE&G made the decision to transfer $7.7 million in funds from the Grid Modernization – Communication System subprogram, which has been consistently under its Stipulation budget by approximately $12 million, driven largely by the savings realized in the wireless communication network scope (also discussed in the IM 2020 Third Quarter Report).

E. Electric Stipulated Base

The Stipulation identified that the electric portion of the Stipulated Base include $100 million in investments at PSE&G's discretion towards electric outside plant higher design and construction standards and/or electric stations life cycle subprograms described in the original ES 2 filing.[3] The outside plant higher design and construction standards work is planned to commence in January 2022. In accordance with what the Stipulation provides, PSE&G plans to fund some of the life cycle station upgrades from the electric program accelerated investment, subject to funds available, after all Electric Station Flood Mitigation projects are funded at their final costs.

As reported in the IM 2020 Second Quarter Report, the initial four stations PSE&G selected for life cycle station upgrades went before the URB in June 2020 for Study level estimate approval and received approval for full funding. These four stations and their current estimate compared to the actuals to date are provided in **Table 20 – ES 2 Life Cycle Station Upgrade Project Status as of March 31, 2021**.

Table 20 – ES 2 Life Cycle Station Upgrade Project Status as of March 31, 2021

Project	Estimate Level	Base	Risk & Contingency	Total	Actuals to Date	% of Actuals to Estimate	Forecasted In-Service Date*
1. Hamilton	Study	$14,500,000	$3,700,000	$18,200,000	$599,155	3%	10/12/2022 (↑)
2. Paramus	Study	$14,800,000	$5,400,000	$20,200,000	$1,199,046	6%	11/7/2022 (↓)
3. Plainfield	Study	$18,400,000	$4,200,000	$22,600,000	$896,956	4%	10/6/2022
4. Woodbury	Study	$15,400,000	$3,300,000	$18,700,000	$1,091,303	6%	12/27/2022 (↑)

[3] As noted in the Stipulation, the electric life cycle upgrades are part of the electric Stipulated Base to be recovered in the Company's next base rate case provided the investments are found to be prudent. The Stipulation also notes that should the 16 stations that comprise the Electric Station Flood Mitigation subprogram be completed for under the $389 million allocated for that subprogram, PSE&G may reallocate such unused funds to stations identified in the life cycle station upgrade portion of PSE&G's petition for accelerated recovery.

Project	Estimate Level	Base	Risk & Contingency	Total	Actuals to Date	% of Actuals to Estimate	Forecasted In-Service Date*
**-Reflects the in-service date of the last major asset (e.g. switchgear), certain activities may take place after this date to support the final in-service date (i.e. when all customers are cutover).* (↑)-*Indicates the forecasted in-service date advanced from the prior quarter.* (↓)-*Indicates the forecasted in-service date slipped from the prior quarter.*							

As shown in **Table 20**, of the four current life cycle station upgrade projects, one had no change in the forecasted in-service date from the end of 2020 to the first quarter of 2021 (Plainfield), while Hamilton's forecasted in-service date advanced twelve days, Woodbury's forecasted in-service date advanced one day, and Paramus's forecasted in-service date slipped 40 days in this period. Given the relatively small magnitude of these changes, the IM has not delved further into the schedule slippage on these projects, but will continue to monitor for potential trends. Additional details on each of these life cycle station upgrade projects is provided in the individual subsections that follow.

1. Hamilton

During the first quarter of 2021, $236,783 was spent on the Hamilton project against a forecast of approximately $196,000. This brought total spend through the end of the first quarter of 2021 on the project to approximately $600,000. Notable activities conducted during the first quarter of 2021 included:

- Site plan hearing held/site plan approved;
- SCD permit issued; and,
- Vendor drawings received (final switchgear arrangement).

The actual spend by quarter for Hamilton as compared to the current URB approved estimate is provided below.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals			*Forecast*			
$0	$362,372	$236,783	$364,637	$1,541,603	$1,787,646	$10,215,337

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$599,155	$18,200,000	$14,508,379	3%

2. Paramus

During the first quarter of 2021, $358,846 was spent on the Paramus project against a forecast of approximately $371,000. This brought total spend through the end of the first quarter of 2021 on the project to approximately $1.2 million. Notable activities conducted during the first quarter of 2021 included:

- Site plan application submitted;
- Soil Conservation District (SCD) permit issued;
- Civil and electrical contingency switchgear drawings IFC; and,
- Vendor drawings received (final switchgear controls).

The actual spend by quarter for Paramus as compared to the current URB approved estimate is provided below.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2024
Actuals			***Forecast***			
$0	$840,200	$358,846	$3,896,282	$1,125,400	$976,500	$ 10,914,117

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$1,199,046	$20,200,000	$18,111,345	6%

3. Plainfield

During the first quarter of 2021, $214,632 was spent on the Plainfield project against a forecast of approximately $273,000. This brought total spend through the end of the first quarter of 2021 on the project to approximately $900,000. Notable activities conducted during the first quarter of 2021 included:

- Site plan hearing held/site plan approved; and,
- SCD permit issued.

The actual spend by quarter for Plainfield as compared to the current URB approved estimate is provided below.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals			***Forecast***			
$0	$682,325	$214,632	$1,058,053	$1,023,860	$1,260,555	$14,562,283

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$896,657	$22,600,000	$18,801,707	4%

4. Woodbury

During the first quarter of 2021, $540,138 was spent on the Woodbury project against a forecast of approximately $595,000. This brought the total spend on the project to approximately $1.09 million. Notable activities conducted during the first quarter of 2021 included:

- License and permitting package issued;
- Civil and electrical drawings IFC; and,
- Site plan hearing held/site plan approved.

The actual spend by quarter for Woodbury as compared to the current URB approved estimate is provided below.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals			***Forecast***			
$0	$551,165	$540,138	$310,000	$127,913	$725,036	$12,191,648

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$1,091,303	$18,700,000	$14,445,900	6%

Findings & Observations:

- The primary activities during the first quarter of 2021 continued to center around the life cycle station upgrade projects with the receipt of vendor drawings (switchgear controls/switchgear arrangement) and the advancement of the licensing and permitting design packages. The Hamilton, Plainfield, and Woodbury projects had site plan hearings held, resulting in approval of the site plans, while the Paramus project submitted its site plan application in March 2021.
- With the exception of the Paramus project, there was only minor variations in the life cycle station upgrade project forecasts from the end of 2020 to the end of the first quarter of 2021. On the Paramus project, the forecast increased $1.3 million (or 8%) in this period to $18.1 million, which was primarily the result of the POs switchgear and other miscellaneous equipment coming in higher than initially estimated. Despite this forecast increase, the Paramus project remains forecasted under its current estimate of $20.2 million.
- There was minor movement to the forecasted in-service dates of the four life cycle station upgrade projects, with each forecasted for completion in the fourth quarter of 2022.

F. Gas M&R Station Upgrades

Through the end of the first quarter of 2021, primary activities in the Gas M&R subprogram continued to focus on advancing the engineering at each station and other pre-construction activities such as reviewing scope and permit documents and performing noise and geotechnical studies. **Table 21 – ES 2 Gas M&R Summary Status as of March 31, 2021** below provides the currently approved estimates for each project within the Gas M&R subprogram, along with the actuals to date and forecasted in-service dates.

Table 21 – ES 2 Gas M&R Summary Status as of March 31, 2021

Project	Estimate Level	Base	Risk & Contingency	Total Estimate	Actuals	% of Actuals to Estimate	Forecasted In-Service
1. Camden*	Study	$24,300,000	$5,000,000	$29,300,000	$1,378,369	5%	Dec 2022 (↑)
2. Central*	Study	$23,900,000	$5,100,000	$29,000,000	$992,709	3%	Dec 2022 (↑)
3. East Rutherford	Study	$13,800,000	$2,700,000	$16,500,000	$868,448	5%	Dec 2022
4. Mount Laurel	Study	$9,400,000	$2,000,000	$11,400,000	$523,484	5%	Dec 2022
5. Paramus*	Study	$11,500,000	$2,200,000	$13,700,000	$699,147	5%	Dec 2023
6. Westampton	Study	$8,300,000	$1,700,000	$10,000,000	$1,519,136	15%	Dec 2021
Subprogram Total		**$91,200,000**	**$18,700,000**	**$109,900,000**	**$5,981,294**	**5%**	**Dec 2023**

**-Included in the Stipulated Base.*
(↑)-*Indicates the forecasted in-service date advanced from the prior quarter.*
(↓)-*Indicates the forecasted in-service date slipped from the prior quarter.*

During the first quarter of 2021, the Camden Study level estimate was approved by the URB at a total estimate of $29.3 million, while the other projects in the subprogram had their previously approved Study level estimates adjusted with slight reductions in the R&C amounts based on a review of the project risks and the overall subprogram risk profile. The only changes to the forecasted in-service date from the end of 2020 to the end of the first quarter of 2021 were the Camden and Central projects advanced one month from January 2023 to December 2022.

Findings & Observations:

- The primary efforts to date on the subprogram continue to be initial planning efforts, including the prior awarding of bids for the design services on the projects, preparing for issuing the major equipment POs, site surveys, and preparation of permitting packages. Continued engineering and design efforts continue to be a main focus of 2021 first quarter activities.
- While still early in the subprogram, the IM has found nothing to date that would jeopardize the subprogram being completed on time and/or on budget. The Camden project had its Study level estimate approved by the URB during the first quarter of 2021, which resulted in the estimate increasing by $13.9 million. Also during the first quarter of 2021, the R&C funds on each of the Gas M&R projects were evaluated based on the current risk profiles of the projects and the subprogram, which led to a slight reduction in R&C. The overall subprogram remains in line with the Stipulation budget of $101 million.

1. Camden

Continuing with the preliminary engineering and planning efforts that advanced through 2020, during the first quarter of 2021 notable activities completed on the Camden project included:

- Received permit package for review;
- Submitted permit package to permitting agencies; and,
- Circulated scope documents for internal review.

In February 2021, the Camden project had its Study level estimate approved by the URB. This updated estimate increased the base estimate by $14.3 million, while reducing the R&C by $0.4 million, resulting in the total project estimate increasing from $15.4 million to $29.3 million. This increase is the result of higher construction costs stemming from the engineer's 50% estimate ($6.3 million), procurement of material based on received quotes ($6.1 million), and additional project management, licensing and permitting, and engineering support not included in the Office level estimate ($1.9 million). The estimate increase was driven largely by the initial assumption that much of the existing equipment and structures could be reused, which upon further investigation was determined not to be possible and resulted in additional costs for construction and equipment.

The actual spend by quarter for Camden as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals			*Forecast*			
$13,326	$859,350	$505,693	$427,753	$3,063,471	$4,145,406	$15,285,001

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$1,378,369	$29,300,000	$24,300,000	5%

2. Central

Continuing the preliminary engineering and planning efforts that advanced through 2020, during the first quarter of 2021, notable activities completed on the Central project included:

- Received drawing package for review;

- Submitted permit package to permitting agencies;
- Circulated scope documents for internal review; and,
- Received internal comments for tie-in sequence.

As indicated above, the risk profile to the project and subprogram was reviewed during the first quarter of 2021, which resulted in a slight reduction to the R&C amount of the current estimate for the Central project from $6.1 million to $5.1 million, reducing the overall estimate from $30.0 million to $29.0 million.

The actual spend by quarter for Central as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals			*Forecast*			
$6,869	$670,582	$315,258	$158,739	$2,686,668	$7,772,398	$12,289,486

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$992,709	$29,000,000	$23,900,000	3%

3. *East Rutherford*

Continuing the preliminary engineering and planning efforts that advanced through 2020, during the first quarter of 2021 notable activities completed on the East Rutherford project included:

- Received preliminary drawing package for review;
- Circulated scope documents for internal review;
- Performed geotechnical fieldwork;
- Received control valve specs for review; and,
- Conducted onsite meeting with Transco to discuss design.

As indicated above, the risk profile to the project and subprogram was reviewed during the first quarter of 2021, which resulted in a slight reduction to the R&C amount of the current estimate for the East Rutherford project from $3.2 million to $2.7 million, reducing the overall estimate from $17.0 million to $16.5 million.

The actual spend by quarter for East Rutherford as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals			*Forecast*			
$9,010	$521,865	$337,573	$254,280	$179,734	$1,046,666	$11,450,871

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$868,448	$16,500,000	$13,800,000	5%

4. Mount Laurel

Continuing the preliminary engineering and planning efforts that advanced through 2020, during the first quarter of 2021 notable activities completed on the Mount Laurel project included:

- Received permit package for review;
- Circulated scope documents for internal review.

As indicated above, the risk profile to the project and subprogram was reviewed during the first quarter of 2021, which resulted in a slight reduction to the R&C amount of the current estimate for the Mount Laurel project from $2.4 million to $2.0 million, reducing the overall estimate from $11.8 million to $11.4 million.

The actual spend by quarter for Mount Laurel as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022
Actuals			*Forecast*			
$5,965	$362,167	$155,351	$247,872	$718,520	$593,333	$7,316,791

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$523,484	$11,400,000	$9,400,000	5%

5. Paramus

Continuing the preliminary engineering and planning efforts that advanced through 2020, during the first quarter of 2021 notable activities completed on the Paramus project included:

- Circulated scope documents for internal review;
- Received noise study results;
- Received control valve specs for review; and,
- Performed geotechnical fieldwork.

As indicated above, the risk profile to the project and subprogram was reviewed during the first quarter of 2021, which resulted in a slight reduction to the R&C amount of the current estimate for the Paramus project from $2.7 million to $2.2 million, reducing the overall estimate from $14.2 million to $13.7 million.

The actual spend by quarter for Paramus as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals			*Forecast*			
$8,842	$462,452	$227,854	$164,703	$82,327	$89,346	$10,464,477

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$699,147	$13,700,000	$11,500,000	5%

6. Westampton

Continuing the preliminary engineering and planning efforts that advanced through 2020, during the first quarter of 2021 notable activities completed on the Westampton project included:

- Circulated scope documents for internal review;
- Burlington soil conservation district approval granted;
- Held virtual pre-bid meeting and onsite review with contractors;
- Received construction bids; and,
- Site plan approval granted by township land development board.

As indicated above, the risk profile to the project and subprogram was reviewed during the first quarter of 2021, which resulted in a slight reduction to the R&C amount of the current estimate for the Westampton project from $2.1 million to $1.7 million, reducing the overall estimate from $10.4 million to $10.0 million.

The actual spend by quarter for Westampton as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022
Actuals			*Forecast*			
$8,395	$1,032,670	$478,072	$2,150,111	$2,974,228	$1,606,645	$49,880

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$1,519,136	$10,000,000	$8,300,000	15%

IV. Additional Information Following the End of the First Quarter of 2021

While the vast majority of this IM report is focused on the activities and status of the ES 2 Program during the first quarter of 2021, the timing of certain Program elements and information provided by PSE&G naturally carried over beyond the end of the calendar quarter. Such information will generally be covered in the next IM quarterly report but given the importance of some of this information as it pertains to the key decisions made on the ES 2 Program, including the related discussion in **Section II.A.**, the IM has provided additional remarks to provide a more complete view of these mitigation changes based on the available information as of the date of this IM 2021 First Quarter Report.

A. Decisions Recorded After the First Quarter of 2021

1. Energy Strong II Electric Program – Contingency Reconfiguration Subprogram, 13kV and 4kV Reclosers

The Stipulation provided the framework for this subprogram, noting: *"PSE&G will invest up to $145 million to harden its electric distribution system and increase system resiliency by implementing contingency reconfiguration strategies, which were also part of the Energy Strong program. These strategies will increase the sections in present loop designs by utilizing reclosers, convert all existing two (2)-section overhead 13kV circuits to three (3)-section circuits by installing additional three (3)-phase reclosers, and install single phase recloser devices on branch lines that operate with only fuses."*

This ROD was issued by PSE&G to document changes in circuits, number of recloser units, and functional recloser types to be included in the Contingency Reconfiguration subprogram.

At the time of the ES 2 filing, PSE&G identified 690 13kV circuits and 500 4kV circuits for inclusion in the ES 2 Contingency Reconfiguration subprogram. As the subprogram progressed through detailed assessment and engineering, each circuit was assessed by PSE&G to determine its current status reflective of updated system plans and changes as well as other work done subsequent to the ES 2 filing, such as Poorest Performing Circuit (PPC) improvements. The results of this review included:

- The identification of 136 initially planned 13kV circuits that were already in three-section loops, which resulted in the removal of 177 13kV reclosers from the subprogram.
- The determination that 102 of the initially planned 4kV circuits were now planned to be upgraded to 13kV within five years based on the need for additional capacity in different areas of the system. This resulted in these circuits, and the related 153 4kV reclosers, being removed from the subprogram as the 4kV reclosers cannot be reused on 13kV circuits and would not be required as system spares.
- The finding that there were additional locations where 13kv branch, feeder, and tie reclosers, and 4kV feeder and tie reclosers could be installed to further isolate the impact of an outage on customers thus improving reliability.

Based on this removal of a set of circuits and reclosers and the identification of opportunities to install devices at other locations, PSE&G considered two alternatives:

1. Sectionalize only the circuits remaining on the filing list after the removal of the 136 13kV circuits and 102 4kV circuits.
2. Conduct a detailed review of 4kV and 13kV circuits to identify cost effective opportunities to include additional circuits in the subprogram utilizing the same cost/benefit process performed for the ES 2 filing in order to improve reliability by reducing the number of customers impacted by an outage.

PSE&G decided to pursue adding additional recloser units to the subprogram utilizing a process consistent with the framework established for the identification and selection of the initial list of circuits included in the subprogram. This will result a cost-effective approach to providing more customers with faster storm restoration and improved reliability.

In reviewing the additional circuits considered for the subprogram, PSE&G's Asset Management reviewed the additional 4kv circuits to determine if they meet the criteria to install reclosers. PSE&G's Engineering group identified three section loop circuits that have a large quantity of customers in a section that could benefit from a feeder recloser. By installing a feeder recloser into a section with a large customer count, PSE&G Operations would be able to restore the customers on one side of the recloser. This will reduce the number of customers impacted by an extended outage. PSE&G's Engineering also identified sections along a circuit that are currently considered part of a mainline section (no sectionalizing device installed) but which can be reconfigured as a branch. By installing a branch recloser to such section, customers on the remainder of the mainline would not be impacted by a fault on the sectionalized length.

As a result of this additional review, PSE&G identified a total of 365~~42~~ reclosers on 342 circuits to add to the subprogram, comprised of ~~89~~90 4kV reclosers and 275~~253~~ 13kV reclosers. These additional recloser are all currently identified as three-phase recloser, which includes 13 devices that will be part of a pilot program to be installed as a branch (single-phase operable) recloser and 37 that are proposed as tie reclosers. As noted in the IM 2020 Fourth Quarter Report, there is currently no expected change to the subprogram forecast as a result of these additional reclosers, as they essentially replace the planned reclosers identified for removal from the subprogram.

Findings & Observations

- The IM finds that PSE&G appropriately reviewed the circuits identified at the time of the ES 2 filing to ensure that their current status still warranted the planned upgrades, including removal of circuits that already were sectionalized since the ES 2 filing or are now planned for 13kV upgrades in the next five years.
- The IM finds that the identification of additional circuits for the subprogram, utilizing the same processes used for the ES 2 filing, will benefit PSE&G customers by improving reliability in alignment with the intent of the subprogram.

2. *Outage Management System (OMS) Implementation*

A major component of the Grid Modernization – Communication System subprogram is the OMS, being planned and developed between PSE&G and the ADMS Vendor, Open Systems International Inc. (OSII). The OMS project operational planning completed in June 2020 confirmed a 24-month implementation schedule that was assumed during contract negotiations. Based on a June 2020 start date, this would lead to the OMS deployment in May 2022. Immediately following the completion of the operational planning, Hurricane Isaias impacted the eastern seaboard, resulting in widespread power outages and exposing system reliability and availability inefficiencies. The impacts from Hurricane Isaias resulted in the failure of multiple infrastructure and systems during the PSEG-LI storm response that uncovered gaps in performance testing on the integrated systems. The OMS experienced multiple issues with the high volume of data transmitted during the storm, which impacted all communication channels and field management activities. The suspected root cause of the OMS performance issues included: SCADA alarms and customer reports not processed at a rate fast enough to keep up with incoming reports; and stale and repeated outage reports were being submitted erroneously to the OMS when initial submission attempts timed out. The OMS unresponsiveness caused delays to work processes and led to a lower quality of estimated time of recovery information. Among the lessons learned from this storm were two that specifically impact the OMS implementation:

1. Do not introduce any major system changes immediately before storm season.
2. Ensure enhanced performance testing is conducted for each system and its ecosystem. These tests should be repeated annually, with the proper infrastructure, to ensure reliability and availability of critical systems when they are needed most.

The above lessons learned dictated the following changes to the OMS implementation:

- Shift the deployment date from May 2022 until after the June-September major storm season.
- Increase the services scope for the additional enhanced performance testing expectations.
- Enhance the OMS architecture to ensure separate development/testing environments for the long-term.
- Including contingency to mitigate performance issues in OMS and its ecosystem.

With the above changes identified, PSE&G considered two alternatives:

1. Continue with the original project plan for a May 2022 go-live date with minimal impact to the current OMS cost and schedule.

2. Reschedule the go-live date until after the storm season and use the additional schedule to address revised enhanced system testing requirements and other lessons learned from Hurricane Isaias. This would result in approximately $2.3 million in additional capital costs to support the added scope and extended critical resources.

PSE&G decided to incorporate the recommended lessons learned into the OMS scope as ignoring those lessons learned and accepting the risks associated without complete ecosystem testing requirements coupled with a deployment immediately ahead of the major storm season was not viewed as a viable option for PSE&G. PSE&G has established December 2022 as the new OMS deployment date, which is the first available date after the annual SAP maintenance window closure (typically October-November) and provides PSE&G time to complete enhanced performance testing on the existing systems, which is a critical path dependency for the OMS testing.

The IM has requested additional information on this decisions, which when received and reviewed will provide the IM a basis from which to offer completed findings and observations on this decision.

ENERGY STRONG PROGRAM

INDEPENDENT MONITOR

2021 FIRST QUARTER REPORT

APPENDIX A – DRAFT REPORT COMMENTS AND RESPONSES

JANUARY 20, 2022

PEGASUS GLOBAL HOLDINGS, INC. ®

Questions & Comments to the IM 2021 First Quarter Report Formally Submitted to the IM

ID #	Question/Comment	IM Response	Report Changes
RCR-IM-1	With reference to page 2 of the Independent Monitor's Draft First Quarter 2021 Report, please explain if the described delay for the Siemens GIS installation for the Hasbrouck Heights 69kV substation due to Covid-19 related delays has been resolved. If not, please explain.	The Siemens GIS installation at the Hasbrouck Heights 69kV project was completed in May 2021.	No change
RCR-IM-2	Please explain if PSE&G has experienced or anticipates any equipment delivery delays for any of the Energy Strong II subprograms. If so, please explain.	Through the execution of the ES 2 Program (beyond the first quarter of 2021), there have been some instances of material or equipment delays experienced in the Program. During the fourth quarter of 2021, the Contingency Reconfiguration subprogram encountered some delays receiving additional 13kV reclosers, however, between the existing inventory and expediting deliveries, there was no resulting impact to the subprogram. Similarly, in the fourth quarter of 2021, PSE&G was informed by its switchgear vendor that material availability (steel, aluminum, insulation, etc.) caused the upcoming shipment of some of the switchgears to be delayed. Of the affected projects, only the Hamilton substation (a life cycle station upgrade project) had a realized impact of 20 days, which was absorbed by float in the schedule	No change
RCR-IM-3	With reference to pages 2, 3, and 23 of the Independent Monitor's Draft First Quarter 2021 Report, please explain why the Newark Planning Board rejected the Company's proposed site plan for the Waverly substation due to "aesthetic" reasons.	The IM cannot speak specifically to why the site plan was rejected, but the comments received from the Newark Planning Board included items such as the height of the lightening mast, lack of vegetation, lack of art on fencing/walls, why a green roof was not considered, etc.	No change
RCR-IM-4	Please explain if the revised site plan for the Waverly substation will increase projected costs for the project.	PSE&G's preliminary office level estimate on the changes resulting from the revised site plan indicate an estimated cost increase of $2.6 million. This is comprised of: additional engineering ($0.8 million), revised fencing and external façade improvements ($1.0 million), and additional charges for extended project duration ($0.8 million).	**Section III.A.15.**
RCR-IM-5	With reference to Table 8 of the Independent Monitor's Draft First Quarter 2021 Report, please confirm that the SAIDI values	SAIDI values by definition are a system-level metric. The SAIDI figures provided in **Section II.D.1.** of this IM report reflect the individual circuit's contribution to the system SAIDI.	No change

ID #	Question/Comment	IM Response	Report Changes
	presented are system-level, not circuit level SAIDI. If not, please explain.		
RCR-IM-6	With reference to Table 12 of the Independent Monitor's Draft First Quarter 2021 Report, please explain if the current forecast for Hasbrouck Heights reflects schedule delays for the transmission component of the project.	The current forecast for the Hasbrouck Heights project reflects the current status of the project based on the information known by PSE&G. There was no resulting cost impact due to the delays resulting from the delays experienced on the Hasbrouck Heights 69kV project as it only shifted the start time of construction.	No change
RCR-IM-7	With reference to Table 12 of the Independent Monitor's Draft First Quarter 2021 Report, please indicate if the current forecast for the Market Street substation will remain below the projected costs.	The current forecasts shown in **Table 12** represent PSE&G's forecasts for the Electric Station Flood Mitigation projects as of the end of the current reporting quarter, in other words what PSE&G expects the final costs to be based on what it currently knows. These forecasts are updated monthly by PSE&G reflecting the current information, status, and progress of the projects at the time. For the Market Street project, as of the end of the first quarter of 2021, PSE&G's forecast for the project was approximately $26.2 million. As of the end of the third quarter of 2021, the forecast increased to approximately $29.0 million, which was driven by additional OP overhead and restoration work required based on the complexity of the work and field conditions and higher than estimated traffic control requirements.	No change
RCR-IM-8	With reference to Table 12 of the Independent Monitor's Draft First Quarter 2021 Report, please indicate if the current forecast for the Ridgefield 13kV substation will remain below the projected costs.	For the Ridgefield 13kV project, as of the end of the first quarter of 2021, PSE&G's forecast for the project was approximately $25.3 million. As of the end of the third quarter of 2021, the forecast increased to approximately $26.0 million, which was driven by materials costs and construction/supervision costs. See also the note on the current forecasts provided in response to RCR-IM-7 above.	No change
RCR-IM-9	With reference to page 15 of the Independent Monitor's Draft First Quarter 2021 Report, please explain the difference in function and definition between "major asset" and "capacitor bank" for in-service date.	For the Electric Station Flood Mitigation projects, the final "major asset" is typically the final switchgear or transformer being placed in-service that allows the station to provide electricity to the customers it serves. Other equipment, such as capacitor banks, may be installed after customers are already being served by the new or rebuilt substation.	**Section III.A.**
RCR-IM-10	With reference to page 16 of the Independent Monitor's Draft First Quarter 2021 Report, please explain the root causes for the anticipated delay in the installation of Transformer #3 with regards to the project schedule.	The delay to the Waverly project is not specific to the installation of Transformer #3, it stems from the site plan rejection by the Newark Planning Board during the first quarter of 2021, which required a revised site plan be developed and submitted for approval prior to the project proceeding. The Transformer #3 is	No change

ID #	Question/Comment	IM Response	Report Changes
		the final major asset to be installed on the Waverly project, which is currently forecasted beyond the end date of the ES 2 Program, while other components of the project are expected to still be completed within the Program window.	
RCR-IM-11	With reference to page 17 of the Independent Monitor's Draft First Quarter 2021 Report, please explain how the Clay Street sanitation wall has been determined to be allocated to transmission project.	The rationale for this decision was discussed in the IM 2020 Fourth Quarter Report (Section IV.A.). In summary, PSE&G is executing both a Clay Street ES 2 project and a Clay Street 69kV transmission project. After reviewing the project scopes and intent and purpose of the wastewater wall, PSE&G's capital accounting determination was that the wastewater wall was not required for flood mitigation and instead serves to improve the health, safety, and reliability of the station. As such, this scope of work was transferred to the 69kV project.	No change
RCR-IM-12	With reference to page 20 of the Independent Monitor's Draft First Quarter 2021 Report, please provide an update regarding the change of location for the Orange Valley project.	Three of four properties being acquired under the Orange Heights 69kV Project have been acquired by PSE&G. The fourth property is under contract with a forecasted closing date of March 31, 2022.	No change
RCR-IM-13	With reference to page 21 of the Independent Monitor's Draft First Quarter 2021 Report, please explain why the Company slowed progress on Ridgefield 4kV for more pressing work on Ridgefield 13kV.	Early in 2021, there were significant weather impacts utilizing the operational resources needed on both the Ridgefield 13kV and Ridgefield 4kV projects. The resources were allocated to the Ridgefield 13kV project to maintain the critical path. The shifting of resources had no impact on the critical path of the Ridgefield 4kV project schedule.	**Section III.A.12.**
RCR-IM-14	With reference to page 22 of the Independent Monitor's Draft First Quarter 2021 Report, please explain why the Toney's Brook project baseline estimate increased by $1.9 million.	The drivers to the $1.9 million increase in the Toney's Brook base estimate include: • Higher concrete quantities ($0.9 million); • Change in T&D surcharge methodology ($0.6 million); and, • Switchgear award higher than estimated ($0.4 million).	No change
RCR-IM-15	With reference to page 25 of the Independent Monitor's Draft First Quarter 2021 Report, please explain if the Company anticipates increased costs as a result of hiring outside contractors due to staffing shortages for recloser installation. If so, please explain. If not, please explain why not.	PSE&G anticipates that the outsourcing of the pole setting for some reclosers in the Metro Division will result in an estimated cost increase of approximately $784,000, which covers the pole setting and preparation work for 197 poles and 136 reclosers. This represents a less than 1% increase in cost per unit for the recloser work. It also benefits the Program by allowing the Metro Division recloser scope to be completed earlier than it otherwise would (avoiding an estimate $100,000 in extended carrying costs and avoiding resource constraints with the overlapping Fuse Saver installations that are commencing in 2022).	**Section III.B.**

ID #	Question/Comment	IM Response	Report Changes
RCR-IM-16	With reference to page 25 of the Independent Monitor's Draft First Quarter 2021 Report, please provide an update on the communications issues associated with the Fuse Savers.	PSE&G has continued bi-weekly meetings with Siemens to resolve the communication issues, which have affected approximately 10% of the devices. The solution to resolve the communication issues involves modifying the external antenna (and modifying the RCU enclosure to accommodate the antenna). PSE&G anticipates the recurring meetings with Siemens will continue early into the full scope Fuse Saver installations to ensure no issues are encountered.	**Section III.B.**
S-INF-1	Please confirm that year-to-year variations in the Program's approved annual budget have not exceeded 10 percent (10%), pursuant to N.J.A.C. 14:3-2A.4(f).	The Stipulation established the ES 2 Program term of October 1, 2019-December 31, 2023. It also established investment levels for the ES 2 Program by subprogram, totaling $691.5 million, and an additional $150.5 million designated for certain capital projects during the ES 2 Program term but to be recovered outside the ES 2 rate mechanism. However, it did not specify an approved annual budget for these investments and as such there is no basis for assessing year-to-year variations.	No change
S-INF-2	**<u>Reference Page 9, Table 7 – Q1 2021 Major Event Performance</u>** Please provide the cumulative SAIFI, CAIDI, and SAIDI of the circuits listed in Table 7 for Q1 2021.	The cumulative SAIDI, CAIDI, and SAIDI from the 2021 Q1 Major Event are as follows, note that like **Table 7** this includes all circuits impacted by the Major Event, including circuits that have not received Energy Strong/ES 2 investments. • CAIDI: 66.63 • SAIFI: 0.04 • SAIDI: 2.85	No change
S-INF-3	**<u>Reference Page 10, Table 8 – Q1 2021 Major Event Additional Information on Selected Circuits</u>** Please reconcile why two (2) circuits (BLO 4016 and FOU 8014) experienced Major Events were no customers were impacted yet an Outage Duration is provided.	The sections of these circuits that are listed in **Table 8** with zero customers reflect the way the circuit is modeled in PSE&G's connectivity model and the restoration/isolation steps used to restore service (e.g. isolating a section of cable for repair). In addition, for the FOU 8014 circuit, the interrupted transformer had no customers assigned to it.	No change
S-INF-4	**<u>Reference Pages 14-15, Table 12 – ES 2 Electric Station Flood Mitigation Project Cost Status as of March 31, 2021</u>** a. What is attributed to the forecasted cost of the Hasbrouck Heights substation project increasing from $17,870,384 in the Independent Monitor's Q4 2020 Report to $20,474,628? b. What is attributed to the forecasted cost of the Leonia substation project decreasing from $30,396,846 in the	Regarding the forecast change from the fourth quarter of 2020 to the first quarter of 2021 on these electric substations: a. The Hasbrouck Heights forecast increased approximately $2.6 million, which was primarily driven by the civil construction bid coming in higher than estimated ($1.2 million) and a higher dewatering estimate reflective of site conditions ($1.3 million).	**Section III.A.4. & Section III.A.7.**

ID #	Question/Comment	IM Response	Report Changes
	Independent Monitor's Q4 2020 Report to $25,082,905?	b. The Leonia forecast decreased by approximately $5.3 million, which was driven by civil and electrical construction awards coming in lower than estimated.	
S-INF-5	**Reference Page 15, Electric Station Flood Mitigation Subprogram** Refer to the statement "Two other projects had forecasted in-service movements greater than 60 days, including Hasbrouck Heights, which improved 64 days based on PS&EG identifying the in-service date as the final major asset instead of the previously identified date of when the capacitor banks were completed…" Please discuss if this treatment is consistent with the in-service dates of the other Electric Station Flood Mitigation projects.	For the Electric Station Flood Mitigation projects, the final "major asset" is typically the final switchgear or transformer being placed in-service that allows the station to provide electricity to the customers it serves. Other equipment, such as capacitor banks, may be installed after customers are already being served by the new or rebuilt substation.	**Section III.A.**
S-INF-6	**Reference Page 20, Orange Valley Substation Project** Regarding the statement "The variance in first quarter spend was largely the result of the project re-allocating an engineering invoice between this ES 2 project and the 69kV project…" Please provide additional details about the Company's decision to re-allocate an engineering invoice to the 69kV project, including the re-allocated costs.	The engineering invoice reallocation was forecasted in error to the Orange Valley ES 2 project, rather than the Orange Valley 69kV project. This reallocation reflects the cost of this engineering work ($35K) being removed from the Orange Valley ES 2 forecast and incorporated into the Orange Valley 69kV forecast.	**Section III.A.10.**
S-INF-7	**Reference Page 22, Toney's Brook Substation Project** Regarding the increase to the base estimate of the Toney's Brook substation project, please provide additional details about the modification titled "Changing in T&D surcharge methodology ($0.6 million)."	The change in T&D surcharge methodology caused an increase in Outside Service Electrical construction planned surcharge rate which increased by over 45% from 2019 to 2020. As a result, approximately $587,000 of the $0.6 million increase on Toney's Brook Conceptual level estimate was attributed to increase in electrical construction. The remainder of the $0.6 million increase is associated with Project Management labor.	**Section III.A.14.**
S-INF-8	**Reference Page 25, Contingency Reconfiguration Subprogram** Refer to the statement "While monitoring performance of the installed Fuse Savers, PSE&G experienced other communication issues between the Fuse Savers and the remote control unit (RCU), where in the supervisory control and data acquisition (SCADA) communication indicated a false open/close alarm on some of the devices. Siemens has provided a prototype Fuse Saver to address the communication issues, which PSE&G will monitor to ensure it addresses the issues prior to placing additional orders." Please indicate if the Company has any plans	The communication issues experienced on the Fuse Savers have only affected approximately 10% of the installed devices. Any device that demonstrates communication issues will be addressed via the solution developed by PSE&G and Siemens. See also the related discussion in response to RCR-IM-16.	**Section III.B.**

ID #	Question/Comment	IM Response	Report Changes
	to address the communications issues on the 80 Fuse Saver devices that were already installed.		
S-INF-9	**<u>Reference Page 26, Contingency Reconfiguration Subprogram</u>** Regarding the "approximate $14 million reduction to the Fuse Saver scope due to the number of units planned for the Program decreasing from 2,572 to 1,967", please discuss the factors considered by the Company in selecting the Fuse Savers that were removed from the Program.	PSE&G has informed the IM that at this time, a decision has not been made on which specific Fuse Savers are to be removed from the program. The increased average cost per unit has resulted in a reduction of the quantity of Fuse Savers that can fit within the program budget. The primary factor that will be used to determine which Fuse Savers to remove from the Program is the cost benefit ratio, consistent with the original prioritization approach.	No change
S-INF-10	**<u>Reference Page 35-36, Camden M&R Station Project</u>** Regarding the statement "This updated estimate increased the base estimate by $14.3 million, while reducing the R&C by $0.4 million, resulting in the total project estimate increasing from $15.4 million to $29.3 million. This increase is the result of higher construction costs stemming from the engineer's 50% estimate ($6.3 million), procurement of material based on received quotes ($6.1 million), and additional project management, licensing and permitting, and engineering support not included in the Office level estimate ($1.9 million)." a. Please provide the originally budgeted costs for construction (from the engineer's 50% estimate) and for procurement of material based on received quotes. b. Please describe any specific factors that led to the higher costs for construction and material procurement.	Regarding the Camden M&R project: a. The originally budgeted costs were $4.7 million for construction and $4.3 million for procurement of material. b. The original estimate was based on reusing much of the existing Liquid Propane Air (LPA) equipment and raising the existing LPA building. Due to a remediation project at the site, the existing building will need to be demolished and relocated. This change resulted in additional construction costs for foundations that will be needed to achieve the FEMA +1' elevation and additional demolition costs. Similarly, two existing 1200 HP air compressors, switchgear, and auxiliary equipment were determined to not be suitable for reuse. Additionally, new LPA mixing control capabilities requires additional control valves and automation.	**Section III.F.1.**
S-INF-11	**<u>Reference Pages 39-40, Decisions Recorded After the First Quarter of 2021, Energy Strong II Electric Program – Contingency Reconfiguration Subprogram, 13kV and 4kV Reclosers</u>** Refer to the statement "As a result of this additional review, PSE&G identified a total of 342 reclosers to add to the subprogram, comprised of 89 4kV reclosers and 253 13kV reclosers." a. Please provide the total number of 4kV and 13kV circuits associated with this work, including a breakdown of the total number of sections currently within these circuits.	Regarding the additional reclosers identified for the Contingency Reconfiguration subprogram: a. Of the additional recloser identified, now updated to 365 units, there are 961 sections. This includes 90 4kV reclosers on 57 circuits and 275 13kV recloser on 206 circuits. b. Of the 365 additional reclosers, all are currently identified as three-phase reclosers. This includes 13 reclosers that will be part of a pilot program to be installed as a branch (single-phase operable) recloser. c. Of the 365 additional recloser, 37 are proposed as tie reclosers.	**Section IV.A.1.**

ID #	Question/Comment	IM Response	Report Changes
	b. Of the 342 additional reclosers, please provide a breakdown of three-phase reclosers versus single-phase reclosers. c. Please indicate how many of the additional reclosers will be used to create new tie points between circuits. d. Please indicate if the Company considered historical reliability when selecting the circuits that would received these additional reclosers.	d. PSE&G's selection of these additional circuits was consistent with the cost-benefit process utilized for the selection of the initial circuits for the subprogram, which included an assessment of historical performance and number of customers served.	
S-INF-12	**Reference Pages 40-41, Decisions Recorded After the First Quarter of 2021, Energy Strong II Electric Program – Outage Management System (OMS) Implementation** Refer to the statement "Immediately following the completion of the operational planning, Hurricane Isaias impacted the eastern seaboard, resulting in widespread power outages and exposing system reliability and availability inefficiencies. Among the lessons learned from this storm were two that specifically impact the OMS implementation." Please provide additional details about the OMS issues experienced during Hurricane Isaias.	The impacts from Hurricane Isaias resulted in the failure of multiple infrastructure and systems during the PSEG-LI storm response that uncovered gaps in performance testing on the integrated systems. The OMS experienced multiple issues with the high volume of data transmitted during the storm, which impacted all communication channels and field management activities. The suspected root cause of the OMS performance issues included: SCADA alarms and customer reports not processed at a rate fast enough to keep up with incoming reports; and stale and repeated outage reports were being submitted erroneously to the OMS when initial submission attempts timed out. The OMS unresponsiveness caused delays to work processes and led to a lower quality of estimated time of recovery information.	**Section IV.A.2.**
Rate Counsel 12/20/2021 Letter to the IM	At the end of the first quarter 2021, the Energy Strong II ("ESII") program remains in the early stages. The Independent Monitor reports that spending for the quarter ending March 31, 2021 has been $40,652,703 or 5.2 percent of the current forecast of $770,614,891 program (including the $100 million for Electric Stipulated Base and excluding $78.5 million of risk and contingency). Rate Counsel notes that the parties stipulated to $842 million to complete the ES II Program with $641 million for electric, $50.5 million for gas, and $150.5 million within Stipulated Base for electric and gas spending.	The IM provides additional clarification that the $770,614,891 ES 2 Program forecast as of the end of the first quarter of 2021 includes both the $100 million in Electric Stipulated Base and the $50.5 million in Gas Stipulated Base.	No change
Rate Counsel 12/20/2021 Letter to the IM	Rate Counsel also notes that the budget for Electric stipulated base has been set to $100 million for the life cycle subprogram. In the report for this quarter, Pegasus continued to provide Study level estimates for the four substations (Hamilton, Paramus, Plainfield, and Woodbury). The current Study level estimates for the program are $79,700,000 including $16,600,000 for risk and contingency.	The IM provides additional clarification that the Electric Stipulated Base budget of $100 million established by the Stipulation includes investments in electric station life cycle projects and electric outside plant higher design and construction standards projects. The estimates detailed in this IM report for the noted substations reflect the currently approved projects in this subprogram.	No change

ID #	Question/Comment	IM Response	Report Changes
Rate Counsel 12/20/2021 Letter to the IM	The current forecast for the Electric Flood mitigation program decreased from $339,403,267 in the Fourth Quarter Report to $331,374,281 in the First Quarter Report, not including risk and contingency estimates. Table 12 – ES 2 Electric Station Flood Mitigation Project Cost Status as of March 31, 2021, states that the spending amount for the subprogram is $318,900,000 in budgeted base project costs and $59,800,000 allocated to risk and contingency. The Independent Monitor notes two formal Records of Decision ("ROD") were issued during the first quarter of 2021. These two RODs included 13kV and 4kV reclosers related to the Contingency Reconfiguration program (ESII-CR-1); and outage management system ("OMS") implementation (ESII-GM-5).	The IM provides additional clarification that the $318.9 million base estimate total and $59.8 million R&C total are reflective of the current project estimates, which are at different estimate phases depending on how advanced the individual project is. The current forecast as of the end of the first quarter of 2021 for the Electric Station Flood Mitigation subprogram is $331.4 million. Additionally, the two RODs discussed in this IM report were issued during the second quarter of 2021, not the first quarter.	No change
Rate Counsel 12/20/2021 Letter to the IM	The First Quarter Report notes that two substations have forecasted in-service dates that have moved more than 60 days. These two substations are Hasbrouck Heights and Waverly. According to Pegasus, "the Hasbrouck Heights forecasted in-service date previously moved in the fourth quarter of 2020 from early December 2022 to mid-April 2023 due to Covid-19 related delays on the Siemens GIS installation on the associated Hasbrouck Heights 69kV project, which has resulted in the Hasbrouck Heights ES 2 project delaying the start of construction from July 2021 to January 2022. The fourth quarter in-service date was based on the capacitor bank in-service date (April 2023), which has now been updated by PSE&G to reflect the switchgear in-service date currently forecasted for February 2023." For Waverly, Pegasus notes, "the Waverly in-service date slipped 314 days from the forecasted in-service date at the end of the prior quarter. This was due to PSE&G being denied approval of the site plan by the Newark Planning Board, which requires PSE&G to address the comments received, coordinate community meetings on the new site plan application, and re-submit to the Newark Planning Board."	The IM confirms this information as accurate.	No change
Rate Counsel 12/20/2021 Letter to the IM	The First Quarter Report noted that the Contingency Reconfiguration subprogram total forecast decreased from $162,806,273 in the Fourth Quarter report to $148,927,422. The stipulated budget for the subprogram is $145 million. Pegasus observed that the decrease in the program costs was attributed to	The IM confirms this information as accurate.	No change

ID #	Question/Comment	IM Response	Report Changes
	the “reduction to the Fuse Saver scope due to the number of units planned for the Program decreasing from 2,572 to 1,967 due to the higher cost per unit observed in the pilot program.”		

ENERGY STRONG 2 PROGRAM INDEPENDENT MONITOR 2021 SECOND QUARTER REPORT

PREPARED AND SUBMITTED BY

PEGASUS GLOBAL HOLDINGS, INC. ®

CONFIDENTIAL

MAY 5, 2022

Table of Contents

Appendices

List of Acronyms and Abbreviations

Advanced Distribution Management Systems .... ADMS

Allowance for Funds Used During Construction .... AFUDC

Architectural and Engineering .... A/E

Board of Public Utilities .... BPU

Construction Work In Progress .... CWIP

Costs of Removal .... COR

Distribution Management System .... DMS

Distributed Energy Resource Management System .... DERMS

Distribution Supervisory Control and Data Acquisition .... DSCADA

Energy Strong 2 .... ES 2

Flood Hazard Area .... FHA

Gas Metering & Regulating .... Gas M&R

Independent Monitor .... IM

Inside Plant .... IP

Issued for Bidders .... IFB

Issued for Construction .... IFC

Issued for Review .... IFR

New Jersey Department of Environmental Protection .... NJDEP

Open Systems International Inc. .... OSII

Outage Management System .... OMS

Outside Plant .... OP

Poorest Performing Circuit .... PPC

Public Service Electric & Gas .... PSE&G

Purchase Orders .... POs

Record of Decision .... ROD

Remote Control Unit .... RCU

Remote Terminal Unit .... RTU

I. Executive Summary

Public Service Electric & Gas's (PSE&G's) Energy Strong 2 (ES 2) Program was established from a Stipulation that the involved parties agreed to in August 2019, as approved by a Board of Public Utilities (BPU) Order dated September 11, 2019, with an effective date of September 21, 2019. The Stipulation provided the ES 2 Program would be comprised of five primary subprograms: Electric Station Flood Mitigation; Contingency Reconfiguration; Grid Modernization – Communications; Grid Modernization – Advanced Distribution Management Systems (ADMS); and Gas Metering & Regulating (Gas M&R) Station Upgrades. In addition, a Stipulated Base spend was established that includes both an electric component (higher outside plant (OP) design standards and station life cycle upgrades) and a gas component (overlapping with the Gas M&R subprogram).

During the second quarter of 2021, the bulk of the spend within the ES 2 Program continued to be in the two largest subprograms: Electric Station Flood Mitigation with six projects continuing in construction; and Contingency Reconfiguration that continues to advance the installation and commissioning of reclosers largely in alignment with PSE&G's plan. Within the other subprograms, the Grid Modernization – Communication System subprogram placed one additional fiber installation project in-service, and continued the retrofit recloser installations, with 685 units installed during the second quarter of 2021, bringing the total number of retrofit reclosers installed to 1,432 units out of a current forecast of 2,449 units. The Grid Modernization – ADMS subprogram continued to formalize system requirements and prepared for factory acceptance testing on the platform. While the Gas M&R subprogram kicked off the Westampton project, while other stations continued to advance design, prepared construction bids, and continued other preliminary activities. An additional project (State Street – OP) was added to the life cycle upgrades portion of the Electric Stipulated Base, while the four previously approved projects continued to advance their design efforts, with the Paramus project having its site plan approved in June 2021 and commencing construction for the contingency switchgear. **Table 1 – ES 2 Subprogram & Stipulated Base Status as of June 30, 2021** below provides the spend to date on the subprograms within the ES 2 Program and Stipulated Base compared to the total forecast and forecasted completion for each.

Table 1 – ES 2 Subprogram & Stipulated Base Status as of June 30, 2021

Subprogram	Q2 Spend	Total Spend to Date*	Total Forecast*	% of Actuals to Forecast	Forecasted Completion**	Stipulation Funding Amount
Electric Station Flood Mitigation	$20,807,542	$90,603,138	$346,463,155	26%	Dec 2024	$389M
Contingency Reconfiguration	$13,419,784	$85,558,983	$147,070,235	58%	Dec 2023	$145M
Grid Modernization – Communications	$7,862,176	$33,389,013	$60,377,806	55%	Dec 2023	$72M
Grid Modernization – ADMS	$2,168,187	$21,141,005	$42,712,616	49%	Dec 2022	$35M
Electric Stipulated Base	$5,319,246	$9,105,707	$100,000,000	9%	Dec 2023	$100M
Gas M&R Station Upgrades^	$4,237,932	$10,219,223	$92,000,002	11%	Dec 2023	$101M
*Total**	$53,814,867	$250,150,685	$788,758,650	32%	Dec 2024	$842M

-Note: total figures may not fully align due to rounding. Additionally, the total forecast includes only the base cost for the Electric Station Flood Mitigation and Gas M&R subprograms as PSE&G does not include risk and contingency (R&C) in its forecasts for these projects. See **Table 11 and **Table 20** for the Electric Station Flood Mitigation and Gas M&R project estimates, respectively, with base costs and R&C shown. The Electric Station Flood Mitigation total spend and total forecast also does not include $133,616 previously spent on the Constable Hook project that is being removed from the ES 2 Program.*

**-Final in-service date. ^-Includes both the ES 2 projects and the Stipulated Base gas projects.

During the second quarter of 2021, PSE&G submitted updated estimates to its Utility Review Board (URB) for the two Grid Modernization subprograms (including separate estimates for the wireless network/retrofits scope and fiber installation/cutover scope of the Grid Modernization – Communication Network subprogram). The original and current estimates for these Grid Modernization components are provided in **Table 2 – Grid Modernization Subprograms Updated Estimates as of June 30, 2021**. As shown in **Table 2**, while the ADMS and fiber installation/cutover scopes saw increases to their estimates, there was no net change to the Grid Modernization initiatives as the wireless network/retrofits scope saw a corresponding reduction. These updated estimates are discussed in more detail within **Section III.C.** and **Section III.D.** of this report.

Table 2 – Grid Modernization Subprograms Updated Estimates as of June 30, 2021

Subprogram/Scope	Current Estimate Level	Filing Estimate	Current Estimate	Variance
ADMS	Conceptual	$35,000,000	$42,700,000	+$7,700,000
Grid Modernization – ADMS Subtotal	***Conceptual***	***$35,000,000***	***$42,700,000***	***+$7,700,000***
Wireless Network & Retrofits	Conceptual	$48,600,000	$35,100,000	($13,500,000)
Fiber	Study	$23,400,000	$27,500,000	+$4,100,000
Grid Modernization – Communication System Subtotal	***Conceptual / Study***	***$72,000,000***	***$62,600,000***	***($9,500,000)***
Grid Modernization Placeholder	**-**	-	***$1,700,000***	***+$1,700,000***
Total		**$107,000,000**	**$107,000,000**	**$0**

Given the prominence of the Electric Station Flood Mitigation subprogram, which represents over half of the total ES 2 Program spending, a summary of the projects within this subprogram is provided below in **Table 3 – ES 2 Electric Station Flood Mitigation Status as of June 30, 2021**.

Table 3 – ES 2 Electric Station Flood Mitigation Status as of June 30, 2021

Project	Total Estimate (rounded)	Actuals	% of Actuals to Estimate	Forecasted In-Service Date*
1. Academy Street	$10,500,000	$5,159,731	49%	10/25/2021
2. Clay Street	$33,800,000	$2,156,501	6%	12/19/2022 (↑)
3. Front Street^	$27,400,000	$190,915	1%	11/2/2023
4. Hasbrouck Heights	$22,700,000	$2,020,326	9%	2/7/2023
5. Kingsland	$8,300,000	$381,286	5%	10/4/2023
6. Lakeside Avenue	$47,900,000	$956,178	2%	12/13/2023
7. Leonia	$27,500,000	$13,034,343	47%	9/30/2022
8. Market Street	$26,900,000	$23,514,129	87%	9/23/2021^^
9. Meadow Road	$9,000,000	$786,103	9%	9/22/2023 (↓)
10. Orange Valley	$20,200,000	$594,041	3%	12/29/2023 (↓)
11. Ridgefield 13kV	$27,600,000	$13,319,925	48%	11/8/2022 (↓)
12. Ridgefield 4kV	$19,500,000	$18,777,287	96%	**5/16/2021** (↑)
13. State Street	$22,400,000	$1,193,633	5%	9/23/2022
14. Toney's Brook	$18,800,000	$963,752	5%	4/21/2023

Project	Total Estimate (rounded)	Actuals	% of Actuals to Estimate	Forecasted In-Service Date*
15. Waverly	$35,400,000	$6,062,028	17%	12/18/2024 (↓)
16. Woodlynne	$19,400,000	$1,519,097	8%	10/10/2023

-Reflects the in-service date of the last major asset (e.g. switchgear), certain activities may take place after this date to support the final in-service date (i.e. when all customers are cutover).* ***Bold* *dates indicate the actual in-service date.*

(↑)-*Indicates the forecasted in-service date advanced from the prior quarter.*

(↓)-*Indicates the forecasted in-service date slipped from the prior quarter.*
^- The Front Street project was proposed by PSE&G during the second quarter of 2021 to replace the cancelled Constable Hook project.
^^-See ***Section IV.A.*** *for additional information on the Market Street in-service date following the end of the second quarter of 2021.*

As indicated in **Table 2**, the projects that have previously started construction (Academy Street, Leonia, Market Street, Ridgefield 13kV, Ridgefield 4kV, and Waverly) continue to have the highest spend. Additionally, five of the stations (Clay Street, Hasbrouck Heights, Leonia, Ridgefield 13kV, and State Street) had new estimates approved by the URB in during the second quarter of 2021, while the Front Street project was also approved by the URB to replace the cancelled Constable Hook project. **Table 2** also shows that six of the sixteen projects had movement during the second quarter of 2021 in the forecasted in-service date, with two advancing and four slipping. Of these six projects, four of the projects (Market Street, Ridgefield 4kV, Ridgefield 13kV, and Orange Valley) had forecasted in-service dates change by less than two weeks, with the Ridgefield 4kV project achieving its in-service status on May 16, 2021. The Clay Street forecasted in-service date advanced 50 days from the status as of the end of the first quarter of 2021. Only one project (Waverly) had movement more than 60 days, which is the threshold the Independent Monitor (IM) applied during the original Energy Strong Program for evaluating changes to the project schedules. The Waverly in-service date slipped an additional 92 days from the forecasted in-service date at the end of the prior quarter, which continues to reflect the impacts of the project's site plan denial in March 2021. The project team continues to work on a new site plan application, which once approved will provide PSE&G with a clearer view of the Waverly schedule, including potential opportunities to advance the in-service date.

The IM has found nothing to date that would jeopardize the ES 2 Program being completed on budget. However, schedule challenges, particularly on the Waverly substation and other projects with forecasted in-service dates near the Program end date will continue to warrant further monitoring by the IM to ensure the ES 2 Program is completed within the defined timeline.

As noted in the IM 2020 First Quarter Report, the IM conducts its assessment in accordance with Generally Accepted Government Auditing Standards (GAGAS, or more commonly referred to as the "Yellow Book" standards). The Yellow Book provides a framework for conducting performance management reviews/audit engagements with competence, integrity, objectivity, and independence that result in information used for oversight, accountability, transparency, and improvements of the audited programs and operations. On March 18, 2022, a draft report was presented and submitted to PSE&G, BPU Staff, and Rate Counsel. Per the Yellow Book, the transmittal of a draft report is intended to allow for review and comment by the audited entity and others to develop a fair, complete, and objective report. A summary of the comments on the draft report and the IM's responses are provided in **Appendix A – Draft Report Comments and Responses**. This **Appendix A** also identifies specific sections within this

IM 2021 Second Quarter Report that have been edited, supplemented with additional information, or otherwise revised in response to the comments received.

II. Program Status

A. Key Decisions

In order to capture formalized key decisions regarding the ES 2 Program, PSE&G completes a “Record of Decision” (ROD) that includes a description of the decision; alternatives considered; the decision made; and rationale for the decision. The RODs are assessed by the IM as they are completed to review their impact to the Program. In addition, the IM may request PSE&G complete a ROD to formalize a decision if such a decision has not yet been formalized through the ROD process.

The current and pending RODs as of the date of this IM 2021 Second Quarter Report are presented below in **Table 4 – ES 2 Records of Decisions**.

Table 4 – ES 2 Records of Decisions

Subprogram	Record of Decision	IM Comments
Electric Station Flood Mitigation	Academy Street & State Street Change in Mitigation Method	Reasonable and appropriate *(See Section B.1. in the IM 2020 First Quarter Report)*
Electric Station Flood Mitigation	Engineering Support for Energy Strong Program Projects	Reasonable and appropriate *(See Section B.2. in the IM 2020 First Quarter Report)*
Grid Modernization – Communication System	Wireless Communication Network	Reasonable and appropriate *(See Section II.A.1. in the IM 2020 Third Quarter Report)*
Grid Modernization – Communication System	Substation Communication Center	Reasonable and appropriate *(See Section II.A.2. in the IM 2020 Third Quarter Report)*
Grid Modernization – Communication System	Fiber Scope	Reasonable and appropriate *(See Section IV.A. in the IM 2020 Third Quarter Report)*
Electric Station Flood Mitigation	Constable Hook, Lakeside, & Orange Valley Change in Mitigation Method	Reasonable and appropriate *(See Sections II.A.3. and IV.B. in the IM 2020 Third Quarter Report and additional discussion in Section II.A.1. and Section IV.B. of the IM 2020 Fourth Quarter Report)*
Grid Modernization – Communication System	Communication Retrofit of Replacement and non ES-II Units	Reasonable and appropriate *(See Section II.A.2. in the IM 2020 Fourth Quarter Report)*
Electric Station Flood Mitigation	Market Street Radioactive Soil Testing and Handling	Reasonable and appropriate *(See Section II.A.3. in the IM 2020 Fourth Quarter Report)*
Electric Station Flood Mitigation	Transfer of Clay Street Wastewater Wall Scope from ES2FM to Clay Street 69kV Project	Reasonable and appropriate *(See Section IV.A. in the IM 2020 Fourth Quarter Report)*
Contingency Reconfiguration	Energy Strong II Electric Program – Contingency Reconfiguration Subprogram, 13kV and 4kV Reclosers	Reasonable and appropriate *(See Section IV.A. in the IM 2021 First Quarter Report and* ***Section II.A.1.*** *in this report)*

Subprogram	Record of Decision	IM Comments
Grid Modernization – ADMS	Outage Management System (OMS) Implementation	Reasonable and appropriate *(See Section IV.A. in the IM 2021 First Quarter Report and* ***Section II.A.2.*** *in this report)*

During the second quarter of 2021, two key decisions were issued by PSE&G, each of which was initially discussed in the IM 2021 First Quarter Report and summarized below.

1. Energy Strong II Electric Program – Contingency Reconfiguration Subprogram, 13kV and 4kV Reclosers

This ROD was issued by PSE&G to document changes in circuits, number of recloser units, and functional recloser types to be included in the Contingency Reconfiguration subprogram.

At the time of the ES 2 filing, PSE&G identified 690 13kV circuits and 500 4kV circuits for inclusion in the ES 2 Contingency Reconfiguration subprogram. As the subprogram progressed through detailed assessment and engineering, each circuit was assessed by PSE&G to determine its current status reflective of updated system plans and changes as well as other work done subsequent to the ES 2 filing, such as Poorest Performing Circuit (PPC) improvements and other reliability enhancements outside of the ES 2 Program. Based on the results of this review, 238 circuits were identified for removal from the subprogram, comprising of 177 of the initially planned 13kV reclosers and 153 of the initially planned 4kV reclosers, which included 54 circuits that were part of the PPC improvements and 78 other circuits that received reliability enhancements. The removal of these circuits presented PSE&G with the opportunity to conduct a detailed review of its 4kV and 13kV circuits to identify cost effective opportunities to include additional circuits in the subprogram following the same cost/benefit process utilized for the ES 2 filing.

As a result of this additional review, PSE&G identified a total of 342 reclosers to add to the subprogram, comprised of 89 4kV reclosers and 253 13kV reclosers. As noted in the IM 2020 Fourth Quarter Report, there is currently no expected change to the subprogram forecast as a result of these additional reclosers, as they essentially replace the planned reclosers identified for removal from the subprogram.

Findings & Observations

- The IM finds that PSE&G appropriately reviewed the circuits identified at the time of the ES 2 filing to ensure that their current status still warranted the planned upgrades, including removal of circuits that already were sectionalized since the ES 2 filing or are now planned for 13kV upgrades in the next five years.
- The IM finds that the identification of additional circuits for the subprogram, utilizing the same processes used for the ES 2 filing, will benefit PSE&G customers by improving reliability in alignment with the intent of the subprogram.

2. Outage Management System (OMS) Implementation

A major component of the Grid Modernization – Communication System subprogram is the OMS, being planned and developed between PSE&G and the ADMS Vendor, Open Systems International Inc. (OSII). The OMS project operational planning completed in June 2020 confirmed a 24-month implementation schedule that was assumed during contract negotiations. Based on a June 2020 start date, this would lead to the OMS deployment in May 2022.

Immediately following the completion of the operational planning, Hurricane Isaias impacted the eastern seaboard, resulting in widespread power outages and exposing system reliability and availability inefficiencies. These impacts were unique from prior Major Events in that the failure of multiple infrastructure and systems during the Hurricane Isaias response uncovered gaps in performance testing on the integrated systems. Lessons learned from this storm included avoiding introducing any major system changes immediately before storm season and ensuring enhanced performance testing is conducted for each system and its ecosystem.

PSE&G opted to incorporate the recommended lessons learned into the OMS scope as ignoring those lessons learned and accepting the risks associated without complete ecosystem testing requirements coupled with a deployment immediately ahead of the major storm season was not viewed as a viable option for PSE&G. PSE&G has established December 2022 as the new OMS deployment date, which is the first available date after the annual SAP maintenance window closure (typically October-November) and provides PSE&G time to complete enhanced performance testing on the existing systems, which is a critical path dependency for the OMS testing. PSE&G anticipates that the additional scope and extension of critical resources based on the revised deployment date will result in approximately $2.3 million in additional costs to the subprogram. These additional costs are comprised of the following components:

- Extend OSI services contract: $1.5 million
- Extend Cognizant services contract: $0.2 million
- Extend Pontoon services contract: $0.2 million
- Extend internal subject matter experts: $0.2 million
- Development Environment: $0.2 million
- Development Contingency: $0.3 million
- Reduced travel and expenses: ($0.3 million)
  Total: $2.3 million

<u>Findings & Observations</u>

- While this decision results in a higher cost for the subprogram, the alternative of maintaining the original scope and planned May 2022 go-live date exposes PSE&G to risks associated with introducing a new system immediately before storm season and having less robust performance testing.
- The IM finds it appropriate for PSE&G to incorporate the lessons learned from Hurricane Isaias into the scope and planning for the OMS implementation.

B. Program Management

Beginning in July 2020, the IM began participating in a bi-weekly call with PSE&G to review its bi-weekly ES 2 Program Dashboard. As with ES 1, the Dashboard provides a mechanism for PSE&G to monitor and control activities to be completed in order to achieve key near-term milestones, including a focus on recently completed activities, any key issues, and other key metrics (e.g. installation targets) as appropriate. These calls have proven to be an effective way for the IM to stay informed on current and upcoming activities and to allow a venue for discussions between the IM and PSE&G on these activities and status updates and continue to be held on a recurring basis.

C. Cost Assignments

1. Costs of Removal (COR)

Costs of Removal (COR) generally include costs for such activities as environmental removal, removal of inside station equipment, structures, foundations, towers and fixtures, conductors and other electrical devices, poles and fixtures, transformers, plant demolition, foundations, and removal of underground conduit and other wiring. Generally, COR are charged to Accumulated Depreciation and are amortized and recovered through a component of depreciation expense. The specific method and amount of recovery is determined in gas and electric rate cases before the BPU.

Table 5 – ES 2 Program Costs of Removal as of June 30, 2021, below itemizes the charges to COR for the second and first quarters of 2021, total 2020, total 2019 (which was only the fourth quarter) and total ES 2 Program COR to date. These amounts do not reflect any salvage value reductions, which have been *de minimis* in the ES 2 Program through June 30, 2021.

Table 5 – ES 2 Program Costs of Removal as of June 30, 2021

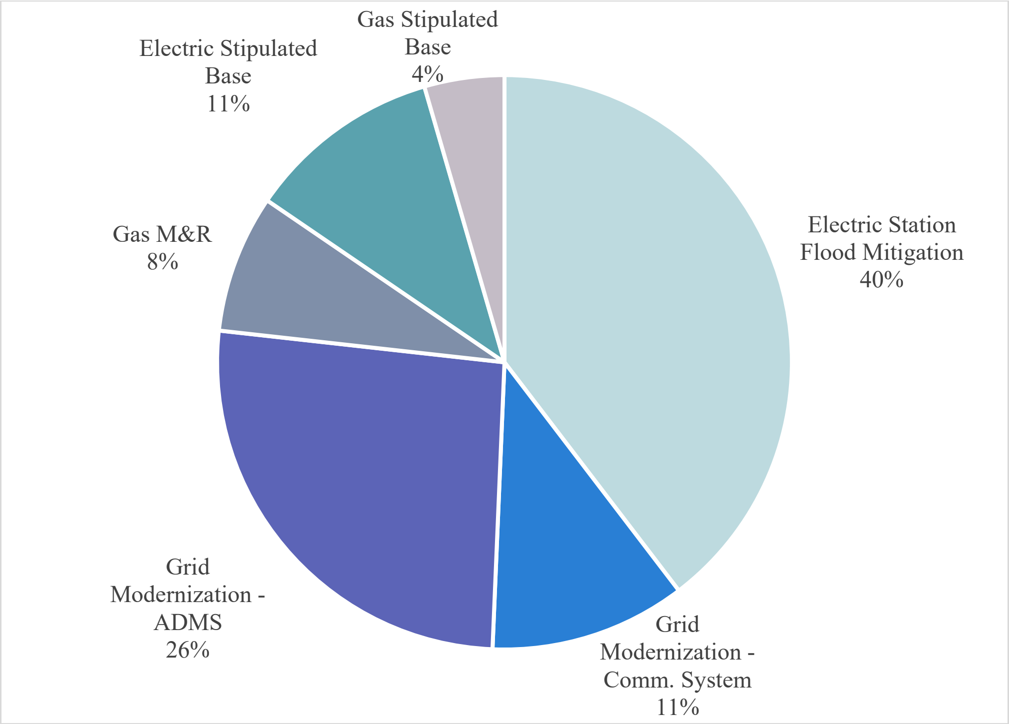
Subprogram	Q2 2021	Q1 2021	Year-to-Date 2021	Total 2020	Total 2019 (Q4)	Total COR
	(in $ thousands)					
Electric Station Flood Mitigation	$1,141.0	$1,129.5	$2,270.5	$1,021.1	$0	$3,291.6
Contingency Reconfiguration	$485.2	$622.9	$1,108.1	$2,198.9	$431.0	$3,738.0
Grid Modernization – Communications	$37.9	$37.8	$75.7	$24.4	$0	$100.1
Grid Modernization – ADMS	$0	$0	$0	$0	$0	$0
Electric Stipulated Base	$0	$0	$0	$0	$0	$0
Gas M&R Station Upgrades	$87.6	$0	$87.6	$0	$0	$87.6
Gas Stipulated Base	$0	$0	$0	$0	$0	$0
Total	$1,751.7	$1,790.2	$3,541.9	$3,244.4	$431.0	$7,217.3

The reduction in Contingency Reconfiguration COR for the second quarter of 2021 from the first quarter is primarily attributable to fewer recloser removal jobs during the second quarter. COR charges for the Gas M&R subprogram during the second quarter of 2021 reflect the demolition of existing on-site buildings at the Westhampton project.

2. Construction Work-in-Progress (CWIP) & In-Service Transfers

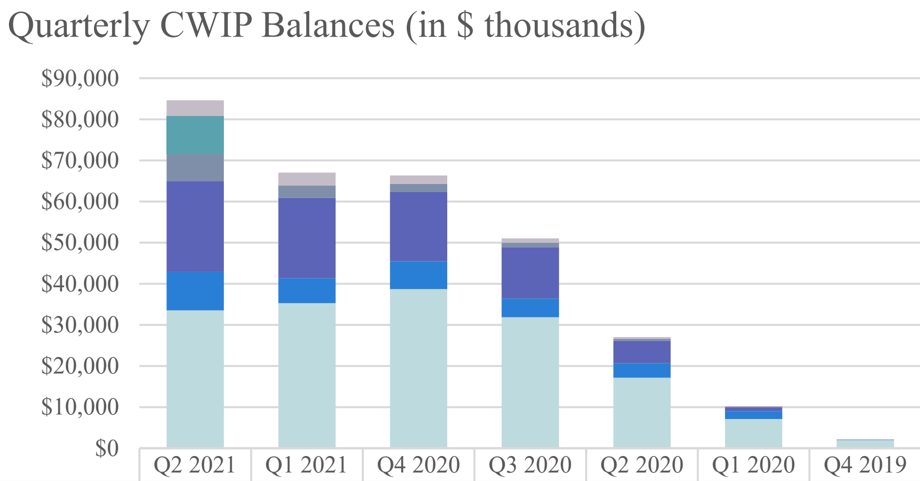
As of June 30, 2021, the ES 2 Program CWIP balance was $84.6 million, compared to $67.0 million as of March 31, 2021. The largest components of as of the end of the second quarter of 2021 were the Waverly ($6.2 million), Leonia ($5.6 million), and Academy Street ($5.4 million) substations, as well as the Paramus substation Electric Stipulated Base lifecycle project ($5.4 million), and work associated with ADMS ($22.1 million). The Electric Station Flood Mitigation subprogram comprises the largest component of total end of period CWIP outstanding, as depicted in **Figure 1 – ES 2 CWIP as of June 30, 2021** below.

Figure 1 – ES 2 CWIP as of June 30, 2021



In addition, the **Figure 2 – ES 2 CWIP Balances by Subprogram as of June 30, 2021** below depicts the composition of end-of-quarter CWIP balances by subprogram for the second and first quarters of 2021, each quarter of 2020, and the fourth quarter of 2019.

Figure 2 – ES 2 CWIP Balances by Subprogram as of June 30, 2021



	Q2 2021	Q1 2021	Q4 2020	Q3 2020	Q2 2020	Q1 2020	Q4 2019
Gas Stipulated Base	$3,808	$3,143	$2,057	$1,031	$449	$160	$29
Electric Stipulated Base	$9,280	$-	$-	$-	$-	$-	$-
Gas M&R	$6,574	$2,981	$1,975	$1,118	$502	$131	$23
Grid Modernization - ADMS	$22,085	$19,600	$16,837	$12,502	$5,428	$969	$36
Grid Modernization - Comm. System	$9,343	$6,026	$6,760	$4,529	$3,508	$1,908	$75
Electric Station Flood Mitigation	$33,531	$35,299	$38,727	$31,860	$17,149	$7,101	$1,987

Transfers from CWIP to plant in-service totaled $17.2 million during the second quarter of 2021, mainly comprised of $11.1 million of assets at the Ridgefield substation. Total ES 2 Program transfers from CWIP have been $34.6 million through June 30, 2021. It should be noted that work related to certain assets, such as the reclosers under the Contingency Reconfiguration subprogram, generally can be completed without being recorded through CWIP. As such, no Allowance for Funds Used During Construction (AFUDC) is recorded on these expenditures. This accounting treatment is fully in accord with generally accepted accounting principles and the Company's accounting policies.

3. Allowance for Funds Used During Construction (AFUDC)

The amount of quarterly AFUDC recorded by the Company for each Energy Strong subprogram during the second and first quarters of 2021, total AFUDC for the years 2020 and 2019, and total ES 2 Program AFUDC accrued to date, is shown below in **Table 6 – ES 2 Program AFUDC as of June 30, 2021**.

Table 6 – ES 2 Program AFUDC as of June 30, 2021

Subprogram	Q2 2021	Q1 2021	Total 2020	Total 2019 (Q4)	Total AFUDC
	(in $ thousands)				
Electric Station Flood Mitigation	**$576.7**	**$558.6**	**$936.5**	**$9.9**	**$2,081.7**
Contingency Reconfiguration	**$0**	**$0**	**$0**	**$0**	**$0**
Grid Modernization – Communications	**$95.5**	**$59.0**	**$184.3**	**$0.2**	**$339.0**
Grid Modernization – ADMS	**$316.9**	**$274.2**	**$352.7**	**$0.1**	**$943.9**
Electric Stipulated Base	**$80.5**	**$49.6**	**$44.0**	**$0**	**$174.1**

Subprogram	Q2 2021	Q1 2021	Total 2020	Total 2019 (Q4)	Total AFUDC
	(in $ thousands)				
Gas M&R Station Upgrades (incl. Stip. Base)	**$107.6**	**$72.2**	**$70.0**	**$0.2**	**$250.0**
Total	**$1,177.2**	**$1,013.6**	**$1,587.5**	**$10.4**	**$3,788.7**

During the first quarter of each year, the AFUDC rate is reviewed for possible reset as it applies to the current year based on updated capital structure and component cost data. For the year 2021, the new AFUDC rate was calculated to be 6.81%, using the capital structure and component costs as of January 31, 2021. This rate is lower than the 2020 rate of 6.95%, primarily due to a significantly lower interest rate used for short-term debt in the AFUDC calculation, and also to a reduction in the Company's embedded cost of long-term debt. In calculating the 2021 AFUDC rate, the Company used (i) a 3.85% embedded cost of long-term debt (vs. 4.02% in 2020), (ii) a short-term debt rate of 0.32% (vs. 1.86% in 2020), and (iii) a cost of equity of 9.60% (unchanged from 2020).

Subsequent to the annual reset calculation referred to above, and during the course of each year, the AFUDC rate is also recalculated as it applies to each fiscal quarter. If the recalculated rate changes by 25 basis points from the rate then in effect, the rate is reset and retroactively applied to January 1 of that year. For the second quarter of 2021, based on data as of June 30, 2021, the recalculated weighted average AFUDC accrual rate (6.83%) did not meet this criterion to warrant changing from the annual rate (6.81%) in effect. Therefore, AFUDC was accrued during the second quarter of 2021 at the calculated rate of 6.81%.

AFUDC accrued for ES 2 projects during the second quarter of 2021 increased over AFUDC accrued during the first quarter of 2021 as the result of increases in total average CWIP balances for almost all subprograms.

The IM observes that the Company's calculation of the AFUDC rate and its application is in accordance with both PSE&G's accounting policy and Plant Instruction 3(17) of the Federal Energy Regulatory Commission's Uniform Systems of Accounts prescribed for public utilities.

The IM also notes that the relevant AFUDC information as it relates to second quarter 2021 ES 2 project costs is consistent with the applicable dictates of the Stipulation entered into with respect to these ES 2 projects. The IM will continue to review future ES 2 Program AFUDC accruals for consistency with relevant provisions of the Stipulation for accounting and reporting purposes only, and not as a party to, or in expressing an opinion concerning, any rate proceedings.

4. Allocated Overheads

PSE&G follows a philosophy of allocating overhead costs, whether at the Service Company or from utility support organizations, to the operating company or unit receiving the benefit, and ultimately, if appropriate, settling costs to individual assets. Where possible, services are charged directly to the entity receiving the benefit, but where direct charging of costs is not feasible, cost allocations from the Service Company to operating companies are prescribed in a BPU-approved schedule issued pursuant to a BPU order in July 2003. The Stipulation requires the Company to follow its current practices with regard to capitalized overheads.

For the ES 2 Program electric and gas distribution projects, allocated overhead costs should primarily come from utility-related labor costs associated with administrative and supervisory personnel, labor and other costs associated with bargaining unit personnel, fringe benefits, materials handling costs, payroll taxes and depreciation expense. Shown below in **Table 7 – ES 2 Program Overhead Allocations as of June 30, 2021** are the allocated overhead costs charged to ES 2 projects for the first and second quarters of 2021, the total 2021 year-to-date, total 2020, total 2019 (the fourth quarter of 2019), and total ES 2 Program allocated overheads to date.

Table 7 – ES 2 Program Overhead Allocations as of June 30, 2021

Subprogram	Q2 2021	Q1 2021	2021 Year-to-Date	Total 2020	Total 2019 (Q4)	Total Overhead Allocations
		(in $ thousands)				
Electric Station Flood Mitigation	**$4,352**	**$5,588**	**$9,940**	**$14,023**	**$287**	**$24,250**
Contingency Reconfiguration	**$4,006**	**$4,215**	**$8,221**	**$17,109**	**$3,415**	**$28,745**
Grid Modernization – Communications	**$2,506**	**$1,743**	**$4,249**	**$3,625**	**$12**	**$7,886**
Grid Modernization – ADMS	**$124**	**$119**	**$243**	**$426**	**$11**	**$680**
Electric Stipulated Base	**$287**	**$126**	**$413**	**$259**	**$0**	**$672**
Gas M&R Station Upgrades (incl. Stip. Base)	**$119**	**$131**	**$250**	**$291**	**$15**	**$556**
Total*	**$11,393**	**$11,922**	**$23,316**	**$35,733**	**$3,740**	**$62,788**

The overwhelming majority of overhead costs allocated to ES 2 projects during the second quarter of 2021 are costs allocated from areas that support all utility distribution and transmission projects, including ES 2 projects. More specifically, most of the second quarter allocated costs reflect labor costs of supervisory, administrative and operations planning personnel, labor and other costs from bargaining unit personnel, and fringe benefits associated with these labor costs. The changes in overhead costs for the second quarter 2021 from the first quarter of 2021 largely reflect more bargaining unit grid modernization labor in the second quarter, and the periodic fluctuations in certain costs, such as outside services, which receive no overhead surcharges.

As noted in the IM's Report for the First Quarter of 2021, the Company revised its overhead surcharging methodology in the first quarter of 2020 by, among other things, consolidating the number of overhead surcharge cost pools from 38 cost pools based on geographic/organizational bases to three statewide/functional cost pools and one materials handling pool. This change resulted in one-time charges to several ES 2 projects recorded only for that quarter, and which were included in the figures provided in the IM's report. The IM believes the amounts allocated to ES 2 projects reflect application of the same surcharge methodology as amounts charged for non-ES 2 projects.

D. System Performance

1. Current Reporting Quarter Major Events

During the second quarter of 2021, there was one Major Event reported in PSE&G's service territory concerning a load shedding event at the Montclair Substation. As this Major Event was non-weather related and did not involve ES 2 investments there is no additional information for the IM to report on this Major Event.

III. Project Status

A. Electric Station Flood Mitigation

A summary of the subprogram plan as of the end of the second quarter of 2021 is provided below in **Table 8 – ES 2 Electric Station Flood Mitigation Subprogram Milestone Schedule as of June 30, 2021**.

Table 8 – ES 2 Electric Station Flood Mitigation Milestone Schedule as of June 30, 2021

Project	Plan Status Point	2019		2020				2021				2022				2023					2024
		Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4		
1. Academy Street	Dec. 2019		KO					C					IS		CO					*December 31, 2023 - ES 2 Program End Date*	
	Dec. 2020		KO		C							IS		CO							
	Jun. 2021		KO		C						IS			CO							
2. Clay Street	Dec. 2019	*Schedule Under Development*																			
	Dec. 2020			KO							C								IS		CO (Q2)
	Jun. 2021			KO							C				IS						CO (Q2)
3. Front Street^	Dec. 2019	*Not in ES 2 Program*																			
	Dec. 2020	*Not in ES 2 Program*																			
	Jun. 2021								KO				C						IS		CO (Q2)
4. Hasbrouck Heights	Dec. 2019		KO						C						IS		CO				
	Dec. 2020		KO									C					IS		CO		
	Jun. 2021		KO									C				IS					CO (Q1)
5. Kingsland	Dec. 2019			KO				C			IS		CO								
	Dec. 2020			KO										C					IS		CO (Q2)
	Jun. 2021			KO											C				IS		CO (Q2)
6. Lakeside Avenue	Dec. 2019*				KO				C										IS		CO (Q2)
	Dec. 2020						KO							C					IS		CO (Q2)
	Jun. 2021						KO							C					IS		CO (Q4)
7. Leonia	Dec. 2019	*Schedule Under Development*																			
	Dec. 2020			KO		C									IS		CO				
	Jun. 2021			KO		C								IS			CO				
8. Market Street	Dec. 2019			KO				C	OS		CO										
	Dec. 2020			KO					C	OS		CO									
	Jun. 2021			KO						C/OS			CO								

Project	Plan Status Point	2019		2020				2021				2022				2023					2024
		Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4		
9. Meadow Road	Dec. 2019	*Schedule Under Development*																		*Dec. 31, 2023 - ES 2 Program End Date*	
	Dec. 2020			KO											C				IS		CO (Q2)
	Jun. 2021			KO											C			IS			CO (Q2)
10. Orange Valley	Dec. 2019	*Schedule Under Development*																			
	Dec. 2020					KO										C					IS (Q1); CO (Q3)
	Jun. 2021					KO										C			IS		CO (Q3)
11. Ridgefield 13kV	Dec. 2019			KO	C										IS		CO				
	Dec. 2020			KO	C										IS		CO				
	Jun. 2021			KO	C										IS			CO			
12. Ridgefield 4kV	Dec. 2019			KO						C	OS			CO							
	Dec. 2020			KO	C				OS		CO										
	Jun. 2021			KO	C				OS		CO										
13. State Street	Dec. 2019		KO					C								IS					CO (Q1)
	Dec. 2020		KO						C				IS								CO (Q1)
	Jun. 2021		KO						C					IS							CO (Q1)
14. Toney's Brook	Dec. 2019			KO						C									IS		CO (Q2)
	Dec. 2020			KO										C			IS				CO (Q2)
	Jun. 2021			KO										C			IS				CO (Q2)
15. Waverly	Dec. 2019	*Schedule Under Development*																			
	Dec. 2020			KO			C												IS		CO (Q2)
	Jun. 2021			KO			C														IS (Q4); CO (Q2 2025)
16. Woodlynne	Dec. 2019		KO												C				IS		CO (Q2)
	Dec. 2020		KO												C				IS		CO (Q2)
	Jun. 2021		KO												C				IS		CO (Q2)

Legend: KO = Kickoff; C = Construction; IS = Fully In-Service (major assets in-service); OS = Out-of-Service (if eliminated); CO = Closeout
-Actuals are indicated with an underline (Note: for the Market Street and Ridgefield 4kV projects, outside plant construction began in the first quarter of 2020, the construction milestone indicated on this chart reflects inside plant construction).
***-The Dec. 2019 Lakeside Avenue project schedule was based on the original raise and rebuild mitigation strategy; the current schedule reflects the proposed mitigation method change that contemplates relocating the substation.**
^-The Front Street project was proposed by PSE&G during the second quarter of 2021 to replace the cancelled Constable Hook project.

A summary of the subprogram status as of the end of the second quarter of 2021 is provided below **Table 9 – ES 2 Electric Station Flood Mitigation Summary Status as of June 30, 2021**.

Table 9 – ES 2 Electric Station Flood Mitigation Summary Status as of June 30, 2021

Activity	Total # of Projects	Specific Projects
Kickoff Meeting	16	Academy Street; Clay Street; Front Street; Hasbrouck Heights; Kingsland; Lakeside Avenue; Leonia; Market Street; Meadow Road; Orange Valley; Ridgefield 13kV; Ridgefield 4kV; State Street; Toney's Brook; Waverly; Woodlynne

Activity	Total # of Projects	Specific Projects
Key Drawing Review	15	Academy Street; Clay Street; Hasbrouck Heights; Kingsland; Lakeside Avenue; Leonia; Market Street; Meadow Road; Orange Valley; Ridgefield 13kV; Ridgefield 4kV; State Street; Toney's Brook; Waverly; Woodlynne
Scope Locked	15	Academy Street; Clay Street; Hasbrouck Heights; Kingsland; Lakeside Avenue; Leonia; Market Street; Meadow Road; Orange Valley; Ridgefield 4kV; Ridgefield 13kV; State Street; Toney's Brook; Waverly; Woodlynne
Major Equipment Purchase Orders (POs)	16*	Academy Street; Clay Street; Hasbrouck Heights; Kingsland; Lakeside; Leonia*; Meadow Road; Orange Valley; Ridgefield 13kV*; State Street; Toney's Brook; Waverly*; Woodlynne
A/E Contract Award (or selection of PSE&G internal engineering)	16	Academy Street[1]; Clay Street[1]; Front Street[3]; Hasbrouck Heights[1]; Kingsland[2]; Lakeside Avenue[3]; Leonia[2]; Market Street[2]; Meadow Road[2]; Orange Valley[1]; Ridgefield 13kV[2]; Ridgefield 4kV[2]; State Street[2]; Toney's Brook[3]; Waverly[3]; Woodlynne[1]
Construction Start**	6	Academy Street; Leonia; Market Street; Ridgefield 4kV; Ridgefield 13kV; Waverly
In-Service	2^	Market Street; Ridgefield 4kV

**-Three of the listed projects (Leonia, Ridgefield 13kV, and Waverly) have two switchgears, thus the current count reflects 16 switchgears at 13 substations.*
[1]-Indicates Burns & McDonnell is serving as the A/E.
[2]-Indicates PSE&G internal resources are serving as the A/E.
[3]-Indicates Black & Veatch is serving as the A/E.
***-Includes inside plant and/or OP construction.*
^-The Ridgefield 4kV and Market Street projects completed their 4kV to 13kV conversions, while the Market Street project has a final in-service activity associated with the 26kV reconfiguration that is forecasted for September 2021.

Beyond the key activities summarized in **Table 9** above, **Table 10 – ES 2 Electric Station Flood Mitigation Upcoming Activities for Q3 2021** summarizes the planned activities for each project during the third quarter of 2021, including any carryover of activities from earlier periods.

Table 10 – ES 2 Electric Station Flood Mitigation Upcoming Activities for Q3 2021

Station	Upcoming Activities for Q3 2021	Carryover Activities from Q2 2021
1. Academy Street	• Continued engineering and construction	• Continued engineering and construction
2. Clay Street	• Continued engineering	• Continued engineering
3. Constable Hook	*Removed from the ES 2 Program*	
4. Hasbrouck Heights	• Contingency plan control drawings issued for construction (IFC)	• Continued engineering
5. Kingsland	• Commence license and permitting design	• Continued engineering
6. Lakeside Avenue	• Submit site plan application • Vendor drawings received (final switchgear arrangement)	• Continued engineering
7. Leonia	• Continued engineering and construction • Start commissioning of 13kV switchgear #1	• Continued engineering and construction
8. Market Street	• Final in-service date (26kV reconfiguration) • Start civil and electrical demolition	• Continued construction
9. Meadow Road	• Continued engineering	• Continued engineering
10. Orange Valley	• Continued engineering	• Continued engineering

Station	Upcoming Activities for Q3 2021	Carryover Activities from Q2 2021
11. Ridgefield 13kV	• Phase 1 electrical construction start • Phase 1 civil construction complete • Phase 2 electrical construction PO issued	• Continued engineering and construction
12. Ridgefield 4kV	• Completed electrical construction (OP) • Start civil and electrical demolition	• Start electrical demolition
13. State Street	• 70% estimate completed • Switchgear delivered	• 70% estimate completed • Continued engineering and construction
14. Toney's Brook	• Major licenses and permits issued	• Continued engineering
15. Waverly	• Updated license and permitting package for site plan; special hearing requested • Continued engineering	• Continued engineering
16. Woodlynne	• 70% estimated completed	• 70% estimate completed • Continued engineering
17. Front Street	• Switchgear PO issued • Permit compliance matrix completed • Scope document approved	• None

The current project estimates, including base and R&C amounts, is shown below in **Table 11 – ES 2 Electric Station Flood Mitigation Project Cost Status as of June 30, 2021**. **Table 11** also shows the current estimate level based on PSE&G's estimating processes and as approved by the URB, the actual spend, and percentage of actuals to estimate as of the end of the second quarter of 2021.

Table 11 – ES 2 Electric Station Flood Mitigation Project Cost Status as of June 30, 2021

Project	Estimate Level	Base	Risk & Contingency	Total	Current Forecast	Actuals to Date	% of Actuals to Estimate
1. Academy Street	Definitive	$9,800,000	$700,000	$10,500,000	$9,704,216	$5,159,731	49%
2. Clay Street	Conceptual	$30,300,000	$3,500,000	$33,800,000	$30,822,360	$2,156,501	6%
3. Constable Hook	*Removed from ES 2 Program**						
3. Front Street	Study	$23,000,000	$4,400,000	$27,400,000	$24,472,716	$190,915	1%
4. Hasbrouck Heights	Conceptual	$20,500,000	$2,200,000	$22,700,000	$20,307,880	$2,020,326	9%
5. Kingsland	Study	$5,400,000	$2,900,000	$8,300,000	$6,418,540	$381,286	5%
6. Lakeside Avenue	Study	$39,400,000	$8,500,000	$47,900,000	$39,356,279	$956,178	2%
7. Leonia	Conceptual	$25,000,000	$2,500,000	$27,500,000	$25,007,945	$13,034,343	47%
8. Market Street	Definitive	$25,200,000	$1,700,000	$26,900,000	$29,385,009	$23,514,129	87%
9. Meadow Road	Study	$7,200,000	$1,800,000	$9,000,000	$7,397,100	$786,103	9%

Project	Estimate Level	Base	Risk & Contingency	Total	Current Forecast	Actuals to Date	% of Actuals to Estimate
10. Orange Valley	Study	$16,000,000	$4,200,000	$20,200,000	$15,240,393	$594,041	3%
11. Ridgefield 13kV	Conceptual	$25,300,000	$2,300,000	$27,600,000	$25,515,519	$13,319,925	48%
12. Ridgefield 4kV	Definitive	$18,500,000	$1,000,000	$19,500,000	$21,202,217	$18,751,152	96%
13. State Street	Study	$19,300,000	$3,100,000	$22,400,000	$19,053,000	$1,193,633	5%
14. Toney's Brook	Conceptual	$16,200,000	$2,600,000	$18,800,000	$16,254,329	$963,752	5%
15. Waverly	Study	$29,400,000	$6,000,000	$35,400,000	$35,070,653	$6,062,028	17%
16. Woodlynne	Study	$15,800,000	$3,600,000	$19,400,000	$21,255,000	$1,519,097	8%
Subprogram Total		**$326,300,000**	**$51,000,000**	**$377,300,000**	**$346,463,155**	**$90,603,138**	**24%**
-As of the end of the second quarter of 2021, the cancelled Constable Hook project had an estimate of $5.3 million and had incurred $133,616 in spend that will be removed from the ES 2 Program, the estimated costs and actual spend for Constable Hook is not included in **Table 11**.*							

Findings & Observations

- Six of the sixteen Electric Station Flood Mitigation projects had movement in the forecasted in-service date during the second quarter of 2021, with two advancing and four slipping. Of these six projects, four of the projects (Market Street, Ridgefield 4kV, Ridgefield 13kV, and Orange Valley) had forecasted in-service dates change by less than two weeks. The Clay Street forecasted in-service date advanced 50 days from the status as of the end of the first quarter of 2021. Only one project (Waverly) had movement more than 60 days, which saw the in-service date slip an additional 92 days from the forecasted in-service date at the end of the prior quarter, which continues to reflect the impacts of the project's site plan denial in March 2021.
- The Ridgefield 4kV project became the first in the subprogram to be placed fully in-service, with the in-service date achieved on May 16, 2021.
- Five projects had new estimates approved by the URB during the second quarter of 2021, including: the Clay Street project advancing to the Conceptual level with a new estimate of $33.8 million (decreasing $8.2 million from the prior estimate); the Hasbrouck Heights project advancing to the Conceptual level with a new estimate of $22.7 million (increasing $4.7 million from the prior estimate); the Leonia project advancing to the Conceptual level with a new estimate of $27.5 million (decreasing $4.7 million from the prior estimate); the Ridgefield 13kV project advancing to the Conceptual level with a new estimate of $25.5 million (increasing $2.1 million from the prior estimate); and the State Street project with a new Study level estimate that reflects the scope change that removed the OP portion of the project (added as a life cycle station upgrade project) and resulted in a new estimate of $22.4 million (decreasing $22.7 million from the prior estimate).

- The IM has found nothing to date that would jeopardize the subprogram being completed on budget. However, the status of the later projects in this subprogram, and in particular Waverly, will have to continue to be closely followed to monitor if the projects can be completed within the ES 2 Program window. As of the end of the second quarter of 2021, the Waverly project shows a final in-service date in December 2024. The Waverly project has multiple major asset in-service dates for the 26kV switchgear, 4kV switchgear, and three transformers, which are currently forecasted from December 2022 (26kV switchgear) to December 2024 (Transformer #3). PSE&G has informed the IM that the project team has every intention of improving the in-service dates and will be examining the potential to shorten durations and/or work activities concurrently to pull the final in-service date back into 2023.

1. Academy Street

During the second quarter of 2021, $405,843 was spent on the Academy Street project compared to a forecast of approximately $373,000, which brought the total spend to approximately $5.2 million. The forecasted in-service date for the Academy Street project continues to remain October 25, 2021, which is unchanged from the previous quarter.

The primary activity conducted during the first quarter of 2021 on the Academy Street project was the continued advancement of construction activities. Construction, which started in July 2020 for non-permit work on Academy Street, advanced 10% during the second quarter to reach 75% complete inside plant (100% complete OP), while the total project is reported at 84% complete as of the end of the second quarter of 2021.

The actual spend by quarter for Academy Street as compared to the current approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022
Actuals				*Forecast*		
$150,398	$4,224,550	$378,939	$405,843	$912,107	$1,531,237	$2,101,141

Actuals to Date	Estimate	% of Actuals to Estimate
$5,159,731	$10,500,000	49%

2. Clay Street

During the second quarter of 2021, $595,723 was spent on the Clay Street project compared to a forecast of approximately $639,000, which brought the total spend to approximately $2.2 million. The forecasted in-service date for the Clay Street project advanced from February 7, 2023, as of the end of the first quarter of 2021 to December 19, 2022, as of the end of the second quarter of 2021.

The primary activities on the Clay Street project during the second quarter of 2021 included the IFC release of civil drawings (foundation) and electrical and control drawings. The project team also submitted an updated estimate that transitioned to the 70%/Conceptual level with a total estimate of $33.8 million that represented a $8.2 million decrease from the prior estimate. The $8.2 million reduction was driven by a $3.7 million reduction to R&C based on the current risk profile for the project and a $4.5 million reduction to the base estimate, which was the result of:

- Scope change for wastewater wall: -$6.8 million[1]
- Engineering contract lower than previously estimated: -$0.5 million
- Environmental costs higher than previously estimated: $0.3 million
- Revised commissioning estimate: $0.4 million
- Revised Division cutover estimate: $0.5 million
- Switchgear equipment award higher than estimated: $1.6 million

While the updated estimate resulted in a $8.2 million decrease from the prior estimate, the total forecast for the project increased from $29.8 million as of the end of the first quarter of 2021 to $30.8 million as of the end of the second quarter of 2021. This $1.0 million forecast increase was driven by higher than previously estimated cutover costs based on an updated estimate from the Division ($0.5 million) and an increase in surcharge rates based on the 2020 surcharge methodology ($0.5 million).

The actual spend by quarter for Clay Street as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2024
Actuals				*Forecast*		
$116,409	$879,339	$565,030	$595,723	$1,387,173	$8,023,416	$19,255,270

Actuals to Date	Estimate	% of Actuals to Estimate
$2,156,501	$33,800,000	6%

3. Front Street

As discussed in the IM 2020 Fourth Quarter Report, the Constable Hook project was removed from the ES 2 Program. During the second quarter of 2021, PSE&G presented the Front Street project as a replacement for the cancelled Constable Hook project within the Electric Station Flood Mitigation subprogram. The Front Street substation was originally constructed in 1957 and much of its equipment is the originally installed equipment, which contributed to the substation ranking in the worst 33% of all distribution substations (as of April 2019). While the scope of this proposed project involves life cycle upgrades, it also has a flood mitigation component as the new equipment will be installed in accordance with flood hazard rules (where the existing equipment is situated two feet below the New Jersey Department of Environmental Protection (NJDEP) flood hazard area level). The Front Street project saw its Study level estimate approved by the URB in April 2021, with a total estimate of $27.4 million, comprised of a base estimate of $23.0 million and R&C set at $4.4 million. The IM understands that as of the fourth quarter of 2021 the formal regulatory process of adding this substation to the ES 2 Program continues.

The actual spend by quarter for Front Street as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2024
Actuals				*Forecast*		
$0	$0	$0	$190,915	$360,764	$322,538	$23,598,499

[1] The ROD on this change was discussed in the IM 2020 Fourth Quarter Report, Section IV.A.

Actuals to Date	Estimate	% of Actuals to Estimate
$190,915	$27,400,000	1%

4. Hasbrouck Heights

During the second quarter of 2021, $189,748 was spent on the Hasbrouck Heights project compared to a forecast of approximately $193,000, which brought the total spend to approximately $2.0 million. The forecasted in-service date for the Hasbrouck Heights project continues to remain February 7, 2023, which is unchanged from the previous quarter. Notable activities completed during the second quarter of 2021 included:

- Electrical construction PO issued;
- Control drawings IFC; and,
- Construction permits issued.

During the second quarter of 2021, the project team also submitted an updated estimate that transitioned to the Conceptual estimate level with a total estimate of $22.7 million that represented a $4.7 million increase from the prior estimate. The $4.7 million increase was the result of a $0.9 million reduction to R&C based on the current risk profile for the project and a $5.6 million increase to the base estimate, which was the result of:

- 4kV switchgear awards higher than estimated: $1.6 million;
- Civil construction bids higher than estimated: $1.2 million;
- Higher dewatering estimate: $1.2 million;
- Relay Tech estimate increased based on revised breakers quantity: $1.0 million; and,
- Change in T&D surcharge methodology: $0.6 million (comprised of $0.1 million in outside services electrical construction and $0.5 million in internal labor).

The actual spend by quarter for Hasbrouck Heights as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals				*Forecast*		
$149,848	$1,129,934	$550,795	$189,748	$896,791	$4,584,100	$12,806,663

Actuals to Date	Estimate	% of Actuals to Estimate
$2,020,326	$22,700,000	9%

5. Kingsland

During the second quarter of 2021, $36,886 was spent on the Kingsland project compared to a forecast of $56,000, which brought the total spend to $381,285. The forecasted in-service date for the Kingsland project continues to remain October 4, 2023, which is unchanged from the previous quarter. There continued to be minimal activities performed on this project during the second quarter of 2021.

The actual spend by quarter for Kingsland as compared to the current approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals				*Forecast*		
$104,112	$209,667	$30,621	$36,886	$253,489	$196,262	$5,587,504

Actuals to Date	Estimate	% of Actuals to Estimate
$381,285	$8,300,000	5%

6. Lakeside Avenue

During the second quarter of 2021, $174,268 was spent on the Lakeside Avenue project compared to a forecast of approximately $125,000. Notable activities completed during the second quarter of 2021 included the issuance of the licensing and permitting package.

The actual spend by quarter for Lakeside Avenue as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2024
Actuals				*Forecast*		
$148,943	$453,994	$178,973	$174,268	$102,867	$212,444	$38,084,790

Actuals to Date	Estimate	% of Actuals to Estimate
$956,177	$47,900,000	2%

7. Leonia

During the second quarter of 2021, approximately $4.1 million was spent on the Leonia project compared to a forecast of approximately $4.2 million, which brought the total spend to approximately $13.0 million. Notable activities completed during the second quarter of 2021 included:

- Control drawings IFC;
- Construction permits issued;
- Civil construction (phase 2) started;
- Demolition of first existing 13kV switchgear started;
- Installation of pipe piles started;
- Switchgear delivered to site and set; and,
- Electrical construction (phase 2) started.

Construction at Leonia, which started in August 2020, has advanced to 57% complete inside plant as of the end of the second quarter of 2021, up from 38% complete as of the end of the prior quarter, with the total project reported at 64% complete.

At the end of the first quarter of 2021 the Conceptual level estimate was developed by the project team, this estimate was approved by the URB in April 2021 and resulted in the total estimate for the project being reduced to $27.5 million from $32.2 million. The reduction in the current estimate was the result of:

- Construction awards lower than estimated: -$4.4 million;
- Change in T&D surcharge methodology: $1.2 million (comprised of $0.6 million in outside services electrical construction and $0.6 million in internal labor); and,

- Higher design and engineering hours than estimated: $0.5 million.

In addition, the R&C amount was reduced by $2.0 million based on the current risk profile for the project.

The actual spend by quarter for Leonia as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals				*Forecast*		
$44,792	$6,033,379	$2,809,628	$4,146,544	$1,188,203	$1,827,066	$8,958,332

Actuals to Date	Estimate	% of Actuals to Estimate
$13,034,343	$27,500,000	47%

8. Market Street

During the second quarter of 2021, $3,147,454 was spent on the Market Street project compared to a forecast of approximately $3.4 million, which brought the total spend to approximately $23.5 million. Notable activities completed during the second quarter of 2021 included the commencement and completion of OP 4kV to 13kV conversion work, which puts the Market Street project partially in-service with the final in-service forecasted for September 2021 when the 26kV reconfiguration work is completed (see additional discussion on the Market Street in-service date within **Section IV.A.**).

Construction at Market Street, which started in August 2020, advanced to 90% complete OP as of the end of the second quarter of 2021, up from 75% as of the end of the prior quarter. Inside plant construction is anticipated to being in September 2021 and the overall project is reported at 77% complete as of the end of the second quarter of 2021.

The total forecast for the Market Street project increased from $26.1 million as of the end of the first quarter of 2021 to $29.3 million as of the end of the second quarter of 2021. This forecast increase was driven by additional OP overhead and restoration work along with the associated material and surcharges based on the complexity of the work and the field conditions, including higher than estimated traffic control costs as per city/county requirements.

The actual spend by quarter for Market Street as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022
Actuals				*Forecast*		
$251,193	$16,079,601	$4,035,880	$3,147,454	$3,764,648	$1,076,627	$1,029,606

Actuals to Date	Estimate	% of Actuals to Estimate
$23,514,128	$26,900,000	87%

9. Meadow Road

During the second quarter of 2021, $70,220 was spent on the Meadow Road project compared to a forecast of $84,000, which brought the total spend to approximately $786,000. While preliminary design work progressed during the second quarter of 2021, there continued to be minimal other activities on the

Meadow Road project during the second quarter of 2021, with the bulk of this project's activities planned for 2022-2023.

The actual spend by quarter for Meadow Road as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2024
Actuals				*Forecast*		
$63,128	$535,081	$117,672	$70,220	$69,000	$76,000	$6,465,998

Actuals to Date	Estimate	% of Actuals to Estimate
$786,102	$9,000,000	9%

10. Orange Valley

During the second quarter of 2021, $146,827 was spent on the Orange Valley project compared to a forecast of approximately $69,000, which bought the total spend to approximately $594,000. The variance in first quarter spend was primarily the result of the key drawing package being completed early (anticipated for July and completed in June). Other activities completed during the second quarter of 2021 included the issuance of license and permitting packages and the award of the switchgear PO, with the bulk of this project's activities planned for 2022-2023.

The actual spend by quarter for Orange Valley as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2024
Actuals				*Forecast*		
$77,029	$362,895	$7,291	$146,827	$103,425	$115,980	$14,426,947

Actuals to Date	Estimate	% of Actuals to Estimate
$594,041	$20,200,000	3%

11. Ridgefield 13kV

During the second quarter of 2021, $3,665,283 was spent on the Ridgefield 13kV project compared to a forecast of approximately $3.6 million, which brought the total spend to approximately $13.3 million. Notable activities completed during the second quarter of 2021 included:

- Civil construction (phase 2) bid and PO issued;
- Demolition of first existing 13kV switchgear;
- Phase 1/2 electrical permits issued;
- Switchgear delivered to site;
- Controls drawings IFC; and,
- Piles installation commenced.

Construction at Ridgefield 13kV advanced to 58% complete inside plant as of the end of the second quarter of 2021, compared to 33% complete at the end of the prior quarter, with the total project at a reported 62% completion.

During the second quarter of 2021, the project team also submitted an updated estimate that transitioned to the Conceptual estimate level with a total estimate of $27.6 million that represented a $2.1 million increase from the prior estimate. The $2.1 million increase was the result of a $3.6 million reduction to R&C based on the current risk profile for the project and a $5.7 million increase to the base estimate, which was the result of:

- Procuring contingency switchgear and associated miscellaneous material and cutover work: $2.4 million;
- Change in T&D surcharge methodology: $1.7 million (comprised of $0.6 million in outside services electrical construction and $1.1 million in internal labor);
- Construction supervision and support based on scope and duration: $0.8 million;
- Phase 1 civil construction award higher than estimated: $0.4 million; and,
- Permanent switchgear awards higher than estimated: $0.4 million.

The actual spend by quarter for Ridgefield 13kV as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals				*Forecast*		
$205,982	$6,232,692	$3,215,967	$3,665,283	$2,435,520	$1,548,363	$8,211,711

Actuals to Date	Estimate	% of Actuals to Estimate
$13,319,925	$27,600,000	48%

12. Ridgefield 4kV

During the second quarter of 2021, $4,559,439 was spent on the Ridgefield 4kV project compared to a forecast of approximately $4.1 million, which brought the total spend to approximately $18.8 million. The variance in spend this quarter was driven by additional cable, splicing and labor required as a result of rerouting two underground circuits around an existing gas main and the need to rebuild secondary buses in order to complete four 13kV conversions, which was partially offset by part of the Division's paving work postponed until July due to township work-hour restrictions. Activities completed during the second quarter of 2021 on the Ridgefield 4kV project included the commencement and completion of 4kV to 13kV conversion work, with the project being placed in-service as of May 16, 2021. The total project is reported at 85% complete as of the end of the second quarter of 2021, up from 81% complete as of the end of the prior quarter.

The total forecast for the Ridgefield 4kV increased from $18.8 million as of the end of the first quarter of 2021 to $21.2 million as of the end of the second quarter of 2021. This forecast increase was driven by additional engineering and overhead labor required to remove primary wires and complete the 4-13kV conversions; the contract for manhole rebuild work was awarded higher than estimated; and additional labor and material required to rebuild several secondary buses and reroute two underground circuits around an existing gas main that was not known at the time of the prior estimate.

The actual spend by quarter for Ridgefield 4kV as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022
Actuals				*Forecast*		
$143,414	$11,239,534	$2,808,765	$4,559,439	$1,931,069	$459,997	$60,000

Actuals to Date	Estimate	% of Actuals to Estimate
$18,751,152	$19,500,000	96%

13. State Street

During the second quarter of 2021, $216,479 was spent on the State Street project compared to a forecast of approximately $178,000, which brought the total spend to approximately $1.2 million. The activities performed on State Street during the second quarter of 2021 included the issuance of construction permits and civil and electrical construction POs awarded.

A new Study level estimate was submitted and approved by the URB during the second quarter of 2021. This updated estimate reduced the total project estimate from $45.1 million to $22.4 million, driven by the release of $19.7 million in base and $3.0 million of R&C following the OP scope change that will see that scope of work funded under a new project. The OP work associated with the State Street project, estimated at $22.7 million, is now part of the Electric Stipulated Base (see **Section II.E.5.**).

The State Street scope within the Electric Station Flood Mitigation subprogram involves the relocation of the State Street substation from its current site to the new location identified at Cooper Street. The State Street OP scope being executed under the Electric Stipulated Base involves the extensive underground installation required to connect the new 4kV circuits back to the existing 4kV circuits and to maintain the current capacity of these circuits. PSE&G informed the IM that discussions it had with BPU Staff and Rate Counsel regarding the mitigation change on the State Street project resulted in the decision to recover the increased cost for the State Street project stemming from the change in mitigation method (then estimated at $16.5 million) in the Company’s next rate case as opposed to the ES 2 accelerated recovery. PSE&G’s view is that while these increased costs on State Street are prudent and can and should be recovered by way of the accelerated recovery mechanism, it will in this one circumstance defer its request for recovery and credit the additional cost associated with the State Street OP scope toward the Company’s stipulated base requirements for the ES 2 Program.

The actual spend by quarter for State Street as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals				*Forecast*		
$77,590	$662,148	$237,415	$216,479	$6,071,171	$1,473,376	$10,314,820

Actuals to Date	Estimate	% of Actuals to Estimate
$1,193,633	$22,400,000	5%

14. Toney’s Brook

During the second quarter of 2021, $289,769 was spent on the Toney’s Brook project compared to a forecast of approximately $400,000, which brought the total spend to approximately $1.0 million. The variance in spend this quarter was driven by the civil/layout issued for review (IFR) milestone not completed in June as assumed, however there was no resulting change to the forecasted in-service date. Notable activities completed during the second quarter of 2021 included the release of civil and electrical IFC drawings.

The actual spend by quarter for Toney's Brook as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2024
Actuals				*Forecast*		
$211,940	$373,096	$88,947	$289,769	$195,119	$211,127	$14,884,332

Actuals to Date	Estimate	% of Actuals to Estimate
$963,751	$18,800,000	5%

15. Waverly

During the second quarter of 2021, $2,837,893 was spent on the Waverly project compared to a forecast of approximately $3.1 million, which brought the total spend to approximately $6.1 million. The majority of the actual spend during the second quarter of 2021 was associated with the delivery of the 26kV switchgear in April 2021 ($2.3 million), with the remaining spend in the quarter related to project support costs (Project Management, licensing and permitting) of $0.2 million, engineering costs of $0.2 million, and A/E procured equipment of $0.15 million. The variance in second quarter forecasted to actual spend was largely driven by material shortages (conduit) that pushed the start of Metro Division activities into the third quarter.

As reported in the IM 2021 First Quarter Report, the project team requested a special meeting to maintain the project's schedule, which was held in March 2021. The Newark Planning Board denied the site plan application at this meeting, which requires the project team to prepare a new site plan application. The revised site plan continued to be developed through the second quarter of 2021, including receiving feedback from the community at outreach meetings held this quarter. Due to the site plan not being approved in the March 2021 meeting, the entire project has shifted out, including pushing the in-service date from the fourth quarter of 2023 to the fourth quarter of 2024 (for transformer #3, which is the final asset). PSE&G is continuing to look at opportunities to reduce the activity durations and pull the schedule back.

Construction at Waverly, which started in October 2020, was paused with the site plan denial and remains at 6% complete as of the end of the second quarter of 2021.

The total forecast for the Ridgefield 4kV increased from $33.8 million as of the end of the first quarter of 2021 to $35.0 million as of the end of the second quarter of 2021. This forecast increase was driven by higher carrying costs based on the extended project duration stemming from the initial site plan denial, along with additional engineering and licensing and permitting costs related to performing the required site plan revisions.

The actual spend by quarter for Waverly as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2025
Actuals				*Forecast*		
$103,748	$2,460,815	$659,572	$2,837,893	$498,727	$573,923	$27,935,974

Actuals to Date	Estimate	% of Actuals to Estimate
$6,062,028	$35,400,000	17%

16. Woodlynne

During the second quarter of 2021, $132,630 was spent on the Woodlynne project compared to a forecast of approximately $122,000, which brought the total spend to approximately $1.5 million. Notable activities completed during the second quarter of 2021 included the issuance of construction permits and civil and electrical POs issued.

The total forecast for the Woodlynne increased from $18.3 million as of the end of the first quarter of 2021 to $21.2 million as of the end of the second quarter of 2021. This forecast increase was driven by higher than previously estimated civil construction work, which was slightly offset by lower in-house engineering costs and lower than estimated costs of piles procurement.

The actual spend by quarter for Woodlynne as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2024
Actuals				*Forecast*		
$110,982	$993,298	$282,187	$132,630	$1,215,299	$1,247,199	$17,273,405

Actuals to Date	Estimate	% of Actuals to Estimate
$1,519,097	$19,400,000	8%

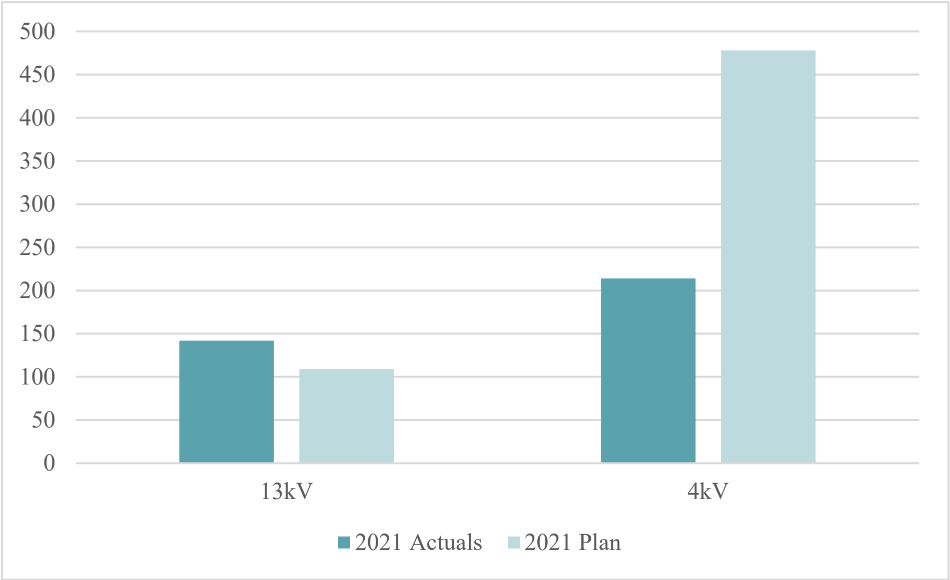
B. Contingency Reconfiguration

During the second quarter of 2021, work continued to progress in the Contingency Reconfiguration subprogram with all four Divisions continuing to install reclosers with a total of 193 installed during the quarter and 179 commissioned. **Table 12 – ES 2 Program Recloser Status as of June 30, 2021** provides a summary of the recloser aspect of the Contingency Reconfiguration subprogram, indicating the current status of engineering, installation, and commissioning; while **Figure 3 – 2021 Recloser Installations as of June 30, 2021** compares the installed reclosers as of the end of the second quarter of 2021 against PSE&G's 2021 installation plan.

Table 12 – ES 2 Program Recloser Status as of June 30, 2021

Type	Engineering Packages Completed (1 recloser ea.)			Reclosers Installed			Reclosers Commissioned		
	Q2 Qty.	*2021 Total*	*Program Total*	*Q2 Qty.*	*2021 Total*	*Program Total*	*Q2 Qty.*	*2021 Total*	*Program Total*
13kV	94	146	845	95	142	803	85	136	780
4kV	111	188	442	98	214	371	94	210	367
Total	205	334	1,287	193	356	1,174	179	346	1,147

Figure 3 – 2021 Recloser Installations as of June 30, 2021



As shown in **Table 13** and **Figure 3**, PSE&G continued to maintain progress during the second quarter of 2021 and stayed on track for the 2021. As discussed in the IM 2021 First Quarter Report, there was an identified resource constraints within the Metro Division that stemmed from attrition at the end of the year and two larger projects in the Division with firm in-service dates, leading to a shortage of approximately 30 full-time equivalents compared to normal. While new hires have been brought on board, they will not be able to work on crews until their training is completed. To mitigate impacts, PSE&G engaged a contractor to perform the pole settings from the recloser scope, which commenced early in the second quarter of 2021. As also shown in **Figure 3**, the 2021 installation plan shifts the focus primarily to the 4kV reclosers from the 13kV reclosers that were prioritized in 2020. However, actual installations of 13kV reclosers will continue above the initial 2021 plan due to the change in reclosers planned for the subprogram following PSE&G's review, which resulted in an additional 275 13kV reclosers and 90 4kV reclosers (also discussed in Section IV.A.1. of the IM 2021 First Quarter Report and **Section II.A.1.** of this IM 2021 Second Quarter Report).

The Fuse Saver pilot program commenced in November 2020 and was primarily completed in January 2021.[2] In total, this phase of the Fuse Saver pilot program included the installation and commissioning of 80 Fuse Saver devices. As noted in the IM 2020 Second Quarter Report, PSE&G's Asset Management group determined a pilot program would be initiated prior to the full scope to ensure these new devices work as intended. During execution of the pilot program, PSE&G observed factors that will help it prepare for execution of the full Fuse Saver scope, including installation specifications (the remote control unit (RCU) must be placed directly below the Fuse Saver to avoid communications issues), and cost elements for some of the locations (new poles, traffic control, etc.). While monitoring performance of the installed Fuse Savers, PSE&G experienced other communication issues between the Fuse Savers and the RCU, wherein the SCADA communication indicated a false open/close alarm on some of the devices. Siemens has provided a prototype Fuse Saver to address the communication issues, which PSE&G will

[2] In the second quarter of 2021, PSE&G decided to install the remaining 34 Fuse Savers in its inventory to capture additional cost and performance data to better inform the planning and execution of the full scope of work. These installations were completed across the second and third quarters of 2021.

monitor to ensure it addresses the issues prior to placing additional orders. Because of this, the full Fuse Saver scope is no longer anticipated to commence in 2021, as it awaits approval by PSE&G's Asset Management group to proceed with the full scope, aside from the installation of additional units from existing stock. A final decision on the Fuse Saver scope is expected to be made before the end of 2021.

The current forecasted final in-service dates for the primary components that make up the Contingency Reconfiguration subprogram are provided in **Table 13 – ES 2 Contingency Reconfiguration Forecasted Completion Dates as of June 30, 2021**. This table also shows the forecasted dates as of the end of the first quarter of 2021 to show movement to the forecast as of the end of the second quarter of 2021.

Table 13 – ES 2 Contingency Reconfiguration Forecasted Completion Dates as of June 30, 2021

Scope & Division		Q1 2021 Forecasted Completion Date	Q2 2021 Forecasted Completion Date
Reclosers	Central	12/31/2021	1/31/2022
	Metro	12/31/2021	1/31/2022
	Palisades	11/30/2021	10/31/2021
	Southern	12/31/2021	1/31/2022
Fuse Savers	Central	12/30/2023	12/30/2023
	Metro	12/30/2023	12/30/2023
	Palisades	12/30/2023	12/30/2023
	Southern	12/30/2023	12/30/2023

As shown in **Table 13**, the forecasted final in-service date for each Division's Fuse Saver program remained constant as PSE&G continues its evaluation of the Fuse Saver pilot program before making a final scope decision. While the recloser scope of work saw minor movement across each Division (three slipping one month, one advancing one month from the prior quarter), which was driven by the current scope and status in each Division.

The Contingency Reconfiguration subprogram costs through the end of the second quarter of 2021 are presented in **Table 14 – ES 2 Contingency Reconfiguration Costs as of June 30, 2021**.

Table 14 – Contingency Reconfiguration Costs as of June 30, 2021

Scope & Division		2019	2020	Q1 2021	Q2 2021	Total to Date	Forecast	% of Actuals to Forecast
		Actuals						
Reclosers	Central	$2,737,167	$12,050,820	$3,007,686	$2,392,608	$20,188,282	$25,054,781	81%
	Metro	$2,231,431	$10,726,610	$587,396	$4,051,716	$17,597,154	$23,888,564	74%
	Palisades	$2,515,569	$12,119,436	$3,109,037	$2,591,672	$20,335,714	$23,161,122	88%
	Southern	$2,081,220	$12,405,684	$5,008,143	$4,065,891	$23,560,938	$28,952,061	81%
Fuse Savers	Central	$9,970	$789,937	$375,811	$107,384	$1,283,102	$12,463,404	10%
	Metro	$7,557	$561,915	$216,511	$89,860	$875,843	$11,526,731	8%
	Palisades	$7,468	$522,454	$133,552	$63,808	$727,282	$8,833,380	8%
	Southern	$9,792	$859,014	$65,018	$56,845	$990,669	$13,190,192	8%
Total		**$9,600,174**	**$50,035,871**	**$12,503,156**	**$13,419,784**	**$85,558,985**	**$147,070,235**	**58%**

Findings & Observations:

- PSE&G continued to maintain progress during the second quarter of 2021 and stayed on track for the 2021, assisted by the engagement of a pole setting contractor to alleviate resource constraints in the Metro Division.
- As previously reported, 80 Fuse Saver devices were installed as part of the pilot program for these devices. PSE&G is monitoring the performance of these initial devices after encountering communication issues on approximately 10% of the installed units. The solution developed with Siemens utilizes an external antenna to improve communications.
- The forecasted completion of the recloser scope of this subprogram saw some adjustment during the second quarter of 2021 with most Divisions seeing an approximate one month slip to the completion of the recloser scope, other than the Palisades Division that saw the 13kV recloser completion date improve by 30 days and no change to the 4kV recloser completion date, and the 4kV completion date for the Southern Division, which slipped 92 days based on the engineering package readiness (specifically for tie reclosers). For the Fuse Savers, there was no change to the forecasted completion dates during the second quarter of 2021 while PSE&G continues to assess its final decision on the scope of this work.
- The Contingency Reconfiguration subprogram forecast remained fairly constant as of the end of the second quarter, with a slight decrease of approximately $1.9 million from the first quarter of 2021. This was largely driven by a net 14-unit reduction in the number of 13kV reclosers planned based on the current status of the network.

C. Grid Modernization – Communication System

The Stipulation identified the Grid Modernization – Communication System subprogram to include up to $72 million invested in installing a private wireless communications network to eliminate the use of dedicated phone lines for remote communication for both PSE&G and customer equipment. The overall network will provide coverage using both wireless and fiber technologies to all switching devices on the PSE&G system.

As reported in the IM 2020 Second Quarter Report, PSE&G made the strategic decision to focus on new recloser installations and has delayed the ramp-up in retrofit installations from August 2020 to January 2021 due to resource constraints. No overall impacts are expected from this decision and PSE&G plans to regain the planned retrofit installations by the middle of 2021 as it shifts focus from new recloser installations to the retrofit reclosers. During the second quarter of 2021, retrofit installations continued to ramp up with 684 installations completed during the quarter against a target of 680. In total, 1,432 retrofit reclosers have been installed on the Program through the end of the second quarter out of a total program forecast of 2,364 (which is periodically reviewed and updated).

As previously reported, the fiber scope includes installing fiber to electric substations and electric operations centers, in addition to cutting over stations with existing fiber service to the PSE&G fiber network. PSE&G preliminarily identified 41 installation projects and 12 cutovers for the subprogram, with two of 41 installation projects since removed due to the scheduled elimination of the targeted substations (see additional post-second quarter of 2021 information on the approved fiber projects in **Section IV.B.**). The list of identified fiber installation and cutover projects is presented in **Table 15 – Fiber Projects by Division**.

Table 15 – Fiber Projects by Division

Division	Fiber Installation	Fiber Cutover
Central	Cranford; Elizabeth Sub HQ; Rahway; Hadley Road HQ; Roselle; Central HQ; Carteret; Edison; Keasby; Mechanic Street; First Street; Lehigh Avenue	Elizabeth; Henry Street
Metro	East Orange; Metro HQ; Bloomfield; Central Avenue; Haldeon; Irvington; Irvington Sub HQ; Montclair; South Orange; Norfolk Street; Waverly	-
Palisades	Bergen Point; Hackensack Sub HQ; Fort Lee; Harrison; Ridgewood; West New York; Palisades HQ; Culver Avenue; Morgan Street; Howell Street	Tonnelle Avenue; Spring Valley Road; Union City; Fairview; Polk Street; West Orange
Southern	Southern HQ; Princeton; Chauncey Street; Bordentown; Haddon Heights; Thirty Second Street	Delair; East Riverton; Riverside; Mount Holly
Total	***39 projects***	***12 projects***

During the second quarter of 2021, one additional fiber installation projects (Roselle) was placed in-service. This brought the total projects in-service as of the end of the second quarter of 2021 to nine for the fiber installation projects and eight for the fiber cutover projects. **Table 16 – ES 2 Program Fiber Projects Status as of June 30, 2021** provides a summary of the status of the fiber installation and cutover projects within the subprogram as of the end of the second quarter of 2021 and the projects in italics represent those placed in-service.

Table 16 – ES 2 Program Fiber Projects Status as of June 30, 2021

Project Name	Q2 2021 Status	Budget*	Forecast**
Fiber Installation Projects			
Bergen Point	*In-Service (Q1 2021)*	$750,000	$701,459
Bloomfield	Continued construction	$300,000	$1,482,687
Bordentown	Inside plant (IP) civil construction completed	$0	$682,285
Carteret	OP construction mobilized; IP civil construction completed	$0	$753,816
Central Ave	IP IFC issued	$480,000	$112,759
Central HQ	IP IFC issued; OP IFC issued	$570,000	$1,800,274
Chauncey Street	OP IFC issued	$840,000	$875,395
Cranford	*In-Service (Q4 2020)*	$300,000	$357,876
Culver Ave	Preliminary engineering	$0	$832,145
East Orange	*In-Service (Q1 2021)*	$480,000	$1,143,568
Edison	Preliminary engineering	$0	$1,070,066
Elizabeth Sub HQ	*In-Service (Q1 2021)*	$555,000	$749,712
First Street	OP construction completed; IP IFC issued	$300,000	$618,118
Fort Lee	Continued construction	$480,000	$1,263,941
Hackensack Sub HQ	*In-Service (Q4 2020)*	$825,000	$595,412
Haddon Heights	Preliminary engineering	$0	$738,942
Hadley Rd HQ	IP civil construction completed	$0	$1,460,786
Haledon	IP IFC issued; OP construction mobilized	$300,000	$567,567
Harrison	IP construction mobilized	$300,000	$576,805
Howell Street	Preliminary engineering [see also updated status in **Section IV.B.**]	$0	$0
Irvington	OP construction mobilized	$300,000	$174,633
Irvington Sub HQ	OP IFC issued; OP Construction mobilized	$300,000	$601,657
Keasbey	Preliminary engineering	$840,000	$784,856

Project Name	Q2 2021 Status	Budget*	Forecast**
Lehigh Avenue	Preliminary engineering	$0	$818,014
Mechanic Street	Preliminary engineering	$1,200,000	$925,256
Metro HQ	*In-Service (Q1 2021)*	$300,000	$582,568
Montclair	OP IFC issued	$840,000	$2,147,782
Morgan Street	IP IFC issued; IP construction mobilized; OP IFC issued	$0	$518,181
Norfolk St	IP IFC issued	$300,000	$186,265
Palisades HQ	Continued construction	$255,000	$409,690
Princeton	OP construction completed	$300,000	$1,132,137
Rahway	*In-Service (Q1 2021)*	$390,000	$1,026,601
Ridgewood	OP IFC issued	$390,000	$483,367
Roselle	*In-Service (Q2 2021)*	$390,000	$428,183
So Orange	OP IFC issued; OP construction mobilized; OP construction completed	$390,000	$312,099
Southern HQ	*In-Service (Q4 2020)*	$570,000	$708,350
Thirty Second Street	Preliminary engineering	$0	$0
Waverly	Preliminary engineering; project being rescheduled to align with the completion of the new control house as part of the Waverly substation project under the Electric Station Flood Mitigation subprogram.	$300,000	$439,640
West New York	IP IFC issued	$300,000	$997,565
Fiber Cutover Projects*			
Delair	*In-Service (Q4 2020)*	$50,000	$117,340
East Riverton	*In-Service (Q4 2020)*	$50,000	$117,340
Elizabeth	*In-Service (Q1 2021)*	$50,000	$215,592
Fairview	Completion dependent upon Fort Lee fiber installation project (tentative start of construction in September 2021)	$50,000	$89,786
Henry St	Battery rack installation pending; site visit with Central Division scheduled	$50,000	$215,592
Mount Holly	*In-Service (Q4 2020)*	$50,000	$117,340
Polk Street	Completion dependent upon West New York fiber installation project (engineering in progress)	$50,000	$89,786
Riverside	*In-Service (Q4 2020)*	$50,000	$117,340
Spring Valley Rd	*In-Service (Q1 2021)*	$50,000	$89,786
Tonnelle Ave	*In-Service (Q4 2020)*	$50,000	$89,786
Union City	*In-Service (Q1 2021)*	$50,000	$89,786
West Orange	Completion dependent upon redundant link to Montclair substation being ready (two redundant fiber links required for each router to support reliability guidelines)	$50,000	$56,866
Substation Remote Terminal Unit (RTU) Cutovers			
Scope: 204 units	5 cutovers completed	$1,540,000	$1,929,597

**-The fiber projects with $0 budgets were not part of the original project list and were added to the subprogram following PSE&G's review of the fiber requirements and status of all its substations and operation centers (see Section IV.A. of the IM 2020 Third Quarter Report), subject to the availability of funds.*
***-The forecast data is the current forecast information received as of the date of this report (i.e. it reflects the forecast as of early 2022). For the projects with a $0 forecast, these have been either identified for removal (Howell Street) or were projects identified as potential additions to the subprogram that are unlikely to advance due to lack of additional funds (Thirty Second Street).*
****-The cutover projects have budgets authorized and tracked by Division. Thus, costs for each station are calculated by taking the budget/forecast for a Division and dividing by the number of stations in the scope for that Division.*

During the second quarter of 2021, updated estimates for the wireless network and retrofits scope (Conceptual level estimate) and for the fiber installation and substation cutover scope (Study level estimate) were approved by the URB. The wireless network and retrofits scope saw its total estimate decrease from $48.6 million as originally approved to $35.1 million. This $13.5 million reduction was driven by the selection of FirstNet as the wireless network vendor in lieu of the original plan to build a solely owned and operated private network.[3] The fiber installation and substation cutover scope saw its total estimate increase from $23.4 million to $27.5 million. This $4.1 million increase was the result of a comprehensive review of the fiber requirements and status of all PSE&G substations and Operations Centers that refined the scope based on current communication needs from what was identified in the original ES 2 filing.

The Grid Modernization – Communication System subprogram costs through the end of the second quarter of 2021 are presented in **Table 17 – ES 2 Grid Modernization – Communication System Costs as of June 30, 2021**.

Table 17 – ES 2 Grid Modernization – Communication System Costs as of June 30, 2021

Scope & Division		2019	2020	Q1 2021	Q2 2021	Total to Date	Forecast	% of Actuals to Forecast
		Actuals						
Retrofit Reclosers	Central	$0	$884,278	$1,067,295	$1,027,602	$2,979,175	$6,872,724	43%
	Metro	$0	$818,620	$436,089	$683,893	$1,938,602	$5,762,666	34%
	Palisades	$0	$825,174	$754,869	$965,416	$2,545,459	$6,349,520	40%
	Southern	$0	$929,058	$956,444	$1,005,852	$2,891,354	$7,124,742	41%
Fiber	Central	$1,691	$2,418,851	$796,586	$1,349,407	$4,566,535	$7,790,984	59%
	Metro	$1,457	$1,866,697	$340,713	$831,337	$3,040,204	$7,230,419	42%
	Palisades	$1,582	$2,046,762	$248,558	$725,030	$3,021,932	$4,822,458	63%
	Southern	$4,731	$910,483	$645,219	$1,029,156	$2,589,590	$3,569,301	73%
	Cutovers*	$0	$876,502	$323,458	$86,115	$1,286,075	$2,945,462	44%
Wireless Network		$74,306	$6,035,441	$287,086	$312,404	$6,709,236	$7,909,532	85%
Bulk Purchase**		$0	$1,524,874	$450,013	($154,037)	$1,820,850	$0	-
Total		**$83,767**	**$19,136,741**	**$6,306,330**	**$7,862,176**	**$33,389,011**	**$60,377,806**	**78%**

**-Includes fiber communication cutovers and substation RTU cutovers (the latter of which began having spend in Q1 2021).*
***-The Bulk Purchase account is used for the purchase of bulk equipment, which is the then assigned to a specific Division when the equipment is released with a credit back to the Bulk Purchase account. Thus, this account is forecasted to have a $0 balance at the end of the ES 2 Program.*

Findings & Observations:

- During the second quarter of 2021, retrofit installations continued to advance following the ramp-up earlier in 2021 with 685 installations completed during the quarter against a target of 680. In total, 1,432 retrofit reclosers have been installed on the Program through the end of the second quarter of 2021 out of a total program forecast of 2,364 (which continues to be periodically reviewed and updated).
- One additional fiber installation project was placed in-service during the second quarter of 2021, bringing the total number of projects in-service to nine fiber installation projects and eight fiber cutover projects.
- An updated Grid Modernization – Communication System subprogram estimate was approved by the URB during the second quarter of 2021, which resulted in the wireless network & retrofits

[3] See related discussion in Section II.A.1. of the IM 2020 Third Quarter Report.

estimate decreasing by $13.5 million to $35.1 million, driven by the savings realized in the wireless network vendor selection. The fiber scope estimate increased $4.1 million to $27.5 million, which was driven by an updated review of the fiber and communication requirements and current status of all PSE&G substations and Operations Centers. Collectively with the updated estimate to the Grid Modernization – ADMS subprogram, there was no net change to the total estimate of the two Grid Modernization subprograms (after the addition of $1.7 million as a placeholder for future subprogram needs).

D. Grid Modernization – ADMS

The Grid Modernization – ADMS scope is split between three primary sections: Distribution Management System (DMS)/Distributed Energy Resource Management System (DERMS), the Outage Management System (OMS), and ADMS platform upgrades. The primary activities in 2021 are focused on the continued development of the systems and platforms that comprise this subprogram.

The scope for each primary component of the Grid Modernization – ADMS subprogram and notable activities conducted during the second quarter of 2021 are presented as follows:

DMS/DERMS

- Scope: Provide software and associated services to deploy a Smart Network in order to meet a subset of the ES 2 Program's objectives and use cases.
- Q2 2021 Activities:
  - Reviewed program development system configuration.
  - Conducted 3rd party interface requirement meetings.
  - Received AMI and weather interface software and license pricing.
  - Conducted factory acceptance testing activities.
- Forecasted Completion as of the end of the second quarter of 2021: 12/9/2022.

OMS

- Scope: Provide a single user interface for more efficient management of trouble orders and analysis of outage data through an integrated OMS, system interfaces, and geographic view of all integrated outage data through an integrated OMS, system interfaces, and geographic view of all integrated outage data and damage locations. OMS will include tolls for dynamic visualization supporting incident management, damage location identification, dashboards, and the as-operated real-time view of PSE&G's network model. Field personnel also will have access to many of these tools as it relates to the incident(s) assigned to them via the Compass mobile crew application. 10 years' worth of existing OMS data will be migrated into the new system as well.
- Q2 2021 Activities:
  - Completed legacy data for conversion requirements.
  - Completed Power BI training session.
  - Conducted feedback sessions with Divisions.
  - Conducted design review workshops.
  - Reviewed list of reports to finalize reporting requirements.
  - Drafted damage assessment process and design.
- Forecasted Completion as of the end of the second quarter of 2021: 12/2/2022.

ADMS Platform

- Scope: Replace, enhance, and expand the existing Distribution Supervisory Control and Data acquisition (DSCADA) platform elements inclusive of infrastructure components (servers and workstations) and applications (Monarch, Spectra, and Integra) to create an integrated ADMS platform.
- Q2 2021 Activities:
  - Approved test lead candidate for cognizant.
- Forecasted In-Service as of the end of the second quarter of 2021: 12/10/2021.

During the second quarter of 2021, the Grid Modernization – ADMS subprogram transitioned to a Conceptual level estimate that was approved by the URB at $42.7 million, an increase of $7.7 million from the prior $35.0 million estimate. The increase was primarily the result of a more refined scope, including:

- Increased interface and hardware architecture requirements identified since the original ES 2 filing ($5.4 million); and,
- Increased performance testing scope requirements as a result of lessons learned from Tropical Storm Isaias ($2.3 million).[4]

The Grid Modernization – ADMS subprogram costs through the end of the second quarter of 2021 are presented in **Table 18 – ES 2 Grid Modernization – ADMS Costs as of June 30, 2021**.

Table 18 – ES 2 Grid Modernization – ADMS Costs as of June 30, 2021

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022
Actuals				*Forecast*		
$36,213	$16,447,624	$2,488,980	$2,168,187	$2,916,157	$3,477,015	$15,178,439

Actuals to Date	Forecast	% of Actuals to Forecast
$21,141,005	$42,712,616	49%

Findings & Observations:

- The resource constraints continue to be monitored by PSE&G but have not led to additional issues. During the second quarter of 2021 a new ADMS test lead was also brought on board.
- The Grid Modernization – ADMS forecast increased approximately $2.3 million during the second quarter of 2021 from the end of the first quarter of 2021. This was also reflected in an updated estimate for the subprogram, with this increase driven by additional performance testing scope requirements and an extended schedule as a result of lessons learned from Hurricane Isaias. Likewise, the forecasted completion date for the OMS scope shifted from May 2022 to December 2022 based on the lessons learned.

E. Electric Stipulated Base

The Stipulation identified that the electric portion of the Stipulated Base include $100 million in investments at PSE&G's discretion towards electric OP higher design and construction standards and/or

[4] See related discussion in Section IV.A.2. of the IM 2021 First Quarter Report and in **Section II.A.2.** of this IM 2021 Second Quarter Report.

electric stations life cycle subprograms described in the original ES 2 filing.[5] The bulk of OP higher design and construction standards work is planned to commence in January 2022, which will involve the hardening of selected 13kV circuits with poor storm performance by changing the construction standard from cross-arm open wire to spacer cable construction. In accordance with what the Stipulation provides, PSE&G plans to fund some of the life cycle station upgrades from the electric program accelerated investment, subject to funds available, after all Electric Station Flood Mitigation projects are funded at their final costs.

As reported in the IM 2020 Second Quarter Report, the initial four stations PSE&G selected for life cycle station upgrades went before the URB in June 2020 for Study level estimate approval and received approval for full funding. In the second quarter of 2021 a fifth station, State Street, was approved by the URB for its OP scope to be transferred from the related Electric Station Flood Mitigation project to the life cycle scope. These five stations and their current estimate compared to the actuals to date are provided in **Table 19 – ES 2 Life Cycle Station Upgrade Project Status as of June 30, 2021**.

Table 19 – ES 2 Life Cycle Station Upgrade Project Status as of June 30, 2021

Project	Estimate Level	Base	Risk & Contingency	Total	Actuals to Date	% of Actuals to Estimate	Forecasted In-Service Date*
1. Hamilton	Study	$14,500,000	$3,700,000	$18,200,000	$1,000,011	6%	10/12/2022
2. Paramus	Study	$14,800,000	$5,400,000	$20,200,000	$5,376,035	27%	11/15/2022 (↓)
3. Plainfield	Study	$18,400,000	$4,200,000	$22,600,000	$1,264,500	6%	10/20/2022 (↓)
4. Woodbury	Study	$15,400,000	$3,300,000	$18,700,000	$1,447,528	8%	12/27/2022
5. State Street (OP)	Study	$19,700,000	$3,000,000	$22,700,000	$17,633	0%	3/15/2023

**-Reflects the in-service date of the last major asset (e.g. switchgear), certain activities may take place after this date to support the final in-service date (i.e. when all customers are cutover).*
(↑)-*Indicates the forecasted in-service date advanced from the prior quarter.*
(↓)-*Indicates the forecasted in-service date slipped from the prior quarter.*

As shown in **Table 19**, of the four prior life cycle station upgrade projects, both the Paramus and Plainfield projects saw a slight slip of 8 and 14 days, respectively, to the forecasted in-service date. Given the relatively small magnitude of these changes, the IM has not performed additional schedule analyses on these projects but will continue to monitor for potential trends. The State Street OP project has its initial forecasted in-service date set for March 15, 2023. Additional details on each of these life cycle station upgrade projects is provided in the individual subsections that follow.

Findings & Observations:

- The primary activities during the second quarter of 2021 continued to center around advancing the engineering and procurement for the life cycle station upgrade projects. The Paramus project also became the first of these stations to commence construction.

[5] As noted in the Stipulation, the electric life cycle upgrades are part of the electric Stipulated Base to be recovered in the Company's next base rate case provided the investments are found to be prudent. The Stipulation also notes that should the 16 stations that comprise the Electric Station Flood Mitigation subprogram be completed for under the $389 million allocated for that subprogram, PSE&G may reallocate such unused funds to stations identified in the life cycle station upgrade portion of PSE&G's petition for accelerated recovery.

- The Hamilton and Woodbury projects saw their forecasts increase by 11% and 19%, respectively, from the end of the first quarter of 2021. On Hamilton, the increase was driven by a higher than previously estimated civil construction costs; while on Woodbury, the increase was driven by updated estimates for electrical construction, testing and commissioning, wire checkers costs, Division support, and a correction to the total switchgear PO value. Despite these increases, the current forecasts for both projects remain below their respective estimates.
- There was minor movement to the forecasted in-service dates for the Paramus and Plainfield projects during the second quarter of 2021, with Paramus slipping 8 days and Plainfield slipping 14 days from the forecasted in-service date as of the end of the first quarter. Each of the original four life cycle station upgrade projects remains forecasted for completion in the fourth quarter of 2022.
- One new life cycle station upgrade project, State Street (OP), was added to the Electric Stipulated Base set of projects. This OP scope was originally part of the State Street project within the Electric Station Flood Mitigation subprogram but was split out in accordance with PSE&G's notice of mitigation change on the original State Street project.

1. Hamilton

During the second quarter of 2021, $400,855 was spent on the Hamilton project against a forecast of approximately $388,000. This brought total spend through the end of the second quarter of 2021 on the project to approximately $1.0 million. Notable activities conducted during the second quarter of 2021 included:

- Civil and electrical drawings IFC; and,
- Civil construction out for bid.

The actual spend by quarter for Hamilton as compared to the current URB approved estimate is provided below.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals				*Forecast*		
$0	$362,372	$236,783	$400,855	$1,044,531	$1,703,282	$12,455,452

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$1,000,011	$18,200,000	$16,203,276	6%

2. Paramus

During the second quarter of 2021, $4,176,989 was spent on the Paramus project against a forecast of approximately $4.1 million. This brought total spend through the end of the second quarter of 2021 on the project to approximately $5.4 million. Notable activities conducted during the second quarter of 2021 included:

- Civil construction start (contingency switchgear);
- Electrical construction PO issued and start of electrical construction; and,
- Partial 4kV contingency feeder rows delivered.

The actual spend by quarter for Paramus as compared to the current URB approved estimate is provided below.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2024
Actuals				*Forecast*		
$0	$840,200	$358,846	$4,176,989	$1,215,200	$1,314,500	$11,108,617

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$5,376,035	$20,200,000	$19,014,352	27%

3. Plainfield

During the second quarter of 2021, $367,543 was spent on the Plainfield project against a forecast of approximately $914,000. The variance between actual and forecasted spend was largely the result of Division work planned for June that was shifted to July-August due to weather constraints (which contributed to the 14-day slip in the in-service date noted above). This brought total spend through the end of the second quarter of 2021 on the project to approximately $900,000. Notable activities conducted during the second quarter of 2021 included civil and electrical drawings IFC.

The actual spend by quarter for Plainfield as compared to the current URB approved estimate is provided below.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2024
Actuals				*Forecast*		
$0	$682,325	$214,632	$367,543	$1,787,346	$1,202,569	$15,390,900

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$1,264,500	$22,600,000	$19,645,315	4%

4. Woodbury

During the second quarter of 2021, $356,225 was spent on the Woodbury project against a forecast of approximately $356,000. This brought the total spend on the project to approximately $1.4 million. Notable activities conducted during the second quarter of 2021 included:

- Planning board hearing and permits issued;
- Controls drawings IFC; and,
- Civil and electrical construction out for bid.

The actual spend by quarter for Woodbury as compared to the current URB approved estimate is provided below.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals				*Forecast*		
$0	$551,165	$540,138	$356,225	$228,137	$633,995	$15,590,340

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$1,447,528	$18,700,000	$17,900,000	6%

5. State Street (Outside Plant)

The scope of work for the State Street OP project is comprised of new 4kV OP underground and overhead distribution equipment including manholes and duct banks as required to connect the existing State Street 4kV circuits to the new State Street substation located at Cooper Street.

During the second quarter of 2021, $17,633 was spent on the State Street (OP) project against a forecast of approximately $128,000. This variance was primarily due an error that captured the forecast for July 2021 within the June 2021 forecast. This was the first quarter with spend on this project and the minimal spend to date was related to setting up the project and initial planning efforts.

The actual spend by quarter for State Street (OP) as compared to the current URB approved estimate is provided below.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals				*Forecast*		
$0	$0	$0	$17,633	$469,426	$145,608	$19,067,333

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$17,633	$22,700,000	$19,700,000	0%

F. Gas M&R Station Upgrades

Through the end of the second quarter of 2021, primary activities in the Gas M&R subprogram continued to focus on advancing the engineering at each station and other pre-construction activities such as reviewing scope and permit documents and performing noise and geotechnical studies. **Table 20 – ES 2 Gas M&R Summary Status as of June 30, 2021** below provides the currently approved estimates for each project within the Gas M&R subprogram, along with the actuals to date and forecasted in-service dates.

Table 20 – ES 2 Gas M&R Summary Status as of June 30, 2021

Project	Estimate Level	Base	Risk & Contingency	Total Estimate	Actuals	% of Actuals to Estimate	Forecasted In-Service
1. Camden*	Study	$24,300,000	$5,000,000	$29,300,000	$1,669,208	6%	Dec 2022
2. Central*	Study	$23,900,000	$5,100,000	$29,000,000	$1,182,818	4%	Dec 2022
3. East Rutherford	Study	$13,800,000	$2,700,000	$16,500,000	$1,128,559	7%	Dec 2022
4. Mount Laurel	Study	$9,400,000	$2,000,000	$11,400,000	$673,165	6%	Dec 2022
5. Paramus*	Study	$11,500,000	$2,200,000	$13,700,000	$828,841	6%	Dec 2023
6. Westampton	Definitive	$9,100,000	$900,000	$10,000,000	$4,736,632	47%	Dec 2021
Subprogram Total		**$92,000,000**	**$17,900,000**	**$109,900,000**	**$10,219,223**	**9%**	**Dec 2023**
**-Included in the Stipulated Base.*							
(↑)-Indicates the forecasted in-service date advanced from the prior quarter.							
(↓)-Indicates the forecasted in-service date slipped from the prior quarter.							

During the second quarter of 2021, the Westampton project saw its 70%/Conceptual level estimate internally approved in May 2021, followed by the URB approval of the 90%/Definitive level estimate in June 2021. The total estimate remains at $10.0 million, unchanged from the prior estimate for the project, but includes $0.8 million released from R&C to the base estimate. There were no changes to the forecasted in-service dates for the Gas M&R project in this period.

Findings & Observations:

- The primary efforts to date on the subprogram continue to be primarily related to pre-construction planning efforts, including the issuing material procurement POs, performing geotechnical tests and groundwater studies. The Westampton project became the first Gas M&R station to enter construction, which commenced in April 2021 and is forecasted to be complete by the end of the year. Engineering and procurement efforts continued to be a main focus of 2021 second quarter activities at the other stations.
- While still early in the subprogram, the IM has found nothing to date that would jeopardize the subprogram being completed on time and/or on budget. The Westampton project advanced through the Conceptual level estimate to have it Definitive level estimate approved by the URB in June 2021, which resulted in no net change to the project's estimate. The overall subprogram currently has a total forecast of $92 million, which remains under the Stipulation budget of $101 million.

1. Camden

During the second quarter of 2021, $290,839 was spent on the Camden project compared to a forecast of approximately $378,000, which brought the total spend to approximately $1.7 million. Continuing with the pre-construction efforts, during the second quarter of 2021 notable activities completed on the Camden project included:

- Completed geotechnical borings;
- Issued material procurement PO;
- Presented and received conditional zoning board approval; and,
- Received NJDEP Flood Hazard Area (FHA) permit.

The actual spend by quarter for Camden as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals				*Forecast*		
$13,326	$859,350	$505,693	$290,839	$1,695,488	$5,650,303	$15,285,001

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$1,669,208	$29,300,000	$24,300,000	6%

2. Central

During the second quarter of 2021, $190,109 was spent on the Central project compared to a forecast of approximately $247,000, which brought the total spend to approximately $1.2 million. Continuing with the pre-construction efforts, during the second quarter of 2021, notable activities completed on the Central project included:

- Received preliminary cathodic protection drawings for review;
- Issued material procurement PO;
- Completed 3D model review of station design;
- Submitted environmental key plan to township; and,
- Prepared construction bid package.

The actual spend by quarter for Central as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals				*Forecast*		
$6,869	$670,582	$315,258	$190,109	$2,636,014	$7,791,681	$12,289,486

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$1,182,817	$29,000,000	$23,900,000	4%

3. East Rutherford

During the second quarter of 2021, $260,112 was spent on the East Rutherford project compared to a forecast of approximately $245,000, which brought the total spend to approximately $1.1 million. Continuing the pre-construction efforts, during the second quarter of 2021 notable activities completed on the East Rutherford project included:

- Collected water samples for groundwater study and received groundwater study report; and,
- Received Licensing & Permitting drawing package.

The actual spend by quarter for East Rutherford as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals				*Forecast*		
$9,010	$521,865	$337,573	$260,112	$234,569	$985,999	$11,450,873

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$1,128,560	$16,500,000	$13,800,000	7%

4. Mount Laurel

During the second quarter of 2021, $149,682 was spent on the Mount Laurel project compared to a forecast of approximately $122,000, which brought the total spend to approximately $673,000. Continuing the pre-construction efforts, during the second quarter of 2021 notable activities completed on the Mount Laurel project included:

- Competed soft digs to confirm underground pipe locations;
- Completed page turn of 90% design drawings;
- Performed station boundary survey; and,
- Received information for bidders (IFB) construction drawing package.

The actual spend by quarter for Mount Laurel as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals				*Forecast*		
$5,965	$362,167	$155,351	$149,682	$441,985	$968,060	$7,316,791

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$673,166	$11,400,000	$9,400,000	6%

5. Paramus

During the second quarter of 2021, $129,694 was spent on the Paramus project compared to a forecast of approximately $142,000, which brought the total spend to approximately $829,000. Continuing the pre-construction efforts, during the second quarter of 2021 notable activities completed on the Paramus project included the issuance of the material procurement PO.

The actual spend by quarter for Paramus as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals				*Forecast*		
$8,842	$462,452	$277,854	$129,694	$123,989	$82,693	$10,464,477

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$828,841	$13,700,000	$11,500,000	6%

6. Westampton

During the second quarter of 2021, $3,217,496 was spent on the Westampton project compared to a forecast of approximately $3.0 million, which brought the total spend to approximately $4.7 million. Construction on the Westampton project commenced in April 2021, while other notable activities completed on the Westampton project during the second quarter of 2021 included:

- Started foundation work and completed data building foundation;
- Received fully executed interconnection agreement with Transco;
- Set data building on foundation;
- Received demolition permits;
- Completed successful hydrotest of all prefabricated piping;
- Completed asbestos remediation at existing regulator building; and,
- Received new regulator building.

During the second quarter of 2021, the project team internally approved the Conceptual level estimate in May 2021 and submitted an updated estimate to the URB in June 2021 that transitioned to the Definitive estimate level with a total estimate of $10.0 million that represented no net change to the total estimate but saw $0.8 million of R&C released into the base estimate. The $0.8 million increase in the base estimate was the result of:

- Increased construction costs based on revised environmental estimates and increased oversight duration ($0.4 million);
- Increased procurement costs based on POs issued ($0.3 million); and,
- Project management, design & engineering, and licensing & permitting adjustments ($0.1 million).

The actual spend by quarter for Westampton as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals				*Forecast*		
$8,395	$1,032,670	$478,072	$3,217,496	$2,252,945	$1,948,690	$161,734

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$4,736,632	$10,000,000	$9,100,000	47%

IV. Additional Information Following the End of the Second Quarter of 2021

While the vast majority of this IM report is focused on the activities and status of the ES 2 Program during the second quarter of 2021, the timing of certain Program elements and information provided by PSE&G naturally carried over beyond the end of the calendar quarter. Such information will generally be covered in the next IM quarterly report but given the importance of some of this information, the IM has provided additional remarks to provide a more complete view of the status of the ES Program based on the available information as of the date of this IM 2021 Second Quarter Report.

A. Market Street In-Service Date

As of the end of the second quarter of 2021, the Market Street in-service was forecasted for September 2021 when the 26kV equipment associated with the 26kV reconfiguration work was to be installed. Following the second quarter of 2021, engineering design was completed for the 26kV reconfiguration, which allowed PSE&G to determine that no new equipment was needed for the reconfiguration, and thus no further in-service date required for the Market Street project beyond the 4kV to 13kV OP conversion scope that was completed as of June 25, 2021.

B. Updated Fiber Projects

During the fourth quarter of 2021, PSE&G's DSCADA and Transmission Fiber Infrastructure (TFI) groups evaluated that the Howell Street fiber project would not provide the redundancy and resiliency benefits that the ES 2 Program aims to obtain, as the Howell Street substation shares a site with the Jerset City switching station that already has a TFI rack that links back to Howell Street, and thus the Howell Street project was removed from the ES 2 Program. This is consistent with the approach used by PSE&G for the fiber projects, which initially identified a pool of 41 fiber installations for the ES 2 Program and previously removed two projects where a future substation elimination is planned. At this time, PSE&G does not anticipate replacing the cancelled fiber projects with new fiber projects.

ENERGY STRONG PROGRAM
INDEPENDENT MONITOR
2021 SECOND QUARTER REPORT

APPENDIX A – DRAFT REPORT COMMENTS AND RESPONSES

MAY 5, 2022

PEGASUS GLOBAL HOLDINGS, INC. ®

Questions & Comments to the IM 2021 Second Quarter Report Formally Submitted to the IM

ID #	Question/Comment	IM Response	Report Changes
RCR-INF-1	With reference to page 3 of the Independent Monitor's Draft Second Quarter 2021 Report, please provide an update to the Waverly site plan approval process.	The Waverly site plan received unanimous approval during the City of Newark's Planning Board meeting on December 14, 2021. Normally, it would then be memorialized in the next meeting, however, the City attorney was out with Covid-19 at that time, which coupled with a backlog of applications resulted in it not being memorialized until the February 3, 2022 meeting.	No change
RCR-INF-2	With reference to page 3 of the Independent Monitor's Draft Second Quarter 2021 Report, please explain if the revised and delayed site plan for the Waverly substation will increase projected costs for the project.	As noted in the IM's 2021 First Quarter Report, PSE&G's preliminary office level estimate on the changes resulting from the revised site plan indicate an estimated cost increase of $2.6 million. This is comprised of: additional engineering ($0.8 million), revised fencing and external façade improvements ($1.0 million), and additional charges for extended project duration ($0.8 million).	No change
RCR-INF-3	With reference to page 5 of the Independent Monitor's Draft Second Quarter 2021 Report, please indicate how many of the 330 reclosers (177 13kV reclosers and 153 4kV reclosers) would be part of the Company's Poorest Performing Circuit program.	Of these 330 reclosers on 238 circuits identified for removal from the ES 2 Program, 54 circuits were part of the last two years Poorest Performing Circuit.	**Section II.A.1.**
RCR-INF-4	With reference to page 5 of the Independent Monitor's Draft Second Quarter 2021 Report, please indicate how many of the 330 reclosers (177 13 kV reclosers and 153 4kV reclosers) are part of some other program that is neither Energy Strong 2 nor the Poorest Performing Circuit program. Please identify the program(s).	Of these 330 recloser on 238 circuits identified for removal from the ES 2 Program, beyond the 54 circuits mentioned in response to RCR-INF-3 as part of the Poorest Performing Circuit initiative, 78 circuits received other reliability enhancements outside of the ES 2 Program.	**Section II.A.1.**
RCR-INF-5	With reference to page 5 of the Independent Monitor's Draft Second Quarter 2021 Report, please explain why the replacement reclosers are skewed towards 13kV reclosers.	The number and type of reclosers added to the Contingency Reconfiguration subprogram was the result of PSE&G's detailed review of 4kV and 13kV circuits that sought to identify cost effective opportunities to include additional circuits in the program in order to improve reliability by reducing the number of customers impacted by an outage and evaluated the options utilizing the same cost benefit process performed for the ES 2 filing.	No change

<table>
<tr><th>ID #</th><th>Question/Comment</th><th>IM Response</th><th>Report Changes</th></tr>
<tr><td>RCR-INF-6</td><td>With reference to page 5 of the Independent Monitor’s Draft Second Quarter 2021 Report, please describe the gaps in performance testing and the lessons learned by Hurricane Isaias.</td><td>Initially discussed in the IM 2021 First Quarter Report (Section IV.A.2.), the gaps in performance testing on the integrated systems included the OMS experiencing multiple issues with the high volume of data transmitted during the storm, which impacted all communication channels and field management activities. The suspected root cause of the OMS performance issues included: SCADA alarms and customer reports not processed at a rate fast enough to keep up with incoming reports; and stale and repeated outage reports were being submitted erroneously to the OMS when initial submission attempts timed out. The OMS unresponsiveness caused delays to work processes and led to a lower quality of estimated time of recovery information.

Among the lessons learned from this storm were two that specifically impact the OMS implementation:
1. Do not introduce any major system changes immediately before storm season.
2. Ensure enhanced performance testing is conducted for each system and its ecosystem. These tests should be repeated annually, with the proper infrastructure, to ensure reliability and availability of critical systems when they are needed most.
The above lessons learned dictated the following changes to the OMS implementation:
• Shift the deployment date from May 2022 until after the June-September major storm season.
• Increase the services scope for the additional enhanced performance testing expectations.
• Enhance the OMS architecture to ensure separate development/testing environments for the long-term.
• Including contingency to mitigate performance issues in OMS and its ecosystem.</td><td>No change</td></tr>
<tr><td>RCR-INF-7</td><td>With reference to page 5 of the Independent Monitor’s Draft Second Quarter 2021 Report, please describe the enhanced performance testing in response to Hurricane Isaias.</td><td>See the response to RCR-INF-6 above.</td><td>No change</td></tr>
<tr><td>RCR-INF-8</td><td>With reference to page 5 of the Independent Monitor’s Draft Second Quarter 2021 Report, please explain what portion of the $2.3 million increase in costs is attributed to additional scope and what is attributable to the revised deployment date.</td><td>The estimated $2.3 million cost increase related to the OMS implementation is comprised of the following components:<table><tr><th>Component</th><th>Cost</th></tr><tr><td>Extend OSI services contract</td><td>$1.5 million</td></tr><tr><td>Extend Cognizant services contract</td><td>$0.2 million</td></tr></table></td><td>Section II.A.2.</td></tr>
</table>

<table>
<tr><th>ID #</th><th>Question/Comment</th><th>IM Response</th><th>Report Changes</th></tr>
<tr><td></td><td></td><td><table>
<tr><td>Extend Pontoon services contract</td><td>$0.2 million</td></tr>
<tr><td>Extend Internal subject matter experts</td><td>$0.2 million</td></tr>
<tr><td>Development Environment</td><td>$0.2 million</td></tr>
<tr><td>Development Contingency</td><td>$0.3 million</td></tr>
<tr><td>Reduced Travel & Expenses</td><td>($0.3 million)</td></tr>
<tr><td>Total</td><td>$2.3 million</td></tr>
</table></td><td></td></tr>
<tr><td>RCR-INF-9</td><td>With reference to Table 11 ES 2 Electric Substation Flood Mitigation Project Cost Status as of June 30, 2011, please explain the increase in the projected cost of the Clay Street Substation from $29.8 to $30.8 million.</td><td>The Q1 2021 to Q2 2021 forecast increase on the Clay Street substation project was driven by higher than previously estimated cutover costs based on an updated estimate from the Division ($0.5 million) and an increase in surcharge rates based on the 2020 surcharge methodology ($0.5 million).</td><td>Section III.A.2.</td></tr>
<tr><td>RCR-INF-10</td><td>With reference to Table 11 ES 2 Electric Substation Flood Mitigation Project Cost Status as of June 30, 2021, please explain the increase in the projected cost of the Market Street Substation from $26.1 to $29.3 million.</td><td>The forecast increase on the Market Street project was driven by additional OP overhead and restoration work along with associated material and surchargers based on the complexity of the work and the field conditions, including higher than estimated traffic control as per city/county requirements.</td><td>Section III.A.8.</td></tr>
<tr><td>RCR-INF-11</td><td>With reference to Table 11 ES 2 Electric Substation Flood Mitigation Project Cost Status as of June 30, 2021, please explain the increase in the projected cost of the Ridgefield 4kV Substation from $18.8 to $21.2 million.</td><td>The forecast increase on Ridgefield 4kV project was driven by: additional engineering and overhead labor required to remove primary wires and complete the 4-13kV conversions; the contract for manhole rebuild work was awarded higher than estimated; additional labor and material required to rebuild several secondary buses and reroute two underground circuits around an existing gas main that was not known at the time of the prior estimate.</td><td>Section III.A.12.</td></tr>
<tr><td>RCR-INF-12</td><td>With reference to Table 11 ES 2 Electric Substation Flood Mitigation Project Cost Status as of June 30, 2021, please explain the decrease in the projected cost of the State Street Substation from $38.9 to $19.0 million.</td><td>The forecast decrease on the State Street project was driven by the scope change that split the OP scope into a separate project carried out under the Electric Stipulated Base.</td><td>No change</td></tr>
<tr><td>RCR-INF-13</td><td>With reference to Table 11 ES 2 Electric Substation Flood Mitigation Project Cost Status as of June 30, 2021, please explain the increase in the projected cost of the Waverly Substation from $33.8 to $35.0 million.</td><td>The forecast increase on the Waverly project was driven by higher carrying costs based on the extended duration stemming from the site plan denial along with additional engineering and licensing and permitting costs related to site plan revisions (see also the response to RCR-INF-2 above).</td><td>Section III.A.15.</td></tr>
<tr><td>RCR-INF-14</td><td>With reference to Table 11 ES 2 Electric Substation Flood Mitigation Project Cost Status as of June 30, 2021, please explain the increase in the projected cost of the Woodlynne Substation from $18.3 to $21.2 million.</td><td>The forecast increase on the Woodlynne project was driven by higher than previously estimated civil construction work, which was slightly offset by lower in-house engineering costs and lower than estimated costs of piles procurement.</td><td>Section III.A.16.</td></tr>
</table>

ID #	Question/Comment	IM Response	Report Changes
RCR-INF-15	With reference to page 22 of the Independent Monitor's Draft Second Quarter 2021 Report, please explain why the outside plant portion of the project has been incorporated into the Company's $100 million electric base component that was originally intended for life cycle station upgrades.	PSE&G informed the IM that discussions it had with BPU Staff and Rate Counsel regarding the mitigation change on the State Street project resulted in the decision to recover the increased cost for the State Street project (then estimated at $16.5 million) in the Company's next rate case as opposed to the ES 2 accelerated recovery. PSE&G's view is that while these increased costs on State Street are prudent and can and should be recovered by way of the accelerated recovery mechanism, it will in this one circumstance defer its request for recovery and credit the additional cost toward the Company's stipulated base requirements for the ES 2 Program.	**Section III.A.13.**
RCR-INF-16	With reference to page 32 of the Independent Monitor's Draft Second Quarter 2021 Report, please describe the proposed outside plant scope of work for the State Street substation proposed by the Company as part of the $100 million electric base.	Related to the change in mitigation method for the State Street project that changed the scope from raise and rebuilt to relocate, the State Street OP scope is comprised of new 4kV OP underground and overhead distribution equipment including manholes and duct banks as required to connect the existing State Street 4kV circuits to the new State Street substation.	**Section III.E.5.**
RCR-INF-17	With reference to page 32 of the Independent Monitor's Draft Second Quarter 2021 Report, please distinguish the difference of the proposed outside plant scope of work for the State Street substation, and the $19.09 million forecasted for the State Street substation as part of the Electric Station Flood Mitigation subprogram.	The State Street scope within the Electric Station Flood Mitigation subprogram contemplates the relocation of the State Street substation from its current site to the new location identified at Cooper Street. The State Street OP scope being executed under the Electric Stipulated Base involves the extensive underground installation required to connect the new 4kV circuits back to the existing 4kV circuits and to maintain the current capacity of these circuits.	**Section III.A.13.**
S-INF-1	**<u>Reference Page 16, Electric Station Flood Mitigation Projects (Clay Street)</u>** What is attributed to the forecasted in-service date for the Clay Street project advancing 50 days?	The advancement of the forecasted in-service date for the Clay Street project experienced during the second quarter of 2021 was driven by the planned start of electrical construction advancing from August 2022 to June 2022.	No change
S-INF-2	**<u>Reference Page 18, Electric Station Flood Mitigation Projects (Hasbrouck Heights)</u>** Please provide additional details about the "Change in T&D surcharge methodology" which resulted in the estimated cost of the Hasbrouck Heights project increasing by $0.6 million.	The change in surcharge methodology primarily impacted outside service electrical construction and various internal labor categories (Project Manager, Staff Engineer, Project Engineer, Project Controls Engineer), which resulted in the following estimate change: • Outside Services Electrical Construction: $0.1 million • Internal Labor: $0.5 million • Total Change in T&D Surcharge Methodology increase: $0.6 million	**Section III.A.4.**
S-INF-3	**<u>Reference Page 19, Electric Station Flood Mitigation Projects (Leonia)</u>**	The change in surcharge methodology primarily impacted outside service electrical construction and various internal labor categories	**Section III.A.7.**

ID #	Question/Comment	IM Response	Report Changes
	Please provide additional details about the "Change in T&D surcharge methodology" which resulted in the estimated cost of the Leonia project increasing by $1.2 million.	(Project Manager, Staff Engineer, Project Engineer, Project Controls Engineer), which resulted in the following estimate change: • Outside Services Electrical Construction: $0.6 million • Internal Labor: $0.6 million • Total Change in T&D Surcharge Methodology increase: $1.2 million	
S-INF-4	**<u>Reference Page 21, Electric Station Flood Mitigation Projects (Ridgefield 13kV)</u>** Please provide additional details about the "Change in T&D surcharge methodology" which resulted in the estimated cost of the Ridgefield 13kV project increasing by $1.7 million.	The change in surcharge methodology primarily impacted outside service electrical construction and various internal labor categories (Project Manager, Staff Engineer, Project Engineer, Project Controls Engineer), which resulted in the following estimate change: • Outside Services Electrical Construction: $0.6 million • Internal Labor: $1.1 million • Total Change in T&D Surcharge Methodology increase: $1.7 million	**Section III.A.11.**
S-INF-5	**<u>Reference Page 23, Electric Station Flood Mitigation Projects (Waverly)</u>** Regarding the Waverly project: a. Please provide additional details describing the work included within the approximately $2.8 million in spending during the second quarter of 2021. b. Please confirm that this work will not be affected by the Newark Planning Board's denial of the site plan for the project.	The majority of the actual spend during the second quarter of 2021 was associated with the delivery of the 26kV switchgear in April 2021 ($2.3 million), with the remaining spend in the quarter related to project support costs (Project Management, licensing and permitting) of $0.2 million, engineering costs of $0.2 million, and A/E procured equipment of $0.15 million. The Waverly project site plan was approved by the City in early 2022 with the construction permits received in April 2022.	**Section III.A.15.**
S-INF-6	**<u>Reference Page 24, Table 12 – ES 2 Program Recloser Status as of June 30, 2021</u>** Please provide the total number of 13kV reclosers and 4kV reclosers currently expected to be installed within the Contingency Reconfiguration subprogram.	Recloser installations were completed in early 2022 with a final amount of 932 13kV reclosers and 510 4kV recloser installed during the ES 2 Program.	No change
S-INF-7	**<u>Reference Page 25, Figure 3 – 2021 Recloser Installations as of June 30, 2021</u>** What is attributed to the actual 13kV recloser installations (as of June 30, 2011) exceeding planned 13kV recloser installations for all of 2021?	The change in the number of 13kV reclosers planned stemmed from the decision to identify opportunities to include additional circuits in the subprogram (discussed in Section IV.A.1. of the IM 2021 First Quarter Report and **Section II.A.1.** of this IM 2021 Second Quarter Report). As a result of this review, 365 reclosers on 342 circuits were identified for inclusion in the subprogram, which was comprised of 275 13kV units and 90 4kV units. These were added after the 2021 installation plan was established, which resulted in the actual 13kV recloser installations exceeding the 2021 installation plan.	**Section III.B.**

ID #	Question/Comment	IM Response	Report Changes
S-INF-8	**<u>Reference Page 27, Grid Modernization – Communication System</u>** Regarding retrofit recloser installations: a. Please compare the current forecast (2,364 retrofit reclosers) to the originally planned total. b. Please compare the currently forecasted cost of retrofit recloser installations to the originally budgeted cost.	Regarding the retrofit recloser installations: a. PSE&G initially forecasted that 2,601 units would be installed as part of the ES 2 Program, which included 204 substation RTU retrofits. As execution progressed, PSE&G split the tracking of substation RTU retrofits out from the recloser retrofits. The forecasted units also continued periodically to update the forecast based on reviews of current phone line devices, circuit reconfigurations, and removed or replaced units. At completion in December 2021, 2,318 recloser retrofits were installed. b. The budget for the retrofit reclosers was established at $29.6 million while the forecast as of December 2021 was $25.9 million.	
S-INF-9	**<u>Reference Page 27, Table 15 – Fiber Projects by Division</u>** Please confirm that the Waverly fiber project is not expected to be impacted by the site plan denial associated with the Waverly substation project.	The site plan delay on the Waverly substation project resulted in a delay to the Waverly fiber project. The fiber racks and equipment can only be installed after the new control house is built. As such, the Waverly fiber project will be rescheduled to align with the substation control house construction.	**Table 16**
S-INF-10	**<u>Reference Page 28, Table 16 – ES 2 Program Fiber Projects Status as of June 30, 2021</u>** For each fiber project, please compare the forecasted cost to the originally budgeted cost.	The budget and forecasted fiber project cost information has been incorporated into **Table 16**.	**Table 16**
S-INF-11	**<u>Reference Page 32, Electric Stipulated Base</u>** Refer to the statement "The bulk of outside plant higher design and construction standards work is planned to commence in January 2022." a. Please provide additional details about any "outside plant higher design and construction standards" projects that the Company currently expects to include within the "Electric Stipulated Base" spending (excluding the State Street project). b. Please estimate the total spending associated with "outside plant higher design and construction standards" that the Company currently expects to include within "Electric Stipulated Base" spending (excluding the State Street project).	Regarding these requests relating to the Electric Stipulated Base OP higher design and construction standards: a. The OP-Higher Design Standards projects will harden selected 13kV circuits with poor storm performance by changing the construction standard from cross-arm open wire construction to spacer cable construction. In addition to replacing the cross-arms and wires, the scope also provides for replacing poles as needed to meet the higher design standards. b. The original assumption of 1/3 Lifecycle stations and 2/3 OP-Higher Design Standards will be revised by PSE&G based on opportunities to shift Lifecycle stations from Stipulated Base to be funded under the Accelerated Recovery given the final estimates of the 16 electric station flood mitigation stations four previously approved life cycle station projects.	**Section III.E.**

ID #	Question/Comment	IM Response	Report Changes
S-INF-12	**Reference Page 40, Updated Fiber Projects** Regarding the removal of the Howell Street fiber project from the program: a. Please provide additional detail describing the Company's determination that this project would not provide sufficient redundancy and resiliency benefits. b. Please indicate if the Company is considering adding additional fiber projects to replace any removed fiber projects.	The Howell Street substation is located on the same property as the Jersey City Switching Station, which already has a TFI rack that links back to Howell Street. Therefore, PSE&G determined an additional TFI rack at Howell Street was not required for redundancy and resiliency benefits. PSE&G is not anticipating to replace the cancelled fiber projects with new fiber projects.	**Section IV.B.**
4/7/2022 Letter from Rate Counsel	In addition to the above informal questions issued by Rate Counsel, the IM also received a letter on April 7, 2022 from Rate Counsel that provided additional comments on the draft IM 2021 Q2 Report. The nature of the comments in this letter generally summarized the key contents of the draft report and did not include additional specific questions and/or requests, as such the IM is noting receipt of the letter here but has no further response to it.	N/A	N/A
PSE&G-1	Referencing **Table 1**, the total spend to date excludes the Front Street project in the Electric Station Flood Mitigation subprogram.	The IM has corrected the total spend as of the end of the second quarter of 2021 on the Electric Station Flood Mitigation subprogram to $90,603,138, which reflects the inclusion of the Front Street project ($190,915 spend) and still excludes the cancelled Constable Hook project ($133,616 spend). In review of **Table 1**, the IM also identified that the total forecast for the Electric Station Flood Mitigation subprogram included the actual spend associated with the cancelled Constable Hook project, which has now been removed for a revised total forecast of $346,463,155 as of the end of the second quarter of 2021. Similar corrections were also made to **Table 11**.	**Table 1 & Table 11**
PSE&G-2	Referencing the following, "During the second quarter of 2021, retrofit installations continued to ramp up with 685 installations completed during the quarter against a target of 680. In total, 1,432 retrofit reclosers have been installed on the Program through the end of the second quarter out of a total program forecast of 2,364 (which is periodically reviewed and updated)." The number of installations completed during the second quarter of 2021 should be 684 units, not 685 (the total of 1,432 is correct, however).	The IM has corrected the number of retrofit recloser installations completed during the second quarter of 2021 to 684 units.	**Section III.C.**

ID #	Question/Comment	IM Response	Report Changes
PSE&G-3	Referencing the first bullet under "Findings & Observations" for the Grid Modernization – ADMS subprogram, it should state "resource constraints" not "recourse constraints".	The identified typo has been corrected in this final report.	**Section III.D.**

ENERGY STRONG 2 PROGRAM INDEPENDENT MONITOR 2021 THIRD QUARTER REPORT

PREPARED AND SUBMITTED BY

PEGASUS GLOBAL HOLDINGS, INC. ®

CONFIDENTIAL

AUGUST 24, 2022

Table of Contents

List of Acronyms and Abbreviations

Advanced Distribution Management Systems .... ADMS

Advanced Metering Interface .... AMI

Allowance for Funds Used During Construction .... AFUDC

Architect and Engineer .... A/E

Board of Public Utilities .... BPU

Construction Work In Progress .... CWIP

Costs of Removal .... COR

Distribution Management System .... DMS

Distributed Energy Resource Management System .... DERMS

Distribution Supervisory Control and Data Acquisition .... DSCADA

Energy Strong 2 .... ES 2

Gas Metering & Regulating .... Gas M&R

Independent Monitor .... IM

Inside Plant .... IP

Issued for Bid .... IFB

Issued for Construction .... IFC

Mobile Work Management System .... MWMS

New Jersey Department of Environmental Protection .... NJDEP

New Jersey Sports and Exposition Authority .... NJSEA

Open Systems International Inc. .... OSII

Outage Management System .... OMS

Outside Plant .... OP

Pipeline and Hazardous Materials Safety Administration .... PHMSA

Public Service Electric & Gas .... PSE&G

Purchase Order .... PO

Record of Decision .... ROD

Remote Control Unit .... RCU

Remote Terminal Unit .... RTU

Risk and Contingency .... R&C

Supervisory Control and Data Acquisition ....SCADA

System Average Interruption Duration Index .... SAIDI

Utility Review Board .... URB

I. Executive Summary

Public Service Electric & Gas's (PSE&G's) Energy Strong 2 (ES 2) Program was established from a Stipulation that the involved parties agreed to in August 2019, as approved by a Board of Public Utilities (BPU) Order dated September 11, 2019, with an effective date of September 21, 2019. The Stipulation provided the ES 2 Program would be comprised of five primary subprograms: Electric Station Flood Mitigation; Contingency Reconfiguration; Grid Modernization – Communications; Grid Modernization – Advanced Distribution Management Systems (ADMS); and Gas Metering & Regulating (Gas M&R) Station Upgrades. In addition, a Stipulated Base spend was established that includes both an electric component (higher outside plant design standards and station life cycle upgrades) and a gas component (overlapping with the Gas M&R subprogram). This report contains the Independent Monitor's (IM's) findings and observations on the ES 2 Program elements and other information on the Program's status as of the third quarter of 2021.

During the third quarter of 2021, the bulk of the spend within the ES 2 Program continued to be in the two largest subprograms: Electric Station Flood Mitigation with six projects continuing in construction; and Contingency Reconfiguration that continues to advance the installation and commissioning of reclosers largely in alignment with PSE&G's plan. Within the other subprograms, the Grid Modernization – Communication System subprogram placed eight additional fiber installation projects and one additional fiber cutover project in-service, and continued the retrofit recloser installations, with 562 units installed during the third quarter of 2021, bringing the total number of retrofit reclosers installed to 1,994 units out of a current forecast of 2,357 units. The Grid Modernization – ADMS subprogram completed the factory acceptance testing and received and setup server hardware equipment. The Gas M&R subprogram continued construction on the Westampton project, while other stations continued to advance design, submitted site plan/permit packages, and continued other preliminary activities. The Hamilton, Plainfield, and Woodbury projects in the Electric Stipulated Base scope commenced construction during the third quarter of 2021, while construction continued to advance on the Paramus project. **Table 1 – ES 2 Subprogram & Stipulated Base Status as of September 30, 2021** below provides the spend to date on the subprograms within the ES 2 Program and Stipulated Base compared to the total forecast and forecasted completion for each.

Table 1 – ES 2 Subprogram & Stipulated Base Status as of September 30, 2021

Subprogram	Q3 Spend	Total Spend to Date*	Total Forecast*	% of Actuals to Forecast	Forecasted Completion**	Stipulation Funding Amount***
Electric Station Flood Mitigation	$10,647,819	$101,384,572	$346,555,960	29%	Dec 2024	$389M
Contingency Reconfiguration	$11,715,206	$97,274,191	$145,494,461	67%	Dec 2023	$145M
Grid Modernization – Communications	$6,721,006	$40,110,017	$63,110,594	64%	Dec 2023	$64.3M
Grid Modernization – ADMS	$2,368,648	$23,509,654	$42,722,333	55%	Dec 2022	$42.7M
Electric Stipulated Base	$4,279,681	$13,385,388	$100,000,000	13%	Dec 2023	$100M
Gas M&R Station Upgrades^	$2,950,314	$13,169,538	$95,801,855	14%	Dec 2023	$101M
*Total**	$38,682,675	$288,833,359	$793,685,204	36%	Dec 2024	$842M

-Note: total figures may not fully align due to rounding. Additionally, the total forecast includes only the base cost for the Electric Station Flood Mitigation and Gas M&R subprograms as PSE&G does not include risk and contingency (R&C) in its forecasts for these projects. See **Table 11 and **Table 20** for the Electric Station Flood Mitigation and Gas M&R project estimates, respectively, with base costs and R&C shown.*
***-Final in-service date.*
****-Following the $7.7 million transfer in July 2021 from the Grid Modernization – Communications subprogram to the Grid Modernization – ADMS subprogram.*
^-Includes both the ES 2 projects and the Stipulated Base gas projects.

Given the prominence of the Electric Station Flood Mitigation subprogram, which represents over half of the total ES 2 Program spending, a summary of the projects within this subprogram is provided below in **Table 2 – ES 2 Electric Station Flood Mitigation Status as of September 30, 2021**.

Table 2 – ES 2 Electric Station Flood Mitigation Status as of September 30, 2021

Project	Total Estimate (rounded)	Actuals	% of Actuals to Estimate	Forecasted In-Service Date*
1. Academy Street	$10,500,000	$5,431,127	52%	10/20/2021 (↑)
2. Clay Street	$33,800,000	$3,255,941	10%	12/27/2022 (↓)
3. Front Street^	$27,400,000	$1,261,050	5%	11/6/2023 (↓)
4. Hasbrouck Heights	$22,700,000	$2,091,795	9%	2/7/2023
5. Kingsland	$8,300,000	$531,370	6%	10/4/2023
6. Lakeside Avenue	$47,900,000	$1,045,328	2%	11/8/2023 (↑)
7. Leonia	$26,400,000	$14,399,755	55%	10/10/2022 (↓)
8. Market Street	$29,900,000	$25,293,157	85%	**6/25/2021**
9. Meadow Road	$9,000,000	$899,374	10%	9/22/2023
10. Orange Valley	$20,200,000	$702,848	4%	12/29/2023
11. Ridgefield 13kV	$27,600,000	$14,893,425	54%	11/11/2022 (↓)
12. Ridgefield 4kV	$21,300,000	$20,404,916	96%	**5/16/2021**
13. State Street	$21,400,000	$1,764,732	8%	9/23/2022
14. Toney's Brook	$18,800,000	$1,122,883	6%	4/21/2023
15. Waverly	$35,400,000	$6,339,767	18%	12/18/2024
16. Woodlynne	$19,400,000	$1,947,106	10%	10/10/2023

-Reflects the in-service date of the last major asset (e.g. switchgear), certain activities may take place after this date to support the final in-service date (i.e. when all customers are cutover).* ***Bold* *dates indicate the actual in-service date.*

(↑)-*Indicates the forecasted in-service date advanced from the prior quarter.*

(↓)-*Indicates the forecasted in-service date slipped from the prior quarter.*
^- The Front Street project was proposed by PSE&G during the second quarter of 2021 to replace the cancelled Constable Hook project.

As indicated in **Table 2**, the projects that previously started construction (Academy Street, Leonia, Market Street, Ridgefield 13kV, Ridgefield 4kV, and Waverly) continue to have the highest total spend to date. Additionally, four of the stations (Leonia, Market Street, Ridgefield 4kV, and State Street) had new estimates approved by the PSE&G's Utility Review Board (URB) in during the third quarter of 2021. **Table 2** also shows that six of the sixteen projects had movement during the third quarter of 2021 in the forecasted in-service date, with two advancing and four slipping. Of these six projects, five of the projects (Academy Street, Clay Street, Front Street, Leonia, and Ridgefield 13kV) had forecasted in-service dates change by less than two weeks. While the Lakeside Avenue forecasted in-service date advanced 35 days from the status as of the end of the second quarter of 2021. As previously reported, the Waverly final in-service date is currently forecasted for December 2024, unchanged from the prior quarter while the project team continues to work on a new site plan application, which once approved will provide PSE&G with a clearer view of the Waverly schedule, including potential opportunities to advance the in-service date.

The IM has found nothing to date that would jeopardize the ES 2 Program being completed on budget. However, schedule challenges, particularly on the Waverly substation and other projects with forecasted in-service dates near the Program end date will continue to warrant further monitoring by the IM to ensure the ES 2 Program is completed within the defined timeline.

As per N.JA.C. Section 14:3-2A.5(c)2, the IM reports are to address:

i. *The effectiveness of Infrastructure Investment Program investments in meeting project objectives;*
ii. *The cost-effectiveness and efficiency of investments;*
iii. *The appropriateness of cost assignments; and*
iv. *Any other information required by the Board.*

The IM focuses the majority of the discussion within each report on these primary objectives and has summarized the findings on these areas as follows:

- **Effectiveness of ES 2 investments in meeting project objectives**: The objectives for each subprogram within the ES 2 were defined within PSE&G's ES 2 filing and confirmed by the Stipulation. The overall objectives focused on improving system resiliency, reliability, and hardening through rebuilding or replacing selected substations, installing smart control and monitoring devices on distribution circuits (reclosers, fuse savers, etc.), installing ADMS and a new communication system, and rebuilding selected Gas M&R stations. Within **Section III** of this report, the IM provides a review of the status of the efforts performed to meet these objectives for each subprogram.
- **Cost-effectiveness and efficiency of investments**: To assess the cost effectiveness and efficiency of ES 2 investments, the IM began with a review of the initial scope, estimate, and related planning documents for each project to establish a baseline to monitor progress against as the work advances. The IM concurrently reviewed the program governance and structure, including the Company's policies and procedures, to understand how the Company intended to execute the projects. As the Program execution advances, the IM evaluates actual costs against the initial estimates and current forecasts, including seeking additional information relating to any variances identified. In the initial IM report on the ES 2 Program (the IM 2020 First Quarter Report), a review of the Program governance and the policies and procedures utilized by PSE&G was performed with the IM finding it provided a solid foundation for PSE&G to execute the Program. While the overall Program's current cost forecast is below the Stipulation amount, the IM has observed cost increases realized on specific projects or aspects of the Program and found the majority of these increases stem from scope evolution and/or more detailed estimates from the time of the ES 2 filing, as well as the more recent changes in general market conditions (e.g. Covid-19 impacts, supply chain issues, etc.).

- **Appropriateness of cost assignments**: The IM receives and reviews recurring data concerning the accumulation of costs within the Program. Based on that review, the IM submits follow-up questions to the Company regarding that data for the reporting period. Such follow-up questions generally focus on the following aspects:
    - Review of any unusual changes in cost elements from period-to-period, including but not limited to allowance for funds used During construction (AFUDC), cost of removal (COR), and the allocation of overheads.
    - Review spend on capital accounts, such as Construction Work in Progress (CWIP) as it relates to overall spend, AFUDC, and COR.
    - Verify cost accumulations and classifications appear to be in accordance with Generally Accepted Accounting Principles (GAAP), to the extent the IM has access to such information.
    - Review and investigation of prior period adjustments and/or corrections to capital accounts.
    - Engage the Company's Internal Audit group on specific areas to audit, review, and assess – particularly for areas in which the IM has limited or no visibility (proprietary data, accounting systems, etc.).

  Through the above steps, the IM tracks and monitors how the Company is recording costs to support the finding that the cost assignments appear to be appropriately applied.

Within the Stipulation, it also noted the IM was to review and report "on the impact of the Program on overall system performance during severe weather events." In each quarterly report, the IM reviews any Major Events that occurred in the reporting period, including the system performance metrics provided by PSE&G, and seeks additional information as appropriate to have a more robust view of the system performance. The results of this review are detailed within **Section D**. of the IM report.

As noted in the IM 2020 First Quarter Report, the IM conducts its assessment in accordance with Generally Accepted Government Auditing Standards (GAGAS, or more commonly referred to as the "Yellow Book" standards). The Yellow Book provides a framework for conducting performance management reviews/audit engagements with competence, integrity, objectivity, and independence that result in information used for oversight, accountability, transparency, and improvements of the audited programs and operations. On June 7, 2022, a draft IM 2021 Third Quarter Report was submitted to PSE&G, BPU Staff, and Rate Counsel. Per the Yellow Book, the transmittal of a draft report is intended to allow for review and comment by the audited entity and others to develop a fair, complete, and objective report. A summary of the comments on the draft report and the IM's responses are provided in **Appendix A – Draft Report Comments and Responses**. This **Appendix A** also identifies specific sections within this IM 2021 Third Quarter Report that have been edited, supplemented with additional information, or otherwise revised in response to the comments received.

II. Program Status

A. Key Decisions

In order to capture formalized key decisions regarding the ES 2 Program, PSE&G completes a "Record of Decision" (ROD) that includes a description of the decision; alternatives considered; the decision made; and rationale for the decision. The RODs are assessed by the IM as they are completed to review their impact to the Program. In addition, the IM may request PSE&G complete a ROD to formalize a decision if such a decision has not yet been formalized through the ROD process.

The current and pending RODs as of the date of this IM 2021 Third Quarter Report are presented below in **Table 3 – ES 2 Records of Decisions**.

Table 3 – ES 2 Records of Decisions

Subprogram	Record of Decision	IM Comments
Electric Station Flood Mitigation	Academy Street & State Street Change in Mitigation Method	Reasonable and appropriate *(See Section B.1. in the IM 2020 First Quarter Report)*
Electric Station Flood Mitigation	Engineering Support for Energy Strong Program Projects	Reasonable and appropriate *(See Section B.2. in the IM 2020 First Quarter Report)*
Grid Modernization – Communication System	Wireless Communication Network	Reasonable and appropriate *(See Section II.A.1. in the IM 2020 Third Quarter Report)*
Grid Modernization – Communication System	Substation Communication Center	Reasonable and appropriate *(See Section II.A.2. in the IM 2020 Third Quarter Report)*
Grid Modernization – Communication System	Fiber Scope	Reasonable and appropriate *(See Section IV.A. in the IM 2020 Third Quarter Report)*
Electric Station Flood Mitigation	Constable Hook, Lakeside, & Orange Valley Change in Mitigation Method	Reasonable and appropriate *(See Sections II.A.3. and IV.B. in the IM 2020 Third Quarter Report and additional discussion in Section II.A.1. and Section IV.B. of the IM 2020 Fourth Quarter Report)*
Grid Modernization – Communication System	Communication Retrofit of Replacement and non-ES-II Units	Reasonable and appropriate *(See Section II.A.2. in the IM 2020 Fourth Quarter Report)*
Electric Station Flood Mitigation	Market Street Radioactive Soil Testing and Handling	Reasonable and appropriate *(See Section II.A.3. in the IM 2020 Fourth Quarter Report)*
Electric Station Flood Mitigation	Transfer of Clay Street Wastewater Wall Scope from ES2FM to Clay Street 69kV Project	Reasonable and appropriate *(See Section IV.A. in the IM 2020 Fourth Quarter Report)*
Contingency Reconfiguration	Energy Strong II Electric Program – Contingency Reconfiguration Subprogram, 13kV and 4kV Reclosers	Reasonable and appropriate *(See Section IV.A. in the IM 2021 First Quarter Report and Section II.A.1. in the IM 2021 Second Quarter Report)*
Grid Modernization – ADMS	Outage Management System (OMS) Implementation	Reasonable and appropriate *(See Section IV.A. in the IM 2021 First Quarter Report and Section II.A.2.*

Subprogram	Record of Decision	IM Comments
		the IM 2021 Second Quarter Report)

During the third quarter of 2021, there were no additional RODs issued.

B. Program Management

Beginning in July 2020, the IM began participating in a bi-weekly call with PSE&G to review its bi-weekly ES 2 Program Dashboard. As with the original Energy Strong Program, the Dashboard provides a mechanism for PSE&G to monitor and control activities to be completed in order to achieve key near-term milestones, including a focus on recently completed activities, any key issues, and other key metrics (e.g. installation targets) as appropriate. These calls have proven to be an effective way for the IM to stay informed on current and upcoming activities and to allow a venue for discussions between the IM and PSE&G on these activities and status updates and continue to be held on a recurring basis.

During the third quarter of 2021, PSE&G issued notice to the BPU that it is transferring $7.7 million of funds from the Grid Modernization – Communication System subprogram to the Grid Modernization – ADMS subprogram. The Stipulation provides that PSE&G can immediately reallocate funds amongst the electric subprograms of the ES 2 Program provided that the amount transferred is 5% or less of the overall ES 2 Program electric investment amount. At $7.7 million, this transfer represents approximately 1% of the total $641 million allocated for electric investments in the ES 2 Program. This transfer was supported by the updated estimates completed in the second quarter of 2021 for these two Grid Modernization subprograms (which saw the Grid Modernization – Communication System subprogram estimate decrease by $9.4 million and the Grid Modernization – ADMS subprogram estimate increase by $7.7 million).

C. Cost Assignments

1. Costs of Removal (COR)

Costs of Removal (COR) generally include costs for such activities as environmental removal, removal of inside station equipment, structures, foundations, towers and fixtures, conductors and other electrical devices, poles and fixtures, transformers, plant demolition, foundations, and removal of underground conduit and other wiring. Generally, COR are charged to Accumulated Depreciation and are amortized and recovered through a component of depreciation expense. The specific method and amount of recovery is determined in gas and electric rate cases before the BPU.

Table 4 – ES 2 Program Costs of Removal as of September 30, 2021, below itemizes the charges to COR for the first three quarters of 2021, total 2020, total 2019 (which was only the fourth quarter) and total ES 2 Program COR to date. These amounts do not reflect any salvage value reductions, which have been *de minimis* in the ES 2 Program through September 30, 2021.

Table 4 – ES 2 Program Costs of Removal as of September 30, 2021

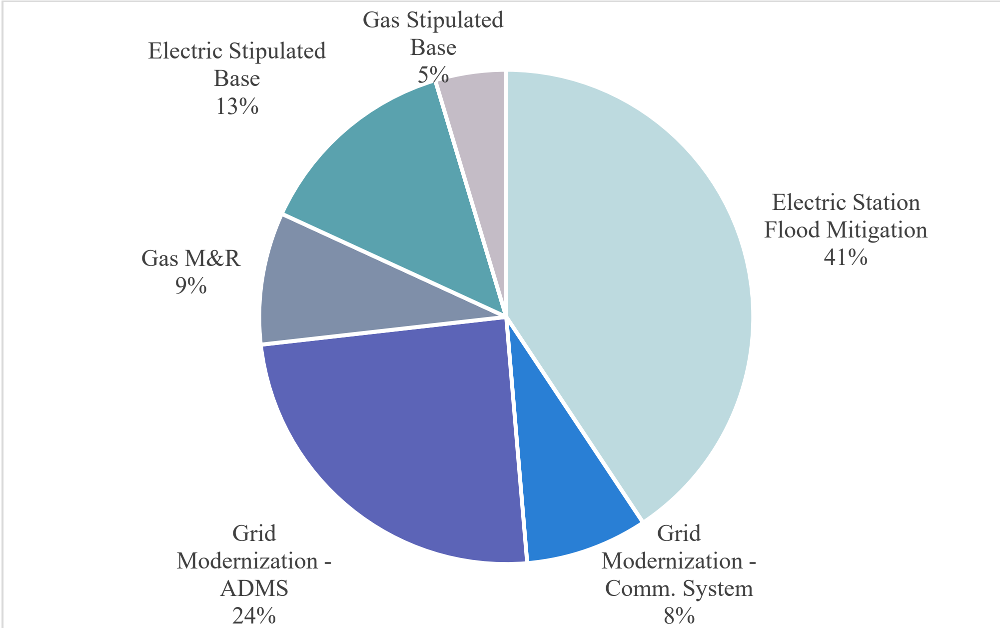
Subprogram	Q3 2021	Q2 2021	Q1 2021	Year-to-Date 2021	Total 2020	Total 2019 (Q4)	Total COR
	(in $ thousands)						
Electric Station Flood Mitigation	**$1,464.2**	**$1,141.0**	**$1,129.5**	**$3,734.7**	**$1,021.1**	**$0**	**$4,755.8**
Contingency Reconfiguration	**$811.4**	**$485.2**	**$622.9**	**$1,919.5**	**$2,198.9**	**$431.0**	**$4,549.4**
Grid Modernization – Communications	**$38.6**	**$37.9**	**$37.8**	**$114.3**	**$24.4**	**$0**	**$138.7**
Grid Modernization – ADMS	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Electric Stipulated Base	**$3.2**	**$0**	**$0**	**$3.2**	**$0**	**$0**	**$3.2**
Gas M&R Station Upgrades	**$63.5**	**$87.6**	**$0**	**$151.1**	**$0**	**$0**	**$151.1**
Gas Stipulated Base	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Total	**$2380.9**	**$1,751.7**	**$1,790.2**	**$5,922.8**	**$3,244.4**	**$431.0**	**$9,598.2**

The increase in COR for the third quarter of 2021 from the second quarter reflects, (i) demolition and removal of various 4kV equipment at the Market Street and Ridgefield Electric Station Flood Mitigation elimination projects, and (ii) higher levels of pole fixture, switches, and other equipment removal across virtually all districts in connection with the reclosure projects.

2. Construction Work-in-Progress (CWIP) & In-Service Transfers

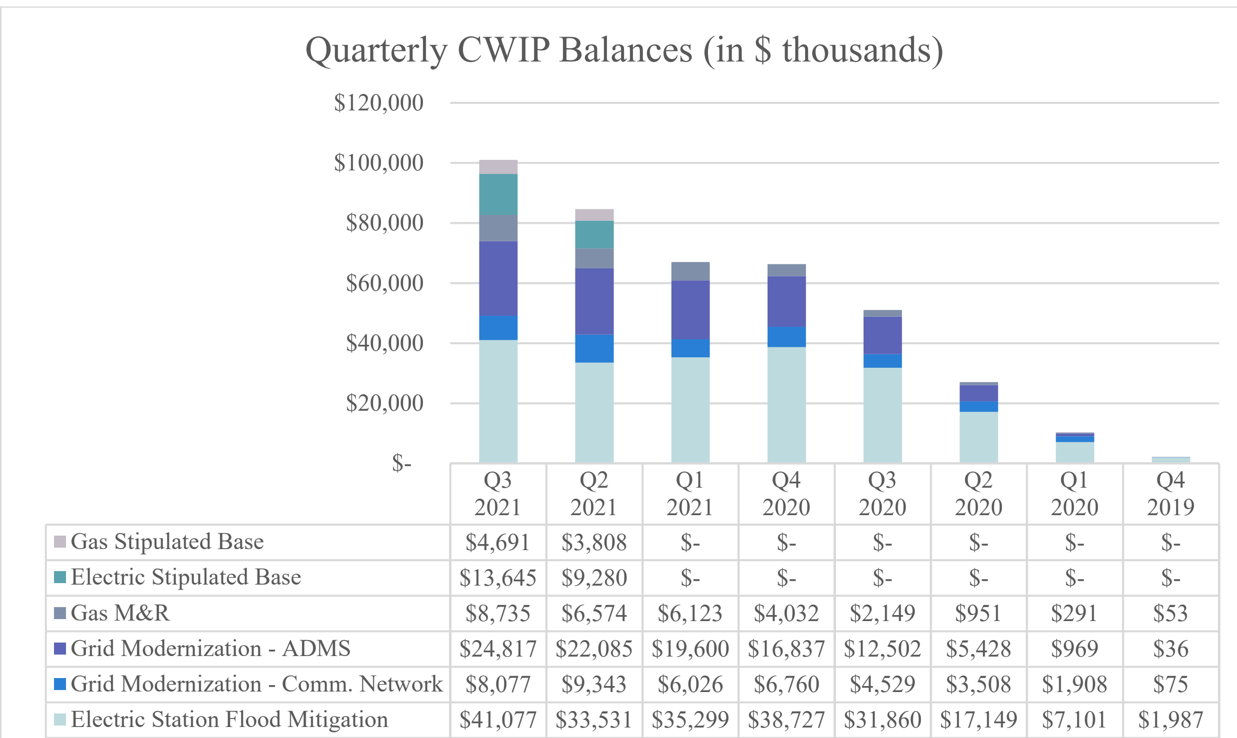
As of September 30, 2021, the Energy Strong CWIP balance was $101.0 million, compared to $84.6 million as of June 30, 2021. The largest components of the September 30, 2021 CWIP were the Leonia ($7.0 million), Waverly ($6.6 million), Westampton ($6.5 million), Ridgefield ($6.4 million) and Academy Street ($5.8 million) substations, as well as the Paramus substation Electric Stipulated Base lifecycle project ($7.1 million), and work associated with the Advanced Distribution and Management System ($24.8 million). The Electric Station Flood Mitigation subprogram comprises the largest component of total end of period CWIP outstanding, as depicted in **Figure 1 – ES 2 CWIP as of September 30, 2021** below.

Figure 1 – ES 2 CWIP as of September 30, 2021



In addition, the **Figure 2 – ES 2 CWIP Balances by Subprogram as of September 30, 2021** below depicts the composition of end-of-quarter CWIP balances by subprogram for the third, second and first quarters of 2021, each quarter of 2020, and the fourth quarter of 2019.

Figure 2 – ES 2 CWIP Balances by Subprogram as of September 30, 2021



	Q3 2021	Q2 2021	Q1 2021	Q4 2020	Q3 2020	Q2 2020	Q1 2020	Q4 2019
Gas Stipulated Base	$4,691	$3,808	$-	$-	$-	$-	$-	$-
Electric Stipulated Base	$13,645	$9,280	$-	$-	$-	$-	$-	$-
Gas M&R	$8,735	$6,574	$6,123	$4,032	$2,149	$951	$291	$53
Grid Modernization - ADMS	$24,817	$22,085	$19,600	$16,837	$12,502	$5,428	$969	$36
Grid Modernization - Comm. Network	$8,077	$9,343	$6,026	$6,760	$4,529	$3,508	$1,908	$75
Electric Station Flood Mitigation	$41,077	$33,531	$35,299	$38,727	$31,860	$17,149	$7,101	$1,987

Transfers from CWIP to plant in service totaled $3.8 million during the third quarter of 2021, comprised of fiber projects in the Grid Modernization – Communication Network subprogram. Total ES 2 Program transfers from CWIP have been $38.4 million through September 30, 2021. It should be noted that work related to certain assets, such as the reclosers under the Contingency Reconfiguration subprogram, generally can be completed without being recorded through CWIP. As such, no AFUDC is recorded on these expenditures. This accounting treatment is in accord with generally accepted accounting principles and the Company's accounting policies.

3. Allowance for Funds Used During Construction (AFUDC)

The amount of quarterly AFUDC recorded by the Company for each Energy Strong subprogram during the third, second and first quarters of 2021, AFUDC for 2021 to date, total AFUDC for the years 2020 and 2019 and total Energy Strong AFUDC accrued to date, is shown below in **Table 5 – ES 2 Program AFUDC as of September 30, 2021**.

Table 5 – ES 2 Program AFUDC as of September 30, 2021

Subprogram	Q3 2021	Q2 2021	Q1 2021	Year-to-Date 2021	Total 2020	Total 2019 (Q4)	Total AFUDC
	(in $ thousands)						
Electric Station Flood Mitigation	**$581.6**	**$576.7**	**$558.6**	**$1,716.9**	**$936.5**	**$9.9**	**$2,663.3**
Contingency Reconfiguration	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Grid Modernization – Communications	**$105.2**	**$95.5**	**$59.0**	**$259.7**	**$184.3**	**$0.2**	**$444.2**
Grid Modernization – ADMS	**$363.5**	**$316.9**	**$274.2**	**$954.6**	**$352.7**	**$0.1**	**$1,307.4**
Electric Stipulated Base	**$160.9**	**$80.5**	**$49.6**	**$291.0**	**$44.0**	**$0**	**$335.0**
Gas M&R Station Upgrades (incl. Stip. Base)	**$157.0**	**$107.6**	**$72.2**	**$336.8**	**$70.0**	**$0.2**	**$407.0**
Total	**$1,368.2**	**$1,177.2**	**$1,013.6**	**$3,559.0**	**$1,587.5**	**$10.4**	**$5,156.9**

During the first quarter of each year, the AFUDC rate is reviewed for possible reset as it applies to the current year based on updated capital structure and component cost data. For the year 2021, the new AFUDC rate was calculated to be 6.81%, using the capital structure and component costs as of January 31, 2021. This rate is lower than the 2020 rate of 6.95%, primarily due to a significantly lower interest rate used for short-term debt in the AFUDC calculation, and also to a reduction in the Company's embedded cost of long-term debt. In calculating the 2021 AFUDC rate, the Company used (i) a 3.85% embedded cost of long-term debt (vs. 4.02% in 2020), (ii) a short-term debt rate of 0.32% (vs. 1.86% in 2020), and (iii) a cost of equity of 9.60% (unchanged from 2020).

Subsequent to the annual reset calculation referred to above, and during the course of each year, the AFUDC rate is also recalculated as it applies to each fiscal quarter. If the recalculated rate changes by 25 basis points from the rate then in effect, the rate is reset and retroactively applied to January 1 of that year. For the third quarter of 2021, based on data as of September 30, 2021, the recalculated weighted average AFUDC accrual rate (6.84%) did not meet this criterion to warrant changing from the annual rate (6.81%) in effect. Therefore, AFUDC was accrued during the third quarter of 2021 at the calculated rate of 6.81%.

AFUDC accrued for Energy Strong projects during the third quarter of 2021 increased over AFUDC accrued during the second quarter of 2021 as the result of increases in total average CWIP balances for almost all subprograms.

The IM observes that the Company's calculation of the AFUDC rate and its application is in accordance with both PSE&G's accounting policy and Plant Instruction 3(17) of the Federal Energy Regulatory Commission's Uniform Systems of Accounts prescribed for public utilities.

The IM also notes that the relevant AFUDC information as it relates to third quarter 2021 Energy Strong project costs is consistent with the applicable dictates of the Stipulation entered into with respect to these Energy Strong projects. The IM will continue to review future Energy Strong AFUDC accruals for consistency with relevant provisions of the Stipulation for accounting and reporting purposes only, and not as a party to, or in expressing an opinion concerning, any rate proceedings.

4. Allocated Overheads

PSE&G follows a philosophy of allocating overhead costs, whether at the Service Company or from utility support organizations, to the operating company or unit receiving the benefit, and ultimately, if appropriate, settling costs to individual assets. Where possible, services are charged directly to the entity receiving the benefit, but where direct charging of costs is not feasible, cost allocations from the Service Company to operating companies are prescribed in a BPU-approved schedule issued pursuant to a BPU order in July 2003. The Stipulation requires the Company to follow its current practices with regard to capitalized overheads.

For ES 2 electric and gas distribution projects, allocated overhead costs should primarily come from utility-related labor costs associated with administrative and supervisory personnel, labor and other costs associated with bargaining unit personnel, fringe benefits, materials handling costs, payroll taxes and depreciation expense. Shown below in **Table 6 – ES 2 Program Overhead Allocations as of September 30, 2021** are the allocated overhead costs charged to ES 2 subprograms for the first three quarters of 2021, total 2021 year to date, total 2020, total 2019 and total ES 2 Program allocated overheads to date.

Table 6 – ES 2 Program Overhead Allocations as of September 30, 2021

Subprogram	Q3 2021	Q2 2021	Q1 2021	Year-to-Date 2021	Total 2020	Total 2019 (Q4)	Total Overhead Allocations
	(in $ thousands)						
Electric Station Flood Mitigation	**$2,527**	**$4,352**	**$5,588**	**$12,467**	**$14,023**	**$287**	**$26,776**
Contingency Reconfiguration	**$3,683**	**$4,006**	**$4,215**	**$11,904**	**$17,109**	**$3,415**	**$32,428**
Grid Modernization – Communications	**$2,230**	**$2,506**	**$1,743**	**$6,479**	**$3,625**	**$12**	**$10,116**
Grid Modernization – ADMS	**$125**	**$124**	**$119**	**$368**	**$426**	**$11**	**$805**
Electric Stipulated Base	**$903**	**$287**	**$126**	**$1,316**	**$259**	**$0**	**$1,575**
Gas M&R Station Upgrades (incl. Stip. Base)	**$185**	**$169**	**$131**	**$485**	**$291**	**$15**	**$791**

Subprogram	Q3 2021	Q2 2021	Q1 2021	Year-to-Date 2021	Total 2020	Total 2019 (Q4)	Total Overhead Allocations
	(in $ thousands)						
Total	**$9,653**	**$11,444**	**$11,922**	**$33,019**	**$35,733**	**$3,740**	**$72,491**

The overwhelming majority of overhead costs allocated to ES 2 projects during the third quarter of 2021 are costs allocated from areas that support all utility distribution and transmission projects, including ES 2 projects. More specifically, most (approximately 75%) of the third quarter allocated costs reflect labor costs of supervisory, administrative and operations planning personnel, labor and other costs from bargaining unit personnel, and fringe benefits associated with these labor costs. The decreases in overhead costs for the third quarter 2021 from the second quarter of 2021 reflect generally lower total subprogram spending levels. Additionally, the IM 2021 Second Quarter Report indicated a total of $11.393 million in allocated overheads during the second quarter of 2021. This figure was updated with revised information provided to the IM after the issuance of that report in which PSE&G identified that the original data provided to the IM contained an error based on when the data was extracted (i.e. the original data was extracted earlier in the month than it should have been). The correct allocated overheads data for the second quarter of 2021 is the $11.444 million shown above in **Table 6**.

D. System Performance

1. Current Reporting Quarter Major Events

During the third quarter of 2021, there were two Major Events reported in PSE&G's service territory, one concerning a load shedding event in East Orange on September 1-2, 2021, which overlapped with a State of Emergency issued by Governor Murphy on September 1, 2021, due to heavy rains and flooding associated with the remnants of Hurricane Ida. The weather associated with the State of Emergency saw heavy rains fall across PSE&G's service territory over a three-week period. The direct impacts from the remnants of Hurricane Ida were experienced on September 1-2, 2021 and resulted in 105,722 PSE&G customers experiencing service interruptions. During the following weeks through the Major Event period an additional 109,470 PSE&G customers experienced service interruptions. In total, 215,192 PSE&G customers were affected by this Major Event, with 99% of those customers returned to service within 48 hours.

The IM has received PSE&G's report on the performance of its investments from this Major Event and has reproduced the results in **Table 7 – Q3 2021 Major Event Performance** below.

Table 7 – Q3 2021 Major Event Performance

Circuit	5 Year Baseline SAIDI*	Report Quarter SAIDI*
ADA 8012	**0.02574**	**0.02991**
ADA 8024		**0.01838**
ALD 8015	0.12276	0.00000
ALD 8016	0.00654	0.00000
ALD 8022	0.05448	0.00000
BAO 8014		**0.00164**
BAO 8023		**0.04859**
BEA 8003	0.00238	0.00000

Circuit	5 Year Baseline SAIDI*	Report Quarter SAIDI*
BEA 8010	**0.07397**	**0.17328**
BEF 8014	**0.01387**	**0.10160**
BEN 8016	**0.01934**	**0.14705**
BEN 8021	**0.00143**	**0.01645**
BEN 8022	0.00232	0.00181
BEN 8023	0.18243	0.00000
BLO 4006	**0.00535**	**0.38192**
BRU 8011	0.04127	0.03143

Circuit	5 Year Baseline SAIDI*	Report Quarter SAIDI*
BRU 8012	0.01648	0.00240
BRU 8013	**0.00121**	**0.00249**
BUS 8013	0.21323	0.01037
BUS 8015	0.00494	0.00000
CAS 8001	0.02438	0.00084
CED 8013	0.00134	0.00062
CED 8021	0.10724	0.02195
CED 8022	0.05071	0.00061
CET 4012	0.17321	0.09823
CET 4019		**0.06238**
CHA 4013	0.01874	0.00586
CIN 8001	0.12834	0.00237
CIN 8004	0.03186	0.00000
CIN 8005	0.04256	0.00000
CIN 8043	0.18459	0.00262
CLF 8025	0.00177	0.00000
CLK 8014	0.20056	0.00000
CLK 8022	0.06677	0.00673
CLK 8023	**0.00019**	**0.00079**
CLK 8024	0.01526	0.00000
CLK 8032	**0.01489**	**0.07217**
CON 8001		**0.01379**
COR 8015	**0.00123**	**0.01616**
COR 8042	0.05446	0.00000
CRX 8001	0.16798	0.03532
CRX 8009	0.20824	0.00560
CUT 8006	0.59550	0.00073
CUT 8007	0.67234	0.02496
CUT 8041	0.07628	0.00142
DAY 8001	0.15084	0.00440
DAY 8002	0.03617	0.00371
DEA 4001		**0.02289**
DFD 8007	0.06056	0.00496
DFD 8009	**0.03737**	**0.03992**
DFD 8031	0.13025	0.06888
DFD 8041	**0.20440**	**0.42586**
DOR 8012		**0.01725**
DOR 8025		**0.00000**
DVB 8011	0.02010	0.00304
DVB 8013	**0.00455**	**0.00499**
EAO 4019	0.03000	0.01262
EAO 4023	0.08458	0.01803
EAT 8011	0.09890	0.03162
EAT 8013	0.13363	0.00078
EAT 8021	**0.01128**	**0.06889**

Circuit	5 Year Baseline SAIDI*	Report Quarter SAIDI*
EAT 8022	0.08703	0.00068
EAT 8025		**0.00000**
FAW 8011	0.63063	0.00000
FAW 8014	0.21021	0.00000
FAW 8015	0.06006	0.00000
FAW 8016	0.12332	0.00000
FED 4010	0.01943	0.00289
FED 4022		**0.01411**
FIT 8003	0.01301	0.00000
FRA 8012		**0.00000**
FRA 8021		**0.00000**
GBK 8011	0.27452	0.00068
GBK 8014	0.30784	0.02020
GET 4007	0.06673	0.00000
HAD 4002	**0.03536**	**0.05181**
HAT 8012		**0.00000**
HAT 8021	0.00164	0.00000
HAT 8022	0.30670	0.02147
HAT 8023	0.01869	0.00000
HAT 8027	0.00007	0.00000
HAT 8034		**0.00000**
HAT 8035	0.04291	0.00501
HAW 8032	0.22973	0.00000
HAW 8041	**0.00290**	**0.00888**
HID 8011	0.11110	0.01377
HID 8013	0.02446	0.00369
HID 8044	0.08229	0.01545
HID 8045	0.12747	0.01115
HNC 8021	0.02280	0.00745
HNC 8025	0.49719	0.01143
HOE 8044	0.00039	0.00000
HOM 8003	**0.01571**	**0.02652**
JAC 8012	0.09238	0.03152
JAC 8024	0.25423	0.00265
KEN 4006		**0.00237**
KIL 8023		**0.00026**
KIL 8041	0.02511	0.00000
KIL 8043	0.00194	0.00110
KIL 8044	0.03622	0.00609
KIN 8011		**0.00000**
KIN 8012		**0.00004**
KIN 8022	**0.01206**	**0.01380**
KIN 8023	0.02086	0.00033
KUL 8012	**0.02022**	**0.11076**
KUS 8002	**0.06162**	**0.06911**

Circuit	5 Year Baseline SAIDI*	Report Quarter SAIDI*
KUS 8004	0.00500	0.00181
KUS 8042	0.07830	0.02821
KUS 8044	0.01605	0.00000
KUS 8045	0.02505	0.00179
LAF 8026	0.04406	0.01141
LAU 8011	0.30809	0.00382
LAU 8012	0.09474	0.00058
LAU 8021	0.44101	0.01061
LAU 8023	0.82844	0.06185
LAU 8025	**0.02009**	**0.10303**
LAU 8034	0.60195	0.00061
LAW 8015	0.02138	0.00766
LAW 8016	0.14895	0.00054
LCE 8003	0.15926	0.00242
LCE 8005	0.11803	0.00228
LCE 8010	0.05624	0.00090
LCE 8012	0.30622	0.00000
LCE 8032	0.30801	0.00085
LCE 8033	0.42672	0.00000
LCE 8034	0.08300	0.01673
LEO 8005	0.61152	0.01065
LEO 8006	0.07368	0.00191
LEO 8032	0.00287	0.00136
LEO 8034	0.03370	0.00439
LEO 8041	**0.05678**	**0.19273**
LEV 8002	**0.06064**	**0.06469**
LEV 8008	**0.04412**	**0.22621**
LEV 8012	0.25318	0.00790
LEV 8016	0.00021	0.00000
LOC 8014		**0.00000**
LUM 8014	0.29932	0.00336
MAD 8022	0.41375	0.01250
MAI 8013	0.05318	0.04007
MAR 8002	0.04356	0.00225
MAR 8008	0.30277	0.00017
MAR 8010	0.29544	0.00000
MAR 8012	0.05857	0.00003
MAR 8013	0.36502	0.00035
MAR 8016	0.26336	0.00163
MDF 8012	0.58371	0.00116
MDF 8023	0.26488	0.00220
MDF 8024	0.26556	0.00261
MEA 8013	0.04040	0.01311
MEA 8024	0.09438	0.04539
MIN 8013	0.00714	0.00000

Circuit	5 Year Baseline SAIDI*	Report Quarter SAIDI*
MIN 8015	0.01242	0.00052
MIN 8026	0.01780	0.00000
MON 8002	0.35076	0.01259
MON 8003	0.27132	0.00639
MOT 8001	0.08290	0.00011
MOT 8002	0.12549	0.03369
MRO 8012	1.08732	0.01453
MRO 8013	0.46710	0.00476
MRO 8022	0.23183	0.00411
MRO 8023	0.19878	0.00363
MRO 8024	0.29163	0.09292
MSD 8001	0.40760	0.00000
NBS 8012	0.09414	0.00000
NBS 8013		**0.91343**
NBS 8021		**0.00000**
NED 8013	0.03270	0.00074
NED 8024		**0.00257**
NED 8025	0.01640	0.01282
NEW 8013	**0.01180**	**0.38418**
NEW 8014	**0.01839**	**0.04522**
NEW 8023	0.02660	0.01247
NEW 8025	0.00343	0.00187
NEW 8032		**0.00063**
NEW 8034	0.10522	0.02843
NEW 8041	**0.00280**	**0.00362**
NEW 8044	0.00273	0.00101
NIN 4001	0.05314	0.04194
NOT 8011		**0.00000**
NOT 8023	0.00214	0.00032
NRB 8014	0.03116	0.00000
NRB 8022		**0.00000**
NRP 4004		**0.01437**
NRP 4010		**0.04988**
OAK 4004	0.05636	0.00000
ORA 4002	0.07591	0.00126
PAT 4003		**0.00721**
PEH 8004		**0.00387**
PEH 8015		**0.03327**
PEH 8025	0.00149	0.00000
PEK 8018	0.08524	0.00000
PEK 8021	0.00069	0.00010
PEK 8023	0.05457	0.00088
PEK 8026	**0.04523**	**0.18109**
PEK 8035	0.28036	0.00550
PIE 8013	0.02355	0.08797

Circuit	5 Year Baseline SAIDI*	Report Quarter SAIDI*
PIE 8015	0.05606	0.00000
PLI 8004	**0.01320**	**0.03537**
PLI 8007	0.05542	0.00000
PLI 8008	0.19552	0.00115
POH 8012		**0.00000**
POH 8013	0.00898	0.00428
POH 8015	0.12765	0.00000
POH 8022	0.01503	0.00000
POL 4001		**0.00248**
RFL 8011	**0.00742**	**0.02311**
RFL 8021		**0.00007**
RFL 8023	**0.00885**	**0.02943**
RFL 8032	0.12446	0.00056
RFL 8034	0.04180	0.01396
RGW 4004	0.00776	0.00647
RIV 8006	0.00765	0.00604
RUN 8001		**0.00032**
RUN 8004	0.29484	0.00485
RVR 8022		**0.00000**
SAD 8032		**0.00000**
SAD 8043	**0.00775**	**0.02839**
SAD 8044	**0.00192**	**0.00594**
SDH 8021		**0.00154**
SDH 8026	0.01685	0.00155
SDH 8034		**0.00000**
SMV 8011	**0.00774**	**0.01043**
SMV 8013		**0.00293**
SMV 8021		**0.24553**
SMV 8024		**0.00000**
SMV 8025	0.01386	0.00575
SOH 8022	0.16946	0.00000
SOO 4011	0.62019	0.00232
SOO 4012	0.14426	0.03350
SOP 4007		**0.01162**
SPF 8012	0.78752	0.04433
SPF 8016		**0.00000**
SPF 8023	0.01271	0.00188
SPF 8024	0.00263	0.00000
SPF 8025	0.09408	0.00000

Circuit	5 Year Baseline SAIDI*	Report Quarter SAIDI*
SUN 8011	0.05952	0.01374
SUN 8013		**0.00000**
SUN 8021		**0.00000**
SUN 8034	0.02298	0.00204
SUN 8035	0.03902	0.00000
SUN 8044		**0.01258**
SWT 8001		**0.01151**
TNY 4002	**0.05690**	**0.13013**
TNY 4003	**0.03940**	**0.45732**
TUR 8004	0.00879	0.00019
VIL 8001	0.24055	0.00000
WAD 8011	0.08512	0.02281
WAD 8013	0.12231	0.02871
WAN 8014		**0.04307**
WAN 8015		**0.00009**
WAN 8025	0.66194	0.00000
WAV 4018	**0.02277**	**0.03127**
WEW 8021	0.21824	0.02186
WEW 8025	0.00255	0.00115
WEW 8031		**0.00088**
WEW 8033	0.03506	0.02681
WEW 8041		**0.00957**
WEW 8042	0.01304	0.00000
WEW 8044	0.07375	0.00735
WFL 8012	0.02690	0.02304
WFL 8032	**0.11140**	**0.27363**
WFL 8034	0.04228	0.00082
WOR 8011	0.02748	0.00579
WOR 8013	**0.13969**	**0.37336**
WOR 8022	**0.00042**	**0.00517**
WOR 8025	0.03185	0.00000
WYN 4003	0.31855	0.00312
YRD 8014	0.05063	0.02029
YRD 8024	0.08273	0.00820

**-System Average Interruption Duration Index (SAIDI) calculations are in minutes; bold values indicate circuits with a higher Major Event SAIDI than the 5-year Major Event SAIDI average.*

In the circuit data in **Table 7** above, the "0.00000" indicates an outage, but the value is beyond five decimal points captured by PSE&G, while blank cells indicate no outage in the 5-year window. Additionally, all circuits impacted by this Major Event had received investments during either the original Energy Strong Program or through ES 2. As indicated above, there were 269 circuits impacted by this

Major Event 177 of which had a current Major Event SAIDI better than the 5-year Major Event SAIDI average, while an additional 51 circuits had no Major Event outage within the 5-year comparison window, leaving 41 circuits that both had a prior Major Event outage within the past 5-years and had worse performance during this Major Event.

Additional information on the 15 worse performing circuits from this Major Event is provided below in **Table 8 – Q3 2021 Major Event Additional Information on Selected Circuits.** Note that some of these circuits had more than one incident during the Major Event, resulting in a total of 57 incidents from these 15 circuits, and that some show zero customers impacted, which reflects the way the circuit is modeled in PSE&G's connectivity model and the restoration/isolation steps used to restore service (e.g. isolating a section of cable for repair).

Table 8 – Q3 2021 Major Event Additional Information on Selected Circuits

Circuit	5-Year Baseline SAIDI*	Report Quarter SAIDI*	Customers Impacted	Outage Duration*
BEA 8010	0.07397	0.17328	1,644	257
BEA 8010	0.07397	0.17328	19	175
BEF 8014	0.01387	0.10160	873	230
BEF 8014	0.01387	0.10160	873	56
BEN 8016	0.01934	0.14705	410	247
BEN 8016	0.01934	0.14705	1,053	247
BLO 4006	0.00535	0.38192	1,505	567
BLO 4006	0.00535	0.38192	60	179
BLO 4006	0.00535	0.38192	63	69
BLO 4006	0.00535	0.38192	403	174
DFD 8041	0.20440	0.42586	729	303
DFD 8041	0.20440	0.42586	331	303
DFD 8041	0.20440	0.42586	373	364
DFD 8041	0.20440	0.42586	1	3,661
DFD 8041	0.20440	0.42586	44	2,220
DFD 8041	0.20440	0.42586	105	3,877
DFD 8041	0.20440	0.42586	20	4,057
KUL 8012	0.02022	0.11076	878	310
LAU 8025	0.02009	0.10303	62	164
LAU 8025	0.02009	0.10303	1,394	155
LAU 8025	0.02009	0.10303	663	18
LAU 8025	0.02009	0.10303	37	325
LAU 8025	0.02009	0.10303	30	100
LEO 8041	0.05678	0.19273	387	885
LEO 8041	0.05678	0.19273	0	1,042
LEO 8041	0.05678	0.19273	8	1,041
LEO 8041	0.05678	0.19273	20	1,042
LEO 8041	0.05678	0.19273	1,324	43
LEO 8041	0.05678	0.19273	1,324	34
LEV 8008	0.04412	0.22621	2,603	183
LEV 8008	0.04412	0.22621	82	970
NEW 8013	0.01180	0.38418	32	778
NEW 8013	0.01180	0.38418	1,131	258
NEW 8013	0.01180	0.38418	894	258
NEW 8013	0.01180	0.38418	478	830
PEK 8026	0.04523	0.18109	1,556	286

Circuit	5-Year Baseline SAIDI*	Report Quarter SAIDI*	Customers Impacted	Outage Duration*
PEK 8026	0.04523	0.18109	0	53
TNY 4002	0.05690	0.13013	0	182
TNY 4002	0.05690	0.13013	1,380	115
TNY 4002	0.05690	0.13013	39	183
TNY 4002	0.05690	0.13013	451	115
TNY 4002	0.05690	0.13013	17	178
TNY 4002	0.05690	0.13013	52	223
TNY 4002	0.05690	0.13013	6	178
TNY 4002	0.05690	0.13013	599	86
TNY 4002	0.05690	0.13013	775	45
TNY 4003	0.03940	0.45732	0	653
TNY 4003	0.03940	0.45732	647	652
TNY 4003	0.03940	0.45732	1,013	652
TNY 4003	0.03940	0.45732	1,660	25
WFL 8032	0.11140	0.27363	2	2,169
WFL 8032	0.11140	0.27363	1	2,169
WFL 8032	0.11140	0.27363	11	2,169
WFL 8032	0.11140	0.27363	135	4,756
WOR 8013	0.13969	0.37336	1,780	385
WOR 8013	0.13969	0.37336	1,350	172
WOR 8013	0.13969	0.37336	0	62
**-Calculated in minutes.*				

As indicated in **Table 8**, in addition to the original Energy Strong Program and ES 2 investments that increased sectionalizing of circuits to reduce the number of customers impacted by outages, the customer impact from a Major Event is also a function of the nature of the outages (extent of damage) and the location of damage relative to the various interrupting devices on the circuit, that is, reclosers or fuses. Additionally, the circuits in **Table 8** with zero customers reflect the way the circuit is modeled in PSE&G's connectivity model and the restoration/isolation steps used to restore service (e.g. isolating a section of cable for repair, or a transformer with no assigned customers). For some circuits, the 5-year baseline outage(s) were smaller or affected fewer customers, including different device operations (fuse with 10 customers vs. fuse with 150 customers) than the incident from the current Major Event being reported. Some circuits had more non-reclosing device operations in this Major Event (more fuse jobs) or more customers served by the circuit due to circuit rearrangements. Three of the circuits that had more severe outages than the five-year average were DFD 8041, LEO 8041, and WFL 8032, each of which had an outage involving tree impacts, with additional circuit-specific information as follows:

- DFD 8041: a tornado touched down in the area and resulted in the primary line down from wind/tree impacts.
- LEO 8041: a tree brought down all three phases, resulting in no circuit operation.
- WFL 8032: large tree impact resulted in multiple phases down in addition to flooding in the area.

Beyond the circuit-level performance, this Major Event and the flooding associated with resulted in water entering eight of the substations that were raised and rebuilt as part of the original Energy Strong

Program,[1] however, due to the storm hardening at those stations none was interrupted by these flooding events.

III. Project Status

A. Electric Station Flood Mitigation

A summary of the subprogram plan as of the end of the third quarter of 2021 is provided below in **Table 9 – ES 2 Electric Station Flood Mitigation Subprogram Milestone Schedule as of September 30, 2021**.

Table 9 – ES 2 Electric Station Flood Mitigation Milestone Schedule as of September 30, 2021

Project	Plan Status Point	2019		2020				2021				2022				2023					2024
		Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4		
1. Academy Street	Dec. 2019		KO					C					IS		CO					*December 31, 2023 - ES 2 Program End Date*	
	Dec. 2020		KO		C							IS		CO							
	Sep. 2021		KO		C						IS			CO							
2. Clay Street	Dec. 2019	*Schedule Under Development*																			
	Dec. 2020			KO							C								IS		CO (Q2)
	Sep. 2021			KO							C				IS						CO (Q2)
3. Front Street^	Dec. 2019	*Not in ES 2 Program*																			
	Dec. 2020	*Not in ES 2 Program*																			
	Sep. 2021								KO				C						IS		CO (Q2)
4. Hasbrouck Heights	Dec. 2019		KO						C						IS		CO				
	Dec. 2020		KO									C					IS		CO		
	Sep. 2021		KO									C					IS		CO		
5. Kingsland	Dec. 2019			KO				C			IS		CO								
	Dec. 2020			KO										C					IS		CO (Q2)
	Sep. 2021			KO											C				IS		CO (Q2)
6. Lakeside Avenue	Dec. 2019*				KO				C										IS		CO (Q2)
	Dec. 2020						KO							C					IS		CO (Q2)
	Sep. 2021						KO							C					IS		CO (Q3)
7. Leonia	Dec. 2019	*Schedule Under Development*																			
	Dec. 2020			KO		C									IS		CO				
	Sep. 2021			KO		C									IS		CO				
8. Market Street	Dec. 2019			KO				C	OS		CO										
	Dec. 2020			KO					C	OS		CO									
	Sep. 2021			KO						C/OS			CO								
9. Meadow Road	Dec. 2019	*Schedule Under Development*																			
	Dec. 2020			KO											C				IS		CO (Q2)
	Sep. 2021			KO											C			IS			CO (Q2)

[1] The eight substations upgraded during ES 1 that experienced water intrusions included: Belmont, Cranford, Ewing, Hoboken, New Milford, Port Street, Rahway, and Somerville.

Project	Plan Status Point	2019		2020				2021				2022				2023					2024
		Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4		
10. Orange Valley	Dec. 2019	*Schedule Under Development*																		*December 31, 2023 - ES 2 Program End Date*	
	Dec. 2020					<u>KO</u>										C					IS (Q1); CO (Q3)
	Sep. 2021					<u>KO</u>									C						IS (Q1); CO (Q3)
11. Ridgefield 13kV	Dec. 2019			<u>KO</u>	C										IS		CO				
	Dec. 2020			<u>KO</u>	<u>C</u>										IS		CO				
	Sep. 2021			<u>KO</u>	<u>C</u>										IS			CO			
12. Ridgefield 4kV	Dec. 2019			<u>KO</u>						C	OS			CO							
	Dec. 2020			<u>KO</u>	<u>C</u>				OS		CO										
	Sep. 2021			<u>KO</u>	<u>C</u>				<u>OS</u>		CO										
13. State Street	Dec. 2019		<u>KO</u>					C								IS					CO (Q1)
	Dec. 2020		<u>KO</u>						C				IS								CO (Q1)
	Sep. 2021		<u>KO</u>						<u>C</u>					IS							CO (Q1)
14. Toney's Brook	Dec. 2019			<u>KO</u>						C									IS		CO (Q2)
	Dec. 2020			<u>KO</u>										C			IS				CO (Q2)
	Sep. 2021			<u>KO</u>										C			IS				CO (Q2)
15. Waverly	Dec. 2019	*Schedule Under Development*																			
	Dec. 2020			<u>KO</u>			<u>C</u>												IS		CO (Q2)
	Sep. 2021			<u>KO</u>			<u>C</u>														IS (Q4); CO (Q2 2025)
16. Woodlynne	Dec. 2019		<u>KO</u>												C				IS		CO (Q2)
	Dec. 2020		<u>KO</u>												C				IS		CO (Q2)
	Sep. 2021		<u>KO</u>												C				IS		CO (Q2)

<u>Legend</u>: KO = Kickoff; C = Construction; IS = Fully In-Service (major assets in-service); OS = Out-of-Service (if eliminated); CO = Closeout
-Actuals are indicated with an underline (Note: for the Market Street and Ridgefield 4kV projects, outside plant construction began in the first quarter of 2020, the construction milestone indicated on this chart reflects inside plant construction).
***-The Dec. 2019 Lakeside Avenue project schedule was based on the original raise and rebuild mitigation strategy; the current schedule reflects the proposed mitigation method change that contemplates relocating the substation.**
^-The Front Street project was proposed by PSE&G during the second quarter of 2021 to replace the cancelled Constable Hook project.

A summary of the subprogram status as of the end of the third quarter of 2021 is provided below **Table 10 – ES 2 Electric Station Flood Mitigation Summary Status as of September 30, 2021**.

Table 10 – ES 2 Electric Station Flood Mitigation Summary Status as of September 30, 2021

Activity	Total # of Projects	Specific Projects
Kickoff Meeting	16	Academy Street; Clay Street; Front Street; Hasbrouck Heights; Kingsland; Lakeside Avenue; Leonia; Market Street; Meadow Road; Orange Valley; Ridgefield 13kV; Ridgefield 4kV; State Street; Toney's Brook; Waverly; Woodlynne
Key Drawing Review	16	Academy Street; Clay Street; Front Street; Hasbrouck Heights; Kingsland; Lakeside Avenue; Leonia; Market Street; Meadow Road;

Activity	Total # of Projects	Specific Projects
		Orange Valley; Ridgefield 13kV; Ridgefield 4kV; State Street; Toney's Brook; Waverly; Woodlynne
Scope Locked	16	Academy Street; Clay Street; Front Street; Hasbrouck Heights; Kingsland; Lakeside Avenue; Leonia; Market Street; Meadow Road; Orange Valley; Ridgefield 4kV; Ridgefield 13kV; State Street; Toney's Brook; Waverly; Woodlynne
Major Equipment Purchase Orders (POs)	17*	Academy Street; Clay Street; Front Street; Hasbrouck Heights; Kingsland; Lakeside; Leonia*; Meadow Road; Orange Valley; Ridgefield 13kV*; State Street; Toney's Brook; Waverly*; Woodlynne
Architect/ Engineer (A/E) Contract Award (or selection of PSE&G internal engineering)	16	Academy Street[1]; Clay Street[1]; Front Street[3]; Hasbrouck Heights[1]; Kingsland[2]; Lakeside Avenue[3]; Leonia[2]; Market Street[2]; Meadow Road[2]; Orange Valley[1]; Ridgefield 13kV[2]; Ridgefield 4kV[2]; State Street[2]; Toney's Brook[3]; Waverly[3]; Woodlynne[1]
Construction Start**	7	Academy Street; Leonia; Market Street; Ridgefield 4kV; Ridgefield 13kV; State Street; Waverly
In-Service	2	Market Street; Ridgefield 4kV

**-Three of the listed projects (Leonia, Ridgefield 13kV, and Waverly) have two switchgears, thus the current count reflects 17 switchgears at 14 substations.*
[1]-Indicates Burns & McDonnell is serving as the A/E.
[2]-Indicates PSE&G internal resources are serving as the A/E.
[3]-Indicates Black & Veatch is serving as the A/E.
***-Includes inside plant and/or outside plant construction.*

Beyond the key activities summarized in **Table 10** above, **Table 11 – ES 2 Electric Station Flood Mitigation Upcoming Activities for Q4 2021** summarizes the planned activities for each project during the fourth quarter of 2021, including any carryover of activities from earlier periods.

Table 11 – ES 2 Electric Station Flood Mitigation Upcoming Activities for Q4 2021

Station	Upcoming Activities for Q4 2021	Carryover Activities from Q3 2021
1. Academy Street	• Place switchgear in-service on 1st circuit	• Continued engineering and construction
2. Clay Street	• Civil and electrical drawings (phase 2) Issued for Construction (IFC) • Electrical construction out for bid	• Continued engineering
3. Front Street	• Switchgear Purchase Order (PO) issued • License and permitting package issued • Site plan submitted for approval	• Continued engineering
4. Hasbrouck Heights	• Switchgear and capacitor bank delivered	• Continued engineering
5. Kingsland	• License and permitting package issued • Civil and electrical drawings IFC	• Commence license and permitting design • Continued engineering
6. Lakeside Avenue	• Site plan submittal • Vendor drawings received (final switchgear arrangement)	• Submit site plan application • Vendor drawings received (final switchgear arrangement)
7. Leonia	• 13kV switchgear #1 in-service	• Continued engineering and construction • Start commissioning of 13kV switchgear #1

Station	Upcoming Activities for Q4 2021	Carryover Activities from Q3 2021
8. Market Street	• Electrical demolition complete	• Start civil and electrical demolition
9. Meadow Road	• Receive New Jersey Department of Environmental Protection (NJDEP) permit	• Continued engineering
10. Orange Valley	• City council approval of site plan amendment • Vendor drawings received (final switchgear arrangement)	• Continued engineering
11. Ridgefield 13kV	• Commissioning and in-servicing switchgear #2	• Continued construction
12. Ridgefield 4kV	• Complete civil demolition	• Continued demolition
13. State Street	• Switchgear delivered • Start electrical construction	• 70% estimate completed • Switchgear delivered
14. Toney's Brook	• Start preliminary civil manhole/conduit work • Controls drawings IFC	• Continued engineering
15. Waverly	• Vendor drawings received (final switchgear controls) • Civil and electrical drawings IFC • New Site Plan meeting	• Site plan meeting requested • Continued engineering
16. Woodlynne	• Construction permits received	• Continued engineering

The current project estimates, including base and R&C amounts, is shown below in **Table 12 – ES 2 Electric Station Flood Mitigation Project Cost Status as of September 30, 2021**. **Table 12** also shows the current estimate level based on PSE&G's estimating processes and as approved by the URB, the actual spend, and percentage of actuals to estimate as of the end of the third quarter of 2021.

Table 12 – ES 2 Electric Station Flood Mitigation Project Cost Status as of September 30, 2021

Project	Estimate Level	Base	Risk & Contingency	Total	Current Forecast	Actuals to Date	% of Actuals to Estimate
1. Academy Street	Definitive	$9,800,000	$700,000	$10,500,000	$9,012,316	$5,431,127	52%
2. Clay Street	Conceptual	$30,300,000	$3,500,000	$33,800,000	$30,735,399	$3,255,941	10%
3. Front Street*	Study	$23,000,000	$4,400,000	$27,400,000	$25,889,200	$1,261,050	5%
4. Hasbrouck Heights	Conceptual	$20,500,000	$2,200,000	$22,700,000	$20,480,201	$2,091,795	9%
5. Kingsland	Study	$5,400,000	$2,900,000	$8,300,000	$6,418,540	$531,370	6%
6. Lakeside Avenue	Study	$39,400,000	$8,500,000	$47,900,000	$39,356,279	$1,045,328	2%
7. Leonia	Definitive	$24,900,000	$1,500,000	$26,400,000	$24,851,796	$14,399,755	55%
8. Market Street	Definitive	$29,100,000	$800,000	$29,900,000	$29,032,028	$25,293,157	85%

Project	Estimate Level	Base	Risk & Contingency	Total	Current Forecast	Actuals to Date	% of Actuals to Estimate
9. Meadow Road	Study	$7,200,000	$1,800,000	$9,000,000	$7,441,372	$899,374	10%
10. Orange Valley	Study	$16,000,000	$4,200,000	$20,200,000	$14,765,212	$702,848	4%
11. Ridgefield 13kV	Conceptual	$25,300,000	$2,300,000	$27,600,000	$25,987,975	$14,893,425	54%
12. Ridgefield 4kV	Definitive	$20,800,000	$500,000	$21,300,000	$20,716,895	$20,404,916	96%
13. State Street	Conceptual	$19,100,000	$2,300,000	$21,400,000	$19,040,411	$1,764,732	8%
14. Toney's Brook	Conceptual	$16,200,000	$2,600,000	$18,800,000	$16,254,329	$1,122,883	6%
15. Waverly	Study	$29,400,000	$6,000,000	$35,400,000	$35,319,007	$6,339,767	18%
16. Woodlynne	Study	$15,800,000	$3,600,000	$19,400,000	$21,255,000	$1,947,106	10%
Subprogram Total**		**$332,200,000**	**$47,800,000**	**$380,000,000**	**$346,555,960**	**$101,384,573**	**27%**

**-The Front Street project was proposed by PSE&G during the second quarter of 2021 to replace the cancelled Constable Hook project.*
***-The Subprogram Total presented in this Table 12 excludes the $5.3 million previously estimated for the cancelled Constable Hook project and excludes an additional $3.7 million approved by the URB for the subprogram and currently allocated as a placeholder. The currently approved URB funding for the subprogram includes both these amounts, resulting in a total subprogram estimate of $389.0 million. The cancelled Constable Hook project and the subprogram placeholder are also not included in the current $346.6 million subprogram forecast.*

Findings & Observations

- Six of the sixteen Electric Station Flood Mitigation projects had movement in the forecasted in-service date during the third quarter of 2021, with two advancing and four slipping. Of these six projects, five of the projects (Academy Street, Clay Street, Front Street, Leonia, and Ridgefield 13kV) had forecasted in-service dates change by less than two weeks. The Lakeside Avenue forecasted in-service date advanced 35 days from the status as of the end of the second quarter of 2021.

- Following the Market Street and Ridgefield 4kV projects being placed in-service during the second quarter of 2021, the next project forecasted to go in-service is the Academy Street project in October 2021.

- Four projects had new estimates approved by the URB during the third quarter of 2021, including the Leonia project advancing to the Definitive level with a new estimate of $26.4 million (decreasing $1.1 from the prior estimate); the Market Street project submitting a revised Definitive level estimate with a new estimate of $29.9 million (increasing $3.0 million from the prior estimate); the Ridgefield 4kV project submitted a revised Definitive level estimate with a new estimate of $21.3 million (increasing $1.8 million from the prior estimate); and the State Street project advancing to the Conceptual level with a new estimate of $21.4 million (decreasing $1.0 million from the prior estimate).

- The IM has found nothing to date that would jeopardize the subprogram being completed on budget. However, the status of the later projects in this subprogram, and in particular Waverly, will have to continue to be closely followed to monitor if the projects can be completed within the ES 2 Program window. As of the end of the third quarter of 2021, the Waverly project continues to show a final in-service date in December 2024. The Waverly project has multiple major asset in-service dates for the 26kV switchgear, 4kV switchgear, and three transformers, which are currently forecasted from December 2022 (26kV switchgear) to December 2024 (Transformer #3). PSE&G has informed the IM that the project team has every intention of improving the in-service dates and will be examining the potential to shorten durations and/or work activities concurrently to pull the final in-service date back into 2023.

1. Academy Street

During the third quarter of 2021, $217,396 was spent on the Academy Street project compared to a forecast of approximately $600,000, which brought the total spend to approximately $5.4 million. The variance in spend during the third quarter of 2021 was driven by the focus on commissioning the Fairmount 69kV project before bringing the Academy Street project in-service. Despite that delay to commissioning activities, the forecasted in-service date for the Academy Street project advanced by five days from the prior quarter to October 20, 2021.

The primary activity conducted during the third quarter of 2021 on the Academy Street project was the continued advancement of construction activities. Construction, which started in July 2020 for non-permit work on Academy Street, advanced 13% during the third quarter to reach 88% complete inside plant (100% complete outside plant), while the total project is reported at 90% complete as of the end of the third quarter of 2021.

The actual spend by quarter for Academy Street as compared to the current approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022
Actuals					***Forecast***	
$150,398	$4,224,550	$378,939	$405,843	$271,396	$1,046,595	$2,534,594

Actuals to Date	Estimate	% of Actuals to Estimate
$5,431,127	$10,500,000	52%

2. Clay Street

During the third quarter of 2021, $1,099,440 was spent on the Clay Street project compared to a forecast of approximately $1.1 million, which brought the total spend to approximately $3.3 million. The forecasted in-service date for the Clay Street project as of the end of the third quarter of 2021 slipped eight days from the end of the second quarter to December 27, 2022.

The primary activities on the Clay Street project during the third quarter of 2021 included the IFC release of control drawings and civil construction work going out for bid.

The actual spend by quarter for Clay Street as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2024
Actuals					*Forecast*	
$116,409	$879,339	$565,030	$595,723	$1,099,440	$4,968,997	$22,510,461

Actuals to Date	Estimate	% of Actuals to Estimate
$3,255,941	$33,800,000	10%

3. *Front Street*

During the third quarter of 2021, $1,070,135 was spent on the Front Street project compared to a forecast of approximately $431,000, which brought total spend to approximately $1.3 million. The variance in spend during the third quarter of 2021 was driven by a change in the payment terms for the temporary switchgear from full payment at delivery to partial milestones. The forecasted in-service date for the Front Street project as of the end of the third quarter of 2021 slipped four days from the end of the second quarter to November 6, 2023.

The primary activities on the Front Street project during the third quarter of 2021 included the issuance of the PO for the temporary switchgear, completion of the permit compliance matrix, and approval of the scope document.

The actual spend by quarter for Front Street as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2024
Actuals					*Forecast*	
$0	$0	$0	$190,915	$1,070,135	$1,074,477	$23,553,673

Actuals to Date	Estimate	% of Actuals to Estimate
$1,261,050	$27,400,000	5%

4. *Hasbrouck Heights*

During the third quarter of 2021, $71,649 was spent on the Hasbrouck Heights project compared to a forecast of approximately $910,000, which brought the total spend to approximately $2.1 million. The variance in spend during the third quarter of 2021 was driven by inclement weather and limited resource availability that delayed the start of Outside Plant (OP) Division work. The forecasted in-service date for the Hasbrouck Heights project continues to remain February 7, 2023, which is unchanged from the previous quarter.

Notable activities completed during the third quarter of 2021 included the contingency plan control drawings IFC and the start of OP manhole enlargement work.

The actual spend by quarter for Hasbrouck Heights as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals					*Forecast*	
$149,848	$1,129,934	$550,795	$189,748	$71,469	$5,370,203	$13,018,203

Actuals to Date	Estimate	% of Actuals to Estimate
$2,091,795	$22,700,000	9%

5. Kingsland

During the third quarter of 2021, $150,084 was spent on the Kingsland project compared to a forecast of approximately $243,000, which brought the total spend to $531,370. The forecasted in-service date for the Kingsland project continues to remain October 4, 2023, which is unchanged from the previous quarter.

During the third quarter of 2021, the Kingsland project commenced detailed design and license and permitting design work.

The actual spend by quarter for Kingsland as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals					*Forecast*	
$104,112	$209,667	$30,621	$36,886	$150,084	$202,265	$5,684,906

Actuals to Date	Estimate	% of Actuals to Estimate
$531,370	$8,300,000	6%

6. Lakeside Avenue

During the third quarter of 2021, $89,151 was spent on the Lakeside Avenue project compared to a forecast of approximately $105,000. The forecasted in-service date for the Lakeside Avenue project as of the end of the third quarter of 2021 advanced 35 days from the prior quarter to November 8, 2023.

Notable activities completed during the third quarter of 2021 included the submittal of the site plan application, receipt of vendor drawings (final switchgear arrangement), and the commencement of detailed engineering.

The actual spend by quarter for Lakeside Avenue as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2024
Actuals					*Forecast*	
$148,943	$453,994	$178,973	$174,268	$89,151	$216,131	$38,094,820

Actuals to Date	Estimate	% of Actuals to Estimate
$1,045,328	$47,900,000	2%

7. Leonia

During the third quarter of 2021, $1,365,412 was spent on the Leonia project compared to a forecast of approximately $1.4million, which brought the total spend to approximately $14.4 million. The forecasted in-service date for the Leonia project as of the end of the third quarter of 2021 slipped 10 days from the prior quarter to October 10, 2022.

Notable activities completed during the third quarter of 2021 included the commissioning of the 13kV switchgear #1. The Leonia project also advanced to the Definitive level estimate, which was approved by the URB in July 2021. This Definitive level estimate resulted in the total estimate for the project being reduced to $26.4 million from $27.5 million (at the Conceptual level estimate). The reduction in the current estimate was the result of:

- Revised estimate for Division underground work: -$0.4 million;
- Increase in construction costs: $0.3 million; and,
- Reduction in R&C based on the current risk profile for the project: -$1.0 million.

The actual spend by quarter for Leonia as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals					*Forecast*	
$44,792	$6,033,379	$2,809,628	$4,146,544	$1,365,412	$1,642,466	$8,809,575

Actuals to Date	Estimate	% of Actuals to Estimate
$14,399,755	$26,400,000	55%

8. Market Street

During the third quarter of 2021, $1,779,029 was spent on the Market Street project compared to a forecast of approximately $2.0 million, which brought the total spend to approximately $25.3 million. Notable activities conducted during the third quarter of 2021 included the commencement of electrical demolition at the station, which was placed out of service on June 25, 2021 following the completion of the 4kV to 13kV conversion work.

The Market Street project also had a revised Definitive level estimate approved by the URB in August 2021, which resulted in the total estimate increasing by $3.0 million from the previous Definitive level estimate. The increase was driven by:

- Additional OP overhead and restoration work along with associated material and surcharges based on the complexity of the work and the field conditions: $2.8 million, which was comprised of:
  - Unknown OP field conditions: condition of poles, conductors, transformers, and service wires along with space constraints for equipment operation required increased labor and

material to resolve. In addition, hazardous soils required use of backhoes, which in turn required additional road closures/traffic safety control;
   - o Cutover procedures: During the procedures for the 13kV conversions, the City mandated additional police around the work areas to ensure public safety and to minimize traffic detours. While construction activities were ongoing, the system being upgraded needed to remain in service and operations to continue to serve customers, which resulted in a higher that estimated level of effort and materials to complete this work safely and reliably; and,
   - o Traffic control procedures: Included in the conditions of permit approval, County and City officials required additional police presence and other traffic control contractor labor to safeguard work areas and mitigate traffic disruptions.
- Higher than estimated traffic control as per city/county requirements: $1.1 million.
- Reduction in R&C based on the current risk profile for the project: -$0.9 million.

The actual spend by quarter for Market Street as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022
Actuals					*Forecast*	
$251,193	$16,079,601	$4,035,880	$3,147,454	$1,779,029	$3,020,923	$717,949

Actuals to Date	Estimate	% of Actuals to Estimate
$25,293,157	$29,900,000	85%

9. Meadow Road

During the third quarter of 2021, $113,271 was spent on the Meadow Road project compared to a forecast of $69,000, which brought the total spend to approximately $900,000. Preliminary design work continued to progress during the third quarter of 2021, with minimal other activities conducted on the Meadow Road project this quarter as the bulk of this project's activities planned for 2022-2023. The forecasted in-service date for the Meadow Road project as of the end of the third quarter of 2021 remained unchanged from the prior quarter at September 22, 2023.

The actual spend by quarter for Meadow Road as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2024
Actuals					*Forecast*	
$63,128	$535,081	$117,672	$70,220	$113,271	$88,000	$6,453,998

Actuals to Date	Estimate	% of Actuals to Estimate
$899,374	$9,000,000	10%

10. Orange Valley

During the third quarter of 2021, $108,806 was spent on the Orange Valley project compared to a forecast of approximately $75,000, which bought the total spend to approximately $703,000. Preliminary design work continued to progress during the third quarter of 2021, with minimal other activities conducted on the Orange Valley project this quarter as the bulk of this project's activities planned for 2022-2023. The forecasted in-service date for the Orange Valley project as of the end of the third quarter of 2021 remained unchanged from the project quarter at December 29, 2023.

The actual spend by quarter for Orange Valley as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2024
Actuals					*Forecast*	
$77,029	$362,895	$7,291	$146,827	$108,807	$68,426	$13,993,938

Actuals to Date	Estimate	% of Actuals to Estimate
$702,848	$20,200,000	4%

11. Ridgefield 13kV

During the third quarter of 2021, $1,573,500 was spent on the Ridgefield 13kV project compared to a forecast of approximately $2.2 million, which brought the total spend to approximately $14.9 million. The variance in spend during the third quarter of 2021 was driven by manhole and duct bank work planned for September that was postponed due to an obstruction by the concrete slab in the way of the manhole modification that was not part of the original design, and thus was not identified during the design phase of the project. The forecasted in-service date for the Ridgefield 13kV project as of the end of the third quarter of 2021 slipped three days from the prior quarter to November 11, 2022.

Notable activities completed during the third quarter of 2021 included the start of electrical construction and the setting of the first permanent 13kV switchgear. Construction at Ridgefield 13kV advanced to 70% complete inside plant as of the end of the second quarter of 2021, compared to 58% complete at the end of the prior quarter, with the total project at a reported 70% completion.

The actual spend by quarter for Ridgefield 13kV as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals					*Forecast*	
$205,982	$6,232,692	$3,215,967	$3,665,283	$1,573,500	$2,760,022	$8,334,528

Actuals to Date	Estimate	% of Actuals to Estimate
$14,893,425	$27,600,000	54%

12. Ridgefield 4kV

During the third quarter of 2021, $1,653,764 was spent on the Ridgefield 4kV project compared to a forecast of approximately $1.9 million, which brought the total spend to approximately $20.4 million. The variance in spend this quarter was driven by Division accruals released while the invoice was paid against an incorrect workorder (corrected via journal entry). The project was placed in-service on May 16, 2021.

The primary activities performed during the third quarter of 2021 included the commencement of station demolition. The total project is reported at 99% complete as of the end of the second quarter of 2021, up from 85% complete as of the end of the prior quarter.

The Ridgefield 4kV project also had a revised Definitive level estimate approved by the URB in July 2021, which resulted in the total estimate increasing by $1.8 million from the previous Definitive level estimate. The increase was driven by:

- Division manhole rebuild work awarded higher than estimate: $0.3 million;
- Additional Division labor and material required to rebuild several secondary buses and reroute two underground circuits around an existing gas main: $0.8 million;
- Additional engineering and overhead hours required to remove primary wires to complete 4-13kV conversions (involving aerial cable removal omitted from prior estimates): $1.2 million; and,
- Reduction in R&C based on the current risk profile of the project: -$0.5 million.

The actual spend by quarter for Ridgefield 4kV as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022
Actuals					*Forecast*	
$143,414	$11,239,534	$2,808,765	$4,559,439	$1,653,764	$251,980	$60,000

Actuals to Date	Estimate	% of Actuals to Estimate
$20,404,916	$21,300,000	96%

13. State Street

During the third quarter of 2021, $571,099 was spent on the State Street project compared to a forecast of approximately $4.2 million, which brought the total spend to approximately $1.8 million. The variance in spend during the quarter was driven by the switchgear delivery shifting from September as forecasted to October. The forecasted in-service date for the State Street project as of the end of the third quarter of 2021 remains unchanged from the prior quarter at September 23, 2022. The sequencing of the IP and OP scopes of the State Street project always planned on the IP scope being completed prior to the OP scope, with that continued sequencing there is no advancement in the in-service date for this project following the split of the State Street OP scope to an Electric Stipulated Base project.

Notable activities performed on State Street during the third quarter of 2021 included the commencement of civil construction. The State Street project also advanced to the Conceptual level estimate, which was approved by the URB in August 2021. This Conceptual level estimate resulted in the total estimate for the project being reduced to $21.4 million from $22.4 million (at the revised Study level estimate). The reduction in the current estimate was the result of:

- Cost of removal scope award lower than estimated: -$0.5 million;
- Lower carrying cost: -$0.4 million;
- Capacitor banks award higher than estimated: $0.2 million;
- Revised Division electrical construction estimate: $0.5 million;
- Reduction in R&C based on the project's current risk profile: -$0.8 million

The actual spend by quarter for State Street as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals					*Forecast*	
$77,590	$662,148	$237,415	$216,479	$571,099	$6,885,880	$10,389,799

Actuals to Date	Estimate	% of Actuals to Estimate
$1,764,732	$21,400,000	8%

14. Toney's Brook

During the third quarter of 2021, $159,132 was spent on the Toney's Brook project compared to a forecast of approximately $186,000, which brought the total spend to approximately $1.1 million. The forecasted in-service date for the Toney's Brook project as of the end of the third quarter of 2021 remains unchanged from the prior quarter at April 21, 2023.

Notable activities achieved during the third quarter of 2021 included the approval of state and municipal permits.

The actual spend by quarter for Toney's Brook as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2024
Actuals					*Forecast*	
$211,940	$373,096	$88,947	$289,769	$159,132	$437,135	$14,694,311

Actuals to Date	Estimate	% of Actuals to Estimate
$1,122,883	$18,800,000	6%

15. Waverly

During the third quarter of 2021, $277,739 was spent on the Waverly project compared to a forecast of approximately $437,000, which brought the total spend to approximately $6.3 million. The variance in second quarter spend was largely driven an engineering milestone that shifted from September to October and work delayed in September due to lack of resources in the Metro Division. The forecasted in-service date for the Waverly project as of the end of the third quarter of 2021 remains unchanged from the prior quarter at December 18, 2024 as the project awaits resolution of its site plan application.

As reported in the IM 2021 First Quarter Report, the project team requested a special meeting to maintain the project's schedule, which was held in March 2021. The Newark Planning Board denied the site plan application at this meeting, which requires the project team to prepare a new site plan application. The comments received on the original site plan from the Newark Planning Board generally focused on the outward appearance of the substation. The revised site plan was submitted to the Newark Planning Board in early September 2021 with the site plan approval expected to be granted in a December 2021 meeting. The revised site plan incorporated feedback received from community meetings and from discussions with the Director of Arts and Culture for the City of Newark and the Newark Arts Council. The result is redesigned street facing frontages to the substation that includes a fence with brick finish (giving a wall-like appearance) and locations for artwork to be placed, two entrance gates with matching color schemes, portions of the isolation walls that were visible were redesigned to match the brick finishes on the street facing fences, and landscaping around the sidewalk area outside the substation was also added.

The actual spend by quarter for Waverly as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2025
Actuals					*Forecast*	
$103,748	$2,460,815	$659,572	$2,837,893	$277,739	$930,920	$28,048,320

Actuals to Date	Estimate	% of Actuals to Estimate
$6,339,767	$35,400,000	18%

16. Woodlynne

During the third quarter of 2021, $428,009 was spent on the Woodlynne project compared to a forecast of approximately $414,000, which brought the total spend to approximately $1.9 million. The forecasted in-service date for the Woodlynne project as of the end of the third quarter of 2021 remains unchanged from the prior quarter at October 10, 2023.

Preliminary design work continued to progress during the third quarter of 2021, with minimal other activities conducted on the Woodlynne project this quarter as the bulk of this project's activities planned for 2022-2023.

The actual spend by quarter for Woodlynne as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2024
Actuals					*Forecast*	
$110,982	$993,298	$282,187	$132,630	$428,009	$1,248,185	$18,059,709

Actuals to Date	Estimate	% of Actuals to Estimate
$1,947,106	$19,400,000	10%

B. Contingency Reconfiguration

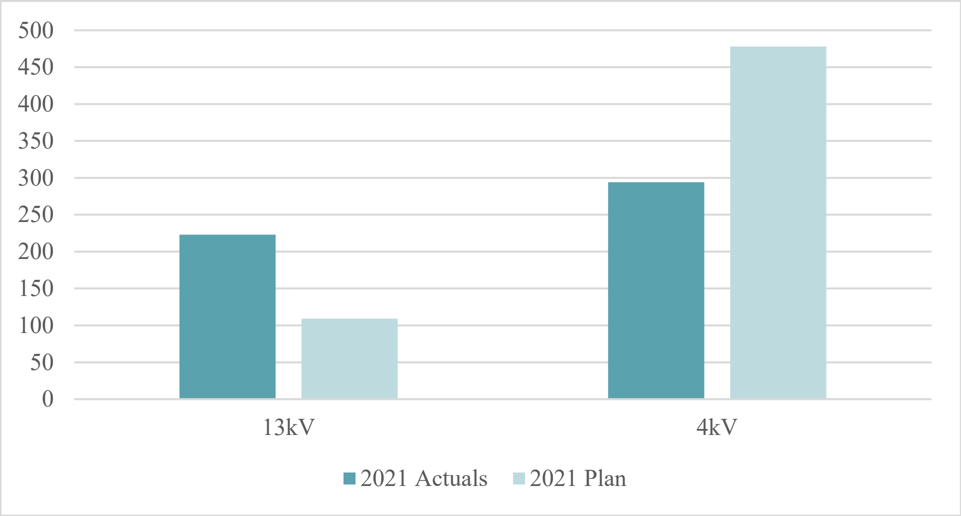
During the third quarter of 2021, work continued to progress in the Contingency Reconfiguration subprogram with all four Divisions continuing to install reclosers with a total of 161 installed during the quarter and 173 commissioned. **Table 13 – ES 2 Program Recloser Status as of September 30, 2021** provides a summary of the recloser aspect of the Contingency Reconfiguration subprogram, indicating the current status of engineering, installation, and commissioning; while **Figure 3 – 2021 Recloser Installations as of September 30, 2021** compares the installed reclosers as of the end of the third quarter of 2021 against PSE&G's 2021 installation plan.[2]

[2] Note that as discussed in the IM 2021 First Quarter Report (Section IV.A.1.) and the IM 2021 Second Quarter Report (Section II.A.1.), the number of reclosers identified the Contingency Reconfiguration subprogram was updated after the 2021 installation plan was established, which resulted in a net reduction of the 4kV reclosers planned for the subprogram and a net increase of the 13kV reclosers planned for the subprogram.

Table 13 – ES 2 Program Recloser Status as of September 30, 2021

Type	Engineering Packages Completed (1 recloser ea.)			Reclosers Installed			Reclosers Commissioned		
	Q3 Qty.	*2021 Total*	*Program Total*	*Q3 Qty.*	*2021 Total*	*Program Total*	*Q3 Qty.*	*2021 Total*	*Program Total*
13kV	74	220	919	81	223	884	91	227	871
4kV	60	248	502	80	294	451	82	294	449
Total	134	468	1,421	161	517	1,335	173	519	1,320

Figure 3 – 2021 Recloser Installations as of September 30, 2021



As shown in **Table 13** and **Figure 3**, PSE&G continued to maintain progress during the third quarter of 2021 and stayed on track for the 2021. As discussed in prior IM reports, there was an identified resource constraints within the Metro Division that prompted PSE&G to engage a contractor to perform the pole settings from the recloser scope, which commenced early in the second quarter of 2021, to reduce schedule impacts including avoiding other potential resource constraints if the recloser installations were to slip further into 2022 and overlap with the Fuse Saver scope.

The Fuse Saver pilot program commenced in November 2020 and was primarily completed in January 2021.[3] In total, this phase of the Fuse Saver pilot program included the installation and commissioning of 80 Fuse Saver devices. During execution of the pilot program, PSE&G observed factors that will help it prepare for execution of the full Fuse Saver scope, including installation specifications (the remote control unit (RCU) must be placed directly below the Fuse Saver to avoid communications issues), and cost elements for some of the locations (new poles, traffic control, etc.). While monitoring performance of the installed Fuse Savers, PSE&G experienced other communication issues between the Fuse Savers and the RCU, wherein the Supervisory Control and Data Acquisition (SCADA) communication indicated a false open/close alarm on some of the devices. Siemens has provided a prototype Fuse Saver to address the communication issues, which PSE&G will monitor to ensure it addresses the issues prior to placing

[3] In the second quarter of 2021, PSE&G decided to install the remaining 34 Fuse Savers in its inventory to capture additional cost and performance data to better inform the planning and execution of the full scope of work. These installations were completed across the second and third quarters of 2021.

additional orders. Because of this, the full Fuse Saver scope is no longer anticipated to commence in 2021.

The current forecasted completion date for the primary components that make up the Contingency Reconfiguration subprogram are provided in **Table 14 – ES 2 Contingency Reconfiguration Forecasted Completion Dates as of September 30, 2021**. This table also shows the forecasted final in-service dates as of the end of the second quarter of 2021 to show movement to the forecast as of the end of the third quarter of 2021.

Table 14 – ES 2 Contingency Reconfiguration Forecasted Completion Dates as of September 30, 2021

Scope & Division		Q2 2021 Forecasted Completion Date	Q3 2021 Forecasted Completion Date
Reclosers	Central	1/31/2022	1/31/2022
	Metro	1/31/2022	1/31/2022
	Palisades	10/31/2021	12/31/2021
	Southern	1/31/2022	1/31/2022
Fuse Savers	Central	12/30/2023	9/30/2023
	Metro	12/30/2023	10/31/2023
	Palisades	12/30/2023	12/30/2023
	Southern	12/30/2023	10/31/2023

As shown in **Table 14**, the forecasted final in-service dates for three of the four Division's Fuse Saver program advanced two to three months based on a reduction of the number of units to be installed, with the final number of units still under evaluation by PSE&G as it seeks the optimal mix of locations (maximizing customers served against locations requiring pole replacements) based on ongoing field assessments to accommodate the higher costs observed in the pilot program and the fixed budget for this scope of work. While the only change to the recloser scope of work was the Palisades Division slipping two months, which was driven by engineering delays on the remaining approved units.

The Contingency Reconfiguration subprogram costs through the end of the third quarter of 2021 are presented in **Table 15 – ES 2 Contingency Reconfiguration Costs as of September 30, 2021**.

Table 15 – Contingency Reconfiguration Costs as of September 30, 2021

Scope & Division		2019	2020	Q1 2021	Q2 2021	Q3 2021	Total to Date	Forecast	% of Actuals to Forecast
		Actuals							
Reclosers	Central	$2,737,167	$12,050,820	$3,007,686	$2,392,608	$2,116,213	$22,304,495	$25,105,143	89%
	Metro	$2,231,431	$10,726,610	$587,396	$4,051,716	$3,926,036	$21,523,190	$24,376,440	88%
	Palisades	$2,515,569	$12,119,436	$3,109,037	$2,591,672	$1,991,442	$22,327,156	$22,913,508	97%
	Southern	$2,081,220	$12,405,684	$5,008,143	$4,065,891	$2,742,523	$26,303,462	$28,940,957	91%
Fuse Savers	Central	$9,970	$789,937	$375,811	$107,384	$255,092	$1,538,195	$12,022,135	13%
	Metro	$7,557	$561,915	$216,511	$89,860	$144,511	$1,020,354	$10,958,702	9%
	Palisades	$7,468	$522,454	$133,552	$63,808	$276,182	$1,003,464	$8,409,356	12%
	Southern	$9,792	$859,014	$65,018	$56,845	$263,207	$1,253,876	$12,768,220	10%
Total		**$9,600,174**	**$50,035,871**	**$12,503,156**	**$13,419,784**	**$11,715,206**	**$97,274,191**	**$145,494,461**	**67%**

Findings & Observations:

- PSE&G continued to maintain progress on the recloser installations during the third quarter of 2021 and stayed on track for the 2021, assisted by the ongoing engagement of a pole setting contractor to alleviate resource constraints in the Metro Division.
- The forecasted completion of the recloser scope of this subprogram remained unchanged from the prior quarter for three of the four Divisions, while the Palisades Division forecasted completion slipped two months based on the progress of engineering. For the Fuse Savers, while the Palisades Division completion remained unchanged, the other three Divisions advanced their forecasted completion date two to three months reflecting a reduction in the number of planned units.
- The Contingency Reconfiguration subprogram forecast was reduced approximately $1.6 million to a total forecast of $145.5 million as of the end of the third quarter of 2021 from the prior quarter. This was largely driven by reductions to the planned number of fuse savers anticipated for the subprogram.

C. Grid Modernization – Communication System

The Stipulation identified the Grid Modernization – Communication System subprogram to include up to $72 million invested in installing a private wireless communications network to eliminate the use of dedicated phone lines for remote communication for both PSE&G and customer equipment. The overall network will provide coverage using both wireless and fiber technologies to all switching devices on the PSE&G system.

As reported in the IM 2020 Second Quarter Report, PSE&G made the strategic decision to focus on new recloser installations and has delayed the ramp-up in retrofit installations from August 2020 to January 2021 due to resource constraints. During the third quarter of 2021, retrofit installations continued to advance with 562 installations completed during the quarter against a target of 573. In total, 1,994 retrofit reclosers have been installed on the Program through the end of the third quarter out of a total program forecast of 2,357 (which is periodically reviewed and updated). The remaining units are expected to be completed by the end of 2021.

As previously reported, the fiber scope includes installing fiber to electric substations and electric operations centers, in addition to cutting over stations with existing fiber service to the PSE&G fiber network. PSE&G preliminarily identified 41 installation projects and 12 cutovers for the subprogram, with two of 41 installation projects since removed due to the scheduled elimination of the targeted substations. The list of identified fiber installation and cutover projects is presented in **Table 16 – Fiber Projects by Division as of September 30, 2021**.

Table 16 – Fiber Projects by Division as of September 30, 2021

Division	Fiber Installation	Fiber Cutover
Central	Cranford; Elizabeth Sub HQ; Rahway; Hadley Road HQ; Roselle; Central HQ; Carteret; Edison; Keasby; Mechanic Street; First Street; Lehigh Avenue	Elizabeth; Henry Street
Metro	East Orange; Metro HQ; Bloomfield; Central Avenue; Haldeon; Irvington; Irvington Sub HQ; Montclair; South Orange; Norfolk Street; Waverly	-

Division	Fiber Installation	Fiber Cutover
Palisades	Bergen Point; Hackensack Sub HQ; Fort Lee; Harrison; Ridgewood; West New York; Palisades HQ; Culver Avenue; Morgan Street; Howell Street*	Tonnelle Avenue; Spring Valley Road; Union City; Fairview; Polk Street; West Orange
Southern	Southern HQ; Princeton; Chauncey Street; Bordentown; Haddon Heights; Thirty Second Street	Delair; East Riverton; Riverside; Mount Holly
Total	***39 projects***	***12 projects***
**-As discussed in Section IV.B. of the IM 2021 Second Quarter Report, the Howell Street project was identified for removal from the subprogram as the result of a PSE&G review of the project conducted in the fourth quarter of 2021.*		

During the third quarter of 2021, eight additional fiber installation projects (Bordentown, Central Ave., Chauncey Street, First Street, Harrison, Norfolk Street, Princeton, and South Orange) and one fiber cutover project (Henry Street) were placed in-service. **Table 17 – Q3 Fiber Projects Budget vs. Actual Cost** shows the original budget of these projects against the actual costs as of the end of the third quarter of 2021.

Table 17 – Q3 Fiber Projects Budget vs. Actual Cost

Project	Budget	Actual (as of Q3 2021)	Variance
Bordentown*	$0	$528,017	$528,017
Central Ave.	$480,000	$110,548	($369,452)
Chauncey Street	$840,000	$849,852	$9,852
First Street	$300,000	$570,579	$270,579
Harrison	$300,000	$563,245	$263,245
Norfolk Street	$300,000	$183,294	($116,706)
Princeton	$300,000	$1,070,766	$770,766
South Orange	$390,000	$302,912	($87,088)
Henry Street (cutover)**	$50,000	$206,685	$156,685
-Not on initial project list and therefore no initial budget, added after review of projects performed (See the ROD on this discussed in Section IV.A. of the IM 2020 Third Quarter Report)* *-Cutover projects were budgeted by Division (each cutover project is budgeted at the Division budget divided by number of stations in the scope for that Division).*			

With the eight additional fiber installation projects and one additional fiber cutover project placed in-service during the third quarter of 2021, it brought the total projects in-service as of the end of the third quarter of 2021 to 17 for the fiber installation projects and nine for the fiber cutover projects. **Table 18 – ES 2 Program Fiber Projects Status as of September 30, 2021** provides a summary of the status of the fiber installation and cutover projects within the subprogram as of the end of the third quarter of 2021 with the projects in italics representing those placed in-service.

Table 18 – ES 2 Program Fiber Projects Status as of September 30, 2021

Project Name	Q3 2021 Status
Fiber Installation Projects	
Bergen Point	*In-Service (Q1 2021)*
Bloomfield	Inside Plant (IP) IFC issued

Project Name	Q3 2021 Status
Bordentown	*In-Service (Q3 2021)*
Carteret	OP IFC issued
Central Ave	*In-Service (Q3 2021)*
Central HQ	Received approved railroad crossing agreement
Chauncey Street	*In-Service (Q3 2021)*
Cranford	*In-Service (Q4 2020)*
Culver Ave	Preliminary engineering
East Orange	*In-Service (Q1 2021)*
Edison	OP construction mobilized
Elizabeth Sub HQ	*In-Service (Q1 2021)*
First Street	*In-Service (Q3 2021)*
Fort Lee	Continued construction
Hackensack Sub HQ	*In-Service (Q4 2020)*
Haddon Heights	Preliminary engineering
Hadley Rd HQ	IP IFC issued
Haledon	IP civil construction complete; OP construction complete
Harrison	*In-Service (Q3 2021)*
Howell Street	Preliminary engineering*
Irvington	IP IFC issued; OP construction complete; IP construction mobilized
Irvington Sub HQ	IP, OP IFC issued; OP construction complete; IP construction mobilized
Keasbey	Preliminary engineering
Lehigh Avenue	Preliminary engineering
Mechanic Street	Preliminary engineering
Metro HQ	*In-Service (Q1 2021)*
Montclair	IP IFC issued
Morgan Street	OP construction mobilized
Norfolk St	*In-Service (Q3 2021)*
Palisades HQ	Continued construction
Princeton	*In-Service (Q3 2021)*
Rahway	*In-Service (Q1 2021)*
Ridgewood	IP IFC issued; IP civil construction complete
Roselle	*In-Service (Q2 2021)*
So Orange	*In-Service (Q3 2021)*
Southern HQ	*In-Service (Q4 2020)*
Thirty Second Street	Preliminary engineering
Waverly	Preliminary engineering
West New York	IP civil construction completed; OP IFC issued
Fiber Cutover Projects	
Delair	*In-Service (Q4 2020)*
East Riverton	*In-Service (Q4 2020)*
Elizabeth	*In-Service (Q1 2021)*

Project Name	Q3 2021 Status
Fairview	Completion dependent upon Fort Lee fiber installation project
Henry St	*In-Service (Q3 2021)*
Mount Holly	*In-Service (Q4 2020)*
Polk Street	Completion dependent upon West New York fiber installation project
Riverside	*In-Service (Q4 2020)*
Spring Valley Rd	*In-Service (Q1 2021)*
Tonnelle Ave	*In-Service (Q4 2020)*
Union City	*In-Service (Q1 2021)*
West Orange	Completion dependent upon redundant link to Montclair substation being ready (two redundant fiber links required for each router to support reliability guidelines)
Substation Remote Terminal Unit (RTU) Cutovers	
Scope: 204 units	9 cutovers completed
**-As indicated in the IM 2021 Second Quarter Report, the Howell Street fiber project was identified for removal from the subprogram during the fourth quarter of 2021.*	

The Grid Modernization – Communication System subprogram costs through the end of the third quarter of 2021 are presented in **Table 19 – ES 2 Grid Modernization – Communication System Costs as of September 30, 2021**.

Table 19 – ES 2 Grid Modernization – Communication System Costs as of September 30, 2021

Scope & Division		2019	2020	Q1 2021	Q2 2021	Q3 2021	Total to Date	Forecast	% of Actuals to Forecast
		Actuals							
Retrofit Reclosers	Central	$0	$884,278	$1,067,295	$1,027,602	$715,214	$3,694,388	$6,817,605	54%
	Metro	$0	$818,620	$436,089	$683,893	$733,376	$2,671,977	$5,485,018	49%
	Palisades	$0	$825,174	$754,869	$965,416	$888,467	$3,433,927	$6,173,947	56%
	Southern	$0	$929,058	$956,444	$1,005,852	$1,082,897	$3,974,252	$7,314,919	54%
Fiber	Central	$1,691	$2,418,851	$796,586	$1,349,407	$1,007,245	$5,573,779	$9,178,564	61%
	Metro	$1,457	$1,866,697	$340,713	$831,337	$1,198,777	$4,238,981	$7,885,388	54%
	Palisades	$1,582	$2,046,762	$248,558	$725,030	$605,647	$3,627,579	$6,022,939	60%
	Southern	$4,731	$910,483	$645,219	$1,029,156	$591,125	$3,180,714	$3,366,815	94%
	Cutovers*	$0	$876,502	$323,458	$86,115	$109,880	$1,395,955	$2,967,868	47%
Wireless Network		$74,306	$6,035,441	$287,086	$312,404	$124,015	$6,833,252	$7,897,530	87%
Bulk Purchase**		$0	$1,524,874	$450,013	($154,037)	($335,637)	$1,485,213	$0	-
Total		**$83,767**	**$19,136,741**	**$6,306,330**	**$7,862,175**	**$6,721,006**	**$40,110,017**	**$63,110,594**	**64%**

**-Includes fiber communication cutovers and substation RTU cutovers (the latter of which began having spend in Q1 2021).*
***-The Bulk Purchase account is used for the purchase of bulk equipment, which is the then assigned to a specific Division when the equipment is released with a credit back to the Bulk Purchase account. Thus, this account is forecasted to have a $0 balance at the end of the ES 2 Program.*

<u>Findings & Observations</u>:

- During the third quarter of 2021, retrofit installations continued to advance following the ramp-up earlier in 2021 with 562 installations completed during the quarter against a target of 573. In total, 1,994 retrofit reclosers have been installed on the Program through the end of the third quarter of

2021 out of a total program forecast of 2,357 (which continues to be periodically reviewed and updated).

- Eight additional fiber installation projects and one fiber cutover project were placed in-service during the third quarter of 2021, bringing the total number of projects in-service to 17 fiber installation projects and nine fiber cutover projects.
- The forecast for the Grid Modernization – Communication system subprogram increased approximately $2.7 million as of the end of the third quarter of 2021 from the prior quarter. The bulk of this increase ($2.6 million) was in the fiber scope, which was driven by the updated fiber and communication requirements based on the current status of the PSE&G substations and Operations Centers selected for this scope, including IP contractor quotes higher than estimated and costs of outsourcing the overhead scope on selected projects to augment Division resources . Overall, the subprogram forecast of $63.1 million remains below the adjusted Stipulation budget amount of $64.3 million (following the $7.7 million transfer of funds to the Grid Modernization – ADMS subprogram).

D. Grid Modernization – ADMS

The Grid Modernization – ADMS scope is split between three primary sections: Distribution Management System (DMS)/Distributed Energy Resource Management System (DERMS), the Outage Management System (OMS), and ADMS platform upgrades. The primary activities in 2021 are focused on the continued development of the systems and platforms that comprise this subprogram.

The scope for each primary component of the Grid Modernization – ADMS subprogram and notable activities conducted during the third quarter of 2021 are presented as follows:

DMS/DERMS

- Scope: Provide software and associated services to deploy a Smart Network in order to meet a subset of the ES 2 Program's objectives and use cases.
- Q3 2021 Activities:
    - Resolved factory acceptance testing action items list and compiled factory acceptance testing results.
    - Conducted advanced metering interface (AMI) use case compilation discussion and completed AMI use case demo from Open Systems International Inc. (OSII).
- Forecasted In-Service Date as of the end of the third quarter of 2021: 12/19/2022.

OMS

- Scope: Provide a single user interface for more efficient management of trouble orders and analysis of outage data through an integrated OMS, system interfaces, and geographic view of all integrated outage data through an integrated OMS, system interfaces, and geographic view of all integrated outage data and damage locations. OMS will include tools for dynamic visualization supporting incident management, damage location identification, dashboards, and the as-operated real-time view of PSE&G's network model. Field personnel also will have access to many of these tools as it relates to the incident(s) assigned to them via the Compass mobile crew application. 10 years' worth of existing OMS data will be migrated into the new system as well.

- Q3 2021 Activities:
    - Conducted additional AMI interface workshops and initial mobile security design sessions.
    - Completed database installation for outage data warehouse.
    - Onboarded mobile work management system (MWMS) interface team and conducted MWMS design workshops.
- Forecasted In-Service Date as of the end of the third quarter of 2021: 12/2/2022.

ADMS Platform

- Scope: Replace, enhance, and expand the existing Distribution Supervisory Control and Data acquisition (DSCADA) platform elements inclusive of infrastructure components (servers and workstations) and applications (Monarch, Spectra, and Integra) to create an integrated ADMS platform.
- Q3 2021 Activities:
    - Reviewed testing gaps, selected testing tools, and created testing strategy.
    - Received all ADMS equipment shipments.
- Forecasted In-Service Date as of the end of the third quarter of 2021: 12/10/2021.

The Grid Modernization – ADMS subprogram costs through the end of the third quarter of 2021 are presented in **Table 20 – ES 2 Grid Modernization – ADMS Costs as of September 30, 2021**.

Table 20 – ES 2 Grid Modernization – ADMS Costs as of September 30, 2021

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals					*Forecast*	
$36,213	$16,447,624	$2,488,980	$2,168,187	$2,368,648	$3,564,757	$15,647,923

Actuals to Date	Forecast	% of Actuals to Forecast
$23,509,654	$42,722,333	55%

Findings & Observations:

- The server equipment received during the third quarter of 2021 required approximately one month to set up the equipment in alignment with PSE&G's security standards. The PSE&G team was able to implement the network segmentation, although the setting up and connecting of the server hardware consumed the bulk of the float in the schedule. However, the forecasted in-service date for the subprogram remains at December 2022 as of the end of the third quarter of 2021.
- The Grid Modernization – ADMS forecast remained nearly unchanged as of the end of the third quarter of 2021 from the second quarter of 2021, with an approximate $10,000 forecast increase to the $42.7 million subprogram.

E. Electric Stipulated Base

The Stipulation identified that the electric portion of the Stipulated Base include $100 million in investments at PSE&G's discretion towards electric outside plant higher design and construction standards and/or electric stations life cycle subprograms described in the original ES 2 filing.[4] The bulk of outside plant higher design and construction standards work is planned to commence in January 2022. In accordance with what the Stipulation provides, PSE&G plans to fund some of the life cycle station upgrades from the electric program accelerated investment, subject to funds available, after all Electric Station Flood Mitigation projects are funded at their final costs.

As reported in the IM 2020 Second Quarter Report, the initial four stations PSE&G selected for life cycle station upgrades went before the URB in June 2020 for Study level estimate approval and received approval for full funding. In the second quarter of 2021 a fifth station, State Street, was approved by the URB for its outside plant scope to be transferred from the related Electric Station Flood Mitigation project to the life cycle scope. These five stations and their current estimate compared to the actuals to date are provided in **Table 21 – ES 2 Life Cycle Station Upgrade Project Status as of September 30, 2021**.

Table 21 – ES 2 Life Cycle Station Upgrade Project Status as of September 30, 2021

Project	Estimate Level	Base	Risk & Contingency	Total	Actuals to Date	% of Actuals to Estimate	Forecasted In-Service Date*
1. Hamilton	Study	$14,500,000	$3,700,000	$18,200,000	$2,083,445	11%	10/12/2022
2. Paramus	Study	$14,800,000	$5,400,000	$20,200,000	$6,940,343	34%	11/11/2022 (↑)
3. Plainfield	Study	$18,400,000	$4,200,000	$22,600,000	$2,478,976	11%	10/17/2022 (↑)
4. Woodbury	Study	$15,400,000	$3,300,000	$18,700,000	$1,811,330	10%	12/27/2022
5. State Street (OP)	Study	$19,700,000	$3,000,000	$22,700,000	$71,294	0%	3/2/2023 (↑)

**-Reflects the in-service date of the last major asset (e.g. switchgear), certain activities may take place after this date to support the final in-service date (i.e. when all customers are cutover).*
(↑)-Indicates the forecasted in-service date advanced from the prior quarter.
(↓)-Indicates the forecasted in-service date slipped from the prior quarter.

As shown in **Table 21**, of the five life cycle station upgrade projects, the Paramus, Plainfield, and State Street OP projects each saw a slight advancement to their forecasted in-service dates, advancing four, three, and 13 days, respectively. Given the relatively small magnitude of these changes, the IM has not performed additional schedule analyses on these projects but will continue to monitor for potential trends. Additional details on each of these life cycle station upgrade projects is provided in the individual subsections that follow.

Findings & Observations:

- The primary activities during the third quarter of 2021 continued to center around advancing the engineering, permitting, and procurement processes for the life cycle station upgrade projects.

[4] As noted in the Stipulation, the electric life cycle upgrades are part of the electric Stipulated Base to be recovered in the Company's next base rate case provided the investments are found to be prudent. The Stipulation also notes that should the 16 stations that comprise the Electric Station Flood Mitigation subprogram be completed for under the $389 million allocated for that subprogram, PSE&G may reallocate such unused funds to stations identified in the life cycle station upgrade portion of PSE&G's petition for accelerated recovery.

Construction also commenced on the Hamilton, Plainfield, and Woodbury projects during the third quarter of 2021, and continued on Paramus, which started construction in the second quarter of 2021.

- There was minor movement to the forecasted in-service dates for the Paramus, Plainfield, and State Street OP projects during the third quarter of 2021, with each advancing between 3-13 days from the prior quarter's forecast. Each of the original four life cycle station upgrade projects remains forecasted for completion in the fourth quarter of 2022 while the State Street OP project is forecasted for completion in the first quarter of 2023.

1. Hamilton

During the third quarter of 2021, $1,083,435 was spent on the Hamilton project against a forecast of approximately $1.3 million. This brought total spend on the project to approximately $2.1 million through the end of the third quarter of 2021.

Notable activities conducted during the third quarter of 2021 included:

- Municipal permits received;
- Controls drawings IFC; and,
- Electrical construction out for bid.

The actual spend by quarter for Hamilton as compared to the current URB approved estimate is provided below.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals					*Forecast*	
$0	$362,372	$236,783	$400,855	$1,083,435	$1,723,783	$12,477,686

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$2,083,446	$18,200,000	$16,284,915	11%

2. Paramus

During the third quarter of 2021, $1,564,308 was spent on the Paramus project against a forecast of approximately $1.7 million. This brought total spend on the project to approximately $6.9 million through the end of the third quarter of 2021.

Notable activities conducted during the third quarter of 2021 included:

- Site plan approval received;
- 4kV contingency feeder rows delivered;
- Civil and electrical drawings IFC; and,
- Civil and electrical construction out for bid.

The actual spend by quarter for Paramus as compared to the current URB approved estimate is provided below. The current forecast of approximately $20.5 million represents an increase to the forecast of approximately $1.5 million from the status as of the end of the second quarter of 2021. This forecast increase was driven by higher than estimated construction and material/equipment awards.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2024
Actuals					*Forecast*	
$0	$840,200	$358,846	$4,176,989	$1,564,308	$1,023,572	$12,533,678

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$6,940,343	$20,200,000	$20,497,593	34%

3. Plainfield

During the third quarter of 2021, $1,214,476 was spent on the Plainfield project against a forecast of approximately $2.2 million. The variance between actual and forecasted spend was driven by lower than estimated hours to complete the work performed in the quarter and some work shifting to October. This brought total spend on the project to approximately $2.5 million through the end of the third quarter of 2021. The current forecast of approximately $22.1 million represents an increase to the forecast of approximately $2.4 million from the status as of the end of the second quarter of 2021. This forecast increase was driven by higher than estimated construction and additional steel quantities with a higher steel price than was initially estimated.

Notable activities conducted during the third quarter of 2021 included:

- Municipal permits approved; and,
- OP construction commenced.

The actual spend by quarter for Plainfield as compared to the current URB approved estimate is provided below.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2024
Actuals					*Forecast*	
$0	$682,325	$214,632	$367,543	$1,214,476	$1,966,058	$17,640,676

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$2,478,976	$22,600,000	$22,085,710	11%

4. Woodbury

During the third quarter of 2021, $363,802 was spent on the Woodbury project against a forecast of approximately $380,000. This brought the total spend on the project to approximately $1.8 million through the end of the third quarter of 2021.

Notable activities conducted during the third quarter of 2021 included the issuance of civil and electrical construction POs.

The actual spend by quarter for Woodbury as compared to the current URB approved estimate is provided below.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals					*Forecast*	
$0	$551,165	$540,138	$356,225	$363,802	$480,591	$15,571,232

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$1,811,330	$18,700,000	$17,863,153	10%

5. State Street (Outside Plant)

During the third quarter of 2021, $53,660 was spent on the State Street (OP) project against a forecast of approximately $42,000. This brought the total spend on the project to approximately $71,000.

Notable activities conducted during the third quarter of 2021 included the signoff of the project's scope document. The forecasted in-service date for the State Street (OP) project, currently forecasted for March 2, 2023, reflects the continued planned sequencing of this project, which will be completed after the State Street project within Electric Station Flood Mitigation subprogram is completed.

The actual spend by quarter for State Street (OP) as compared to the current URB approved estimate is provided below.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals					*Forecast*	
$0	$0	$0	$17,633	$53,660	$729,292	$18,912,003

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$71,294	$22,700,000	$19,712,589	0%

F. Gas M&R Station Upgrades

Through the end of the third quarter of 2021, primary activities in the Gas M&R subprogram continued to focus on advancing the pre-construction activities for the five projects not in construction, while the Westampton project continued its construction activities towards a fourth quarter of 2021 in-service date. **Table 22 – ES 2 Gas M&R Summary Status as of September 30, 2021** below provides the currently approved estimates for each project within the Gas M&R subprogram, along with the actuals to date and forecasted in-service dates.

Table 22 – ES 2 Gas M&R Summary Status as of September 30, 2021

Project	Estimate Level	Base	Risk & Contingency	Total Estimate	Actuals	% of Actuals to Estimate	Forecasted In-Service
1. Camden*	Study	$24,300,000	$5,000,000	$29,300,000	$2,082,756	7%	Dec 2022
2. Central*	Study	$23,900,000	$5,100,000	$29,000,000	$1,493,901	5%	Dec 2022
3. East Rutherford	Study	$13,800,000	$2,700,000	$16,500,000	$1,318,297	8%	Dec 2022
4. Mount Laurel	Study	$9,400,000	$2,000,000	$11,400,000	$794,330	7%	Dec 2022
5. Paramus*	Study	$11,500,000	$2,200,000	$13,700,000	$921,080	7%	Dec 2023
6. Westampton	Definitive	$9,100,000	$900,000	$10,000,000	$6,559,174	66%	Oct 2021 (↑)
Subprogram Total		**$92,000,000**	**$17,900,000**	**$109,900,000**	**$13,169,538**	**12%**	**Dec 2023**
**-Included in the Stipulated Base.* (↑)*-Indicates the forecasted in-service date advanced from the prior quarter.*							

Project	Estimate Level	Base	Risk & Contingency	Total Estimate	Actuals	% of Actuals to Estimate	Forecasted In-Service
(↓)-Indicates the forecasted in-service date slipped from the prior quarter.							

The in-service dates for the Gas M&R projects as of the end of the third quarter of 2021 remained static from the status at the end of the prior quarter except for the Westampton project, which advanced from a forecasted in-service date of December 16, 2021 to October 22, 2021 based on the progression of the construction work.

Findings & Observations:

- The primary efforts to date on the subprogram continue to be primarily related to pre-construction planning efforts, including completing and submitting site plan packages, ordering long lead materials, and preparing construction bid packages. The Westampton project, which commenced construction in April 2021 and is forecasted to be complete by the end of 2021, advanced ahead of schedule.
- The IM has found nothing to date that would jeopardize the subprogram being completed on time and/or on budget. During the third quarter of 2021 there were no updates to the Gas M&R project estimates and the forecast in-service dates remained unchanged from the prior quarter for the majority of the projects, except the Westampton project which advanced approximately two months based on the progress of the works.

1. Camden

During the third quarter of 2021, $413,548 was spent on the Camden project compared to a forecast of approximately $357,000, which brought the total spend to approximately $2.1 million. The current forecast of approximately $26.3 million represents an increase to the forecast of approximately $2.0 million from the status as of the end of the second quarter of 2021. This forecast increase was driven by material costs coming in higher than what was initially estimated.

The forecasted in-service date for the Camden project as of the end of the third quarter of 2021 remains unchanged from the prior quarter at December 30, 2022.

Notable activities completed on the Camden project during the third quarter of 2021 included:

- Received approved resolution from the City of Camden;
- Ordered long lead materials/equipment; and,
- Received issued for bid (IFB) construction package.

The actual spend by quarter for Camden as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals					*Forecast*	
$13,326	$859,350	$505,693	$290,839	$413,548	$1,321,924	$22,868,132

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$2,082,756	$29,300,000	$26,272,811	7%

2. Central

During the third quarter of 2021, $311,084 was spent on the Central project compared to a forecast of approximately $264,000, which brought the total spend to approximately $1.5 million. The current forecast of approximately $25.7 million represents an increase to the forecast of approximately $1.8 million from the status as of the end of the second quarter of 2021. This forecast increase was driven by higher than estimated material costs and additional design efforts required to address the complexity of the station and to incorporate modifications to meet the site plan approval requirements.

The forecasted in-service date for the Central project as of the end of the third quarter of 2021 remains unchanged from the prior quarter at December 30, 2022.

Notable activities completed on the Central project during the third quarter of 2021 included:

- Received construction bids and held bid clarification meetings;
- Received site plan approval from the Township of Edison;
- Submitted Title V air permit; and,
- Building PO issued to vendor.

The actual spend by quarter for Central as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals					*Forecast*	
$6,869	$670,582	$315,258	$190,109	$311,084	$6,765,527	$17,469,616

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$1,493,901	$29,000,000	$25,729,044	5%

3. East Rutherford

During the third quarter of 2021, $189,737 was spent on the East Rutherford project compared to a forecast of approximately $210,000, which brought the total spend to approximately $1.3 million. The forecasted in-service date for the East Rutherford project remains unchanged from the prior quarter at December 30, 2022.

Notable activities completed on the East Rutherford project during the third quarter of 2021 included:

- Issued Pipeline and Hazardous Materials Safety Administration (PHMSA) notification as required for upcoming construction; and,
- Completed final license and permit package and submitted permit application to the New Jersey Sports and Exposition Authority (NJSEA) and Bergen County.

The actual spend by quarter for East Rutherford as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals					*Forecast*	
$9,010	$521,865	$337,573	$260,112	$189,737	$1,030,830	$11,450,873

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$1,318,297	$16,500,000	$13,800,000	7%

4. *Mount Laurel*

During the third quarter of 2021, $121,165 was spent on the Mount Laurel project compared to a forecast of approximately $182,000, which brought the total spend to approximately $794,000. The forecasted in-service date for the Mount Laurel project remains unchanged from the prior quarter at December 30, 2022.

Notable activities completed on the Mount Laurel project during the third quarter of 2021 included:

- Received soil erosion and sediment control permit;
- Submitted site package and received conditional approval from the Burlington County Planning Board; and,
- Received IFB drawing package for review.

The actual spend by quarter for Mount Laurel as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals					*Forecast*	
$5,965	$362,167	$155,351	$149,682	$121,165	$510,606	$8,095,064

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$794,330	$11,400,000	$9,400,000	7%

5. *Paramus*

During the third quarter of 2021, $92,239 was spent on the Paramus project compared to a forecast of approximately $131,000, which brought the total spend to approximately $921,000. The forecasted in-service date for the Paramus project remains unchanged from the prior quarter at December 29, 2023.

Notable activities completed on the Paramus project during the third quarter of 2021 included the receipt of the preliminary drawing package for review.

The actual spend by quarter for Paramus as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals					*Forecast*	
$8,842	$462,452	$227,854	$129,694	$92,239	$114,443	$10,464,477

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$921,080	$13,700,000	$11,500,000	7%

6. Westampton

During the third quarter of 2021, $1,822,542 was spent on the Westampton project compared to a forecast of approximately $1.7 million, which brought the total spend to approximately $6.6 million. The forecasted in-service date for the Westampton project advanced 55 days from the status at the end of the second quarter of 2021 to October 22, 2021, which was the result of the progress of the construction efforts on the project.

Construction on the Westampton project, which commenced in April 2021, was reported at 85% complete as of September 2021. Other notable activities completed on the Westampton project during the third quarter of 2021 included:

- Completed demolition of existing regulator building;
- Completed header piping and regulator piping installation; and,
- Completed new regulator building foundation and started building erection.

The actual spend by quarter for Westampton as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals					*Forecast*	
$8,395	$1,032,670	$478,072	$3,217,496	$1,822,542	$2,191,211	$349,615

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$6,559,174	$10,000,000	$9,100,000	66%

ENERGY STRONG PROGRAM
INDEPENDENT MONITOR
2021 THIRD QUARTER REPORT

APPENDIX A – DRAFT REPORT COMMENTS AND RESPONSES

AUGUST 24, 2022

PEGASUS GLOBAL HOLDINGS, INC. ®

Questions & Comments to the IM 2021 Third Quarter Report Formally Submitted to the IM

ID #	Question/Comment	IM Response	Report Changes
S-INF-1	**Reference Q3 2021 Report, Page 1** Regarding the Grid Modernization – Communication System subprogram, what is attributed to the reduction in forecasted retrofit recloser installations from 2,449 units (See Q2 2021 Report, Page 1) to 2,357 units?	PSE&G periodically revises the number of forecasted retrofit recloser units to be installed under the ES 2 Program based on reviews of current phone line devices, circuit reconfigurations, and previously removed or replaced units. As a result of the updated status of these factors, the number of planned units is subject to being reduced.	No change
S-INF-2	**Reference Q3 2021 Report, Page 2, Table 2 – ES 2 Electric Station Flood Mitigation Status as of September 30, 2021** Regarding the Electric Station Flood Mitigation project "State Street": a. Why has the forecasted in-service date of this project not advanced from September 2022 after the outside plant portion of this project was added to Electric Stipulated Base? b. Why is the outside plant portion of this project not expected to be placed in-service until March 2023 (See Q3 2021 Report, Page 35, Table 20) given that the Electric Station Flood Mitigation portion of this project has been projected to be placed in-service in September 2022 since before the outside plant portion was removed?	When the IP and OP scopes of the State Street project were planned to be executed as one project, the IP portion (which remains in the Electric Station Flood Mitigation subprogram) was forecasted to be placed in-service in September 2022, while the OP portion (now executed under Electric Stipulated Base) had been forecasted to be executed following the completion of the IP scope with a then forecasted in-service date of April 2023. This sequencing is effectively unchanged following the split of the IP and OP scopes on this project, though since that split the forecasted in-service date for the State Street OP project has advanced to March 2023.	**Section III.A.13. & Section III.E.5.**
S-INF-3	**Reference Q3 2021 Report, Pages 8-9, Table 6 – ES 2 Program Overhead Allocations as of September 30, 2021** What is attributed to Q2 2021 overhead allocations increasing from $11,393,000 in the IM's previous report (See Q2 2021 Report, Page 11) to $11,444,000 in this report?	The change in overhead allocations for the second quarter of 2021 from $11.393 million as reported in the IM 2021 Second Quarter Report to $11.444 million in this IM 2021 Third Quarter Report was the result of an error in the original second quarter data provided to the IM by PSE&G. PSE&G informed the IM this error was caused by a difference in the date/time the SAP data was extracted for each report, with the original second quarter data downloaded earlier in the month than typical. The correct amount for the second quarter of 2021 is the $11.444 million shown in **Table 6** of this report.	**Section II.C.4.**

ID #	Question/Comment	IM Response	Report Changes
S-INF-4	**Reference Q3 2021 Report, Page 26, Electric Station Flood Mitigation Projects (Waverly)** a. Please provide additional details about the modifications incorporated into the Waverly substation project and their associated costs which led to the Newark Planning Board approving the site plan in early 2022 (as indicated in the response to S-INF-5 in the IM's Q2 2021 Report). b. Please indicate if the Waverly substation project is currently expected to be placed in service within the Energy Strong II program window.	Regarding the requests concerning the Waverly project: a. When the initial site plan was rejected, the comments received from the Newark Planning Board generally focused on the outward appearance of the substation. The revised site plan incorporated feedback received from community meetings and from discussions with the Director of Arts and Culture for the City of Newark and the Newark Arts Council. The result was redesigned street facing frontages to the substation that included a fence with brick finish (giving a wall-like appearance) and locations for artwork to be placed, two entrance gates with matching color schemes, portions of the isolation walls that were visible were also redesigned to match the brick finishes on the street facing fences, and landscaping around the sidewalk area outside the substation. b. As of April 2022 (the most recent data available to the IM at the time of this report), the final in-service date had improved to February 27, 2024, which still remains outside of the ES 2 program window. This relates to the transformer #3 in-service date, while the 4kV switchgear and transformers #1-2 are forecasted to be in-service in October 2023.	**Section III.A.15.**
S-INF-5	**Reference Q3 2021 Report, Page 28, Contingency Reconfiguration Subprogram** Regarding the Contingency Reconfiguration subprogram, please compare the total number of reclosers currently forecasted to be installed to originally budgeted totals.	At the time of the ES 2 filing, PSE&G estimated 1,816 reclosers to be installed in the Program. With the completion of the recloser scope in January 2022, a total of 1,467 reclosers were installed. The revision to the number of units planned in the subprogram was also discussed in the IM 2021 First and Second Quarter Reports (Section IV.A.1 and Section II.A.1, respectively). Additionally, as of the initial subprogram forecast received by the IM (April 2020, when the IM engagement began), the recloser scope of the Contingency Reconfiguration subprogram had a forecast of $107,976,302, while the final costs of the recloser scope was $101,920,298.	No change
S-INF-6	**Reference Q3 2021 Report, Page 29, Contingency Reconfiguration Subprogram** With respect to the Contingency Reconfiguration subprogram, it is noted that "the forecasted final in-service dates for three of the four Division's Fuse Saver program advanced two to three months based on a reduction of the number of units to be installed."	Regarding the Fuse Saver scope of work: a. PSE&G is still evaluating the number of Fuse Saver units to be removed from the Program through on ongoing field assessments and a prioritization based on customers served and locations not requirement a pole replacement. PSE&G expects this to be an iterative process with the final number of	**Section III.B.**

<table>
<tr><th>ID #</th><th>Question/Comment</th><th>IM Response</th><th>Report Changes</th></tr>
<tr><td></td><td>a. Please provide the total number of Fuse Saver units removed from the program for each division.
b. Please provide additional details describing the Company’s rationale for reducing the number of Fuse Saver units.</td><td>units determined by the average cost per unit based on the most optimal mix of locations with and without pole replacements given the fixed budget.
b. The reduction in the planned number of Fuse Saver units is the result of the higher cost per unit observed in the pilot program.</td><td></td></tr>
<tr><td>S-INF-7</td><td><u>Reference Q3 2021 Report, Page 30, Grid Modernization – Communication System Subprogram</u>
Regarding the Grid Modernization – Communication System subprogram, it is stated that “During the third quarter of 2021, eight additional fiber installation projects (Bordentown, Central Ave., Chauncey Street, First Street, Harrison, Norfolk Street, Princeton, and South Orange) and one fiber cutover project (Henry Street) were placed in-service.” For each of these projects placed in-service during Q3 2021, please compare the final cost to the budgeted cost.</td><td>For the projects placed in-service during the third quarter of 2021, the budgeted vs. actual costs are shown below:
<table>
<tr><th>Project</th><th>Budget</th><th>Actual (as of Q3 2021)</th></tr>
<tr><td>Bordentown*</td><td>$0</td><td>$528,017</td></tr>
<tr><td>Central Ave.</td><td>$480,000</td><td>$110,548</td></tr>
<tr><td>Chauncey Street</td><td>$840,000</td><td>$849,852</td></tr>
<tr><td>First Street</td><td>$300,000</td><td>$570,579</td></tr>
<tr><td>Harrison</td><td>$300,000</td><td>$563,245</td></tr>
<tr><td>Norfolk Street</td><td>$300,000</td><td>$183,294</td></tr>
<tr><td>Princeton</td><td>$300,000</td><td>$1,070,766</td></tr>
<tr><td>South Orange</td><td>$390,000</td><td>$302,912</td></tr>
<tr><td>Henry Street (cutover)**</td><td>$50,000</td><td>$206,685</td></tr>
<tr><td colspan="3">*-Not on initial project list and therefore no initial budget, added after review of projects performed (See the ROD on this discussed in Section IV.A. of the IM 2020 Third Quarter Report)
**-Cutover projects were budgeted by Division (each cutover project is budgeted at the Division budget divided by number of stations in the scope for that Division).</td></tr>
</table></td><td>Section III.C. (Table 17)</td></tr>
<tr><td>S-INF-8</td><td><u>Reference Q3 2021 Report, Page 31, Table 17 – ES 2 Program Fiber Projects Status as of September 30, 2021</u>
With respect to the fiber installation project “Bergen Point”, please discuss if this project will remain used and useful following the upcoming retirement of the Bergen Point substation.</td><td>PSE&G confirmed to the IM that the Bergen Point fiber project will remain used and useful through the schedule retirement of the Bergen Point substation in 2026. PSE&G intends to replace the substation with a 69kV/13kV station and the fiber connectivity design at this new station will determine if any portion of the current Bergen Point fiber installation will remain used and useful.</td><td>No change</td></tr>
<tr><td>S-INF-9</td><td><u>Reference Q3 2021 Report, Page 31, Table 17 – ES 2 Program Fiber Projects Status as of September 30, 2021</u>
With respect to the fiber installation project “Howell Street”, please reconcile why the project’s Q3 2021 status is listed as “preliminary engineering” when the IM’s previous report indicated that this project was removed from the program (<u>See</u> Q2 2021 Report, Page 42).</td><td>As indicated in the IM 2021 Second Quarter Report, the decision to remove the Howell Street fiber project was made during the fourth quarter of 2021. The IM’s approach is to have the main body of the quarterly reports generally reflect the Program status as of the end of the reporting quarter (while providing notable post-quarter information in a separate section of the report). Thus, Table 18 (renumbered after</td><td>Section III.C. (Table 18)</td></tr>
</table>

ID #	Question/Comment	IM Response	Report Changes
		the new Table 17 was added in response to S-INF-7 above) shows the fiber project status as of September 30, 2021.	
S-INF-10	**Reference Q3 2021 Report, Page 32, Table 18 – ES 2 Grid Modernization – Communication System Costs as of September 30, 2021** Regarding the Grid Modernization – Communication System subprogram, what is the currently anticipated in-service date of the Wireless Network project?	The wireless network scope was placed in-service as of December 16, 2021.	No change
S-INF-11	**Reference Q3 2021 Report, Pages 32-33, Grid Modernization – Communication System Subprogram** Refer to the statement "The forecast for the Grid Modernization – Communication system subprogram increased approximately \$2.7 million as of the end of the third quarter of 2021 from the prior quarter. The bulk of this increase (\$2.6 million) was in the fiber scope, which was driven by the updated fiber and communication requirements based on the current status of the PSE&G substations and Operations Centers." Please provide additional details about the updated fiber and communication requirements.	This forecast increase was driven by higher overall cost estimates resulting from changes in communication requirements, costs of outsourcing overhead scope on some projects (needed to augment Division resources), and IP contractor quotes higher than estimated. Updated communication requirements contained within the new cost estimates reflect the adjustment of the project list discussed in the ROD reviewed in Section IV.A. of the IM 2020 Third Quarter Report.	**Section III.C.**
S-INF-12	**Reference Q3 2021 Report, Page 36, Electric Stipulated Base (Paramus Project)** Regarding the Paramus life cycle substation project, what factors are attributed to the forecasted cost (\$20,497,593) exceeding the base cost plus risk and contingency (\$20,200,000)?	The higher forecast on the Paramus life cycle substation project is driven by higher than estimated construction and material/equipment awards.	**Section III.E.2.**
S-INF-13	**Reference Q3 2021 Report, Pages 36-37, Electric Stipulated Base (Plainfield Substation Project)** With respect to the Plainfield life cycle substation project, what is attributed to the forecasted cost increasing from \$19,645,315 (See Q2 2021 Report, Page 37) to \$22,085,710?	The higher forecast on the Plainfield life cycle substation project is driven by higher than estimated construction awards and additional steel with a higher steel price than estimated.	**Section III.E.3.**
S-INF-14	**Reference Q3 2021 Report, Page 39, Gas M&R Station Upgrades (Camden M&R Station Project)** Regarding the Camden M&R station project, what is attributed to the forecasted cost increasing from \$24,300,000 (See Q2 2021 Report, Page 39) to \$26,272,811?	The approximately \$2.0 million increase in the Camden M&R station project forecast from the second to third quarter of 2021 was driven by material costs higher than estimated.	**Section III.F.1.**
S-INF-15	**Reference Q3 2021 Report, Page 39, Gas M&R Station Upgrades (Central M&R Station Project)**	The approximately \$1.8 million increase in the Central M&R station project forecast from the second to third quarter of 2021 was driven by:	**Section III.F.2.**

ID #	Question/Comment	IM Response	Report Changes
	Regarding the Central M&R station project, what is attributed to the forecasted cost increasing from $23,900,000 (See Q2 2021 Report, Pages 39-40) to $25,729,044?	• $0.4 million attributed to: additional design efforts required due to the complexity of the station and drawing modifications to meet the township site plan approval requirements. • $1.5 million attributed to: material costs higher than estimated. • $0.1 million reduction attributed to: reduced licensing and permitting costs based on actuals to date and an updated estimate of remaining work.	
RCR-IM-1	With reference to page 2 of the Independent Monitor's Draft Third Quarter 2021 Report, please provide an update on the status of the Academy Street substation including actual in-service date or anticipated in-service date.	The Academy Street substation project was placed in-service on October 19, 2021, when the switchgear was placed in-service.	No change
RCR-IM-2	With reference to page 2 of the Independent Monitor's Draft Third Quarter 2021 Report, please provide an update on the status of the Market Street substation including actual in-service date or anticipated in-service date.	The Market Street substation elimination project was placed in-service as of June 25, 2021, when all the 4kV circuits were converted to 13kV.	No change
RCR-IM-3	With reference to page 2 of the Independent Monitor's Draft Third Quarter 2021 Report, please provide an update on the status of the Ridgefield 4kV substation including actual in-service date or anticipated in-service date.	The Ridgefield 4kV substation elimination project was placed in-service as of May 16, 2021, when all the 4kV circuits were converted to 13kV.	No change
RCR-IM-4	With reference to page 2 of the Independent Monitor's Draft Third Quarter 2021 Report, please provide an update on the status of anticipated in-service date of substation work expected to be completed in 2022.	As shown in **Table 2**, the Clay Street, Leonia, Ridgefield 13kV, and State Street projects were forecasted as of the end of the third quarter of 2021 to be placed in-service during 2022. As of the end of June 2022 (most current information presently available to the IM), the status of the forecasted in-service dates for these projects is as follows: • Clay Street: slipped to January 2023 due to delays in receiving the above grade structures and electrical construction permits. • Leonia: forecasted for December 2022. • Ridgefield 13kV: forecasted for December 2022. • State Street: forecasted for December 2022.	No change
RCR-IM-5	With reference to page 3 of the Independent Monitor's Draft Third Quarter 2021 Report, please provide an update regarding the Waverly substation site plan approval process.	The site plan received conditional approval by the Newark Planning Board in December 2021 with memorialization of the compliance resolution in January 2022.	No change
RCR-IM-6	With reference to page 3 of the Independent Monitor's Draft Third Quarter 2021 Report, please explain if the delayed site	PSE&G updated the estimate for the Waverly substation project in January 2022. In this updated estimate, the base estimate increased	No change

ID #	Question/Comment	IM Response	Report Changes
	plan for the Waverly substation will increase projected costs for the project.	from $29.4 million to $36.2 million, which included $2.6 million related to additional engineering ($0.8 million), revised fencing and external façade improvements ($1.0 million), and additional charges for extended project duration ($0.8 million).	
RCR-IM-7	With reference to Table 8 of the Independent Monitor's Draft Third Quarter 2021 Report, please provide additional details regarding the outages identified for circuits DFD 8041, LEO 8041, and WFL 8032 including the circumstances leading to the outage and whether something unique about the outage caused it to be much more severe than the reported 5-year baseline level.	These circuits all saw severe impacts from the Major Event, in particular tree impacts. Specific information on each circuit is provided as follows: • DFD 8041: a tornado touched down in the area and resulted in the primary line down from wind/tree impacts. • LEO 8041: a tree brought down all three phases, resulting in no circuit operation. • WFL 8032: large tree impact resulted in multiple phases down in addition to flooding in the area.	**Section II.D.1.**
RCR-IM-8	With reference to page 14 of the Independent Monitor's Draft Third Quarter 2021 Report, please identify the eight substations that experienced water intrusion.	The eight substations that experienced water intrusions during the Major Event included: Belmont, Cranford, Ewing, Hoboken, New Milford, Port Street, Rahway, and Somerville.	**Section II.D.1.**
RCR-IM-9	With reference to page 23 of the Independent Monitor's Draft Third Quarter 2021 Report, please describe the additional outside plant work that resulted in the $2.8 million increase.	The additional OP overhead and restoration work that drove the $2.8 million increase to the Market Street project was driven by unknown OP field conditions, more complicated cutover and traffic control procedures than previously anticipated, and overall quantity of labor and material higher than previously estimated to complete the project scope. Additional details on these cost drivers are as follows: • Unknown OP field conditions: condition of poles, conductors, transformers, and service wires along with space constraints for equipment operation required increased labor and material to resolve. In addition, hazardous soils required use of backhoes, which in turn required additional road closures/traffic safety control. • Cutover procedures: During the procedures for the 13kV conversions, the City mandated additional police around the work areas to ensure public safety and to minimize traffic detours. While construction activities were ongoing, the system being upgraded needed to remain in service and operations to continue to serve customers, which resulted in a higher that estimated level of effort and materials to complete this work safely and reliably. • Traffic control procedures: Included in the conditions of permit approval, County and City officials required additional	**Section III.A.8.**

ID #	Question/Comment	IM Response	Report Changes
		police presence and other traffic control contractor labor to safeguard work areas and mitigate traffic disruptions.	
RCR-IM-10	With reference to page 23 of the Independent Monitor's Draft Third Quarter 2021 Report, please explain if the Company is experiencing higher than estimated traffic control requirements for other projects and if the Company is factoring increased traffic control requirements for future projects. If not, please explain why not.	Generally, PSE&G has not experienced higher than estimated traffic control requirements across the ES 2 Program, however higher traffic costs have been experienced on certain individual projects (e.g. Market Street) based on additional requirements required by the local municipality. PSE&G develops its traffic control estimates based on the amount of street work expected to be executed and the permit requirements for each location.	No change
RCR-IM-11	With reference to page 24 of the Independent Monitor's Draft Third Quarter 2021 Report, please explain if the concrete slab impacting the Ridgefield 13 kV substation was identified during the design phase of the project. If not, please explain why not	The concrete slab that obstructed the manhole/duct bank work was not identified during the design phase of the project. The manhole modifications were not required by the original design and therefore were not part of the original scope.	**Section III.A.11.**
RCR-IM-12	With reference to page 25 of the Independent Monitor's Draft Third Quarter 2021 Report, please describe the additional work that resulted in the $1.2 million increase to remove primary wires to complete 4-13kV conversions.	The additional work was aerial cable removal required to complete the 4kV to 13kV conversions, which had been omitted from the estimate for the OP scope on the project.	**Section III.A.12.**
RCR-IM-13	With reference to page 26 of the Independent Monitor's Draft Third Quarter 2021 Report, please provide an update to the status of the plan application for the Waverly project	The site plan received conditional approval by the Newark Planning Board in December 2021 with memorialization of the compliance resolution in January 2022.	No change
RCR-IM-14	With reference to page 26 of the Independent Monitor's Draft Third Quarter 2021 Report, please indicate if the current forecasted budget remains adequate to address the current delays to the Waverly project. If not, please provide an updated cost estimate for the project.	PSE&G updated the estimate for the Waverly substation project in January 2022. In this updated estimate, the base estimate increased from $29.4 million to $36.2 million, which included: $2.9 million related to equipment awards higher than estimated; $1.1 million from a change in T&D surcharge methodology; $0.2 million from higher than estimated laydown area costs; and $2.6 million related to additional engineering ($0.8 million), revised fencing and external façade improvements ($1.0 million), and additional charges for extended project duration ($0.8 million).	No change
RCR-IM-15	With reference to page 26 of the Independent Monitor's Draft Third Quarter 2021 Report, please provide an update on the project status of the Woodlyne substation work. Please indicate if the Company anticipates any additional costs for the project.	Civil construction on the Woodlynne substation project commenced in February 2022, and as of the end of the first quarter of 2022 there was no change to the forecasted in-service date (which remains at October 10, 2023 – the same status as of the end of the third quarter of 2021 as shown in **Table 2**). In January 2022, PSE&G updated the Woodlynne estimate, which transitioned from the Study (50% level) to Conceptual (70% level) estimate phase. The updated base estimate increased from $15.8	No change

ID #	Question/Comment	IM Response	Report Changes
		million to $21.3 million, driven by higher than estimated civil construction award ($3.9 million), higher than estimated switchgear award ($0.8 million), and increased carrying cost ($0.8 million).	
RCR-IM-16	With reference to page 32 of the Independent Monitor's Draft Third Quarter 2021 Report, please indicate if the Company currently anticipates that progress for the Grid Modernization - Communication System subprogram remains as forecasted. If not, please explain why not and provide an updated budget and project completion forecast.	The forecast for the Grid Modernization – Communication System subprogram increased from $63.1 million as of the end of the third quarter of 2021 to $66.3 million as of the end of the second quarter of 2022. This increase is predominantly the result of higher forecasts in the fiber projects based on actual conditions and will be further discussed in the upcoming IM 2022 Second Quarter Report.	No change
6/27/2022 Letter from Rate Counsel	Rate Counsel notes that the Report does not clearly state the IM's findings regarding: (1) the effectiveness of IIP investments in meeting project objectives; (2) the cost-effectiveness and efficiency of investments; nor (3) the appropriateness of cost assignments. Findings on these issues are required by the IIP rules. Rate Counsel believes findings by the IM on these topics are critical to proper review of the ESII and the prudency review of the Company's investments.	The IM structures its reports such that the majority of the discussion within the reports is focused on these three primary objectives of the IM review. For additional clarity, a summary of the findings on these three points as been incorporated into the executive summary of the report.	**Section I.**
6/27/2022 Letter from Rate Counsel	In the Third Quarter Report, the IM noted that PSE&G increased its estimate for the Market Street substation by a net $3 million primarily due to 1) additional outside plant overhead and restoration work along with associated material and surcharges based on the complexity of the work and the field conditions, 2) higher than estimated traffic control costs, and 3) reduction in the estimated risk and contingency based on the current risk profile for the project. Rate Counsel is interested in understanding if the Company is experiencing increased traffic control costs across all projects and if increased traffic control costs are now included in new project cost estimates.	See the response to **RCR-IM-10** above.	No change

ENERGY STRONG 2 PROGRAM INDEPENDENT MONITOR 2021 FOURTH QUARTER REPORT

PREPARED AND SUBMITTED BY

PEGASUS GLOBAL HOLDINGS, INC. ®

CONFIDENTIAL

DECEMBER 21, 2022

Table of Contents

Appendices

List of Acronyms and Abbreviations

Advanced Distribution Management Systems .... ADMS
Advanced Metering Interface .... AMI
Allowance for Funds Used During Construction .... AFUDC
Architect and Engineer .... A/E
Board of Public Utilities .... BPU
Construction Work In Progress .... CWIP
Costs of Removal .... COR
Distributed Energy Resource Management System .... DERMS
Distribution Management System .... DMS
Distribution Supervisory Control and Data Acquisition .... DSCADA
Energy Strong 2 .... ES 2
Gas Metering & Regulating .... Gas M&R
Independent Monitor .... IM
Inside Plant .... IP
Issued for Construction .... IFC
Issued for Review .... IFR
New Jersey Department of Environmental Protection .... NJDEP
New Jersey Sports and Exposition Authority .... NJSEA
Open Systems International Inc. .... OSII
Outage Management System .... OMS
Outside Plant .... OP
Public Service Electric & Gas .... PSE&G
Purchase Order .... PO
Record of Decision .... ROD
Remote Control Unit .... RCU
Remote Terminal Unit .... RTU
Risk and Contingency .... R&C

Supervisory Control and Data Acquisition .... SCADA

System Average Interruption Duration Index .... SAIDI

Utility Review Board .... URB

I. Executive Summary

Public Service Electric & Gas's (PSE&G's) Energy Strong 2 (ES 2) Program was established from a Stipulation that the involved parties agreed to in August 2019, as approved by a Board of Public Utilities (BPU) Order dated September 11, 2019, with an effective date of September 21, 2019. The Stipulation provided the ES 2 Program would be comprised of five primary subprograms: Electric Station Flood Mitigation; Contingency Reconfiguration; Grid Modernization – Communications; Grid Modernization – Advanced Distribution Management Systems (ADMS); and Gas Metering & Regulating (Gas M&R) Station Upgrades. In addition, a Stipulated Base spend was established that includes both an electric component (higher outside plant design standards and station life cycle upgrades) and a gas component (overlapping with the Gas M&R subprogram). This report contains the Independent Monitor's (IM's) findings and observations on the ES 2 Program elements and other information on the Program's status as of the fourth quarter of 2021.

During the fourth quarter of 2021, the bulk of the spend within the ES 2 Program continued to be in the two largest subprograms: Electric Station Flood Mitigation with two additional projects commencing construction during the quarter, bringing half of the projects in the subprogram past the start of construction; and Contingency Reconfiguration where the bulk of the planned recloser installations have now been completed. Within the other subprograms, the Grid Modernization – Communication System subprogram placed three additional fiber installation projects in-service, with 20 fiber installation projects now completed through the ES 2 Program. The Gird Modernization – Communication System also completed the final recloser retrofit installations during the fourth quarter of 2021, with a total 2,318 retrofits installed, and continued the retrofit substation remote terminal unit (RTU) scope, with 10 substations completed out of a forecasted scope of 196 substations. The Grid Modernization – ADMS subprogram completed sprints 11 and 12 in the Distribution Management System (DMS)/Distributed Energy Resource Management System (DERMS) scope and sprint 9 within the Outage Management System (OMS) scope. The Gas M&R subprogram placed its first project, the Westampton project, in-service while other stations continued to advance pre-construction efforts, including completing site plan packages, ordering long lead materials, and awarding the construction work. The Hamilton, Paramus, Plainfield, and Woodbury projects in the Electric Stipulated Base scope continued construction during the fourth quarter of 2021, while the State Street (Outside Plant) project held its kickoff meeting and commenced detailed engineering. **Table 1 – ES 2 Subprogram & Stipulated Base Status as of December 31, 2021** below provides the spend to date on the subprograms within the ES 2 Program and Stipulated Base compared to the total forecast and forecasted completion for each.

Table 1 – ES 2 Subprogram & Stipulated Base Status as of December 31, 2021

Subprogram	Q4 Spend	Total Spend to Date*	Total Forecast*	% of Actuals to Forecast	Forecasted Completion**	Stipulation Funding Amount***
Electric Station Flood Mitigation	**$19,768,173**	**$121,152,744**	**$347,842,636**	**35%**	**Sep 2024**	**$389M**
Contingency Reconfiguration	**$8,418,831**	**$105,693,021**	**$145,767,428**	**73%**	**Dec 2023**	**$145M**
Grid Modernization – Communications	**$8,254,991**	**$48,365,008**	**$63,628,856**	**76%**	**Dec 2023**	**$64.3M**
Grid Modernization – ADMS	**$2,828,626**	**$26,338,279**	**$43,494,127**	**61%**	**Dec 2022**	**$42.7M**

Subprogram	Q4 Spend	Total Spend to Date*	Total Forecast*	% of Actuals to Forecast	Forecasted Completion**	Stipulation Funding Amount***
Electric Stipulated Base	**$4,669,633**	**$18,055,021**	**$100,000,000**	**18%**	**Dec 2023**	**$100M**
Gas M&R Station Upgrades^	**$7,006,451**	**$20,175,989**	**$107,798,888**	**19%**	**Dec 2023**	**$101M**
Total*	**$50,946,704**	**$339,780,063**	**$808,531,934**	**42%**	**Dec 2024**	**$842M**

-Note: total figures may not fully align due to rounding. Additionally, the total forecast includes only the base cost for the Electric Station Flood Mitigation and Gas M&R subprograms as PSE&G does not include risk and contingency (R&C) in its forecasts for these projects. See **Table 11 and **Table 20** for the Electric Station Flood Mitigation and Gas M&R project estimates, respectively, with base costs and R&C shown.*
***-Final in-service date.*
****-Following the $7.7 million transfer in July 2021 from the Grid Modernization – Communications subprogram to the Grid Modernization – ADMS subprogram.*
^-Includes both the ES 2 projects and the Stipulated Base gas projects.

Given the prominence of the Electric Station Flood Mitigation subprogram, which represents over half of the total ES 2 Program spending, a summary of the projects within this subprogram is provided below in **Table 2 – ES 2 Electric Station Flood Mitigation Status as of December 31, 2021**.

Table 2 – ES 2 Electric Station Flood Mitigation Status as of December 31, 2021

Project	Total Estimate (rounded)	Actuals	% of Actuals to Estimate	Forecasted In-Service Date*
1. Academy Street	$10,500,000	$6,129,738	58%	**10/19/2021** (↑-1)
2. Clay Street	$33,800,000	$3,802,341	11%	11/7/2022 (↑-50)
3. Front Street^	$27,400,000	$2,351,832	9%	11/16/2023 (↓+10)
4. Hasbrouck Heights	$22,700,000	$5,456,031	24%	2/1/2023 (↑-6)
5. Kingsland	$8,300,000	$824,722	10%	6/30/2023 (↑-96)
6. Lakeside Avenue	$47,900,000	$1,173,651	2%	11/8/2023
7. Leonia	$26,400,000	$15,190,427	58%	11/9/2022 (↓+30)
8. Market Street	$29,900,000	$27,012,282	90%	**6/25/2021**
9. Meadow Road	$9,000,000	$1,043,444	12%	9/22/2023
10. Orange Valley	$20,200,000	$797,976	4%	12/29/2023
11. Ridgefield 13kV	$27,600,000	$17,288,355	63%	12/20/2022 (↓+39)
12. Ridgefield 4kV	$21,300,000	$20,646,800	97%	**5/16/2021**
13. State Street	$21,400,000	$8,832,965	41%	9/23/2022
14. Toney's Brook	$18,800,000	$1,526,556	8%	4/21/2023
15. Waverly	$35,400,000	$6,979,786	20%	9/17/2024 (↑-92)
16. Woodlynne	$19,400,000	$2,095,910	11%	10/10/2023

-Reflects the in-service date of the last major asset (e.g. switchgear), certain activities may take place after this date to support the final in-service date (i.e. when all customers are cutover). **Bold dates indicate the actual in-service date.*

(↑)*-Indicates the forecasted in-service date advanced from the prior quarter.*

(↓)*-Indicates the forecasted in-service date slipped from the prior quarter.*
^- The Front Street project was proposed by PSE&G during the second quarter of 2021 to replace the cancelled Constable Hook project.

As indicated in **Table 2**, the projects that started construction prior to the fourth quarter of 2021 (Academy Street, Leonia, Market Street, Ridgefield 13kV, Ridgefield 4kV, and Waverly) continue to have the highest total spend to date, with the Academy Street project also achieving its in-service status during the fourth quarter. The Electric Station Flood Mitigation project estimates remain unchanged from the third quarter of 2021, with a total subprogram estimate of $389 million (comprised of $339.8 in base costs and $49.2 million in R&C). **Table 2** also shows that half of the sixteen projects had movement during the third quarter of 2021 in the forecasted in-service date, with five advancing and three slipping. Of these eight projects, three of the projects (Academy Street, Front Street, Hasbrouck Heights) had forecasted in-service dates change by less than two weeks. The biggest shifts in forecasted in-service dates were on the Kingsland (advancing 96 days) and Waverly (advancing 92 days) projects, with the former driven by material availability that supported schedule improvement and the latter driven by approval of the site plan in December 2021 that improved the construction schedule. The forecasted in-service date for the Waverly project of September 17, 2024, as of the end of 2021, continues to be outside of the ES 2 Program window as PSE&G continues to seek opportunities to improve the schedule. Additional information on the forecasted in-service changes during the fourth quarter of 2021 is provided in the project-specific discussions under **Section III.A.**

As the Covid-19 related impacts continue to be experienced, particularly in the supply chain, and general economic conditions show increased cost pressures, these imparts are starting to be realized in the cost forecasts for the ES 2 Program. These cost impacts were particularly evident within the Gas M&R subprogram that is currently forecasted at approximately $107.8 million (above the Stipulation amount of $101 million), however the overall Program remains forecasted under the total Stipulation amount (forecast of approximately $808.5 million against a Stipulation budget of $842 million). The IM has generally found these cost impacts reflect a change in underlying assumptions and economic conditions from when the initial estimates were prepared and will continue to monitor these cost pressures and any resulting impacts on the Program. Currently, schedule challenges, particularly on the Waverly substation that is forecasted to have its final assets in-service during the third quarter of 2024 and other projects with forecasted in-service dates near the Program end date will continue to warrant further monitoring by the IM to see if opportunities exist to advance the forecasted in-service dates.

As per N.JA.C. Section 14:3-2A.5(c)2, the IM reports are to address:

i. *The effectiveness of Infrastructure Investment Program investments in meeting project objectives;*
ii. *The cost-effectiveness and efficiency of investments;*
iii. *The appropriateness of cost assignments; and*
iv. *Any other information required by the Board.*

The IM focuses the majority of the discussion within each report on these primary objectives, after introducing summarized the findings on these areas in the IM 2021 Third Quarter Report, the IM will continue to provide a summary on these areas for each report with an emphasis on new information relative to the current reporting period. These summarized findings are as follows:

- **Effectiveness of ES 2 investments in meeting project objectives**: The objectives for each subprogram within the ES 2 were defined within PSE&G's ES 2 filing and confirmed by the Stipulation. The overall objectives focused on improving system resiliency, reliability, and hardening through rebuilding or replacing selected substations, installing smart control and monitoring devices on distribution circuits (reclosers, fuse savers, etc.), installing ADMS and a new communication system, and rebuilding selected Gas M&R stations. Within **Section III** of this report, the IM provides a review of the status of the efforts performed to meet these objectives for each subprogram. During the fourth quarter of 2021, the following projects/scopes were placed in-service and/or completed:

- Electric Station Flood Mitigation: Academy Street placed in-service.
- Contingency Reconfiguration: Metro Division recloser scope completed.
- Grid Modernization – Communication System: Recloser retrofit scope completed (final 324 completed in the fourth quarter out of a total scope of 2,318 units); two substation RTU retrofits completed (bringing the total to 10 substations out of a current scope of 196); three fiber installation projects were completed (bringing the total to 20 out of a current scope of 38); and one fiber cutover project was completed (bringing the total to nine out of a current scope of 12).
- Electric Stipulated Base: Paramus contingency switchgear placed in-service.
- Gas M&R: Westampton placed in-service.

- **Cost-effectiveness and efficiency of investments**: To assess the cost effectiveness and efficiency of ES 2 investments, the IM began with a review of the initial scope, estimate, and related planning documents for each project to establish a baseline to monitor progress against as the work advances. As the Program execution advances, the IM continues to evaluate actual costs against the initial estimates and current forecasts, including seeking additional information relating to any variances identified. While the overall Program's current cost forecast is below the Stipulation amount, the IM has observed cost increases realized on specific projects or aspects of the Program and found the majority of these increases stem from scope evolution and/or more detailed estimates from the time of the ES 2 filing, as well as the more recent changes in general market conditions (e.g. Covid-19 impacts, supply chain issues, etc.). The updated subprogram forecasts as of the end of 2021 compared to the end of the third quarter of 2021 were as follows:

  - Electric Station Flood Mitigation: subprogram forecast increased approximately $1.3 million (or 0.4%) to approximately $347.8 million.
  - Contingency Reconfiguration: subprogram forecast increased approximately $273,000 (or 0.2%) to approximately $145.8 million.
  - Grid Modernization – Communication System: subprogram forecast increased approximately $518,000 (or 0.8%) to approximately $63.6 million.
  - Grid Modernization – ADMS: subprogram forecast increased approximately $772,000 (or 1.8%) to approximately $43.5 million.
  - Electric Stipulated Base: subprogram forecast remained at $100.0 million.
  - Gas M&R: subprogram forecast increased approximately $12.0 million (or 13%) to approximately $107.8 million.

  As shown above, the nearly every subprogram within the ES 2 Program saw a cost forecast increase during the fourth quarter of 2021. The majority of these increases were relatively minor (under 2%). However, the Gas M&R subprogram saw a 13% forecast increase that was driven by actual costs for materials and construction for the Central and East Rutherford projects that reflects the ongoing volatility in market conditions compared to when the initial estimates were prepared.

- **Appropriateness of cost assignments**: The IM receives and reviews recurring data concerning the accumulation of costs within the Program. Based on that review, the IM submits follow-up questions to the Company regarding that data for the reporting period. Such follow-up questions generally focus on the following aspects:
    - Review of any unusual changes in cost elements from period-to-period, including but not limited to allowance for funds used During construction (AFUDC), cost of removal (COR), and the allocation of overheads.
    - Review spend on capital accounts, such as Construction Work in Progress (CWIP) as it relates to overall spend, AFUDC, and COR.
    - Verify cost accumulations and classifications appear to be in accordance with Generally Accepted Accounting Principles (GAAP), to the extent the IM has access to such information.
    - Review and investigation of prior period adjustments and/or corrections to capital accounts.
    - Engage the Company's Internal Audit group on specific areas to audit, review, and assess – particularly for areas in which the IM has limited or no visibility (proprietary data, accounting systems, etc.).

    Through the above steps, the IM tracks and monitors how the Company is recording costs to support the finding that the cost assignments appear to be appropriately applied. These cost items are discussed further within **Section II.** of this IM report.

As noted in the IM 2020 First Quarter Report, the IM conducts its assessment in accordance with Generally Accepted Government Auditing Standards (GAGAS, or more commonly referred to as the "Yellow Book" standards). The Yellow Book provides a framework for conducting performance management reviews/audit engagements with competence, integrity, objectivity, and independence that result in information used for oversight, accountability, transparency, and improvements of the audited programs and operations. On September 20, 2022, a draft IM 2021 Fourth Quarter Report was submitted to PSE&G, BPU Staff, and Rate Counsel. Per the Yellow Book, the transmittal of a draft report is intended to allow for review and comment by the audited entity and others to develop a fair, complete, and objective report. A summary of the comments on the draft report and the IM's responses are provided in **Appendix A – Draft Report Comments and Responses**. This **Appendix A** also identifies specific sections within this IM 2021 Fourth Quarter Report that have been edited, supplemented with additional information, or otherwise revised in response to the comments received.

II. Program Status

A. Key Decisions

In order to capture formalized key decisions regarding the ES 2 Program, PSE&G completes a "Record of Decision" (ROD) that includes a description of the decision; alternatives considered; the decision made; and rationale for the decision. The RODs are assessed by the IM as they are completed to review their impact to the Program. In addition, the IM may request PSE&G complete a ROD to formalize a decision if such a decision has not yet been formalized through the ROD process.

The current and pending RODs as of the date of this IM 2021 Fourth Quarter Report are presented below in **Table 3 – ES 2 Records of Decisions**.

Table 3 – ES 2 Records of Decisions

Subprogram	Record of Decision	IM Comments
Electric Station Flood Mitigation	Academy Street & State Street Change in Mitigation Method	Reasonable and appropriate *(See Section B.1. in the IM 2020 First Quarter Report)*
Electric Station Flood Mitigation	Engineering Support for Energy Strong Program Projects	Reasonable and appropriate *(See Section B.2. in the IM 2020 First Quarter Report)*
Grid Modernization – Communication System	Wireless Communication Network	Reasonable and appropriate *(See Section II.A.1. in the IM 2020 Third Quarter Report)*
Grid Modernization – Communication System	Substation Communication Center	Reasonable and appropriate *(See Section II.A.2. in the IM 2020 Third Quarter Report)*
Grid Modernization – Communication System	Fiber Scope	Reasonable and appropriate *(See Section IV.A. in the IM 2020 Third Quarter Report)*
Electric Station Flood Mitigation	Constable Hook, Lakeside, & Orange Valley Change in Mitigation Method	Reasonable and appropriate *(See Sections II.A.3. and IV.B. in the IM 2020 Third Quarter Report and additional discussion in Section II.A.1. and Section IV.B. of the IM 2020 Fourth Quarter Report)*
Grid Modernization – Communication System	Communication Retrofit of Replacement and non-ES-II Units	Reasonable and appropriate *(See Section II.A.2. in the IM 2020 Fourth Quarter Report)*
Electric Station Flood Mitigation	Market Street Radioactive Soil Testing and Handling	Reasonable and appropriate *(See Section II.A.3. in the IM 2020 Fourth Quarter Report)*
Electric Station Flood Mitigation	Transfer of Clay Street Wastewater Wall Scope from ES2FM to Clay Street 69kV Project	Reasonable and appropriate *(See Section IV.A. in the IM 2020 Fourth Quarter Report)*
Contingency Reconfiguration	Energy Strong II Electric Program – Contingency Reconfiguration Subprogram, 13kV and 4kV Reclosers	Reasonable and appropriate *(See Section IV.A. in the IM 2021 First Quarter Report and Section II.A.1. in the IM 2021 Second Quarter Report)*
Grid Modernization – ADMS	Outage Management System (OMS) Implementation	Reasonable and appropriate *(See Section IV.A. in the IM 2021 First Quarter Report and Section II.A.2. the IM 2021 Second Quarter Report)*

During the fourth quarter of 2021, there were no additional RODs issued.

B. Program Management

Beginning in July 2020, the IM began participating in a bi-weekly call with PSE&G to review its bi-weekly ES 2 Program Dashboard. As with the original Energy Strong Program, the Dashboard provides a mechanism for PSE&G to monitor and control activities to be completed in order to achieve key near-term milestones, including a focus on recently completed activities, any key issues, and other key metrics (e.g. installation targets) as appropriate. These calls have proven to be an effective way for the IM to stay informed on current and upcoming activities and to allow a venue for discussions between the IM and PSE&G on these activities and status updates and continue to be held on a recurring basis.

C. Cost Assignments

1. Costs of Removal (COR)

Costs of Removal (COR) generally include costs for such activities as environmental removal, removal of inside station equipment, structures, foundations, towers and fixtures, conductors and other electrical devices, poles and fixtures, transformers, plant demolition, foundations, and removal of underground conduit and other wiring. Generally, COR are charged to Accumulated Depreciation and are amortized and recovered through a component of depreciation expense. The specific method and amount of recovery is determined in gas and electric rate cases before the BPU.

Table 4 – ES 2 Program Costs of Removal as of December 31, 2021, below itemizes the charges to COR for each quarter of 2021, total 2021, total 2020, total 2019 (which was only the fourth quarter) and total ES 2 Program COR to date. These amounts do not reflect any salvage value reductions, which have been *de minimis* in the ES 2 Program through December 31, 2021.

Table 4 – ES 2 Program Costs of Removal as of December 31, 2021

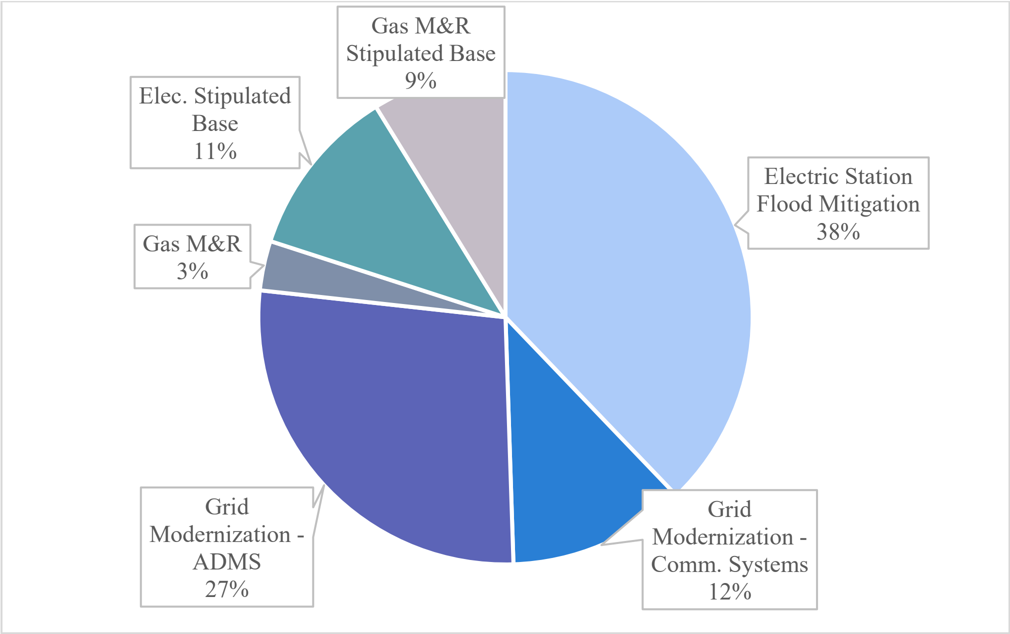
Subprogram	Q4 2021	Q3 2021	Q2 2021	Q1 2021	Total 2021	Total 2020	Total 2019 (Q4)	Total COR
	(in $ thousands)							
Electric Station Flood Mitigation	**$1,824.0**	**$1,464.2**	**$1,141.0**	**$1,129.5**	**$5,558.7**	**$1,021.1**	**$0**	**$6,579.8**
Contingency Reconfiguration	**$330.7**	**$811.4**	**$485.2**	**$622.9**	**$2,250.2**	**$2,198.9**	**$431.0**	**$4,880.1**
Grid Modernization – Communications	**$23.5**	**$38.6**	**$37.9**	**$37.8**	**$137.8**	**$24.4**	**$0**	**$162.2**
Grid Modernization – ADMS	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Electric Stipulated Base	**$146.8**	**$3.2**	**$0**	**$0**	**$150.0**	**$0**	**$0**	**$150.0**
Gas M&R Station Upgrades	**($2.2)**	**$63.5**	**$87.6**	**$0**	**$148.9**	**$0**	**$0**	**$148.9**
Gas Stipulated Base	**$196.1**	**$0**	**$0**	**$0**	**$196.1**	**$0**	**$0**	**$196.1**
Total	**$2,518.9**	**$2380.9**	**$1,751.7**	**$1,790.2**	**$8,441.7**	**$3,244.4**	**$431.0**	**$12,117.1**

The COR charges for the fourth quarter of 2021 primarily reflect COR activities at the Market Street Sub Elimination project, including removal of 4kV cabling and switchgear, circuit breakers, transformers, foundations, and asbestos abatement.

2. Construction Work-in-Progress (CWIP) & In-Service Transfers

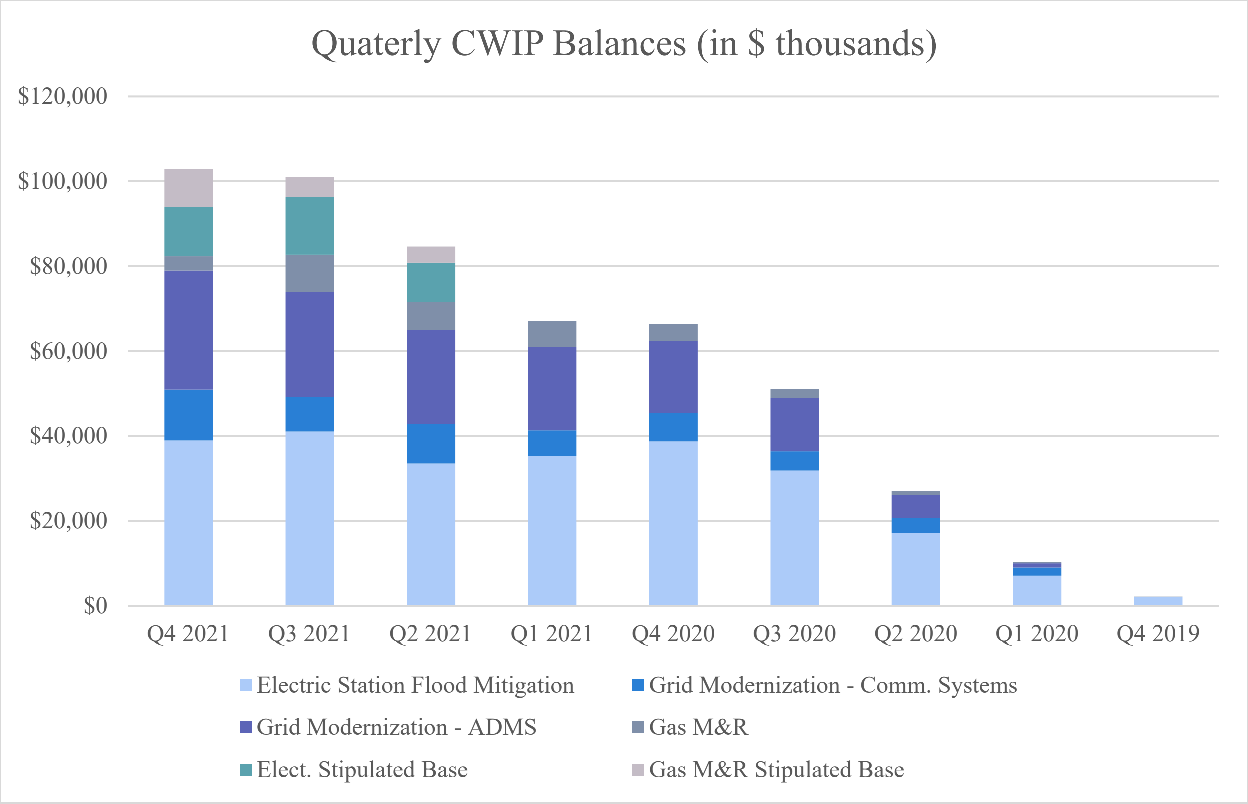
As of December 31, 2021, the Energy Strong CWIP balance was $102.9 million, compared to $101.0 million as of September 30, 2021. The largest components of CWIP as of December 31, 2021, were the State Street ($9.0 million), Waverly ($7.4 million) and Hasbrouck ($5.6 million), projects with the Electric Station Flood Mitigation subprogram, the Central ($4.8 million) Gas Stipulated Base M&R project, and work associated with the Grid Modernization – ADMS subprogram ($28.1 million). The Electric Station Flood Mitigation subprogram comprises the largest component of total end of period CWIP outstanding, as depicted in **Figure 1 – ES 2 CWIP as of December 31, 2021** below.

Figure 1 – ES 2 CWIP as of December 31, 2021



In addition, the **Figure 2 – ES 2 CWIP Balances by Subprogram as of December 31, 2021** below depicts the composition of end-of-quarter CWIP balances by subprogram for each quarter of 2021 and 2020, and the fourth quarter of 2019.

Figure 2 – ES 2 CWIP Balances by Subprogram as of December 31, 2021



Transfers from CWIP to plant in service totaled $32.4 million during the fourth quarter of 2021, the largest quarterly transfer to date. During the fourth quarter, the Academy Street substation and the Westhampton Gas M&R substation projects were completed and placed in-service, and switchgear assets were placed in-service at the Leonia substation and Paramus substation projects. Total ES 2 Program transfers from CWIP have been $70.8 million through December 31, 2021. It should be noted that work related to certain assets, such as the reclosers under the Contingency Reconfiguration subprogram, generally can be completed without being recorded through CWIP. As such, no AFUDC is recorded on these expenditures. This accounting treatment is in accord with generally accepted accounting principles and the Company's accounting policies.

3. Allowance for Funds Used During Construction (AFUDC)

The amount of quarterly AFUDC recorded by the Company for each ES 2 subprogram during each quarter of 2021, total AFUDC for the years 2021, 2020, and 2019, and total Energy Strong AFUDC accrued through the end of 2021, is shown below **Table 5 – ES 2 Program AFUDC as of December 31, 2021**.

Table 5 – ES 2 Program AFUDC as of December 31, 2021

Subprogram	Q4 2021	Q3 2021	Q2 2021	Q1 2021	Total 2021	Total 2020	Total 2019 (Q4)	Total AFUDC
	(in $ thousands)							
Electric Station Flood Mitigation	**$564.3**	**$581.6**	**$576.7**	**$558.6**	**$2,281.2**	**$936.5**	**$9.9**	**$3,227.6**

Subprogram	Q4 2021	Q3 2021	Q2 2021	Q1 2021	Total 2021	Total 2020	Total 2019 (Q4)	Total AFUDC
	(in $ thousands)							
Contingency Reconfiguration	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Grid Modernization – Communications	**$127.2**	**$105.2**	**$95.5**	**$59.0**	**$386.9**	**$184.3**	**$0.2**	**$571.4**
Grid Modernization – ADMS	**$411.0**	**$363.5**	**$316.9**	**$274.2**	**$1,365.6**	**$352.7**	**$0.1**	**$1,718.4**
Electric Stipulated Base	**$233.6**	**$160.9**	**$80.5**	**$49.6**	**$524.6**	**$44.0**	**$0**	**$568.6**
Gas M&R Station Upgrades (incl. Stip. Base)	**$133.2**	**$157.0**	**$107.6**	**$72.2**	**$470.0**	**$70.0**	**$0.2**	**$540.2**
Total	**$1,469.3**	**$1,368.2**	**$1,177.2**	**$1,013.6**	**$5,028.3**	**$1,587.5**	**$10.4**	**$6,626.2**

AFUDC accrued for ES 2 projects during the fourth quarter of 2021 increased over AFUDC accrued during the third quarter of 2021 as the result of increases in total average CWIP balances for the Grid Modernization – Communications and Grid Modernization – ADMS subprograms and the full quarterly effect of AFUDC accrued on the Paramus substation, which saw its contingency switchgear transferred into in-service in December 2021.

During the first quarter of each year, the AFUDC rate is reviewed for possible reset as it applies to the current year based on updated capital structure and component cost data. For the year 2021, the new AFUDC rate was calculated to be 6.81%, using the capital structure and component costs as of January 31, 2021. This rate is lower than the 2020 rate of 6.95%, primarily due to a significantly lower interest rate used for short-term debt in the AFUDC calculation, and also to a reduction in the Company's embedded cost of long-term debt. In calculating the 2021 AFUDC rate, the Company used (i) a 3.85% embedded cost of long-term debt (vs. 4.02% in 2020), (ii) a short-term debt rate of 0.32% (vs. 1.86% in 2020), and (iii) a cost of equity of 9.60% (unchanged from 2020).

Subsequent to the annual reset calculation referred to above, and during the course of each year, the AFUDC rate is also recalculated as it applies to each fiscal quarter. If the recalculated rate changes by 25 basis points from the rate then in effect, the rate is reset and retroactively applied to January 1 of that year. For the fourth quarter of 2021, based on data as of November 30, 2021, the recalculated weighted average AFUDC accrual rate (6.84%) did not meet this criterion to warrant changing from the annual rate (6.81%) in effect. Therefore, AFUDC was accrued during the second quarter of 2021 at the calculated rate of 6.81%.

The IM observes that the Company's calculation of the AFUDC rate and its application is in accordance with both PSE&G's accounting policy and Plant Instruction 3(17) of the Federal Regulatory Commission's Uniform Systems of Accounts prescribed for public utilities.

The IM also notes that the relevant AFUDC information as it relates to fourth quarter 2021 Energy Strong project costs is consistent with the applicable dictates of the Stipulation entered into with respect to these Energy Strong projects. The IM will continue to review future Energy Strong AFUDC accruals for consistency with relevant provisions of the Stipulation for accounting and reporting purposes only, and not as a party to, or in expressing an opinion concerning, any rate proceedings.

4. *Allocated Overheads*

PSE&G follows a philosophy of allocating overhead costs, whether at the Service Company or from utility support organizations, to the operating company or unit receiving the benefit, and ultimately, if appropriate, settling costs to individual assets. Where possible, services are charged directly to the entity receiving the benefit, but where direct charging of costs is not feasible, cost allocations from the Service Company to operating companies are prescribed in a BPU-approved schedule issued pursuant to a BPU order in July 2003. The Stipulation requires the Company to follow its current practices with regard to capitalized overheads.

For ES 2 electric and gas distribution projects, allocated overhead costs should primarily come from utility-related labor costs associated with administrative and supervisory personnel, labor and other costs associated with bargaining unit personnel, fringe benefits, materials handling costs, payroll taxes and depreciation expense. Shown below in **Table 6 – ES 2 Program Overhead Allocations as of December 31, 2021** are the allocated overhead costs charged to ES 2 subprograms for the four quarters of 2021, total 2021, total 2020, total 2019 and total ES 2 Program allocated overheads to date.

Table 6 – ES 2 Program Overhead Allocations as of December 31, 2021

Subprogram	Q4 2021	Q3 2021	Q2 2021	Q1 2021	Total 2021	Total 2020	Total 2019 (Q4)	Total Overhead Allocations
	(in $ thousands)							
Electric Station Flood Mitigation	$1,902	$2,527	$4,352	$5,588	$14,368	$14,023	$287	$28,678
Contingency Reconfiguration	$2,516	$3,683	$4,006	$4,215	$14,420	$17,109	$3,415	$34,944
Grid Modernization – Communications	$2,692	$2,230	$2,506	$1,743	$9,171	$3,625	$12	$12,808
Grid Modernization – ADMS	$133	$125	$124	$119	$501	$426	$11	$938
Electric Stipulated Base	$807	$903	$287	$126	$2,123	$259	$0	$2,382
Gas M&R Station Upgrades (incl. Stip. Base)	$250	$185	$169	$131	$735	$291	$15	$1,041
Total	$8,300	$9,653	$11,444	$11,922	$41,318	$35,733	$3,740	$80,791

The overwhelming majority of overhead costs allocated to ES 2 projects during the fourth quarter of 2021 are costs allocated from areas that support all utility distribution and transmission projects, including ES 2 projects. More specifically, most (approximately 74%) of the 2021 fourth quarter allocated costs reflect labor costs of supervisory, administrative and operations planning personnel, labor and other costs from bargaining unit personnel, and fringe benefits associated with these labor costs. The decreases in overhead costs for the fourth quarter 2021 from the third quarter of 2021 reflect reduced activities that attract overheads, such as material costs and outside services, especially in the Electric Station Flood Mitigation subprogram.

D. System Performance

1. Current Reporting Quarter Major Events

During the fourth quarter of 2021, there was one Major Event reported in PSE&G's service territory from October 25 to November 1, 2021, which involved a State of Emergency related to storm flooding from a Nor'easter and Mutual Aid provided to Jersey City Power & Light. The weather associated with the State of Emergency saw thunderstorms and heavy rains across PSE&G's service territory and resulted in 42,329 PSE&G customers experiencing service interruption with all impacted customers returned to service within 24 hours. None of the switching stations or substations raised and rebuilt during the original Energy Strong Program were affected by floodwaters during this Major Event.

The IM has received PSE&G's report on the performance of its investments from this Major Event and has reproduced the results in **Table 7 – Q4 2021 Major Event Performance** below.

Table 7 – Q4 2021 Major Event Performance

Circuit	5 Year Baseline SAIDI*	Report Quarter SAIDI*
ALD 8015	0.12276	0.00000
ALD 8016	0.00654	0.00000
ALD 8022	0.05448	0.00000
BAO 8006		**0.00202**
BAO 8015	0.00023	0.00000
BEA 8001	0.00458	0.00068
BEF 8021	**0.00320**	**0.01943**
BEM 8001	0.00675	0.00000
BEN 8015	0.01246	0.00018
BRU 8012	0.01648	0.01004
CED 8025	0.00153	0.00092
CIN 8031	0.06823	0.00959
CIN 8033	0.14578	0.00376
CIN 8043	0.18459	0.00114
CLK 8015	0.23135	0.00001
CLK 8016	0.39621	0.00020
CLK 8031		**0.00403**
CON 8001		**0.00188**
CRX 8003	0.07703	0.00671
CRX 8005	0.04402	0.00052
CRX 8007	0.78411	0.00308
CUT 8001	0.12150	0.00000
CUT 8042	0.03420	0.00059
DAY 8001	0.15084	0.00846
DFD 8031	0.13025	0.00143
DFD 8041	0.20440	0.00654
DOR 8035	**0.03042**	**0.03873**
DOR 8045	0.00647	0.00128
DUM 4007	0.00474	0.00425
FAW 8011	0.63063	0.01277

Circuit	5 Year Baseline SAIDI*	Report Quarter SAIDI*
FAW 8014	0.21021	0.00814
FAW 8016	0.12332	0.00964
FOH 4006	0.01339	0.00000
GBK 8014	0.30784	0.00037
HAT 8021	0.00164	0.00072
HNC 8025	0.49719	0.00000
HOM 8033	0.08934	0.00438
JAC 8021	0.00477	0.00000
KIL 8013		**0.00000**
KIL 8016	0.01491	0.00000
KIN 8023	0.02086	0.00578
KUS 8043	0.12886	0.00000
LAF 8015	0.00354	0.00000
LAF 8026	0.04406	0.00000
LAU 8012	0.09474	0.00362
LAU 8023	0.82844	0.00736
LAW 8016	0.14895	0.00062
LAW 8023	0.01733	0.00146
LCE 8032	0.30801	0.01615
LCE 8035	0.01296	0.00089
LCE 8042	0.04252	0.00077
LCE 8044		**0.00000**
LCE 8046	0.01692	0.00072
LCU 8051	0.19366	0.00000
LEO 8005	0.61152	0.00000
LEO 8041	0.05678	0.00352
LEV 8016	**0.00021**	**0.00140**
LOC 8012		**0.00000**
LOI 8001	0.00850	0.00000
LUM 8021	0.26968	0.00891

Circuit	5 Year Baseline SAIDI*	Report Quarter SAIDI*
MAD 8021	0.19231	0.00026
MAD 8031	0.45221	0.00375
MAR 8008	0.30277	0.00067
MAR 8016	0.26336	0.00123
MCL 4007	0.02282	0.00766
MEA 8012		**0.00027**
MEA 8016	0.00228	0.00138
MEA 8024	0.09438	0.03168
MEA 8025	0.11896	0.00119
MEC 8004	0.01253	0.00000
MIN 8013	0.00714	0.00000
MIN 8024		**0.00310**
MON 8002	0.35076	0.00037
MON 8004	0.21535	0.00768
MOT 8003	0.00646	0.00309
MRO 8012	1.08732	0.00054
MRO 8013	0.46710	0.00103
MRO 8023	0.19878	0.01582
MRO 8024	0.29163	0.00441
NBS 8011	0.01516	0.00489
NED 8015	0.09467	0.00000
NED 8016	**0.00729**	**0.00870**
NEW 8011	0.07862	0.00168
NOT 8011		**0.00000**

Circuit	5 Year Baseline SAIDI*	Report Quarter SAIDI*
NRP 4002		**0.00000**
PEK 8036	0.10806	0.00428
PIE 8022		**0.00782**
PLI 8004	**0.01320**	**0.14784**
PLI 8008	0.19552	0.00416
POH 8022	0.01503	0.01445
POH 8023	0.22676	0.00656
RAV 8003	0.00674	0.00000
RUN 8004	0.29484	0.01992
SAD 8008		**0.00000**
SOH 8022	0.16946	0.00230
SUN 8024	**0.00104**	**0.00150**
WAD 8013	0.12231	0.00000
WAD 8041	0.11575	0.00324
WEW 8021	0.21824	0.00073
WEW 8042	0.01304	0.00231
WEW 8044	0.07375	0.00292
WFL 8034	0.04228	0.01247
WOA 4003	0.04886	0.00309
WOR 8013	0.13969	0.00385

**-System Average Interruption Duration Index (SAIDI) calculations are in minutes; bold values indicate circuits with a higher Major Event SAIDI than the 5-year Major Event SAIDI average.*

In the circuit data in **Table 7** above, the "0.00000" indicates an outage, but the value is beyond five decimal points captured by PSE&G, while blank cells indicate no outage in the 5-year window. Additionally, all circuits impacted by this Major Event had received investments during either the original Energy Strong Program or through ES 2. The average of the circuits impacted by this Major Event compared to circuits not impacted is provided in **Table 8 – Impacted vs. Non-Impacted Circuits During Q4 2021 Major Event**.

Table 8 – Impacted vs. Non-Impacted Circuits During Q4 2021 Major Event

Circuits Impacted in Q4 2021 Major Events (104 circuits)		Circuits Not Impacted in Q4 2021 Major Events (903 circuits)
Average of 5-Year Baseline SAIDI	Average of Q4 2021 SAIDI	Average 5-Year Baseline SAIDI
0.14816	0.00528	0.08234

As shown in **Table 8** above the circuits impacted by the fourth quarter of 2021 Major Events had a worse 5-year average SAIDI than the non-impacted circuits, but also showed improved performance during this Major Event.

As indicated in **Table 7** above, there were 104 circuits impacted by this Major Event 86 of which (or 83%) had a current Major Event SAIDI better than the 5-year Major Event SAIDI average, while 12 circuits had no Major Event outage within the 5-year comparison window, leaving six circuits that both had a prior Major Event outage within the past 5-years and had worse performance during this Major Event. Additional information on the six worse performing circuits from this Major Event is provided below in **Table 9 – Q4 2021 Major Event Additional Information on Selected Circuits.** As shown in **Table 9**, some of these circuits had more than one incident during the Major Event, resulting in a total of 12 incidents from these six circuits, and that some may show zero customers impacted, which reflects the way the circuit is modeled in PSE&G's connectivity model and the restoration/isolation steps used to restore service (e.g. isolating a section of cable for repair).

Table 9 – Q4 2021 Major Event Additional Information on Selected Circuits

Circuit	5-Year Baseline SAIDI*	Report Quarter SAIDI*	Customers Impacted	Outage Duration*	Additional Comments
BEF 8021	0.00320	0.01943	5	198	Tree damage
BEF 8021	0.00320	0.01943	47	995	Tree damage
DOR 8035	0.03042	0.03873	872	72	Rotted/broken pole
DOR 8035	0.03042	0.03873	144	225	Open wire
LEV 8016	0.00021	0.00140	0	964	Phase cutout open / large motel customer requested work performed at 8AM
LEV 8016	0.00021	0.00140	47	73	Primary cable burned open
NED 8016	0.00729	0.00870	171	125	Blown fuse
PLI 8004	0.01320	0.14784	305	285	Lightning impact
PLI 8004	0.01320	0.14784	83	157	Defective cable
PLI 8004	0.01320	0.14784	1,720	167	Recloser failure
PLI 8004	0.01320	0.14784	306	206	Recloser failure
SUN 8024	0.00104	0.00150	44	84	Broken ridge pin
**-Calculated in minutes.*					

As indicated in **Table 9**, in addition to the original Energy Strong Program and ES 2 investments that increased sectionalizing of circuits to reduce the number of customers impacted by outages, the customer impact from a Major Event is also a function of the nature of the outages (extent of damage) and the location of damage relative to the various interrupting devices on the circuit, that is, reclosers or fuses. For some circuits, the 5-year baseline outage(s) were smaller or affected fewer customers, including different device operations (fuse with 10 customers vs. fuse with 150 customers) than the incident from the current Major Event being reported. Some circuits had more non-reclosing device operations in this Major Event (more fuse jobs) or more customers served by the circuit due to circuit rearrangements. Additionally, the circuits in **Table 9** with zero customers reflect the way the circuit is modeled in PSE&G's connectivity model and the restoration/isolation steps used to restore service (e.g. isolating a section of cable for repair, or a transformer with no assigned customers).

Beyond the circuit-level performance, the heavy rains from this Major Event did not result in water entering any of the stations that were raised and rebuilt as part of the original Energy Strong Program.

III. Project Status

A. Electric Station Flood Mitigation

A summary of the subprogram plan as of the end of 2021 compared to the status as of the end of 2019 and end of 2020 is provided below in **Table 10 – ES 2 Electric Station Flood Mitigation Subprogram Milestone Schedule as of December 31, 2021**.

Table 10 – ES 2 Electric Station Flood Mitigation Milestone Schedule as of December 31, 2021

Project	Plan Status Point	2019		2020				2021				2022				2023					2024
		Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4		
1. Academy Street	Dec. 2019		KO					C					IS		CO					*December 31, 2023 - ES 2 Program End Date*	
	Dec. 2020		KO		C							IS		CO							
	Dec. 2021		KO		C						IS						CO				
2. Clay Street	Dec. 2019	*Schedule Under Development*																			
	Dec. 2020			KO							C								IS		CO (Q2)
	Dec. 2021			KO							C				IS						CO (Q1)
3. Front Street^	Dec. 2019	*Not in ES 2 Program*																			
	Dec. 2020	*Not in ES 2 Program*																			
	Dec. 2021								KO				C						IS		CO (Q2)
4. Hasbrouck Heights	Dec. 2019		KO						C						IS		CO				
	Dec. 2020		KO									C					IS		CO		
	Dec. 2021		KO									C					IS	CO			
5. Kingsland	Dec. 2019			KO				C			IS		CO								
	Dec. 2020			KO										C					IS		CO (Q2)
	Dec. 2021			KO											C		IS		CO		

Project	Plan Status Point	2019		2020				2021				2022				2023					2024
		Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4		
6. Lakeside Avenue	Dec. 2019*				KO				C										IS	December 31, 2023 - ES 2 Program End Date	CO (Q2)
	Dec. 2020						KO							C					IS		CO (Q2)
	Dec. 2021						KO							C					IS		CO (Q2)
7. Leonia	Dec. 2019	*Schedule Under Development*																			
	Dec. 2020			KO		C									IS		CO				
	Dec. 2021			KO		C									IS		CO				
8. Market Street	Dec. 2019			KO				C	OS		CO										
	Dec. 2020			KO					C	OS		CO									
	Dec. 2021			KO						C/OS	CO										
9. Meadow Road	Dec. 2019	*Schedule Under Development*																			
	Dec. 2020			KO											C				IS		CO (Q2)
	Dec. 2021			KO										C				IS			CO (Q1)
10. Orange Valley	Dec. 2019	*Schedule Under Development*																			
	Dec. 2020					KO										C					IS (Q1); CO (Q3)
	Dec. 2021					KO										C			IS		CO (Q3)
11. Ridgefield 13kV	Dec. 2019			KO	C										IS		CO				
	Dec. 2020			KO	C										IS		CO				
	Dec. 2021			KO	C										IS		CO				
12. Ridgefield 4kV	Dec. 2019			KO						C	OS			CO							
	Dec. 2020			KO	C				OS		CO										
	Dec. 2021			KO	C				OS		CO										
13. State Street	Dec. 2019		KO					C								IS					CO (Q1)
	Dec. 2020		KO						C				IS								CO (Q1)
	Dec. 2021		KO						C					IS				CO			
14. Toney's Brook	Dec. 2019			KO						C									IS		CO (Q2)
	Dec. 2020			KO										C			IS				CO (Q2)
	Dec. 2021			KO										C					IS		CO (Q2)
15. Waverly	Dec. 2019	*Schedule Under Development*																			
	Dec. 2020			KO			C												IS		CO (Q2)
	Dec. 2021			KO			C														IS (Q3); CO (Q1 2025)
16. Woodlynne	Dec. 2019		KO												C				IS		CO (Q2)
	Dec. 2020		KO												C				IS		CO (Q2)
	Dec. 2021		KO												C				IS		CO (Q2)

Legend: KO = Kickoff; C = Construction; IS = Fully In-Service (major assets in-service); OS = Out-of-Service (if eliminated); CO = Closeout

-Actuals are indicated with an underline (Note: for the Market Street and Ridgefield 4kV projects, outside plant construction began in the first quarter of 2020, the construction milestone indicated on this chart reflects inside plant construction).

***-The Dec. 2019 Lakeside Avenue project schedule was based on the original raise and rebuild mitigation strategy; the current schedule reflects the proposed mitigation method change that contemplates relocating the substation.**

^-The Front Street project was proposed by PSE&G during the second quarter of 2021 to replace the cancelled Constable Hook project.

A summary of the subprogram status as of the end of 2021 is provided below **Table 11 – ES 2 Electric Station Flood Mitigation Summary Status as of December 31, 2021**.

Table 11 – ES 2 Electric Station Flood Mitigation Summary Status as of December 31, 2021

Activity	Total # of Projects	Specific Projects
Kickoff Meeting	16	Academy Street; Clay Street; Front Street; Hasbrouck Heights; Kingsland; Lakeside Avenue; Leonia; Market Street; Meadow Road; Orange Valley; Ridgefield 13kV; Ridgefield 4kV; State Street; Toney's Brook; Waverly; Woodlynne
Key Drawing Review	16	Academy Street; Clay Street; Front Street; Hasbrouck Heights; Kingsland; Lakeside Avenue; Leonia; Market Street; Meadow Road; Orange Valley; Ridgefield 13kV; Ridgefield 4kV; State Street; Toney's Brook; Waverly; Woodlynne
Scope Locked	16	Academy Street; Clay Street; Front Street; Hasbrouck Heights; Kingsland; Lakeside Avenue; Leonia; Market Street; Meadow Road; Orange Valley; Ridgefield 4kV; Ridgefield 13kV; State Street; Toney's Brook; Waverly; Woodlynne
Major Equipment Purchase Orders (POs)	18*	Academy Street; Clay Street; Front Street*; Hasbrouck Heights; Kingsland; Lakeside; Leonia*; Meadow Road; Orange Valley; Ridgefield 13kV*; State Street; Toney's Brook; Waverly*; Woodlynne
Architect/ Engineer (A/E) Contract Award (or selection of PSE&G internal engineering)	16	Academy Street[1]; Clay Street[1]; Front Street[3]; Hasbrouck Heights[1]; Kingsland[2]; Lakeside Avenue[3]; Leonia[2]; Market Street[2]; Meadow Road[2]; Orange Valley[1]; Ridgefield 13kV[2]; Ridgefield 4kV[2]; State Street[2]; Toney's Brook[3]; Waverly[3]; Woodlynne[1]
Construction Start**	8	Academy Street; Clay Street; Leonia; Market Street; Ridgefield 4kV; Ridgefield 13kV; State Street; Waverly
In-Service	3	Academy Street; Market Street; Ridgefield 4kV
Partial In-Service	2	Leonia; Ridgefield 13kV

**-Three of the listed projects (Front Street, Leonia, Ridgefield 13kV, and Waverly) have two switchgears, thus the current count reflects 18 switchgears at 14 substations.*
[1]-Indicates Burns & McDonnell is serving as the A/E.
[2]-Indicates PSE&G internal resources are serving as the A/E.
[3]-Indicates Black & Veatch is serving as the A/E.
***-Includes inside plant and/or outside plant construction.*

Beyond the key activities summarized in **Table 11** above, **Table 12 – ES 2 Electric Station Flood Mitigation Upcoming Activities for Q1 2022** summarizes the planned activities for each project during the first quarter of 2022, including any carryover of activities from earlier periods.

Table 12 – ES 2 Electric Station Flood Mitigation Upcoming Activities for Q1 2022

Station	Upcoming Activities for Q1 2022	Carryover Activities from Q4 2021
1. Academy Street	• Continued civil and electrical construction	• Continued civil and electrical construction
2. Clay Street	• Major equipment (4kV sheltered aisle switchgear) delivery • Major municipal licenses and permits issuance	• Continued civil construction
3. Front Street	• Civil and electrical drawings Issued for Review (IFR) • Site plan approval	• Continued engineering
4. Hasbrouck Heights	• 90% estimate complete • Start civil construction	• Continued engineering
5. Kingsland	• Continued engineering	• Continued engineering

Station	Upcoming Activities for Q1 2022	Carryover Activities from Q4 2021
6. Lakeside Avenue	• Control drawings IFR • Civil and electrical drawings Issued for Construction (IFC)	• Continued engineering
7. Leonia	• All cutovers complete – Switchgear #1 • Phase 2 electrical construction complete	• Continued electrical construction
8. Market Street	• Municipal licenses and permits issuance for civil demolition	• Continued site demolition
9. Meadow Road	• Continued engineering	• Continued engineering
10. Orange Valley	• Civil and electrical drawings IFR	• Continued engineering
11. Ridgefield 13kV	• Phase 1 civil and electrical construction complete	• Continued civil and electrical construction
12. Ridgefield 4kV	• Project complete	• Project complete
13. State Street	• 90% estimate complete	• Continued civil and electrical construction
14. Toney's Brook	• Relay settings received by Inside Plant (IP) Construction Relay Group	• Continued engineering
15. Waverly	• Phase 3 controls IFR • Start phase 2 civil construction	• Continued engineering
16. Woodlynne	• Continued engineering	• Continued engineering

The current project estimates, including base and R&C amounts, are shown below in **Table 13 – ES 2 Electric Station Flood Mitigation Project Cost Status as of December 31, 2021**. **Table 13** also shows the current estimate level based on PSE&G's estimating processes and as approved by the Utility Review Board (URB), the actual spend, and percentage of actuals to estimate as of the end of 2021.

Table 13 – ES 2 Electric Station Flood Mitigation Project Cost Status as of December 31, 2021

Project	Estimate Level	Base	Risk & Contingency	Total	Current Forecast	Actuals to Date	% of Actuals to Estimate
1. Academy Street	Definitive	$9,800,000	$700,000	$10,500,000	$8,681,267	$6,129,738	58%
2. Clay Street	Conceptual	$30,300,000	$3,500,000	$33,800,000	$31,302,000	$3,802,341	11%
3. Front Street*	Study	$23,000,000	$4,400,000	$27,400,000	$25,884,733	$2,351,831	9%
4. Hasbrouck Heights	Conceptual	$20,500,000	$2,200,000	$22,700,000	$20,380,526	$5,456,031	24%
5. Kingsland	Study	$5,400,000	$2,900,000	$8,300,000	$6,418,541	$824,722	10%
6. Lakeside Avenue	Study	$39,400,000	$8,500,000	$47,900,000	$39,356,279	$1,173,651	3%
7. Leonia	Definitive	$24,900,000	$1,500,000	$26,400,000	$24,887,497	$15,190,427	58%
8. Market Street	Definitive	$29,100,000	$800,000	$29,900,000	$28,201,027	$27,012,282	90%
9. Meadow Road	Study	$7,200,000	$1,800,000	$9,000,000	$7,497,449	$1,043,444	12%

Project	Estimate Level	Base	Risk & Contingency	Total	Current Forecast	Actuals to Date	% of Actuals to Estimate
10. Orange Valley	Study	$16,000,000	$4,200,000	$20,200,000	$14,769,606	$797,976	4%
11. Ridgefield 13kV	Conceptual	$25,300,000	$2,300,000	$27,600,000	$26,601,954	$17,288,355	63%
12. Ridgefield 4kV	Definitive	$20,800,000	$500,000	$21,300,000	$20,726,799	$20,646,800	97%
13. State Street	Conceptual	$19,100,000	$2,300,000	$21,400,000	$19,417,411	$8,832,965	41%
14. Toney's Brook	Conceptual	$16,200,000	$2,600,000	$18,800,000	$16,254,329	$1,526,556	8%
15. Waverly	Study	$29,400,000	$6,000,000	$35,400,000	$36,199,218	$6,979,786	20%
16. Woodlynne	Study	$15,800,000	$3,600,000	$19,400,000	$21,264,000	$2,095,910	11%
Subprogram Total		**$332,200,000**	**$47,800,000**	**$380,000,000**	**$347,842,636**	**$121,152,745**	**31%**
**-The Front Street project was proposed by PSE&G during the second quarter of 2021 to replace the cancelled Constable Hook project.*							

Findings & Observations

- Eight of the sixteen Electric Station Flood Mitigation projects had movement in the forecasted in-service date during the fourth quarter of 2021, with five advancing and three slipping. The biggest changes came on the Kingsland (advancing 96 days from October 4, 2023 to June 30, 2023), Waverly (advancing 92 days from December 18, 2024 to September 17, 2024), and the Clay Street (slipping 50 days from November 7, 2022 to December 27, 2022) projects.

- Following the Market Street and Ridgefield 4kV projects being placed in-service during the second quarter of 2021, the Academy Street achieved in-service status as of October 19, 2021. The Leonia and Ridgefield 13kV projects also reached partial in-service status during the fourth quarter of 2021 (with each project placing one of its two switchgear in-service).

- There were no updated estimates completed in the subprogram during the fourth quarter of 2021 and the overall subprogram forecast increased $1.3 million (or 0.4%) to $347.8 million as of the end of 2021. The forecast continues to remain under the current subprogram estimate of $380.0 million and the Stipulation amount of $389.0 million.

- The IM has found nothing to date that would jeopardize the subprogram being completed on budget. However, the status of the later projects in this subprogram, and in particular Waverly, will have to continue to be closely followed to monitor if the projects can be completed within the ES 2 Program window. As of the end of 2021, the Waverly project continues to show a final in-service date in 2024, although it has advanced from December to September 2024. The Waverly project has multiple major asset in-service dates for the 26kV switchgear, 4kV switchgear, and three transformers, which are currently forecasted from September 2022 (26kV switchgear) to

September 2024 (Transformer #3). PSE&G has informed the IM that the project team will continue to assess the project schedule and will be examining the potential to shorten durations and/or work activities concurrently to pull the final in-service date back into 2023.

1. Academy Street

During the fourth quarter of 2021, $698,611 was spent on the Academy Street project compared to a forecast of approximately $1.3 million, which brought the total spend to approximately $6.1 million. The variance in spend during the fourth quarter of 2021 was primarily the result of commissioning activities being charged to the Fairmount 69kV Project (same site location) and less than estimated trailing costs after the project was placed in-service. The commissioning activities that were wrongly charged to the Fairmount 69kV project were budgeted to the Academy Street project and were performed by Commissioning Engineers that worked on the Fairmount 69kV project prior to working on the Academy Street project. This error was identified and corrected during the monthly forecast variance analysis process when it was realized that this work was done as planned with cash flow forecasted, but not included in the October actual costs.

The primary activity conducted during the fourth quarter of 2021 was the completion of commissioning for the switchgear with the project being achieving in-service status on October 19, 2021 when the first circuit was completed. Civil and electrical construction work will continue to the fourth quarter of 2022.

The actual spend by quarter for Academy Street as compared to the current approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022
Actuals						*Forecast*
$150,398	$4,224,550	$378,939	$405,843	$271,396	$698,611	$2,551,529

Actuals to Date	Estimate	% of Actuals to Estimate
$6,129,738	$10,500,000	58%

2. Clay Street

During the fourth quarter of 2021, $546,400 was spent on the Clay Street project compared to a forecast of approximately $642,000, which brought the total spend to approximately $3.8 million. The forecasted in-service date for the Clay Street project as of the end of the fourth quarter of 2021 advanced 50 days from the end of the third quarter to November 7, 2022. This shift was the result of a revision to the construction sequence to split the foundation activity, regulators installation, and commissioning activities along with the cutovers into two phases. This also helps alleviate space and manhole access constraints on the project.

The primary activities on the Clay Street project during the fourth quarter of 2021 included the phase 2 civil and electrical drawings being IFC and the civil and electrical POs issued, followed by the start of civil construction late in December.

The actual spend by quarter for Clay Street as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2024
Actuals						***Forecast***
$116,409	$879,339	$565,030	$595,723	$1,099,440	$546,400	$27,499,659

Actuals to Date	Estimate	% of Actuals to Estimate
$3,802,341	$33,800,000	11%

3. Front Street

During the fourth quarter of 2021, $1,090,782 was spent on the Front Street project compared to a forecast of approximately $1.06 million, which brought total spend to approximately $2.4 million. The forecasted in-service date for the Front Street project as of the end of the fourth quarter of 2021 slipped ten days from the end of the third quarter to November 16, 2023.

The primary activities on the Front Street project during the fourth quarter of 2021 included the issuance of the switchgear PO, completion of the license and permitting package, and the submittal of the project site plan.

The actual spend by quarter for Front Street as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2024
Actuals						***Forecast***
$0	$0	$0	$190,915	$1,070,135	$1,090,782	$23,532,901

Actuals to Date	Estimate	% of Actuals to Estimate
$2,351,832	$27,400,000	9%

4. Hasbrouck Heights

During the fourth quarter of 2021, $3,364,236 was spent on the Hasbrouck Heights project compared to a forecast of approximately $3.6 million, which brought the total spend to approximately $5.5 million. The variance in spend during the fourth quarter of 2021 was driven by the contractor's invoice lower than previously accrued and 26kV control house abatement work pushing out pending completion of electrical removal of racks. Despite that work shifting out, the forecasted in-service date for the Hasbrouck Heights project as of the end of the fourth quarter of 2021 advanced six days from the end of the third quarter to February 1, 2023.

Notable activities completed during the fourth quarter of 2021 included the delivery of the 4kV sheltered aisle switchgear and capacitor bank.

The actual spend by quarter for Hasbrouck Heights as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals						***Forecast***
$149,848	$1,129,934	$550,795	$189,748	$71,469	$3,364,236	$14,924,495

Actuals to Date	Estimate	% of Actuals to Estimate
$5,456,031	$22,700,000	24%

5. Kingsland

During the fourth quarter of 2021, $293,352 was spent on the Kingsland project compared to a forecast of approximately $243,000, which brought the total spend to $824,722. The forecasted in-service date for the Kingsland project as of the end of the fourth quarter of 2021 advanced 96 days from the end of the third quarter to June 30, 2023. This advancement in the forecasted in-service date was driven by material availability that supported schedule improvement.

During the fourth quarter of 2021, primary activities on the Kingsland project included constructability reviews, the issuance of the license and permitting package, and the IFC release of civil and electrical drawings.

The actual spend by quarter for Kingsland as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2024
Actuals						*Forecast*
$104,112	$209,667	$30,621	$36,886	$150,084	$293,352	$5,593,820

Actuals to Date	Estimate	% of Actuals to Estimate
$824,722	$8,300,000	10%

6. Lakeside Avenue

During the fourth quarter of 2021, $128,323 was spent on the Lakeside Avenue project compared to a forecast of approximately $168,000. The forecasted in-service date for the Lakeside Avenue project as of the end of the fourth quarter of 2021 remained unchanged from the prior quarter at November 8, 2023.

Notable activities completed during the fourth quarter of 2021 included approval of the site plan at a zoning board meeting, the IFR release of civil and electrical drawings, and a constructability review.

The actual spend by quarter for Lakeside Avenue as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2024
Actuals						*Forecast*
$148,943	$453,994	$178,973	$174,268	$89,151	$128,323	$38,182,628

Actuals to Date	Estimate	% of Actuals to Estimate
$1,173,651	$47,900,000	3%

7. Leonia

During the fourth quarter of 2021, $790,673 was spent on the Leonia project compared to a forecast of approximately $1.08 million, which brought the total spend to approximately $15.2 million. The variance in spend during the fourth quarter was driven by a temporary resource availability within the Division that shifted some non-critical path work to future periods. The forecasted in-service date for the Leonia project as of the end of the fourth quarter of 2021 slipped 30 days from the prior quarter to November 9, 2022.

Notable activities completed during the fourth quarter of 2021 included the 13kV switchgear #1 being placed in-service on October 19, 2021.

The actual spend by quarter for Leonia as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals						*Forecast*
$44,792	$6,033,379	$2,809,628	$4,146,544	$1,365,412	$790,673	$9,697,069

Actuals to Date	Estimate	% of Actuals to Estimate
$15,190,427	$26,400,000	58%

8. Market Street

During the fourth quarter of 2021, $1,719,125 was spent on the Market Street project compared to a forecast of approximately $2.25 million, which brought the total spend to approximately $27.0 million. The variance in spend during the fourth quarter was largely the result of poor weather and resource constraints, including unplanned emergency work that pulled resources from the project.

Notable activities conducted during the fourth quarter of 2021 included the completion of electrical demolition at the station, which was placed out of service on June 25, 2021 following the completion of the 4kV to 13kV conversion work.

The actual spend by quarter for Market Street as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022
Actuals						*Forecast*
$251,193	$16,079,601	$4,035,880	$3,147,454	$1,779,029	$1,719,125	$1,188,746

Actuals to Date	Estimate	% of Actuals to Estimate
$27,012,281	$29,900,000	90%

9. Meadow Road

During the fourth quarter of 2021, $144,070 was spent on the Meadow Road project compared to a forecast of $88,000, which brought the total spend to approximately $1.0 million. The forecasted in-service date for the Meadow Road project as of the end of the fourth quarter of 2021 remained unchanged from the prior quarter at September 22, 2023.

Detailed engineering commenced during the fourth quarter of 2021, in addition the New Jersey Department of Environmental Protection (NJDEP) permit was received and a site plan exception was granted.

The actual spend by quarter for Meadow Road as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2024
Actuals						*Forecast*
$63,128	$535,081	$117,672	$70,220	$113,271	$144,070	$6,454,006

Actuals to Date	Estimate	% of Actuals to Estimate
$1,043,444	$9,000,000	12%

10. Orange Valley

During the fourth quarter of 2021, $95,128 was spent on the Orange Valley project compared to a forecast of approximately $67,000, which bought the total spend to approximately $798,000. The forecasted in-service date for the Orange Valley project as of the end of the fourth quarter of 2021 remained unchanged from the prior quarter at December 29, 2023.

During the fourth quarter of 2021, major activities on the Orange Valley project included the start of detailed engineering, the redevelopment agreement approval by the City Council, vendor drawings received for final switchgear arrangement, and the site plan was submitted.

The actual spend by quarter for Orange Valley as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2024
Actuals						*Forecast*
$77,029	$362,895	$7,291	$146,827	$108,807	$95,128	$13,971,630

Actuals to Date	Estimate	% of Actuals to Estimate
$797,976	$20,200,000	4%

11. Ridgefield 13kV

During the fourth quarter of 2021, $2,394,930 was spent on the Ridgefield 13kV project compared to a forecast of approximately $3.4 million, which brought the total spend to approximately $17.3 million. The variance in spend during the third quarter of 2021 was driven by manhole rebuild work being delayed due to the contractor's workload and Division manhole work and cable pulling being postponed due to IP conduit installation completed later than expected. These delays contributed to the forecasted in-service date for the Ridgefield 13kV project as of the end of the fourth quarter of 2021 slipping 39 days from the prior quarter to December 20, 2022.

Notable activities completed during the fourth quarter of 2021 included the start and completion for commissioning of the 13kV switchgear #2, which was placed in-service on December 16, 2021.

The actual spend by quarter for Ridgefield 13kV as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals						***Forecast***
$205,982	$6,232,692	$3,215,967	$3,665,283	$1,573,500	$2,394,930	$9,313,599

Actuals to Date	Estimate	% of Actuals to Estimate
$17,288,355	$27,600,000	63%

12. Ridgefield 4kV

During the fourth quarter of 2021, $241,884 was spent on the Ridgefield 4kV project compared to a forecast of approximately $267,000, which brought the total spend to approximately $20.4 million. The project was placed in-service on May 16, 2021.

The primary activities performed during the fourth quarter of 2021 included the completion of IP civil demolition.

The actual spend by quarter for Ridgefield 4kV as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022
Actuals						***Forecast***
$143,414	$11,239,534	$2,808,765	$4,559,439	$1,653,764	$241,884	$80,000

Actuals to Date	Estimate	% of Actuals to Estimate
$20,646,799	$21,300,000	97%

13. State Street

During the fourth quarter of 2021, $7,068,233 was spent on the State Street project compared to a forecast of approximately $7.9 million, which brought the total spend to approximately $8.8 million. The variance in spend during the quarter was driven by the project receiving only half of the forecasted feeder rows due to a Covid-19 outbreak at the vendor's facilities. The forecasted in-service date for the State Street project as of the end of the fourth quarter of 2021 remains unchanged from the prior quarter at September 23, 2022.

Notable activities performed on State Street during the fourth quarter of 2021 included the commencement of electrical construction, continued civil construction, and the delivery of the 4kV sheltered aisle switchgear. IP construction on the project advanced to 20% complete, up from 10% at the end of the prior quarter, with the total project reported at 28% complete.

The actual spend by quarter for State Street as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals						***Forecast***
$77,590	$662,148	$237,415	$216,479	$571,099	$7,068,233	$10,584,445

Actuals to Date	Estimate	% of Actuals to Estimate
$8,832,966	$21,400,000	41%

14. Toney's Brook

During the fourth quarter of 2021, $403,672 was spent on the Toney's Brook project compared to a forecast of approximately $341,000, which brought the total spend to approximately $1.5 million. The forecasted in-service date for the Toney's Brook project as of the end of the fourth quarter of 2021 remains unchanged from the prior quarter at April 21, 2023.

Notable activities achieved during the fourth quarter of 2021 included the controls drawings IFC and control and power cables material received on site.

The actual spend by quarter for Toney's Brook as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2024
Actuals						*Forecast*
$211,940	$373,096	$88,947	$289,769	$159,132	$403,672	$14,727,774

Actuals to Date	Estimate	% of Actuals to Estimate
$1,526,555	$18,800,000	8%

15. Waverly

During the fourth quarter of 2021, $277,739 was spent on the Waverly project compared to a forecast of approximately $437,000, which brought the total spend to approximately $6.3 million. The variance in second quarter spend was largely driven an engineering milestone that shifted from September to October and work delayed in September due to lack of resources in the Metro Division. The forecasted in-service date for the Waverly project as of the end of the fourth quarter of 2021 advanced 92 days from the prior quarter to September 17, 2024, which was driven by the site plan approval that in turn improved the construction schedule by advancing the anticipated permit approval dates that are precursors to the start of construction activities.

As previously reported, the project team requested a special meeting to maintain the project's schedule, which was held in March 2021. The Newark Planning Board denied the site plan application at this meeting, which required the project team to prepare a new site plan application. The revised site plan was submitted to the Newark Planning Board in early September 2021 with the site plan approved during a December 2021 meeting. Other activities performed during the fourth quarter of 2021 included the receipt of vendor drawings (final switchgear controls) and civil and electrical drawings IFC.

The actual spend by quarter for Waverly as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2024
Actuals						*Forecast*
$103,748	$2,460,815	$659,572	$2,837,893	$277,739	$640,019	$29,219,432

Actuals to Date	Estimate	% of Actuals to Estimate
$6,979,786	$35,400,000	20%

16. Woodlynne

During the fourth quarter of 2021, $148,804 was spent on the Woodlynne project compared to a forecast of approximately $302,000, which brought the total spend to approximately $2.1 million. The variance in spend during the fourth quarter was driven by lower than estimated spend on civil supervision, security, and safety, and the A/E not reaching a planned payment milestone in December. The forecasted in-service date for the Woodlynne project as of the end of the fourth quarter of 2021 remains unchanged from the prior quarter at October 10, 2023.

Preliminary design work continued to progress during the fourth quarter of 2021, with minimal other activities conducted on the Woodlynne project this quarter as the bulk of this project's activities planned for 2022-2023, including construction scheduled to commence in early 2023.

The actual spend by quarter for Woodlynne as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals						*Forecast*
$110,982	$993,298	$282,187	$132,630	$428,009	$148,804	$19,168,090

Actuals to Date	Estimate	% of Actuals to Estimate
$2,095,910	$19,400,000	11%

B. Contingency Reconfiguration

During the fourth quarter of 2021, work continued to progress in the Contingency Reconfiguration subprogram with all four Divisions continuing to install reclosers with a total of 109 installed during the quarter and 122 commissioned. **Table 14 – ES 2 Program Recloser Status as of December 31, 2021** provides a summary of the recloser aspect of the Contingency Reconfiguration subprogram, indicating the current status of engineering, installation, and commissioning; while **Figure 3 – 2021 Recloser Installations as of December 31, 2021** compares the installed reclosers as of the end of the third quarter of 2021 against PSE&G's 2021 installation plan.[1]

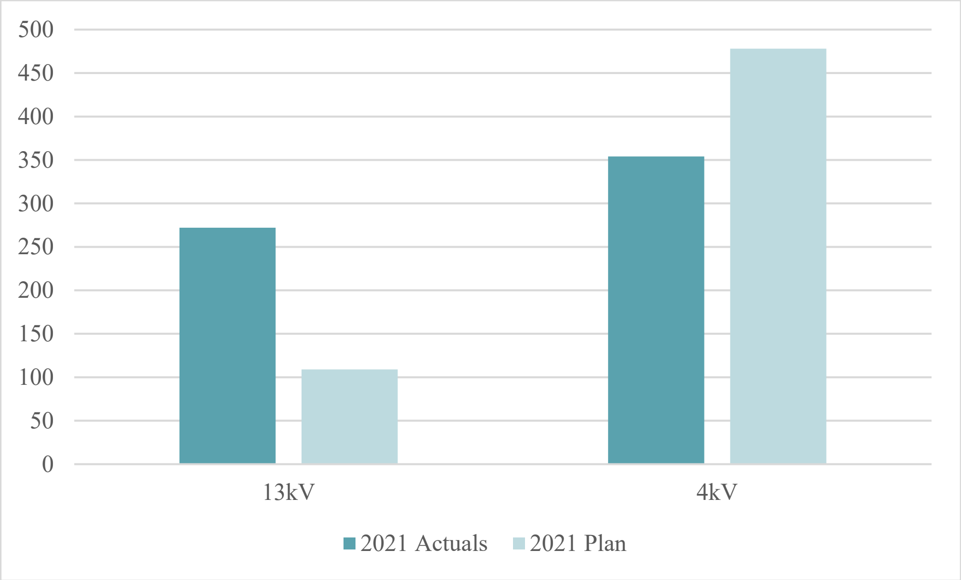
Table 14 – ES 2 Program Recloser Status as of December 31, 2021

Type	Engineering Packages Completed (1 recloser ea.)			Reclosers Installed			Reclosers Commissioned		
	Q4 Qty.	*2021 Total*	*Program Total*	*Q4 Qty.*	*2021 Total*	*Program Total*	*Q4 Qty.*	*2021 Total*	*Program Total*
13kV	29	249	948	49	272	933	61	288	932
4kV	13	261	515	60	354	511	61	353	510

[1] Note that as discussed in the IM 2021 First Quarter Report (Section IV.A.1.) and the IM 2021 Second Quarter Report (Section II.A.1.), the number of reclosers identified the Contingency Reconfiguration subprogram was updated after the 2021 installation plan was established, which resulted in a net reduction of the 4kV reclosers planned for the subprogram and a net increase of the 13kV reclosers planned for the subprogram.

Type	Engineering Packages Completed (1 recloser ea.)			Reclosers Installed			Reclosers Commissioned		
	Q4 Qty.	*2021 Total*	*Program Total*	*Q4 Qty.*	*2021 Total*	*Program Total*	*Q4 Qty.*	*2021 Total*	*Program Total*
Total	42	510	1,463	109	626	1,444	122	641	1,442

Figure 3 – 2021 Recloser Installations as of December 31, 2021



As shown in **Table 14** and **Figure 3**, PSE&G continued to maintain progress during the fourth quarter of 2021 and as of the end of the year only 23 units remained to be installed to complete the recloser scope of the subprogram. As also shown in **Figure 3**, the 2021 installation plan shifted the focus primarily to the 4kV reclosers from the 13kV reclosers that were prioritized in 2020. However, actual installations of 13kV reclosers were above the initial 2021 plan due to the change in reclosers planned for the subprogram following PSE&G's review, which resulted in an additional 275 13kV reclosers and 90 4kV reclosers (also discussed in Section IV.A.1. of the IM 2021 First Quarter Report and Section II.A.1. of the IM 2021 Second Quarter Report).

As previously discussed in prior IM reports, the Fuse Saver pilot program commenced in November 2020 and was primarily completed in January 2021. In total, this phase of the Fuse Saver pilot program included the installation and commissioning of 80 Fuse Saver devices. During execution of the pilot program, PSE&G observed factors that will help it prepare for execution of the full Fuse Saver scope, including installation specifications (the remote control unit (RCU) must be placed directly below the Fuse Saver to avoid communications issues), and cost elements for some of the locations (new poles, traffic control, etc.). While monitoring performance of the installed Fuse Savers, PSE&G experienced other communication issues between the Fuse Savers and the RCU, wherein the Supervisory Control and Data Acquisition (SCADA) communication indicated a false open/close alarm on some of the devices. Siemens has provided a prototype Fuse Saver to address the communication issues, which PSE&G will monitor to ensure it addresses the issues prior to placing additional orders. Because of this, commencement of the full Fuse Saver scope was pushed to 2022. However, PSE&G opted to install the remaining Fuse Saver units from its initial inventory to capture additional cost and performance data to better inform the planning and execution of the full scope of work. This resulted in an additional three 2-

phase units and 30 1-phase units being installed during the second half of 2021, bringing the total number of Fuse Savers installed through the end of 2021 to 113 units out of a forecasted 1,713 units. Costs incurred in the Fuse Saver scope during the fourth quarter of 2021 related to project management costs and direct costs (labor, material, engineering, storage, traffic control), which included some older invoices for work performed prior to the fourth quarter of 2021.

Concerning the forecasted number of Fuse Savers planned to be installed during the ES 2 Program, PSE&G continues to utilize an iterative process to evaluate the number of devices anticipated for the Fuse Saver scope of work. The targeted number of Fuse Saver units is revised based on updated field assessments as well as the final number of units driven by the average cost per unit based on the most optimal mix of locations given the fixed budget. For example, if an identified location requires a pole replacement based on the field conditions, it will have a much higher installation cost than a location not requiring a pole replacement.

The current forecasted completion date for the primary components that make up the Contingency Reconfiguration subprogram are provided in **Table 15 – ES 2 Contingency Reconfiguration Forecasted Completion Dates as of December 31, 2021**. This table also shows the forecasted final in-service dates as of the end of the third quarter of 2021 to show movement to the forecast as of the end of the fourth quarter of 2021.

Table 15 – ES 2 Contingency Reconfiguration Forecasted Completion Dates as of December 31, 2021

Scope & Division		Q3 2021 Forecasted Completion Date	Q4 2021 Forecasted Completion Date
Reclosers	Central	1/31/2022	1/31/2022
	Metro	1/31/2022	12/31/2021 (Actual)
	Palisades	12/31/2021	2/28/2022
	Southern	1/31/2022	1/31/2022
Fuse Savers	Central	9/30/2023	9/30/2023
	Metro	10/31/2023	10/31/2023
	Palisades	12/30/2023	12/30/2023
	Southern	10/31/2023	9/30/2023

As shown in **Table 15**, the forecasted final in-service dates remained constant for the majority of the scopes, with the Metro and Palisades Divisions recloser efforts and the Southern Division Fuse Saver efforts having new forecasted in-service dates. Within the Metro Division recloser scope, improvements in the material availability allowed the schedule to be completed earlier than previously forecasted, with the final installations completed in December 2021. The Palisades Division recloser scope saw the final in-service date shift to February 2022 as the result of three recloser in the Division that required the development and implementation of a unique operating procedure. While the only change to the Fuse Saver scope of work was the Southern Division advancing one month as the installation schedules continue to be developed and refined prior to the commence of that scope in 2022.

The Contingency Reconfiguration subprogram costs through the end of 2021 are presented in **Table 16 – ES 2 Contingency Reconfiguration Costs as of December 31, 2021**.

Table 16 – Contingency Reconfiguration Costs as of December 31, 2021

Scope & Division		2019	2020	Q1 2021	Q2 2021	Q3 2021	Q4 2021	Total to Date	Forecast	% of Actuals to Forecast
		Actuals								
Reclosers	Central	$2,737,167	$12,050,820	$3,007,686	$2,392,608	$2,116,213	$2,336,304	$24,640,799	$25,368,784	97%
	Metro	$2,231,431	$10,726,610	$587,396	$4,051,716	$3,926,036	$2,803,260	$24,326,450	$24,483,210	99%
	Palisades	$2,515,569	$12,119,436	$3,109,037	$2,591,672	$1,991,442	$588,372	$22,915,527	$23,162,771	99%
	Southern	$2,081,220	$12,405,684	$5,008,143	$4,065,891	$2,742,523	$2,221,485	$28,524,946	$28,937,756	99%
Fuse Savers	Central	$9,970	$789,937	$375,811	$107,384	$255,092	$115,831	$1,654,025	$12,061,825	14%
	Metro	$7,557	$561,915	$216,511	$89,860	$144,511	$56,860	$1,077,214	$10,969,592	10%
	Palisades	$7,468	$522,454	$133,552	$63,808	$276,182	$103,572	$1,107,036	$8,462,697	13%
	Southern	$9,792	$859,014	$65,018	$56,845	$263,207	$193,147	$1,447,023	$12,320,792	12%
Total		**$9,600,174**	**$50,035,871**	**$12,503,156**	**$13,419,784**	**$11,715,206**	**$8,418,831**	**$105,693,021**	**$145,767,428**	**73%**

Findings & Observations:

- PSE&G continued to maintain progress on the recloser installations during the fourth quarter of 2021, including completing the Metro Division scope, with the remaining Divisions expected to be completed early in 2022.
- The forecasted completion of the recloser scope of this subprogram remained unchanged from the prior quarter for three of the four Divisions, while the Palisades Division forecasted completion slipped two months based on three reclosers in the Division that required the development and implementation of a unique operating procedure. For the Fuse Savers, while three of the four Division's completion dates remained unchanged, the Southern Division advanced their forecasted completion date one month reflecting an updated installation schedule.
- The Contingency Reconfiguration subprogram forecast remained relatively static as of the end of the fourth quarter of 2021 from the prior quarter, with the total forecast increasing by approximately $273,000 (or 0.2%) to $145.8 million.

C. Grid Modernization – Communication System

The Stipulation identified the Grid Modernization – Communication System subprogram to include up to $72 million invested in installing a private wireless communications network to eliminate the use of dedicated phone lines for remote communication for both PSE&G and customer equipment. The overall network will provide coverage using both wireless and fiber technologies to all switching devices on the PSE&G system.

During the fourth quarter of 2021, the final recloser retrofit installations were completed with 324 units installed during the quarter. In total, 2,318 retrofit reclosers were installed on the Program compared to an initial forecast of 2,561, with the variance driven by updated system status information. Also during the fourth quarter of 2021, two additional retrofits of substation RTUs were completed, bringing the total as of the end of 2021 to 10 substations completed out of a currently forecasted scope of 196 substations. The retrofit substation RTU scope is planned to ramp-up in 2022 with all installation expected to be completed by the fourth quarter of 2022. Under the Wireless Network scope, radios continue to be prepared for the Fuse Savers, which reflects the remaining spend associated with the Wireless Network.

As previously reported, the fiber scope includes installing fiber to electric substations and electric operations centers, in addition to cutting over stations with existing fiber service to the PSE&G fiber network. PSE&G preliminarily identified 41 installation projects and 12 cutovers for the subprogram, with three of 41 installation projects since removed due to the scheduled elimination of the targeted substations or the intended redundancy benefits not achievable after site review. The list of identified fiber installation and cutover projects is presented in **Table 17 – Fiber Projects by Division as of December 31, 2021**.

Table 17 – Fiber Projects by Division as of December 31, 2021

Division	Fiber Installation	Fiber Cutover
Central	Cranford; Elizabeth Sub HQ; Rahway; Hadley Road HQ; Roselle; Central HQ; Carteret; Edison; Keasby; Mechanic Street; First Street; Lehigh Avenue	Elizabeth; Henry Street
Metro	East Orange; Metro HQ; Bloomfield; Central Avenue; Haldeon; Irvington; Irvington Sub HQ; Montclair; South Orange; Norfolk Street; Waverly	-
Palisades	Bergen Point; Hackensack Sub HQ; Fort Lee; Harrison; Ridgewood; West New York; Palisades HQ; Culver Avenue; Morgan Street	Tonnelle Avenue; Spring Valley Road; Union City; Fairview; Polk Street; West Orange
Southern	Southern HQ; Princeton; Chauncey Street; Bordentown; Haddon Heights; Thirty Second Street	Delair; East Riverton; Riverside; Mount Holly
Total	***38 projects***	***12 projects***

During the fourth quarter of 2021, three additional fiber installation projects (Irvington, Irvington Sub HQ, and Morgan Street) were placed in-service. This brought the total projects in-service as of the end of 2021 to 20 for the fiber installation projects and nine for the fiber cutover projects. **Table 18 – ES 2 Program Fiber Projects Status as of December 31, 2021** provides a summary of the status of the fiber installation and cutover projects within the subprogram as of the end of 2021 with the projects in italics representing those placed in-service.

Table 18 – ES 2 Program Fiber Projects Status as of December 31, 2021

Project Name	Q4 2021 Status
Fiber Installation Projects	
Bergen Point	*In-Service (Q1 2021)*
Bloomfield	Continued engineering
Bordentown	*In-Service (Q3 2021)*
Carteret	IP IFC issued
Central Ave	*In-Service (Q3 2021)*
Central HQ	OP overhead construction underway
Chauncey Street	*In-Service (Q3 2021)*
Cranford	*In-Service (Q4 2020)*
Culver Ave	IP IFCs issued; IP civil construction complete; battery installation complete; OP construction mobilized
East Orange	*In-Service (Q1 2021)*
Edison	IP IFC issued
Elizabeth Sub HQ	*In-Service (Q1 2021)*
First Street	*In-Service (Q3 2021)*
Fort Lee	IP civil work complete; OP overhead contractors mobilized; IP IFC issued
Hackensack Sub HQ	*In-Service (Q4 2020)*
Haddon Heights	Preliminary engineering
Hadley Rd HQ	Continued engineering

Project Name	Q4 2021 Status
Haledon	County road occupancy permit received to fix a break in the line between Haledon and Hawthorne substations
Harrison	*In-Service (Q3 2021)*
Howell Street	Removed from ES 2 Program after evaluation determined that the redundancy and resiliency benefits would not be obtained through this project (which shares a site with the Jersey Steet station that already has a TFI rack installed)
Irvington	*In-Service (Q4 2021)*
Irvington Sub HQ	*In-Service (Q4 2021)*
Keasbey	OP IFC issued; OP construction mobilized; IP IFC issued
Lehigh Avenue	Preliminary engineering
Mechanic Street	IP IFC issued
Metro HQ	*In-Service (Q1 2021)*
Montclair	IP civil work complete
Morgan Street	*In-Service (Q4 2021)*
Norfolk St	*In-Service (Q3 2021)*
Palisades HQ	Continued construction
Princeton	*In-Service (Q3 2021)*
Rahway	*In-Service (Q1 2021)*
Ridgewood	Continued construction
Roselle	*In-Service (Q2 2021)*
So Orange	*In-Service (Q3 2021)*
Southern HQ	*In-Service (Q4 2020)*
Thirty Second Street	Preliminary engineering
Waverly	Preliminary engineering
West New York	OP construction mobilized
Fiber Cutover Projects	
Delair	*In-Service (Q4 2020)*
East Riverton	*In-Service (Q4 2020)*
Elizabeth	*In-Service (Q1 2021)*
Fairview	Completion dependent upon Fort Lee fiber installation project
Henry St	*In-Service (Q3 2021)*
Mount Holly	*In-Service (Q4 2020)*
Polk Street	Completion dependent upon West New York fiber installation project
Riverside	*In-Service (Q4 2020)*
Spring Valley Rd	*In-Service (Q1 2021)*
Tonnelle Ave	*In-Service (Q4 2020)*
Union City	*In-Service (Q1 2021)*
West Orange	Completion dependent upon redundant link to Montclair substation being ready (two redundant fiber links required for each router to support reliability guidelines)
Substation Remote Terminal Unit (RTU) Cutovers	
Scope: 196 units	10 cutovers completed

For the three fiber projects placed in-service during the fourth quarter of 2021 (Irvington, Irvington Sub HQ, and Morgan Street), the original budget and actual costs as of December 31, 2021 are presented in **Table 19 – Q4 2021 Fiber Projects Budget vs. Actual Cost**.

Table 19 – Q4 2021 Fiber Projects Budget vs. Actual Cost

Project	Original Budget (ES 2 filing)	Actual Costs as of Dec. 2021	Budget-Actual Variance
Irvington	$300,000	$157,175	($142,825)
Irvington Sub HQ	$300,000	$578,009	$278,009

Project	Original Budget (ES 2 filing)	Actual Costs as of Dec. 2021	Budget-Actual Variance
Morgan Street*	$0	$457,217	$457,217
**-Morgan Street was not on the initial project list in the ES 2 filing and was added after PSE&G reviewed the fiber requirements and current status of all substations and operations centers to verify communication needs (see the ROD on this discussed in Section IV.A. of the IM 2020 Third Quarter Report).*			

The overall Grid Modernization – Communication System subprogram costs through the end of 2021 are presented in **Table 20 – ES 2 Grid Modernization – Communication System Costs as of December 31, 2021**.

Table 20 – ES 2 Grid Modernization – Communication System Costs as of December 31, 2021

Scope & Division		2019	2020	Q1 2021	Q2 2021	Q3 2021	Q4 2021	Total to Date	Forecast	% of Actuals to Forecast
		Actuals								
Retrofit Reclosers	Central	$0	$884,278	$1,067,295	$1,027,602	$715,214	$494,686	$4,189,074	$6,786,837	62%
	Metro	$0	$818,620	$436,089	$683,893	$733,376	$509,422	$3,181,399	$5,590,363	57%
	Palisades	$0	$825,174	$754,869	$965,416	$888,467	$506,721	$3,940,648	$6,200,559	64%
	Southern	$0	$929,058	$956,444	$1,005,852	$1,082,897	$817,622	$4,791,874	$7,325,098	65%
Fiber	Central	$1,691	$2,418,851	$796,586	$1,349,407	$1,007,245	$2,820,417	$8,394,196	$9,513,484	88%
	Metro	$1,457	$1,866,697	$340,713	$831,337	$1,198,777	$715,269	$4,954,250	$7,765,395	64%
	Palisades	$1,582	$2,046,762	$248,558	$725,030	$605,647	$2,023,898	$5,651,478	$6,132,422	92%
	Southern	$4,731	$910,483	$645,219	$1,029,156	$591,125	$200,977	$3,381,691	$3,381,691	100%
	Cutovers*	$0	$876,502	$323,458	$86,115	$109,880	$87,603	$1,483,558	$3,018,032	49%
Wireless Network		$74,306	$6,035,441	$287,086	$312,404	$124,015	$559,481	$7,392,732	$7,914,973	93%
Bulk Purchase**		$0	$1,524,874	$450,013	($154,037)	($335,637)	($481,105)	$1,004,108	$0	-
Total		**$83,767**	**$19,136,741**	**$6,306,330**	**$7,862,176**	**$6,721,006**	**$8,254,991**	**$48,365,008**	**$63,110,594**	**77%**

**-Includes fiber communication cutovers and substation RTU cutovers (the latter of which began having spend in Q1 2021).*
***-The Bulk Purchase account is used for the purchase of bulk equipment, which is the then assigned to a specific Division when the equipment is released with a credit back to the Bulk Purchase account. Thus, this account is forecasted to have a $0 balance at the end of the ES 2 Program.*

Findings & Observations:

- During the fourth quarter of 2021, the final 325 recloser retrofit installations were completed. In total, 2,318 retrofit reclosers were installed in the Program. The retrofit substation RTU scope commenced at the end of the fourth quarter of 2021, with 10 substations completed out of a forecasted scope of 196 substations.

- Three additional fiber installation projects were placed in-service during the fourth quarter of 2021, bringing the total number of projects in-service to 20 fiber installation projects and nine fiber cutover projects. The fiber scope is expected to be completed by the end of 2022.

- The forecast for the Grid Modernization – Communication system subprogram slightly increased from $63.1 million as of the end of the third quarter of 2021 to $63.6 million as of the end of the fourth quarter of 2021. Overall, the subprogram forecast of $63.6 million continues to remain below the adjusted Stipulation budget amount of $64.3 million (following the prior $7.7 million transfer of funds to the Grid Modernization – ADMS subprogram).

D. Grid Modernization – ADMS

The Grid Modernization – ADMS scope is split between three primary sections: DMS/DERMS, the OMS, and ADMS platform upgrades. The primary activities in 2021 are focused on the continued development of the systems and platforms that comprise this subprogram.

The scope for each primary component of the Grid Modernization – ADMS subprogram and notable activities conducted during the fourth quarter of 2021 are presented as follows:

DMS/DERMS

- Scope: Provide software and associated services to deploy a Smart Network in order to meet a subset of the ES 2 Program's objectives and use cases.
- Q4 2021 Activities:
    - Compiled advance metering interface (AMI) interface requirements.
    - Completed sprints 11 and 12.
- Forecasted Completion as of the end of the fourth quarter of 2021: 12/19/2022.

OMS

- Scope: Provide a single user interface for more efficient management of trouble orders and analysis of outage data through an integrated OMS, system interfaces, and geographic view of all integrated outage data through an integrated OMS, system interfaces, and geographic view of all integrated outage data and damage locations. OMS will include tools for dynamic visualization supporting incident management, damage location identification, dashboards, and the as-operated real-time view of PSE&G's network model. Field personnel also will have access to many of these tools as it relates to the incident(s) assigned to them via the Compass mobile crew application. 10 years' worth of existing OMS data will be migrated into the new system as well.
- Q4 2021 Activities:
    - Completed sprint 9 with Open Systems International Inc. (OSII).
    - Onboarded new Project Manager for OMS scope.
    - Reviewed integration/Mulesoft documentation.
    - Completed drafts of SAP integration documentation.
    - Completed onsite workshops at ADMS lab in Edison with System Integrator.
- Forecasted Completion as of the end of the fourth quarter of 2021: 12/23/2022.

ADMS Platform

- Scope: Replace, enhance, and expand the existing Distribution Supervisory Control and Data acquisition (DSCADA) platform elements inclusive of infrastructure components (servers and workstations) and applications (Monarch, Spectra, and Integra) to create an integrated ADMS platform.
- Q4 2021 Activities:

- Completed network segmentation for Newark; drafted network segmentation for Edison.
- Secured vulnerability testing vendor (Dragos).
- Completed setup for industrial defender.

- Forecasted Completion as of the end of the fourth quarter of 2021: 12/10/2021.

With the ADMS Platform being placed in-service in December 2021, this meant the domains (environments) used to manage and support the SCADA system that is in production and used for distribution operations as the system of record were in-service. The platform environments are also currently being used for DMS/DERMS and OMS as these components progress (for example, in performance and release testing). Changes to the shared environments are coordinated and controlled by a team comprised of two Environment Managers (one from PSE&G and one from OSII) and the ADMS-OMS Solution Architect.

The Grid Modernization – ADMS subprogram costs through the end of 2021 are presented in **Table 21 – ES 2 Grid Modernization – ADMS Costs as of December 31, 2021**.

Table 21 – ES 2 Grid Modernization – ADMS Costs as of December 31, 2021

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals						*Forecast*
$36,213	$16,447,624	$2,488,980	$2,168,187	$2,368,648	$2,828,626	$17,155,847

Actuals to Date	Forecast	% of Actuals to Forecast
$26,338,279	$43,494,127	61%

Findings & Observations:

- While the OMS component of the Grid Modernization – ADMS subprogram slipped 21 days from its status as of the end of the third quarter of 2021, the forecasted in-service date for the subprogram continues to remain at December 2022.
- The Grid Modernization – ADMS forecast as of the end of 2021 increased approximately $772,000 from the third quarter of 2021, with the total forecast now at $43.5 million.

E. Electric Stipulated Base

The Stipulation identified that the electric portion of the Stipulated Base include $100 million in investments at PSE&G's discretion towards electric outside plant higher design and construction standards and/or electric stations life cycle subprograms described in the original ES 2 filing.[2] The bulk of outside plant higher design and construction standards work is planned to commence in January 2022. In accordance with what the Stipulation provides, PSE&G plans to fund some of the life cycle station

[2] As noted in the Stipulation, the electric life cycle upgrades are part of the electric Stipulated Base to be recovered in the Company's next base rate case provided the investments are found to be prudent. The Stipulation also notes that should the 16 stations that comprise the Electric Station Flood Mitigation subprogram be completed for under the $389 million allocated for that subprogram, PSE&G may reallocate such unused funds to stations identified in the life cycle station upgrade portion of PSE&G's petition for accelerated recovery.

upgrades from the electric program accelerated investment, subject to funds available, after all Electric Station Flood Mitigation projects are funded at their final costs.

As reported in the IM 2020 Second Quarter Report, the initial four stations PSE&G selected for life cycle station upgrades went before the URB in June 2020 for Study level estimate approval and received approval for full funding. In the second quarter of 2021 a fifth station, State Street, was approved by the URB for its outside plant scope to be transferred from the related Electric Station Flood Mitigation project to the life cycle scope. These five stations and their current estimate compared to the actuals to date are provided in **Table 22 – ES 2 Life Cycle Station Upgrade Project Status as of December 31, 2021**.

Table 22 – ES 2 Life Cycle Station Upgrade Project Status as of December 31, 2021

Project	Estimate Level	Base	Risk & Contingency	Total	Actuals to Date	% of Actuals to Estimate	Forecasted In-Service Date*
1. Hamilton	Study	$14,500,000	$3,700,000	$18,200,000	$3,503,394	19%	10/12/2022
2. Paramus	Study	$14,800,000	$5,400,000	$20,200,000	$7,908,965	39%	12/29/2022 (↓)
3. Plainfield	Study	$18,400,000	$4,200,000	$22,600,000	$4,266,426	19%	11/8/2022 (↓)
4. Woodbury	Study	$15,400,000	$3,300,000	$18,700,000	$2,164,988	12%	12/27/2022
5. State Street (OP)	Study	$19,700,000	$3,000,000	$22,700,000	$211,247	1%	4/30/2023 (↓)

**-Reflects the in-service date of the last major asset (e.g. switchgear), certain activities may take place after this date to support the final in-service date (i.e. when all customers are cutover).*
(↑)*-Indicates the forecasted in-service date advanced from the prior quarter.*
(↓)*-Indicates the forecasted in-service date slipped from the prior quarter.*

As shown in **Table 22**, of the five life cycle station upgrade projects, the Paramus, Plainfield, and State Street OP projects each saw their respective forecasted in-service dates slip during the fourth quarter of 2021, reversing the advancement in these projects gained in the third quarter of 2021. Additional details on each of these life cycle station upgrade projects is provided in the individual subsections that follow.

Findings & Observations:

- Construction continued on the Hamilton, Plainfield, and Woodbury projects, which commenced during the third quarter of 2021, and also continued on Paramus, which started in the second quarter of 2021. The Paramus project placed the contingency switchgear in-service in December 2021.
- The forecasted in-service dates for the Paramus, Plainfield, and State Street OP projects each slipped during the fourth quarter of 2021, reflective of actual site conditions and resource availability. Each of the original four life cycle station upgrade projects remains forecasted for completion in the fourth quarter of 2022 while the State Street OP project is forecasted for completion in the second quarter of 2023.

1. Hamilton

During the fourth quarter of 2021, $1,419,949 was spent on the Hamilton project against a forecast of approximately $1.6 million. The variance between forecasted and actual spend in the fourth quarter was driven by foundations and 4kV duct banks not completed as planned due to contractor unavailability (though no resulting change to the forecasted in-service date). This brought total spend on the project to approximately $3.5 million through the end of 2021.

Notable activities conducted during the fourth quarter of 2021 included the commencement of the first phase of civil works on the project, which includes the installation of foundations for the 4kV equipment, the grounding grid, and new OP duct banks. The electrical scope is expected to commence in the first quarter of 2022.

The actual spend by quarter for Hamilton as compared to the current URB approved estimate is provided below.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals						*Forecast*
$0	$362,372	$236,783	$400,855	$1,083,435	$1,419,949	$13,014,013

Actuals to Date	Estimate	Current Forecast	% of Actuals to Forecast
$3,503,395	$18,200,000	$16,517,408	21%

2. Paramus

During the fourth quarter of 2021, $968,622 was spent on the Paramus project against a forecast of approximately $908,000. This brought total spend on the project to approximately $7.9 million through the end of 2021. The forecasted in-service date for the Paramus project slipped from November 11, 2022, as of the end of the third quarter of 2021, to December 29, 2022, as of the end of the fourth quarter of 2021. This shift was the result of manhole repairs required and correction of a condensation issue within the contingency (temporary) feeder row gear. The condensation was a result of the design of some of the rear panels on the contingency feeder rows as well as the settings on the heaters and humidifiers. The units which did not have vented panels experienced the condensation and when this was corrected, and the settings on the heaters and humidifiers were adjusted, the issue was resolved.

Notable activities conducted during the fourth quarter of 2021 included:

- Civil and Electrical POs issued;
- Control drawings IFC;
- Construction permits received; and,
- The contingency switchgear placed in-service.

The actual spend by quarter for Paramus as compared to the current URB approved estimate is provided below.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2024
Actuals						*Forecast*
$0	$840,200	$358,846	$4,176,989	$1,564,308	$968,622	$12,937,137

Actuals to Date	Estimate	Current Forecast	% of Actuals to Forecast
$7,908,965	$20,200,000	$20,846,102	38%

3. Plainfield

During the fourth quarter of 2021, $1,787,450 was spent on the Plainfield project against a forecast of approximately $2.3 million. The variance between forecasted and actual spend during the fourth quarter was driven by civil activities delayed due to permitting and material availability from the Palisades Division. This brought total spend on the project to approximately $4.3 million through the end of 2021. The forecasted in-service date for the Plainfield project slipped from October 17, 2022, as of the end of the third quarter of 2021, to November 8, 2022, as of the end of the fourth quarter of 2021. This shift was the result of an unknown underground obstruction requiring foundation design changes and the determination that a NJ Transit temporary access permit is required for approved crane use in proximity to the nearby NJ Transit tracks. The unknown underground obstruction at Plainfield included existing below grade concrete structures and direct buried cables that were not included in the record drawings and also resulted in marginal increases to the engineering and construction costs on the project.

Notable activities conducted during the fourth quarter of 2021 included:

- Civil PO issued;
- OP circuit cutovers completed;
- Control drawings IFC; and,
- Electrical construction out for bid.

The actual spend by quarter for Plainfield as compared to the current URB approved estimate is provided below.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2024
Actuals						*Forecast*
$0	$682,325	$214,632	$367,543	$1,214,476	$1,787,450	$17,898,069

Actuals to Date	Estimate	Current Forecast	% of Actuals to Forecast
$4,266,426	$22,600,000	$22,164,495	19%

4. Woodbury

During the fourth quarter of 2021, $353,658 was spent on the Woodbury project against a forecast of approximately $544,000. The variance between forecasted and actual spend in the fourth quarter was driven by foundation work not completed as planned due to material availability and a missed accrual for December work. This brought the total spend on the project to approximately $2.2 million through the end of 2021. The unavailable material involved perimeter wall foundation materials that shifted the construction of the wall foundation from December 2021 to January 2022 (though no resulting change to the forecasted in-service date).

Notable activities conducted during the fourth quarter of 2021 included the issuance of construction permits and the commencement of OP work.

The actual spend by quarter for Woodbury as compared to the current URB approved estimate is provided below.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals						*Forecast*
$0	$551,165	$540,138	$356,225	$363,802	$353,658	$15,919,012

Actuals to Date	Estimate	Current Forecast	% of Actuals to Forecast
$2,164,988	$18,700,000	$18,084,000	12%

5. State Street (Outside Plant)

During the fourth quarter of 2021, $139,953 was spent on the State Street (OP) project against a forecast of approximately $296,000. The variance between forecasted and actual spend in the fourth quarter was driven by lower spend than estimated for A/E supporting underground design work, less A/E work completed in December than forecasted, and the November A/E invoice lower than accrued. This brought the total spend on the project to approximately $211,000. The forecasted in-service date for the State Street OP project slipped from March 2, 2023, as of the end of the third quarter of 2021, to April 30, 2023, as of the end of the fourth quarter of 2021. This shift was the result of a review of the anticipated resource availability.

Notable activities conducted during the fourth quarter of 2021 included the project kickoff meeting and the commencement of detailed engineering.

The actual spend by quarter for State Street (OP) as compared to the current URB approved estimate is provided below.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals						*Forecast*
$0	$0	$0	$17,633	$53,660	$139,953	$19,501,342

Actuals to Date	Estimate	Current Forecast	% of Actuals to Forecast
$211,247	$22,700,000	$19,712,589	0%

F. Gas M&R Station Upgrades

Through the end of 2021, primary activities in the Gas M&R subprogram continued to focus on advancing the pre-construction activities for the five projects not in construction, while the Westampton project continued its construction activities in support of reaching an October 2021 in-service date. **Table 23 – ES 2 Gas M&R Summary Status as of December 31, 2021** below provides the currently approved estimates for each project within the Gas M&R subprogram, along with the actuals to date and forecasted in-service dates.

Table 23 – ES 2 Gas M&R Summary Status as of December 31, 2021

Project	Estimate Level	Base	Risk & Contingency	Total Estimate	Actuals	% of Actuals to Estimate	Forecasted In-Service**
1. Camden*	Study	$24,300,000	$5,000,000	$29,300,000	$3,020,373	10%	Dec 2022
2. Central*	Study	$23,900,000	$5,100,000	$29,000,000	$4,903,727	17%	Dec 2022
3. East Rutherford	Study	$13,800,000	$2,700,000	$16,500,000	$2,314,498	14%	Dec 2022

Project	Estimate Level	Base	Risk & Contingency	Total Estimate	Actuals	% of Actuals to Estimate	Forecasted In-Service**
4. Mount Laurel	Study	$9,400,000	$2,000,000	$11,400,000	$895,473	8%	Dec 2022
5. Paramus*	Study	$11,500,000	$2,200,000	$13,700,000	$1,039,637	8%	Dec 2023
6. Westampton	Definitive	$9,100,000	$900,000	$10,000,000	$8,002,281	80%	***Oct 2021***
Subprogram Total		**$92,000,000**	**$17,900,000**	**$109,900,000**	**$20,175,989**	**18%**	**Dec 2023**
-Included in the Stipulated Base.* *-Bold/italics indicate actual in-service date achieved.* (↑)*-Indicates the forecasted in-service date advanced from the prior quarter.* (↓)*-Indicates the forecasted in-service date slipped from the prior quarter.*							

The in-service dates for the Gas M&R projects as of the end of the fourth quarter of 2021 remained static from the status at the end of the prior quarter. The Westampton project was placed in-service as of October 22, 2021, which was the forecasted date as of the end of the prior quarter.

Findings & Observations:

- The primary efforts to date on the subprogram continue to be primarily related to pre-construction planning efforts, including completing and submitting site plan packages, ordering long lead materials, and awarding the construction work. The Westampton project, which commenced construction in April 2021, was placed in-service as of October 22, 2021, and will have some remaining restoration and punch list work ongoing in 2022.
- The forecast increased on the Central and East Rutherford projects based on the actual PO/contract pricing received for materials and construction, as well as additional engineering efforts. These cost pressures are being evaluated on the other remaining projects. However, despite these increases, the overall subprogram forecast of $107.8 million remains below the current total estimate of $109.9 million (although both are above the Stipulation amount of $101.0 million).
- The IM has found nothing to date that would jeopardize the subprogram being completed on time, while the cost pressures noted above have pushed the forecast over the Stipulation amount. During the fourth quarter of 2021 there were no updates to the Gas M&R project estimates and the forecast in-service dates remained unchanged from the prior quarter, while the first of the six Gas M&R projects was also placed in-service (Westampton).

1. Camden

During the fourth quarter of 2021, $937,617 was spent on the Camden project compared to a forecast of approximately $948,000, which brought the total spend to approximately $3.0 million. The forecasted in-service date for the Camden project as of the end of 2021 remains unchanged from the forecast as of the end of the third quarter at December 30, 2022.

Notable activities completed on the Camden project during the fourth quarter of 2021 included:

- Held pre-bid site walk through;
- Received construction bids; and,
- Resolution compliance completed for City of Camden.

The actual spend by quarter for Camden as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals						*Forecast*
$13,326	$859,350	$505,693	$290,839	$413,548	$937,617	$23,366,961

Actuals to Date	Estimate	Current Forecast	% of Actuals to Forecast
$3,020,373	$29,300,000	$26,387,333	11%

2. Central

During the fourth quarter of 2021, $3,409,826 was spent on the Central project compared to a forecast of approximately $4.0 million, which brought the total spend to approximately $4.9 million. The forecasted in-service date for the Central project as of the end of 2021 remains unchanged from the forecast as of the end of the third quarter at December 30, 2022.

Notable activities completed on the Central project during the fourth quarter of 2021 included:

- Awarded construction contract;
- Held pre-construction meeting and reviewed permit package with contractor;
- Received fully executed agreement with Transco; and,
- Installed air bridges and matting over underground pipeline crossings.

The actual spend by quarter for Central as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project. The current forecast of $34.0 million reflects an increase of approximately $8.2 million from the forecast as of the end of the prior quarter. This increase was driven by the actual PO/contract pricing received for materials and construction and additional engineering efforts. The increase in construction costs reflects the current market conditions, as PSE&G had awarded the work to the lowest bidder, at a price 12.5%-59% below other bidders. The additional engineering efforts involve design evolution on the building configuration (increasing from two buildings to four) and foundations, which also ties into the final piping design. Other design factors include the relocation of the station by-pass away from the regulation building in case of station emergency.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals						*Forecast*
$6,869	$670,582	$315,258	$190,109	$311,084	$3,409,826	$29,064,009

Actuals to Date	Estimate	Current Forecast	% of Actuals to Forecast
$4,903,727	$29,000,000	$33,967,736	14%

3. East Rutherford

During the fourth quarter of 2021, $996,202 was spent on the East Rutherford project compared to a forecast of approximately $927,000, which brought the total spend to approximately $2.3 million. The forecasted in-service date for the East Rutherford project as of the end of 2021 remains unchanged from forecast as of the end of the third quarter at December 30, 2022.

Notable activities completed on the East Rutherford project during the fourth quarter of 2021 included:

- Completed IFC drawing page turn with project team and A/E;
- Awarded construction contract;
- Held pre-construction meeting with contractor;
- Held meeting with Transco to discuss site requirements;
- Received water discharge surface permit; and,
- Submitted response to New Jersey Sports and Exposition Authority (NJSEA) comments on permit application.

The actual spend by quarter for East Rutherford as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project. The current forecast of $18.1 million reflects an increase of approximately $4.3 million from the forecast as of the end of the prior quarter. This increase was driven by the actual PO/contract pricing received for materials and construction and additional engineering efforts. The increase in construction costs reflects the current market conditions, as PSE&G had awarded the work to the lowest bidder, at a price 52%-102% below other bidders. The additional engineering efforts involve a change from one larger heater to two smaller heaters to facilitate maintenance, increased piping wall thickness to mitigate noise levels, updates to temporary regulator skids to allow operational controls during construction, the identified need for upgraded electrical service, and larger diameter piping and valves with longer regulator runs that resulted in an increase to the building size.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals						*Forecast*
$9,010	$521,865	$337,573	$260,112	$189,737	$996,202	$15,809,210

Actuals to Date	Estimate	Current Forecast	% of Actuals to Forecast
$2,314,498	$16,500,000	$18,123,708	13%

4. Mount Laurel

During the fourth quarter of 2021, $101,143 was spent on the Mount Laurel project compared to a forecast of approximately $96,000, which brought the total spend to approximately $895,000. The forecasted in-service date for the Mount Laurel project as of the end of 2021 remains unchanged from the forecast as of the end of the third quarter at December 30, 2022.

Notable activities completed on the Mount Laurel project during the fourth quarter of 2021 included:

- Opened construction bid;
- Issued material procurement PO; and,
- Site plan deemed completed and placed on Burlington County Planning Board agenda for approval.

The actual spend by quarter for Mount Laurel as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals						*Forecast*
$5,965	$362,167	$155,351	$149,682	$121,165	$101,143	$8,504,527

Actuals to Date	Estimate	Current Forecast	% of Actuals to Forecast
$895,473	$11,400,000	$9,400,000	10%

5. Paramus

During the fourth quarter of 2021, $118,557 was spent on the Paramus project compared to a forecast of approximately $93,000, which brought the total spend to approximately $1.0 million. The forecasted in-service date for the Paramus project as of the end of 2021 remains unchanged from the forecast as of the end of the third quarter at December 29, 2023.

Notable activities completed on the Paramus project during the fourth quarter of 2021 included:

- Submitted permit package to township;
- Received comments on site plan application; and,
- Held air permit coordination meeting.

The actual spend by quarter for Paramus as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals						*Forecast*
$8,842	$462,452	$227,854	$129,694	$92,239	$118,557	$10,460,363

Actuals to Date	Estimate	Current Forecast	% of Actuals to Forecast
$1,039,637	$13,700,000	$11,500,000	9%

6. Westampton

During the fourth quarter of 2021, $1,443,107 was spent on the Westampton project compared to a forecast of approximately $1.5 million, which brought the total spend to approximately $8.0 million. The Westampton was placed in-service as of October 22, 2021, remaining activities include site restoration and final punch list items that will carry over into 2022.

The actual spend by quarter for Westampton as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals						*Forecast*
$8,395	$1,032,670	$478,072	$3,217,496	$1,822,542	$1,443,107	$417,830

Actuals to Date	Estimate	Current Forecast	% of Actuals to Forecast
$8,002,281	$10,000,000	$8,420,111	95%

ENERGY STRONG PROGRAM

INDEPENDENT MONITOR

2021 FOURTH QUARTER REPORT

APPENDIX A – DRAFT REPORT COMMENTS AND RESPONSES

DECEMBER 21, 2022

PEGASUS GLOBAL HOLDINGS, INC. ®

Questions & Comments to the IM 2021 Fourth Quarter Report Formally Submitted to the IM

<table>
<tr><th>ID #</th><th>Question/Comment</th><th>IM Response</th><th>Report Changes</th></tr>
<tr><td>S-INF-1</td><td><u>Reference Q4 2021 Report, Page 11, Table 7 – Q4 2021 Major Event Performance</u>
For the 104 circuits impacted by the Q4 2021 Major Event that received investments during either the original Energy Strong Program or through Energy Strong 2, please compare the cumulative five (5)-year baseline System Average Interruption Duration Index (“SAIDI”) of all circuits to the cumulative Q4 2021 SAIDI of all circuits.</td><td>Out of a total of 1,007 circuits, 104 circuits were impacted by the Q4 2021 Major Events and 903 circuits were <u>not</u> impacted by this Major Event. The SAIDI of these circuits is as follows:
<table>
<tr><th colspan="2">Circuits Impacted in Q4 2021 Major Events (104)</th><th>Circuits <u>Not</u> Impacted in Q4 2021 Major Events (903)</th></tr>
<tr><td>Average of 5-Year Baseline SAIDI</td><td>Average of Q4 2021 SAIDI</td><td>Average 5-Year Baseline SAIDI</td></tr>
<tr><td>0.14816</td><td>0.00528</td><td>0.08234</td></tr>
</table>
As shown above the circuits impacted by the Q4 2021 Major Event had a worse 5-year average SAIDI than the non-impacted circuits, but also showed improved performance during this Major Event.</td><td>Section II.D.1. (new Table 8)</td></tr>
<tr><td>S-INF-2</td><td><u>Reference Q4 2021 Report, Page 13, Table 8 – Q4 2021 Major Event Additional Information on Selected Circuits</u>
With respect to the six (6) circuits improved within Energy Strong or Energy Strong 2 that had worse performance during the Q4 2021 Major Event than the five (5)-year baseline:
a. Please describe the improvements made to each circuit within the Energy Strong or Energy Strong 2 program.
b. Please estimate why these investments were not effective in improving the circuit’s SAIDI.</td><td>Regarding these comments on circuit performance:
a. The Contingency Reconfiguration subprogram for both the Energy Strong and ES 2 programs involved increasing the number of sections in present loop designs utilizing reclosers, providing alternative circuit feeds or circuit reconfigurations, and placing new devices on the system that will provide reclosing where it previously did not exist and allow PSE&G to receive outage notifications without customer calls. Reclosers essentially serve as an automatic, high-voltage electric switch that sense and interrupt fault currents and automatically restore service after a momentary outage has occurred. Momentary outages may include situations such as: windblown conductors touching one another; lightning surges flashing over an insulator; small animals bridging between an energized line and grounded surface; tree branches touching energized lines; or switching surges that flash over an insulator. If a fault is permanent, the recloser locks open after a preset number of operations isolating the faulted section from the main</td><td>No change</td></tr>
</table>

ID #	Question/Comment	IM Response	Report Changes
		part of the system to reduce the outage area and help repair crews quickly locate the problem and restore power. b. It is the IM's opinion that the performance of the circuits listed in **Table 9** (renumbered after the new **Table 8** was added in response to **S-INF-1**), which had worse SAIDI metrics in this Major Event than the 5-year average, reflects the nature of these specific outages where circumstances such as additional restoration effort required (such as pole replacement), equipment failure, and/or very low customer counts (lowering the restoration priority) contributed to the comparatively worse performance.	
S-INF-3	**Reference Q4 2021 Report, Page 16, Table 10 – ES 2 Electric Station Flood Mitigation Summary Status as of December 31, 2021** Please provide additional details about the facilities placed in-service at the Leonia and Ridgefield 13kV substations during Q4 2021, which resulted in these substations being classified as partially in-service.	Regarding the partial in-service status achieved by the Leonia and Ridgefield 13kV projects involved one of each projects' switchgears being placed in-service: • For Leonia, the 13kV switchgear #1 was placed in-service as of October 19, 2021 (while switchgear #2 was placed in-service on June 29, 2022). • For Ridgefield 13kV, the 13kV switchgear #2 was placed in-service as of December 16, 2021 (while switchgear #1 is forecasted to be placed in-service in December 2022).	No change
S-INF-4	**Reference Q4 2021 Report, Page 19, Academy Street Substation** Regarding the Academy Street substation project, please refer to the statement "The variance in spend during the fourth quarter of 2021 was primarily the result of commissioning activities being charged to the Fairmount 69kV Project (same site location) and less than estimated trailing costs after the project was placed in-service." a. Please clarify if the costs for commissioning activities that were charged to the Fairmount 69kV project were originally budgeted within the Academy Street substation project. b. If so, please provide additional details explaining why these costs were charged to the Fairmount 69kV project.	The Fairmount 69kV project and the ES 2 Academy Street project are co-located on a common site and are being jointly executed. The commissioning activities that were wrongly charged to the Fairmount 69kV project were budgeted to the Academy Street project and were performed by Commissioning Engineers that worked on the Fairmount 69kV project prior to working on the Academy Street project. This error was identified and corrected during the monthly forecast variance analysis process when it was realized that this work was done as planned with cash flow forecasted, but not included in the October actual costs.	**Section III.A.1.**

ID #	Question/Comment	IM Response	Report Changes
S-INF-5	**<u>Reference Q4 2021 Report, Page 25, Waverly Substation</u>** Regarding the Waverly substation project, please estimate the additional costs expected to be incurred as a result of the increased scope of the revised site plan.	As indicated in response to RCR-IM-6 in the IM 2021 Third Quarter Report, PSE&G updated the Waverly project estimate in January 2022, with the base estimate increasing from $29.4 million to $36.2 million. Of this increase, approximately $2.6 million was related to the site plan revisions, including: additional engineering ($0.8 million), revised fencing and external façade improvements ($1.0 million), and additional charges for extended project duration ($0.8 million).	No change
S-INF-6	**<u>Reference Q4 2021 Report, Page 25, Woodlynne Substation</u>** Regarding the Woodlynne substation project, please provide additional details about the cost savings resulting from "the A/E not reaching a planned payment milestone in December."	The A/E not reaching a planned payment milestone in December resulted in lower than forecasted spend specifically for the fourth quarter of 2021 and has a negligible impact on the overall project cost.	No change
S-INF-7	**<u>Reference Q4 2021 Report, Page 27, Continency Reconfiguration Subprogram</u>** Regarding the Fuse Saver component of the Contingency Reconfiguration subprogram, it is noted that the Company currently forecasts a total of 1,713 units. It is further noted that the Company previously reduced forecasted Fuse Saver installations from 2,572 units to 1,967 units. (<u>See</u> Q1 2021 Report, Page 27). Please discuss the Company's rationale for further reducing the scope of the Fuse Saver component and indicate if any further reductions are expected.	PSE&G continues to utilize an iterative process to evaluate the number of devices anticipated for the Fuse Saver scope of work. The targeted number of Fuse Saver units is revised based on updated field assessments as well as the final number of units driven by the average cost per unit based on the most optimal mix of locations given the fixed budget. For example, if an identified location requires a pole replacement based on the field conditions, it will have a much higher installation cost than a location not requiring a pole replacement.	**Section III.B.**
S-INF-8	**<u>Reference Q4 2021 Report, Page 28, Table 15 – Contingency Reconfiguration Costs as of December 31, 2021</u>** Please provide additional details about the nature of the costs incurred for the Fuse Saver component of the Contingency Reconfiguration subprogram in Q4 2021, given that full Fuse Saver scope was pushed to 2022.	While the full Fuse Saver scope was pushed to 2022, installations of the remaining pilot program units continued in the fourth quarter of 2021, with five additional units installed. One additional unit was also engineering during the fourth quarter of 2021. The costs incurred from the Fuse Saver scope during the fourth quarter of 2021 included project management costs and direct costs (labor, material, engineering, storage, traffic control), which included some older invoices for work prior to the fourth quarter of 2021.	**Section III.B.**
S-INF-9	**<u>Reference Q4 2021 Report, Page 29, Grid Modernization – Communication System Subprogram</u>**	Regarding these comments on the Grid Modernization – Communication System subprogram: a. PSE&G initially planned for 2,561 reclosers to be retrofitted with wireless radio communications.	**Section III.C.**

<table>
<tr><th>ID #</th><th>Question/Comment</th><th>IM Response</th><th>Report Changes</th></tr>
<tr><td></td><td>a. Please compare the final number of retrofit reclosers (2,318) to originally budgeted totals.
b. What is attributed to the forecasted scope of substation RTU retrofits being reduced from 204 units in the IM’s Q3 2021 Report to 196 units in the IM’s Q4 2021 Report?
c. Refer to the statement “Also during the fourth quarter of 2021, two additional retrofits of substation RTUS were completed, bringing the total as of the end of 2021 to 10 substations completed…” please reconcile this with the IM’s Q3 2021 Report, which indicated that nine (9) fiber cutover projects had been placed in-service through Q3 2021. (<u>See</u> Q3 Report, Page 34)</td><td>b. The reduction in planned substation RTU retrofits was due to updated system status information.
c. Under this subprogram, PSE&G is cutting over new fiber installations to 12 existing substations (referenced as the “Fiber Cutover Projects” in Table 18), as of the end of 2021, nine of these 12 projects were completed, which is unchanged from the status as of the end of the third quarter of 2021. This subprogram also involves the retrofitting of RTUs to existing substations and as of the end of 2021, 10 RTU retrofits had been completed. As of the end of the third quarter of 2021, eight RTU retrofits had been completed (although Table 18 from the IM 2021 Third Quarter Report identified nine complete as an error).</td><td></td></tr>
<tr><td>S-INF-10</td><td><u>Reference Q4 2021 Report, Page 30, Grid Modernization – Communication System Subprogram</u>
Regarding the Grid Modernization – Communication System subprogram, it is stated that “During the fourth quarter of 2021, three additional fiber installation projects (Irvington, Irvington Sub HQ, and Morgan Street) were placed in-service.” For each of these projects placed in-service during Q4 2021, please compare the final cost to the budgeted cost.</td><td>For the fiber projects placed in-service during the fourth quarter of 2021, the original budgeted cost compared to the actual costs is as follows:
<table><tr><th>Project</th><th>Original Budget (ES 2 filing)</th><th>Actual Costs as of Dec. 2021</th></tr><tr><td>Irvington</td><td>$300,000</td><td>$157,175</td></tr><tr><td>Irvington Sub HQ</td><td>$300,000</td><td>$578,009</td></tr><tr><td>Morgan Street*</td><td>$0</td><td>$457,217</td></tr><tr><td colspan="3">*-Morgan Street was not on the initial project list in the ES 2 filing and was added after PSE&G reviewed the fiber requirements and current status of all substations and operations centers to verify communication needs (see the ROD on this discussed in Section IV.A. of the IM 2020 Third Quarter Report).</td></tr></table></td><td>Section III.C. (new Table 19)</td></tr>
<tr><td>S-INF-11</td><td><u>Reference Q4 2021 Report, Page 31, Table 18 – ES 2 Grid Modernization – Communication System Costs as of December 31, 2021</u>
Regarding the Wireless Network component of the Grid Modernization – Communication System subprogram, Table 18 reports actual spending through Q4 2021 of $7,392,732 and total forecasted spending of $7,914,973. Please provide additional</td><td>The Wireless Network, as noted, was placed in-service as of December 16, 2021. Remaining work in the Wireless Network scope relates to providing radios for the Fuse Savers currently being installed, which constitutes the approximately half million in remaining spend.</td><td>Section III.C.</td></tr>
</table>

<table>
<tr><th>ID #</th><th>Question/Comment</th><th>IM Response</th><th>Report Changes</th></tr>
<tr><td></td><td>details about the work included within this $522,241 of additional spending, given that the Wireless Network scope was placed in-service as of December 16, 2021. (<u>See</u> Q3 2021 Report, Comment S-INF-10)</td><td></td><td></td></tr>
<tr><td>S-INF-12</td><td><u>Reference Q4 2021 Report, Page 32, Grid Modernization – ADMS Subprogram</u>
For each component of the Grid Modernization – ADMS subprogram (DMS/DERMS, OMS, ADMS), please compare the currently forecasted cost to the originally budgeted cost.</td><td>The original budget and forecasted costs as of December 2021 for the major Grid Modernization – ADMS components are as follows:
<table>
<tr><th>Scope</th><th>Original Budget</th><th>Estimate at Completion (as of Dec 2021)</th><th>Variance</th></tr>
<tr><td>OMS</td><td>$27,289,272</td><td>$27,820,234</td><td>$530,962</td></tr>
<tr><td>DMS/DERMS</td><td>$6,436,387</td><td>$6,665,333</td><td>$228,946</td></tr>
<tr><td>Platform Upgrade</td><td>$4,630,926</td><td>$4,631,667</td><td>$741</td></tr>
<tr><td>ADMS Hardware</td><td>$4,356,031</td><td>$4,376,892</td><td>$20,861</td></tr>
<tr><td>Total</td><td>$42,712,616</td><td>$43,494,127</td><td>$781,511</td></tr>
</table></td><td>No change</td></tr>
<tr><td>S-INF-13</td><td><u>Reference Q4 2021 Report, Page 33, Grid Modernization – ADMS Subprogram</u>
Regarding the ADMS platform component of the Grid Modernization – ADMS subprogram, please indicate if a competitive bidding process was used to select the vulnerability testing vendor (Dragos). If so, please indicate if Dragos submitted the lowest bid.</td><td>PSE&G used a competitive bidding process to select the vulnerability testing vendor. Dragos, the selected vendor, was not the lowest cost bidder, but was the only bidder who met all the requirements for this scope of work.</td><td>No change</td></tr>
<tr><td>S-INF-14</td><td><u>Reference Q4 2021 Report, Page 33, Grid Modernization – ADMS Subprogram</u>
Please discuss how the ADMS platform (completed in December 2021) will be leveraged while the DMS/DERMS and OMS remain under development until December 2022.</td><td>The ADMS Platform put in service the domains (environments) used to manage and support the SCADA system that is in production and used for distribution operations as the system of record. The platform environments are also currently being used for DMS/DERMS and OMS as these components progress. (for example, OMS- SIT/SAT/Performance/Release Testing, DMS/DERMS – Performance/Release Testing).
Changes to the shared environments are coordinated and controlled by a team comprised of two Environment Managers (one from PSE&G and one from OSII) and the ADMS-OMS Solution Architect.</td><td>Section III.D.</td></tr>
<tr><td>S-INF-15</td><td><u>Reference Q4 2021 Report, Page 38, Gas M&R Station Upgrades – Camden</u></td><td>In the first quarter of 2022, PSE&G updated its estimate for the Camden Gas M&R Project, which resulted in a $10.7 million estimate increase from the Study level estimate to a current estimate of $36.6 million. While details of this</td><td>No change</td></tr>
</table>

ID #	Question/Comment	IM Response	Report Changes
	Regarding the Camden Gas M&R project, please indicate if the construction bids received were higher than anticipated, similar to the Central an East Rutherford Gas M&R projects.	estimate will be discussed in the upcoming IM 2022 First Quarter Report, the contractor bids had a minimal impact compared to other cost drivers (site plan remediation impacts, additional electric load requirements, final building design, schedule constraints, etc.).	
S-INF-16	**<u>Reference Q4 2021 Report, Page 39, Gas M&R Station Upgrades</u>** Regarding the Central and East Rutherford Gas M&R projects: a. Please indicate if the construction contracts were awarded to the lowest bidders. If not please explain. b. Please provide additional information about the need for additional engineering efforts.	Regarding these comments on the Central and East Rutherford Gas M&R projects: a. For both these projects, the construction contracts were awarded to the lowest bidder (which was also the highest overall evaluated contractor). On the Central project, the winning bidder's price proposal was 12.5%-59% below the other bidders; while on the East Rutherford project, the winning bidder's price proposal was 52%-102% below the other bidders. b. On Central, the additional engineering efforts involved design evolution of the building configuration (increasing from two buildings to four) and foundations, which also ties to the final piping design. Other factors include a relocation of the station by-pass away from the regulation building in case of station emergency. On East Rutherford, the additional engineering efforts involved a change from one large heater to two smaller heaters to facilitate maintenance, increased piping wall thickness to mitigate noise levels, updates to temporary regulator skids to allow operational controls during construction, the identified need for upgraded electrical service, and larger diameter piping and valves with longer regulator runs that resulted in an increase to the building size.	**Sections III.F.2.** and **III.F.3.**
S-INF-17	**<u>Reference Q4 2021 Report, Page 39, Gas M&R Station Upgrades – East Rutherford</u>** Regarding the East Rutherford Gas M&R project, please provide additional details about the New Jersey Sports and Exposition Authority ("NJSEA") comments on the permit application. Please also indicate if any scope changes are expected as a result of the NJSEA comments.	The comments received from NJSEA on the East Rutherford projects were similar to comments typically received from other municipal planning or zoning boards, and included requests such as: Provide documentation that the standby generator complies with NAJC 19:4-7; Provide a gate detail; Verify that all equipment susceptible to flooding are above elevation of 9 feet NACD88; All imported fill must be approved by NJSEA; Provide copies of approvals from other agencies with jurisdiction such as NJDEP and Bergen County Soil Conservation District; Applicant must comply with the signage requirements to satisfy the East Rutherford Fire Department. PSE&G expects no scope changes to the project as a result of the comments.	No change
S-INF-18	**<u>Reference Q4 2021 Report, Page 40, Gas M&R Station Upgrades</u>**	During the second quarter of 2022, PSE&G updated the estimates for the Mount Laurel and Paramus Gas M&R projects (in addition to the other projects within this subprogram). The Mount Laurel estimate included cost increases identified	No change

ID #	Question/Comment	IM Response	Report Changes
	Regarding the Mount Laurel and Paramus Gas M&R projects, please discuss if the Company expects increased costs for materials and construction, similar to the Central and East Rutherford Gas M&R projects.	for construction and materials based on current quotes received, while the Paramus estimate had no change to the base estimate, but increased R&C by $6.2 million based in part on the observed cost pressures experienced on the more advanced projects in the subprogram.	
S-INF-19	**<u>Reference Q4 2021 Report, Page 41, Gas M&R Station Upgrades – Westampton</u>** Please indicate if the completed Westampton Gas M&R project incorporated any major scope changes as compared to the originally planned scope of work.	No major scope changes were introduced on the Westampton Gas M&R project.	No change
RCR-IM-1	With reference to page 2 of the Independent Monitor's Draft Fourth Quarter 2021 Report, please provide an update on the status of the Orange Valley substation including actual in-service date or anticipated in-service date.	As of the end of the third quarter of 2022 (most recent set of schedule data available as of the date of this report), the Orange Valley forecasted in-service date is in February 2024.	No change
RCR-IM-2	With reference to page 2 of the Independent Monitor's Draft Fourth Quarter 2021 Report, please provide an update on the status of the Waverly substation including actual in-service date or anticipated in-service date.	As of the end of the third quarter of 2022 (most recent set of schedule data available as of the date of this report), the Waverly forecasted in-service date is in April 2024.	No change
RCR-IM-3	With reference to page 2 of the Independent Monitor's Draft Fourth Quarter 2021 Report, please provide an update on the status of the Leonia substation including actual in-service date or anticipated in-service date.	The Leonia project was placed in-service in November 2022.	No change
RCR-IM-4	With reference to page 2 of the Independent Monitor's Draft Fourth Quarter 2021 Report, please provide an update on the status of the Ridgefield 13kV substation including actual in-service date or anticipated in-service date.	As of the end of the third quarter of 2022 (most recent set of schedule data available as of the date of this report), the Ridgefield 13kV forecasted in-service date continues to be December 2022.	No change
RCR-IM-5	With reference to page 2 of the Independent Monitor's Draft Fourth Quarter 2021 Report, please provide an update on the status of anticipated in-service date of any substation work expected to be completed in 2022.	As of the end of 2021, the following Electric Station Flood Mitigation projects were forecasted to be put in-service during 2022: Clay Street, Leonia, Ridgefield 13kV, and State Street. Of these projects, all remain forecasted as of the end of the third quarter of 2022 to be in-service during 2022 with the exception of the Clay Street project that has slipped to March 2023.	No change
RCR-IM-6	With reference to page 2 of the Independent Monitor's Draft Fourth Quarter 2021 Report, please indicate if the Company would seek IIP accelerated	PSE&G informed the IM that it does not have authority to seek accelerated recovery for any substation work that is put into service after December 31, 2023 under the ES 2 Stipulation and Order approving same (dated 9/11/2019).	No change

ID #	Question/Comment	IM Response	Report Changes
	cost recovery treatment for substation work that is not completed until after December 31, 2023. If so, please explain.	However, in accordance with paragraph 20 of the Stipulation, PSE&G does have the option of seeking Board approval to extend the Program beyond the term provided.	
RCR-IM-7	With reference to page 3 of the Independent Monitor's Draft Fourth Quarter 2021 Report, please explain how the approved Waverly substation site plan has enabled PSE&G to accelerate the scheduled completion date by 92 days.	As of the end of the third quarter of 2021, PSE&G forecasted to have the Waverly construction permits approved in July 2022, which was based on projected dates provided from the City of Newark and drives the construction start and in-service dates. The City of Newark had better than anticipated progress in advancing the permitting process, which improved the construction permit timeline to March 2022 and allowed the PSE&G team to implement improved dates for the construction start and in-service milestones. PSE&G also continues to evaluate options to further improve the schedule, such as sequencing activities in parallel if possible. See also the response to **RCR-IM-9**.	**Section III.A.15.**
RCR-IM-8	With reference to page 10 of the Independent Monitor's Draft Fourth Quarter 2021 Report, please indicate if PSE&G has any plans to review the July 2003 BPU-approved cost allocation schedule. If so, please indicate the proposed timing of the review. If not, please explain why not.	PSE&G indicated it has reviewed the 2003 schedule and the amended and restated agreement approved in September 2022.	No change
RCR-IM-9	With reference to pages 18 and 19 of the Independent Monitor's Draft Fourth Quarter 2021 Report, please identify and describe what work activities and project schedule items are being examined to accelerate the scheduled completion date of the Waverly project that is currently scheduled for closeout in first quarter of 2025.	As of the end of the third quarter of 2021, the Waverly project was forecasted to go in-service on 12/18/2024. This was driven by construction permits being anticipated to be received in July 2022 (based on projected dates from the Newark City). Based on better than expected permitting progress identified in the fourth quarter of 2022, the construction permit approval timeline advanced to March 2022, which supported an improved construction start date and overall in-service date, which advanced to 9/17/2024 as of the end of 2021. After the construction permits were received in the first quarter of 2022, the project management team worked with the construction team and Division to improve the construction schedule and sequence by paralleling activities where possible that further advanced the forecasted in-service date to February/March 2024. As part of the regular schedule review efforts, PSE&G will continue to seek opportunities to improve the schedule. See also the response to **RCR-IM-7**.	**Section III.A.15.**
RCR-IM-10	With reference to pages 18 and 19 of the Independent Monitor's Draft Fourth Quarter 2021 Report, please state whether any accelerated or compressed scheduling of the Waverly substation project would increase the current forecasted cost of	Accelerating or compressing the schedule can potentially add costs due to the extra resources/shifts required, which would somewhat be offset by lower carrying costs from the reduced project duration. The actual impacts would be dependent on the specific factors involved (e.g. what the specific carrying costs	No change

ID #	Question/Comment	IM Response	Report Changes
	$36.19 million. If so, please explain. If not, please explain why not.	are, how many extra resources required, how much the schedule was compressed, etc.).	
RCR-IM-11	With reference to page 19 of the Independent Monitor's Draft Fourth Quarter 2021 Report, please provide an update to the Fairmont 69kV project and please indicate if the Company anticipates addition[al] project costs will be allocated from the Academy Street to the Fairmont 69kV project.	There was no allocation of costs from the Academy Street project to the Fairmount 69kV project, the issue was commissioning activities that were budgeted to the Academy Street project but charged in error against the Fairmount 69kV project. This was identified and corrected during the monthly forecast variance analysis process. See also the response to **S-INF-4**.	**Section III.A.1.**
RCR-IM-12	With reference to page 19 of the Independent Monitor's Draft Fourth Quarter 2021 Report, please explain if the Fairmont 69kV project schedule has impacted the closeout of the Academy Street project. If so, please explain.	The Fairmount 69kV project has not impacted the close out of the Academy Street ES 2 project. The retired Academy Station is currently being demolished and close out of the ES 2 Academy Street project is pending completion of demolition.	No change
RCR-IM-13	With reference to page 21 of the Independent Monitor's Draft Fourth Quarter 2021 Report, please indicate if the Company is still experiencing resource availability issues that impact spending for the Leonia substation. If so, please explain what steps the Company is taking to address resource availability. If not, please explain what steps the Company took to resolve resource availability issues.	The resource availability issue resulted in an actual cost/forecast variance for the month of November 2021 and shifted the timing of planned work to future periods. This was a temporary issue and PSE&G has maintained the critical path on the project.	**Section III.A.7.**
RCR-IM-14	With reference to page 22 of the Independent Monitor's Draft Fourth Quarter 2021 Report, please describe the unplanned emergency work that impacted spending for the Market Street substation. Please indicate if the unplanned emergency work impacted other Energy Strong II projects.	The unplanned emergency work in that impacted the Market Street project related to unplanned storms and related events (Tropical Storm Elsa, Tropical Storm Henri, Hurricane Ida, emergency cable failures) that diverted internal resources from the Market Street project to perform restoration efforts. There were no impacts to other ES 2 projects and no other ES 2 projects utilized Southern Division resources in this period.	No change
RCR-IM-15	With reference to page 23 of the Independent Monitor's Draft Fourth Quarter 2021 Report, please explain if the Company is experiencing higher than estimated traffic control requirements for other projects and if the Company is factoring increased traffic control requirements for future projects. If not, please explain why not.	Generally, PSE&G has not experienced higher than estimated traffic control requirements across the ES 2 Program, however higher traffic costs have been experienced on certain individual projects (e.g. Market Street) based on additional requirements required by the local municipality. PSE&G develops its traffic control estimates based on the amount of street work expected to be executed and the permit requirements for each location.	No change
RCR-IM-16	With reference to page 23 of the Independent Monitor's Draft Fourth Quarter 2021 Report, please	PSE&G has recurring schedule review meetings on the project schedules to review the progress and identify possible opportunities for schedule	No change

ID #	Question/Comment	IM Response	Report Changes
	indicate if the Company has identified possible work activities and project schedule items to accelerate the scheduled completion date of the Orange Valley project. If so, please describe.	improvement through resequencing, running activities in parallel, or utilizing extra shifts. The schedule requirements are viewed holistically with the project costs, resource availability, and other relevant project data to provide an informed decision on how best to proceed. For Orange Valley, as of the end of the third quarter of 2022, the forecasted in-service date has slipped to 2/2/2024 due to equipment delivery delays being experienced that are pushing the project's critical path out.	
RCR-IM-17	With reference to page 23 of the Independent Monitor's Draft Fourth Quarter 2021 Report, please indicate if any accelerated or compressed scheduling of the Orange Valley substation project would increase the current forecasted cost of $14.77 million. If so, please explain. If not, please explain why not.	Accelerating or compressing the schedule typically would add costs due to the extra resources/shifts required, which would somewhat be offset by lower carrying costs from the reduced project duration. The actual impacts would be dependent on the specific factors involved (e.g. how many extra shifts required, how much the schedule was compressed, etc.).	No change
RCR-IM-18	With reference to page 29 of the Independent Monitor's Draft Fourth Quarter 2021 Report, please explain why the three reclosers in the Palisades Division require unique operating procedures. Please indicate if the Company has identified other recloser installations that have the same unique requirements. If so, please explain.	The three reclosers in the Palisades Division were to be installed with a unique operating procedure (in a single-phase operation) since the downstream load was primarily single-phase. With the unique operating procedure setting, only the 1 or 2 phases affected by a fault event will have an outage, not all three phases as would be the case with the standard operating procedure. No other reclosers have been identified for the unique operating procedure beyond these three in the Palisades Division. Ultimately, PSE&G installed these three reclosers following the standard operating procedure due to the time required to develop and implement a unique operating procedure. This will require the reclosers to be reprogrammed in the future from the standard operating procedure to the unique operating procedure, as of the end of October 2022, the reclosers are still using the standard operating procedure setting.	No change
RCR-IM-19	With reference to page 32 of the Independent Monitor's Draft Fourth Quarter 2021 Report, please provide an update on the status of the DMS/DERMS scope of work.	During the fourth quarter of 2022, PSE&G has been working on end-to-end testing with OSII on the DMS/DERMS scope as it prepares for operational readiness.	No change
RCR-IM-20	With reference to page 33 of the Independent Monitor's Draft Fourth Quarter 2021 Report, please provide an update on the status of the ADMS Platform scope of work.	Following the ADMS Platform being placed in-service in December 2021, PSE&G has completed system acceptance testing and vulnerability testing, it has also completed deconstruction of the Edison Production rack and imaged workstations for the Divisions in preparation of training.	No change

ID #	Question/Comment	IM Response	Report Changes
RCR-IM-21	With reference to page 35 of the Independent Monitor's Draft Fourth Quarter 2021 Report, please describe the condensation issues affecting the Paramus substation. Please indicate if the condensation issue is related to the design of the temporary feeder row or the result of construction activities.	The condensation was a result of the design of some of the rear panels on the contingency feeder rows as well as the settings on the heaters and humidifiers. The units which did not have vented panels experienced the condensation and when this was corrected, and the settings on the heaters and humidifiers were adjusted, the issue was resolved.	**Section III.E.2.**
RCR-IM-22	With reference to pages 35 and 36 of the Independent Monitor's Draft Fourth Quarter 2021 Report, please describe the unknown underground obstruction affecting the Plainfield substation.	The unknown underground obstructions at Plainfield included existing below grade concrete structures and direct buried cables that were not included in the record drawings. The unknown underground obstructions resulted in marginal increases to engineering and construction costs.	**Section III.E.3.**
RCR-IM-23	With reference to page 36 of the Independent Monitor's Draft Fourth Quarter 2021 Report, please provide an update on the material unavailability issue that impacted the Woodbury project.	The material unavailability issues involved perimeter wall foundations material delivery, which was delayed and pushed the construction of the wall foundation work from December 2021 to January 2022. This work was shifted with no impact to the project critical path and this issue was resolved as of January 2022.	**Section III.E.4.**
RCR-IM-24	With reference to page 36 of the Independent Monitor's Draft Fourth Quarter 2021 Report, please indicate if the Company is still experiencing material unavailability issues that impacted spending for the Woodbury substation. If so, please explain what steps the Company is taking to address material availability. If not, please explain what steps the Company took to resolve material availability issues.	This was a temporary issue. See the response to **RCR-IM 23**.	No change
Rate Counsel 10/11/2022 Letter	At the end of the fourth quarter 2021, the ESII program is slightly over 42 percent completed in spending. The Independent Monitor reports that electric spending for the quarter ending December 31, 2021 has been \$43.946 million or 6.3 percent of the current forecast of \$700.731 million electric ESII program (including the \$100 million for Electric Stipulated Base). Rate Counsel notes that the parties stipulated to \$842 million to complete the ES II Program with \$641 million for electric, \$50.5 million for gas, and \$150.5 million within Stipulated Base for electric and gas spending.	The IM confirms this statement.	No change
Rate Counsel	Rate Counsel continues to note that the budget for Electric stipulated base has been set to \$100 million	The IM confirms this statement.	No change

ID #	Question/Comment	IM Response	Report Changes
10/11/2022 Letter	for the life cycle subprogram. In the report for this quarter, Pegasus continued to provide Study level estimates for the five substations (Hamilton, Paramus, Plainfield, Woodbury, and State Street). The current Study level estimate for the subprogram remains at \$102.4 million including \$19.6 million for risk and contingency.		
Rate Counsel 10/11/2022 Letter	The current forecast for the Electric Flood mitigation program increased slightly from \$346.55 million in the Third Quarter Report to \$347.842 million in the Fourth Quarter Report, including risk and contingency estimates. Table 12 – ES 2 Electric Station Flood Mitigation Project Cost Status as of December 31, 2021, states that the base spending amount for the subprogram remains at \$332.200 million in budgeted base project costs and \$47.8 million allocated to risk and contingency.	The IM confirms this statement.	No change
Rate Counsel 10/11/2022 Letter	In the Fourth Quarter Report, the IM noted that PSE&G decreased its estimate for the Market Street substation by about \$831,000. The IM noted that actual spending was below budgeted spending due to poor weather and resource constraints that included unplanned emergency work that pulled resources away from the project. Rate Counsel is interested in understanding if the Company has adequate resources to address ongoing work across the substations and address unforeseen situations.	PSE&G continuously works with its internal teams and its Divisions to coordinate schedules and allocate resources, including identifying the priority of different scopes of work. Unplanned outages and work related to ensuring the safety of the system are prioritized over standard project or routine work, but generally this type work is limited in duration so any impacts to the project schedules are similarly limited. PSE&G also utilizes contractor labor as appropriate. The IM also notes the forecast for Market Street decreased by approximately \$831,000 during the fourth quarter of 2021, but the project estimate was not updated in this period.	No change
Rate Counsel 10/11/2022 Letter	In the Fourth Quarter Report, the IM noted that PSE&G has forecasted that the Orange Valley substation work is scheduled for completion on December 29, 2023 and that the Waverly substation project is scheduled for completion on September 17, 2024. The scheduled completion date for the Orange Valley substation is near the program end date of December 31, 2023, but the scheduled completion date for the Waverly substation is after the program end date. Rate Counsel is interested in	Since the end of the fourth quarter of 2021, the Waverly schedule has improved significantly based on better than expected timing of the permit approvals that improved the forecasted in-service date to February/March 2024 (see also the response to **RCR-IM-2**, **RCR-IM-7**, and **RCR-IM-9**). This reflects the final in-service date for transformer #3, while the 4kV switchgear and transformers #1-2 are forecasted to be in-service in December 2023. For the Orange Valley project, the most recent schedule data as of the end of the third quarter of 2022 indicates the forecasted in-service date has slipped into early February 2024.	No change

ID #	Question/Comment	IM Response	Report Changes
	understanding if PSE&G plans to accelerate work for both substations, and if accelerated work will impact current budgets for the two substations.	PSE&G continuously assesses the schedule and evaluates opportunities to advance the forecasted in-service date, primarily through resequencing activities or working activities in parallel. New information such as the actual status, updated durations, updated or completed engineering, and current permit or equipment receipt dates informs the current view of the schedule. Part of the schedule assessment also includes determining if it is appropriate to add resources, and if so, what cost impacts might be realized as a result. As both the Orange Valley and Waverly projects will be commencing construction (Phase 3 for Waverly) around the end of 2022/beginning of 2023, it is expected the schedule assumptions will be updated and through the recurring schedule reviews a determination will be reached on if the schedule can be advanced.	
PSEG-1	Under "Findings & Observations" for the Electric Station Flood Mitigation subprogram where the projects placed in-service are noted, the Leonia and Ridgefield 13kV projects achieved partial in-service during the fourth quarter of 2021.	The report finding has been updated to indicate the partial in-service status achieved by Leonia and Ridgefield 13kV.	**Section III.A.**
PSEG-2	Under Section III.A.7., it notes the Leonia switchgear #1 was placed in-service during the fourth quarter of 2021. The actual in-service date for this equipment was October 19, 2021.	The actual in-service date for Leonia's switchgear #1 has been added to the report.	**Section III.A.7.**
PSEG-3	Within the Executive Summary and repeated under "Findings & Observations" for the Grid Modernization – Communication System subprogram, the number of retrofit reclosers completed during the fourth quarter was 324, not 325.	The number of retrofit reclosers completed during the fourth quarter of 2021 has been corrected to 324.	**Sections I.** and **III.C.**

ENERGY STRONG 2 PROGRAM INDEPENDENT MONITOR 2022 FIRST QUARTER REPORT

PREPARED AND SUBMITTED BY

PEGASUS GLOBAL HOLDINGS, INC. ®

CONFIDENTIAL

APRIL 17, 2022

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Appendices

List of Acronyms and Abbreviations

Advanced Distribution Management Systems .... ADMS

Allowance for Funds Used During Construction .... AFUDC

Architect and Engineer .... A/E

Board of Public Utilities .... BPU

Construction Work In Progress .... CWIP

Costs of Removal .... COR

Distribution Management System .... DMS

Distributed Energy Resource Management System .... DERMS

Distribution Supervisory Control and Data Acquisition .... DSCADA

Energy Strong 2 .... ES 2

Gas Metering & Regulating .... Gas M&R

Independent Monitor .... IM

Inside Plant .... IP

Issued for Construction .... IFC

Issued for Review .... IFR

Mobile Work Management System .... MWMS

Open Systems International Inc. .... OSII

Outage Management System .... OMS

Outside Plant .... OP

Outside Plant-Higher Design Standards .... OP-HDS

Plain Old Telephone Service .... POTS

Public Service Electric & Gas .... PSE&G

Purchase Order .... PO

Record of Decision .... ROD

Remote Control Unit .... RCU

Remote Terminal Unit .... RTU

Risk and Contingency .... R&C

Supervisory Control and Data Acquisition .... SCADA

System Acceptance Testing .... SAT

System Average Interruption Duration Index .... SAIDI

Transmission & Distribution .... T&D

Utility Review Board .... URB

Virtual Private Network .... VPN

I. Executive Summary

Public Service Electric & Gas's (PSE&G's) Energy Strong 2 (ES 2) Program was established from a Stipulation that the involved parties agreed to in August 2019, as approved by a Board of Public Utilities (BPU) Order dated September 11, 2019, with an effective date of September 21, 2019. The Stipulation provided the ES 2 Program would be comprised of five primary subprograms: Electric Station Flood Mitigation; Contingency Reconfiguration; Grid Modernization – Communications; Grid Modernization – Advanced Distribution Management Systems (ADMS); and Gas Metering & Regulating (Gas M&R) Station Upgrades. In addition, a Stipulated Base spend was established that includes both an electric component (higher outside plant design standards and station life cycle upgrades) and a gas component (overlapping with the Gas M&R subprogram). This report contains the Independent Monitor's (IM's) findings and observations on the ES 2 Program elements and other information on the Program's status as of the first quarter of 2022.

During the first quarter of 2022, the bulk of the spend within the ES 2 Program continued to be in the largest subprogram, Electric Station Flood Mitigation, with two additional projects commencing construction during the quarter (Hasbrouck Heights and Woodlynne), and no additional projects being placed in-service (with Academy Street, Market Street, and Ridgefield 4kV previously being placed in-service). Within the other subprograms, the Contingency Reconfiguration subprogram completed the final batch of reclosers during the first quarter of 2022 and is now shifting to the Fuse Saver scope of work. The Grid Modernization – Communication System subprogram placed seven additional fiber installation projects and two additional fiber cutover projects in-service, with 27 fiber installation projects and 11 fiber cutover projects now completed in the ES 2 Program and the remaining projects expected to be completed by the end of 2022. The Grid Modernization – Communication System also continued to advance the retrofit substation remote terminal unit (RTU) scope, with the 75 additional substations completed, for a total of 85 completed as of the end of the first quarter of 2022 out of a forecasted scope of 218 substations. The Grid Modernization – ADMS subprogram completed sprints 14 and 15 in the Distribution Management System (DMS)/Distributed Energy Resource Management System (DERMS) scope and sprints 12 and 13 within the Outage Management System (OMS) scope, while the ADMS Platform scope completed additional testing and prepared for Division training. The Gas M&R subprogram saw its highest quarterly spend to date on the ES 2 Program, which reflected three projects entering the construction phase (Camden, Central, and East Rutherford), while closeout and restoration activities continued on the Westampton project that was placed in-service during the fourth quarter of 2021. The Hamilton, Paramus, Plainfield, and Woodbury projects in the Electric Stipulated Base scope continued construction during the fourth quarter of 2021, while the State Street (Outside Plant, or "OP") project continued to advance the detailed engineering.

Table 1 – ES 2 Subprogram & Stipulated Base Status as of March 31, 2022 below provides the spend to date on the subprograms within the ES 2 Program and Stipulated Base compared to the total forecast and forecasted completion for each.

Table 1 – ES 2 Subprogram & Stipulated Base Status as of March 31, 2022

Subprogram	Q1 Spend	Total Spend to Date*	Total Forecast*	% of Actuals to Forecast	Forecasted Completion**	Stipulation Funding Amount***
Electric Station Flood Mitigation	$18,695,029	$139,847,773	$349,562,560	40%	Mar 2024	$389M

Subprogram	Q1 Spend	Total Spend to Date*	Total Forecast*	% of Actuals to Forecast	Forecasted Completion**	Stipulation Funding Amount***
Contingency Reconfiguration	**$2,277,408**	**$107,970,429**	**$145,273,272**	**74%**	**Nov 2023**	**$145M**
Grid Modernization – Communications	**$6,196,033**	**$54,561,042**	**$66,144,306**	**82%**	**Dec 2023**	**$64.3M**
Grid Modernization – ADMS	**$3,197,877**	**$29,536,156**	**$43,525,894**	**68%**	**Apr 2023**	**$42.7M**
Electric Stipulated Base	**$8,262,179**	**$26,317,199**	**$98,591,950**	**27%**	**Dec 2023**	**$100M**
Gas M&R Station Upgrades^	**$11,864,125**	**$32,040,114**	**$128,336,312**	**22%**	**Dec 2023**	**$101M**
Total*	**$50,492,652**	**$390,272,715**	**$831,434,293**	**47%**	**Mar 2024**	**$842M**

-Note: total figures may not fully align due to rounding. Additionally, the total forecast includes only the base cost for the Electric Station Flood Mitigation and Gas M&R subprograms as PSE&G does not include risk and contingency (R&C) in its forecasts for these projects. See **Table 11 and **Table 20** for the Electric Station Flood Mitigation and Gas M&R project estimates, respectively, with base costs and R&C shown.*
***-Final in-service date.*
****-Following the $7.7 million transfer in July 2021 from the Grid Modernization – Communications subprogram to the Grid Modernization – ADMS subprogram.*
^-Includes both the ES 2 projects and the Stipulated Base gas projects.

Given the prominence of the Electric Station Flood Mitigation subprogram, which represents over half of the total ES 2 Program spending, a summary of the projects within this subprogram is provided below in **Table 2 – ES 2 Electric Station Flood Mitigation Status as of March 31, 2022**.

Table 2 – ES 2 Electric Station Flood Mitigation Status as of March 31, 2022

Project	Total Estimate (rounded)	Actuals	% of Actuals to Estimate	Forecasted In-Service Date*
1. Academy Street	$9,300,000	$6,260,799	67%	**10/19/2021**
2. Clay Street	$30,800,000	$8,846,983	29%	1/30/2023 (↓+84)
3. Front Street^	$25,900,000	$2,781,438	11%	10/26/2023 (↑-21)
4. Hasbrouck Heights	$19,300,000	$9,779,630	51%	1/24/2023 (↑-8)
5. Kingsland	$6,400,000	$1,126,185	18%	10/2/2023 (↓+94)
6. Lakeside Avenue	$39,400,000	$1,525,371	4%	9/18/2023 (↑-51)
7. Leonia	$24,900,000	$16,979,539	69%	11/15/2022 (↓+6)
8. Market Street	$29,100,000	$27,820,378	96%	**6/25/2021**
9. Meadow Road	$7,200,000	$1,331,494	19%	9/22/2023
10. Orange Valley	$14,700,000	$909,541	6%	12/29/2023
11. Ridgefield 13kV	$26,100,000	$19,399,451	74%	12/13/2022 (↑-7)
12. Ridgefield 4kV	$20,800,000	$20,689,404	100%	**5/16/2021**
13. State Street	$19,600,000	$9,584,815	49%	12/19/2022 (↓+87)
14. Toney's Brook	$16,200,000	$1,664,826	10%	4/21/2023
15. Waverly	$36,200,000	$7,412,639	21%	3/5/2024 (↑-196)
16. Woodlynne	$21,300,000	$3,735,353	18%	10/10/2023

-Reflects the in-service date of the last major asset (e.g. switchgear), certain activities may take place after this date to support the final in-service date (i.e. when all customers are cutover). **Bold dates indicate the actual in-service date.*

Project	Total Estimate (rounded)	Actuals	% of Actuals to Estimate	Forecasted In-Service Date*
(↑)-*Indicates the forecasted in-service date advanced from the prior quarter in days.* (↓)-*Indicates the forecasted in-service date slipped from the prior quarter in days.* ^- *The Front Street project was proposed by PSE&G during the second quarter of 2021 to replace the cancelled Constable Hook project.*				

As indicated in **Table 2**, the projects that previously started construction (including Academy Street, Leonia, Market Street, Ridgefield 13kV, Ridgefield 4kV, State Street, and Waverly) continue to have the highest total spend to date. For the three projects placed in-service, Academy Street, Market Street, and Ridgefield 4kV, each were completed under their estimates. Additionally, PSE&G updated the base estimates to 10 of the 16 projects during the first quarter of 2022, with a net increase of $15.0 million, which also included the State Street and Hasbrouck Heights project estimates advancing to the Definitive stage.

Table 2 also shows that nine of the 16 projects had movement during the first quarter of 2022 in the forecasted in-service date, with five advancing and four slipping. Of these nine projects, four of the projects (Front Street, Hasbrouck Heights, Leonia, and Ridgefield 13kV) had forecasted in-service dates change by less than three weeks. As previously reported, the Waverly final in-service date was forecasted for September 2024, which had been a slight improvement from the previously forecasted December 2024 in-service date. Following the site plan approval in December 2021, PSE&G's team evaluated and updated the construction schedule, which allowed the in-service date to advance to March 2024 and continues to assess potential opportunities to advance the in-service date. The other largest shift to the forecasted in-service dates was the Kingsland project, which slipped 94 days from June 30, 2023 to October 2, 2023, and was driven by delays to the switchgear delivery on the Ridgefield 13kV project (as PSE&G intends to use the Ridgefield 13kV contingency switchgear on Kingsland). Major equipment deliveries constitute one of the largest current risks to the subprogram as further discussed in **Section III.A.** of this IM report.

While the subprogram forecast increased by approximately $1.7 million during the first quarter of 2022, it remains approximately $40 million under the Stipulation budget. The IM has continued to find nothing to date that would jeopardize the ES 2 Program being completed on budget. However, schedule challenges, particularly on the Waverly substation and other projects with forecasted in-service dates near the Program end date of December 2023 will continue to warrant further monitoring by the IM to confirm the ES 2 Program is completed within the defined timeline.

As per N.JA.C. Section 14:3-2A.5(c)2, the IM reports are to address:

i. *The effectiveness of Infrastructure Investment Program investments in meeting project objectives;*
ii. *The cost-effectiveness and efficiency of investments;*
iii. *The appropriateness of cost assignments; and*
iv. *Any other information required by the Board.*

The IM focuses the majority of the discussion within each report on these primary objectives, after introducing summarized the findings on these areas in the IM 2021 Third Quarter Report, the IM will continue to provide a summary on these areas for each report with an emphasis on new information relative to the current reporting period. These summarized findings are as follows:

- **<u>Effectiveness of ES 2 investments in meeting project objectives</u>**: The objectives for each subprogram within the ES 2 were defined within PSE&G's ES 2 filing and confirmed by the Stipulation. The overall objectives focused on improving system resiliency, reliability, and hardening through rebuilding or replacing selected substations, installing smart control and monitoring devices on distribution circuits (reclosers, fuse savers, etc.), installing ADMS and a new communication system, and rebuilding selected Gas M&R stations. Within **Section III** of this report, the IM provides a review of the status of the efforts performed to meet these objectives for each subprogram. During the first quarter of 2022, the following projects/scopes were placed in-service and/or completed:
  - Electric Station Flood Mitigation: Academy Street, Market Street, and Ridgefield 4kV previously placed in-service.
  - Contingency Reconfiguration: Recloser scope completed with installation of final 23 units and commissioning of the remaining 25 units during the first quarter of 2022.
  - Grid Modernization – Communication System: 75 substation RTU retrofits completed (bringing the total to 85 out of a total scope of 218 substations); seven fiber installation projects were completed (bringing the total to 27); and two fiber cutover projects were completed (bringing the total to eleven out of a current scope of 12).
  - Electric Stipulated Base: Final circuit cutovers completed on the Paramus contingency switchgear.
  - Gas M&R: Westampton previously placed in-service in October 2021, the next stations forecasted for completion are the Camden and East Rutherford stations planned to go in-service by the end of 2022.
- **<u>Cost-effectiveness and efficiency of investments</u>**: To assess the cost effectiveness and efficiency of ES 2 investments, the IM began with a review of the initial scope, estimate, and related planning documents for each project to establish a baseline to monitor progress against as the work advances. As the Program execution advances, the IM continues to evaluate actual costs against the initial estimates and current forecasts, including seeking additional information relating to any variances identified. While the overall Program's current cost forecast is below the Stipulation amount, the IM has observed cost increases realized on specific projects or aspects of the Program and found the majority of these increases stem from scope evolution and/or more detailed estimates from the time of the ES 2 filing, as well as the more recent changes in general market conditions (e.g. Covid-19 impacts, supply chain issues, etc.). The updated subprogram forecasts as of the end of the first quarter of 2022 compared to the end of 2021 were as follows:
  - Electric Station Flood Mitigation: subprogram forecast increased approximately $1.7 million (or 0.5%) to approximately $349.6 million.
  - Contingency Reconfiguration: subprogram forecast decreased approximately $494,000 (or -0.3%) to approximately $145.3 million.
  - Grid Modernization – Communication System: subprogram forecast increased approximately $2.5 million (or 4.0%) to approximately $66.1 million.

  - Grid Modernization – ADMS: subprogram forecast increased approximately $32,000 (or 0.1%) to approximately $43.5 million.
  - Electric Stipulated Base: subprogram forecast decreased approximately $1.4 million (or -1.4%) to approximately $98.6 million.
  - Gas M&R: subprogram forecast increased approximately $20.5 million (or 19.1%) to approximately $128.3 million.

  As shown above, the biggest subprogram forecast changes during the first quarter of 2022 were in the Grid Modernization – Communication System, Electric Stipulated Base, and Gas M&R subprograms. Within the Grid Modernization – Communication System, the recent fiber projects have seen increased material and labor costs, while the Electric Stipulated Base projects saw slight forecast increases across all but the State Street OP project. Within the Gas M&R subprogram, the forecast growth includes the LPA components at certain projects that will be removed from the ES 2 project scope (which will also reduce the forecast accordingly).

- **Appropriateness of cost assignments**: The IM receives and reviews recurring data concerning the accumulation of costs within the Program. Based on that review, the IM submits follow-up questions to the Company regarding that data for the reporting period. Such follow-up questions generally focus on the following aspects:
  - Review of any unusual changes in cost elements from period-to-period, including but not limited to allowance for funds used During construction (AFUDC), cost of removal (COR), and the allocation of overheads.
  - Review spend on capital accounts, such as Construction Work in Progress (CWIP) as it relates to overall spend, AFUDC, and COR.
  - Verify cost accumulations and classifications appear to be in accordance with Generally Accepted Accounting Principles (GAAP), to the extent the IM has access to such information.
  - Review and investigation of prior period adjustments and/or corrections to capital accounts.
  - Engage the Company's Internal Audit group on specific areas to audit, review, and assess – particularly for areas in which the IM has limited or no visibility (proprietary data, accounting systems, etc.).

  Through the above steps, the IM tracks and monitors how the Company is recording costs to support the finding that the cost assignments appear to be appropriately applied. These cost items are discussed further within **Section II.C.** of this IM report.

As noted in the IM 2020 First Quarter Report, the IM conducts its assessment in accordance with Generally Accepted Government Auditing Standards (GAGAS, or more commonly referred to as the "Yellow Book" standards). The Yellow Book provides a framework for conducting performance management reviews/audit engagements with competence, integrity, objectivity, and independence that result in information used for oversight, accountability, transparency, and improvements of the audited programs and operations. On February 13, 2022, a draft IM 2022 Fourth Quarter Report was submitted to PSE&G, BPU Staff, and Rate Counsel. Per the Yellow Book, the transmittal of a draft report is intended to allow for review and comment by the audited entity and others to develop a fair, complete, and objective report. A summary of the comments on the draft report and the IM's responses are provided in

Appendix A – Draft Report Comments and Responses. This **Appendix A** also identifies specific sections within this IM 2022 First Quarter Report that have been edited, supplemented with additional information, or otherwise revised in response to the comments received.

II. Program Status

A. Key Decisions

In order to capture formalized key decisions regarding the ES 2 Program, PSE&G completes a "Record of Decision" (ROD) that includes a description of the decision; alternatives considered; the decision made; and rationale for the decision. The RODs are assessed by the IM as they are completed to review their impact to the Program. In addition, the IM may request PSE&G complete a ROD to formalize a decision if such a decision has not yet been formalized through the ROD process.

The current RODs as of the date of this IM 2022 First Quarter Report are presented below in **Table 3 – ES 2 Records of Decisions**. During the first quarter of 2022, there were no additional RODs issued.

Table 3 – ES 2 Records of Decisions

Subprogram	Record of Decision	IM Comments
Electric Station Flood Mitigation	Academy Street & State Street Change in Mitigation Method	Reasonable and appropriate *(See Section B.1. in the IM 2020 First Quarter Report)*
Electric Station Flood Mitigation	Engineering Support for Energy Strong Program Projects	Reasonable and appropriate *(See Section B.2. in the IM 2020 First Quarter Report)*
Grid Modernization – Communication System	Wireless Communication Network	Reasonable and appropriate *(See Section II.A.1. in the IM 2020 Third Quarter Report)*
Grid Modernization – Communication System	Substation Communication Center	Reasonable and appropriate *(See Section II.A.2. in the IM 2020 Third Quarter Report)*
Grid Modernization – Communication System	Fiber Scope	Reasonable and appropriate *(See Section IV.A. in the IM 2020 Third Quarter Report)*
Electric Station Flood Mitigation	Constable Hook, Lakeside, & Orange Valley Change in Mitigation Method	Reasonable and appropriate *(See Sections II.A.3. and IV.B. in the IM 2020 Third Quarter Report and additional discussion in Section II.A.1. and Section IV.B. of the IM 2020 Fourth Quarter Report)*
Grid Modernization – Communication System	Communication Retrofit of Replacement and non-ES-II Units	Reasonable and appropriate *(See Section II.A.2. in the IM 2020 Fourth Quarter Report)*
Electric Station Flood Mitigation	Market Street Radioactive Soil Testing and Handling	Reasonable and appropriate *(See Section II.A.3. in the IM 2020 Fourth Quarter Report)*
Electric Station Flood Mitigation	Transfer of Clay Street Wastewater Wall Scope from ES2FM to Clay Street 69kV Project	Reasonable and appropriate *(See Section IV.A. in the IM 2020 Fourth Quarter Report)*
Contingency Reconfiguration	Energy Strong II Electric Program – Contingency Reconfiguration Subprogram, 13kV and 4kV Reclosers	Reasonable and appropriate *(See Section IV.A. in the IM 2021 First Quarter Report and Section II.A.1.*

Subprogram	Record of Decision	IM Comments
		in the IM 2021 Second Quarter Report)
Grid Modernization – ADMS	Outage Management System (OMS) Implementation	Reasonable and appropriate *(See Section IV.A. in the IM 2021 First Quarter Report and Section II.A.2. the IM 2021 Second Quarter Report)*

B. Program Management

Beginning in July 2020, the IM began participating in a bi-weekly call with PSE&G to review its bi-weekly ES 2 Program Dashboard. As with the original Energy Strong Program, the Dashboard provides a mechanism for PSE&G to monitor and control activities to be completed in order to achieve key near-term milestones, including a focus on recently completed activities, any key issues, and other key metrics (e.g. installation targets) as appropriate. These calls have proven to be an effective way for the IM to stay informed on current and upcoming activities and to allow a venue for discussions between the IM and PSE&G on these activities and status updates and continue to be held on a recurring basis.

Early in 2022 PSE&G instituted a change in the way it manages the R&C for the Electric Station Flood Mitigation projects shifting from each project maintaining its own R&C funds to managing the R&C at the subprogram level. Prior to this shift, the projects' R&C was updated at the time of an estimate transition (50% to 70% to 90%). This change allows PSE&G to manage the R&C month-to-month based on the current project risk registers, which are updated monthly by the project team and reviewed by the subprogram lead. When the individual projects go through an estimate transition any variance to the base estimate results in additional funds added to the R&C placeholder (if the base estimate decreased) or release of R&C to cover the increase in base. Additionally, PSE&G's Utility Review Board (URB) continues to review and approve any estimate changes.

As part of the exercise in transitioning R&C from the project to the subprogram level, PSE&G also updated the base estimates for any Electric Station Flood Mitigation project that changed by more than $0.5 million (increasing or decreasing). Details of the updated estimates and the results of the shifting of R&C funds on the individual projects are discussed within **Section III.A.** and **Section III.E.**

C. Cost Assignments

1. Costs of Removal (COR)

Costs of Removal (COR) generally include costs for such activities as environmental removal, removal of inside station equipment, structures, foundations, towers and fixtures, conductors and other electrical devices, poles and fixtures, transformers, plant demolition, foundations, and removal of underground conduit and other wiring. Generally, COR are charged to Accumulated Depreciation and are amortized and recovered through a component of depreciation expense. The specific method and amount of recovery is determined in gas and electric rate cases before the BPU.

Table 4 – ES 2 Program Costs of Removal as of March 31, 2022, below itemizes the charges to COR for the first quarter of 2022, the fourth quarter of 2021 (for comparative purposes), total COR for the years 2021, 2020, 2019, and total ES 2 Program COR to date. These amounts do not reflect any salvage value reductions, which have been *de minimis* in the ES 2 Program through March 31, 2022.

Table 4 – ES 2 Program Costs of Removal as of March 31, 2022

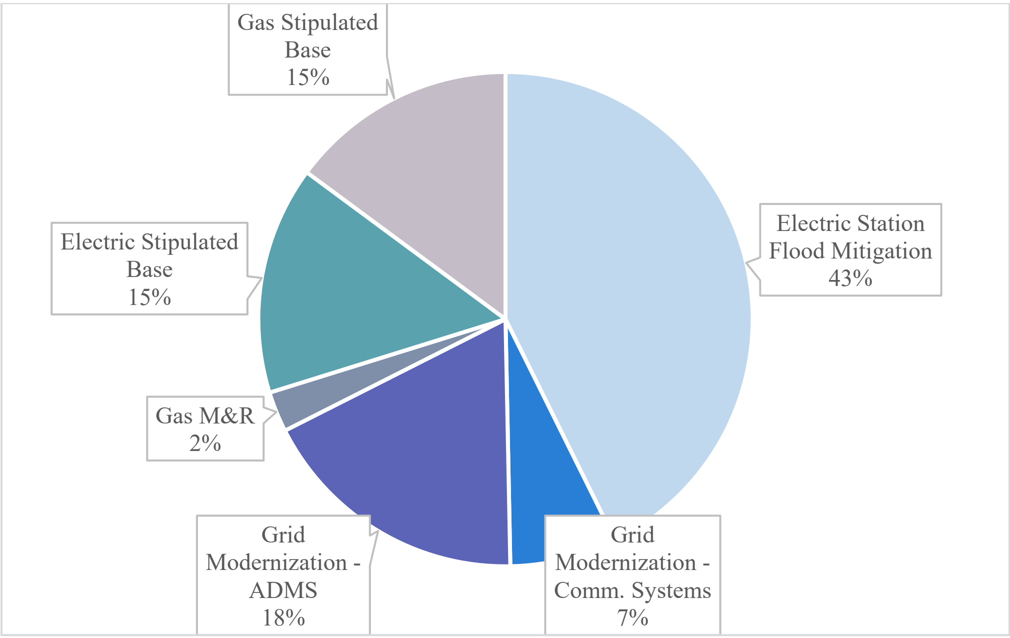
Subprogram	Q1 2022	Q4 2021	Total 2021	Total 2020	Total 2019 (Q4)	Total COR
	(in $ thousands)					
Electric Station Flood Mitigation	**$873.4**	**$1,824.0**	**$5,558.7**	**$1,021.1**	**$0**	**$7,453.2**
Contingency Reconfiguration	**$229.3**	**$330.7**	**$2,250.2**	**$2,198.9**	**$431.0**	**$5,109.4**
Grid Modernization – Communications	**$11.0**	**$23.5**	**$137.8**	**$24.4**	**$0**	**$173.2**
Grid Modernization – ADMS	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Electric Stipulated Base	**$370.0**	**$146.8**	**$150.0**	**$0**	**$0**	**$520.0**
Gas M&R Station Upgrades	**($0.4)**	**($2.2)**	**$148.9**	**$0**	**$0**	**$148.5**
Gas Stipulated Base	**$431.5**	**$196.1**	**$196.1**	**$0**	**$0**	**$627.6**
Total	**$1,914.8**	**$2,518.9**	**$8,441.7**	**$3,244.4**	**$431.0**	**$14,031.9**

The COR charges for the first quarter of 2022 primarily reflect (i) approximately $0.7 million of COR activities at the Market Street substation elimination project, including demolition of the building and foundations, (ii) approximately $0.2 million related to partial removal of foundations at the Paramus lifecycle project, and (iii) approximately $0.4 million related to removal of certain concrete structures, such as a former tank pad, at the Central M&R station.

2. Construction Work-in-Progress (CWIP) & In-Service Transfers

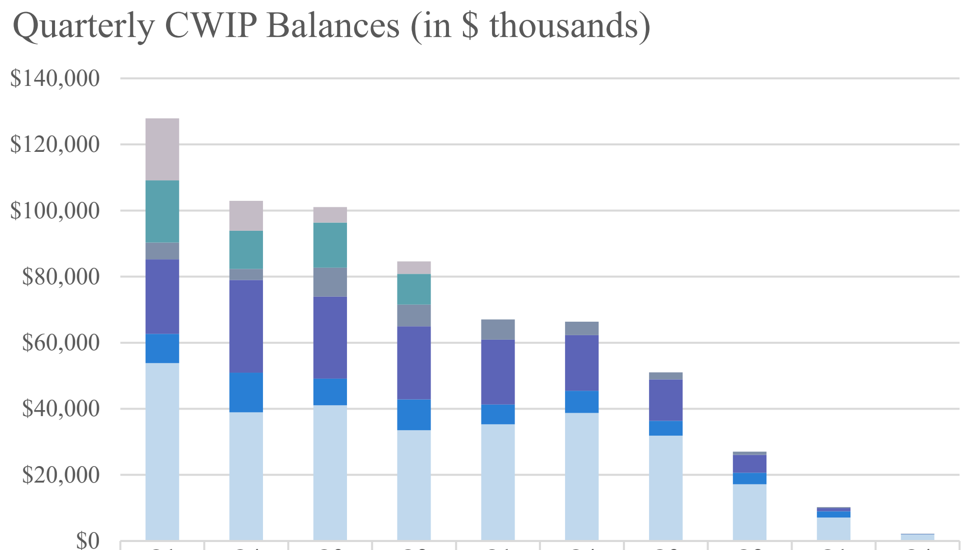
As of March 31, 2022, the ES 2 CWIP balance was $127.9 million, compared to $102.9 million as of December 31, 2021. The largest components of CWIP as of the end of the first quarter of 2022 were the Hasbrouck ($10.0 million), State Street ($9.9 million), Clay Street ($9.1 million), and Waverly ($7.9 million) Electric Station Flood Mitigation substation projects, the Central ($11.6 million) and Camden ($6.0 million) Gas M&R projects, the Hamilton ($7.4 million) and Plainfield ($5.3 million) substations Lifecycle projects, and work associated with the ADMS subprogram ($22.5 million). The Electric Station Flood Mitigation subprogram comprises the largest component of total end of period CWIP outstanding, as depicted in **Figure 1 – ES 2 CWIP as of March 31, 2022** below.

Figure 1 – ES 2 CWIP as of March 31, 2022



In addition, the **Figure 2 – ES 2 CWIP Balances by Subprogram as of March 31, 2022** below depicts the composition of end-of-quarter CWIP balances by subprogram for the first quarter of 2022, each quarter of 2021 and 2020, and the fourth quarter of 2019.

Figure 2 – ES 2 CWIP Balances by Subprogram as of March 31, 2022



	Q1 2022	Q4 2021	Q3 2021	Q2 2021	Q1 2021	Q4 2020	Q3 2020	Q2 2020	Q1 2020	Q4 2019
Gas Stipulated Base	$18,757	$9,042	$4,691	$3,808	$-	$-	$-	$-	$-	$-
Electric Stipulated Base	$18,841	$11,560	$13,645	$9,280	$-	$-	$-	$-	$-	$-
Gas M&R	$5,086	$3,338	$8,735	$6,574	$6,123	$4,032	$2,149	$951	$291	$53
Grid Modernization - ADMS	$22,534	$28,057	$24,817	$22,085	$19,600	$16,837	$12,502	$5,428	$969	$36
Grid Modernization - Comm. Systems	$8,847	$11,991	$8,077	$9,343	$6,026	$6,760	$4,529	$3,508	$1,908	$75
Electric Station Flood Mitigation	$53,834	$38,947	$41,077	$33,531	$35,299	$38,727	$31,860	$17,149	$7,101	$1,987

Electric Station Flood Mitigation · Grid Modernization - Comm. Systems · Grid Modernization - ADMS · Gas M&R · Electric Stipulated Base · Gas Stipulated Base

Transfers from CWIP to plant in service totaled $15.1 million during the first quarter of 2022. During the first quarter of 2022, $6.6 million of Grid Modernization fiber projects were transferred to plant in service, as well as $8.4 million of assets associated with the ADMS subprogram. The ADMS assets transferred were hardware and software which were completed and successfully tested, and replaced the Company’s legacy Distribution Supervisory Control and Data Acquisition (DSCADA) system, which was at the end of its lifecycle. Total ES 2 transfers from CWIP have been $85.9 million through March 31, 2022. It should be noted that work related to certain assets, such as the reclosers under the Contingency Reconfiguration subprogram, generally can be completed without being recorded through CWIP. As such, no allowance for funds used during construction (AFUDC) is recorded on these expenditures. This accounting treatment is in accord with generally accepted accounting principles and the Company’s accounting policies.

3. Allowance for Funds Used During Construction (AFUDC)

The amount of quarterly AFUDC recorded by the Company for the ES 2 subprogram during the first quarter of 2022, the fourth quarter of 2021 (for comparative purposes), total AFUDC for the years 2021, 2020, and 2019, and total ES 2 Program AFUDC accrued through the end of 2021, is shown below **Table 5 – ES 2 Program AFUDC as of March 31, 2022**.

Table 5 – ES 2 Program AFUDC as of March 31, 2022

Subprogram	Q1 2022	Q4 2021	Total 2021	Total 2020	Total 2019 (Q4)	Total AFUDC
	(in $ thousands)					
Electric Station Flood Mitigation	**$759.0**	**$564.3**	**$2,281.2**	**$936.5**	**$9.9**	**$3,986.6**
Contingency Reconfiguration	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Grid Modernization – Communications	**$115.6**	**$127.2**	**$386.9**	**$184.3**	**$0.2**	**$687.0**
Grid Modernization – ADMS	**$385.7**	**$411.0**	**$1,365.6**	**$352.7**	**$0.1**	**$2,104.1**
Electric Stipulated Base	**$230.0**	**$233.6**	**$524.6**	**$44.0**	**$0**	**$798.6**
Gas M&R Station Upgrades (incl. Stip. Base)	**$208.3**	**$133.2**	**$470.0**	**$70.0**	**$0.2**	**$748.5**
Total	**$1,698.6**	**$1,469.3**	**$5,028.3**	**$1,587.5**	**$10.4**	**$8,324.8**

AFUDC accrued for ES 2 projects during the first quarter of 2022 increased over AFUDC accrued during the fourth quarter of 2021 primarily as the result of increases in total average CWIP balances, especially for the Electric Station Flood Mitigation and Gas M&R/Gas Stipulated Base projects.

During the first quarter of each year, the AFUDC rate is reviewed for possible reset as it applies to the current year based on updated capital structure and component cost data. For the year 2022, the new AFUDC rate was calculated to be 6.92%, using the capital structure and component costs as of January 31, 2022. This rate is higher than the 2021 rate of 6.81%, primarily due to a zero balance of short-term in the 2022 calculation (vs. a $44 million balance of short-term debt in 2021), and also to an 8% reduction in the Company's amount of long-term debt outstanding (lowering the debt component of the capital structure from 45.5% to 44.8%), and a reduction in the embedded cost of long-term debt, both as used in the AFUDC calculation. In calculating the 2022 AFUDC rate, the Company used (i) a 3.63% embedded cost of long-term debt (vs. 3.85% in 2021), (ii) no short-term debt, and (iii) a cost of equity of 9.60% (unchanged from 2021).

Subsequent to the annual reset calculation referred to above, and during the course of each year, the AFUDC rate is also recalculated as it applies to each fiscal quarter. If the recalculated rate changes by 25 basis points from the rate then in effect, the rate is reset and retroactively applied to January 1 of that year. For the first quarter of 2022, based on data as of March 31, 2022, the recalculated weighted average AFUDC accrual rate (6.92%) did not meet this criterion to warrant changing from the annual rate (6.92%) in effect. Therefore, AFUDC was accrued during the first quarter of 2022 at the calculated rate of 6.92%.

The IM observes that the Company's calculation of the AFUDC rate and its application is in accordance with both PSE&G's accounting policy and Plant Instruction 3(17) of the Federal Energy Regulatory Commission's Uniform Systems of Accounts prescribed for public utilities.

The IM also notes that the relevant AFUDC information as it relates to ES 2 project costs in the first quarter of 2022 is consistent with the applicable dictates of the Stipulation entered into with respect to these ES 2 projects. The IM will continue to review future ES 2 Program AFUDC accruals for consistency with relevant provisions of the Stipulation for accounting and reporting purposes only, and not as a party to, or in expressing an opinion concerning, any rate proceedings.

4. Allocated Overheads

PSE&G follows a philosophy of allocating overhead costs, whether at the Service Company or from utility support organizations, to the operating company or unit receiving the benefit, and ultimately, if appropriate, settling costs to individual assets. Where possible, services are charged directly to the entity receiving the benefit, but where direct charging of costs is not feasible, cost allocations from the Service Company to operating companies are prescribed in a BPU-approved schedule issued pursuant to a BPU order in July 2003 as updated in September 2022. The Stipulation requires the Company to follow its current practices with regard to capitalized overheads.

For ES 2 electric and gas distribution projects, allocated overhead costs should primarily come from utility-related labor costs associated with administrative and supervisory personnel, labor and other costs associated with bargaining unit personnel, fringe benefits, materials handling costs, payroll taxes and depreciation expense. Shown below in **Table 6 – ES 2 Program Overhead Allocations as of March 31, 2022** are the allocated overhead costs charged to ES 2 projects for the first quarter of 2022, the fourth quarter of 2021 (for comparative purposes), total 2021, total 2020, total 2019 and total ES 2 Program allocated overheads to date.

Table 6 – ES 2 Program Overhead Allocations as of March 31, 2022

Subprogram	Q1 2022	Q4 2021	Total 2021	Total 2020	Total 2019 (Q4)	Total to Date
	(in $ thousands)					
Electric Station Flood Mitigation	$2,185	$1,902	$14,368	$14,023	$287	$30,863
Contingency Reconfiguration	$843	$2,516	$14,420	$17,109	$3,415	$35,787
Grid Modernization – Communications	$1,802	$2,692	$9,171	$3,625	$12	$14,610
Grid Modernization – ADMS	$76	$133	$501	$426	$11	$1,014
Electric Stipulated Base	$1,449	$807	$2,123	$259	$0	$3,832
Gas M&R Station Upgrades (incl. Stip. Base)	$197	$250	$735	$291	$15	$1,238
Total	**$6,552**	**$8,300**	**$41,318**	**$35,733**	**$3,740**	**$87,344**

The overwhelming majority of overhead costs allocated to ES 2 projects during the first quarter of 2022 are costs allocated from areas that support all utility distribution and transmission projects, including ES 2 projects. More specifically, most (approximately 77%) of the 2022 first quarter allocated costs reflect labor costs of supervisory, administrative and operations planning personnel, labor and other costs from bargaining unit personnel, and fringe benefits associated with these labor costs. The decrease in overhead costs for the first quarter of 2022 from the fourth quarter 2021 reflects the completion of recloser scope of work in the Contingency Reconfiguration subprogram early in the first quarter of 2022 and completion of the Grid Modernization recloser retrofit scope in the fourth quarter of 2021.

D. System Performance

1. Current Reporting Quarter Major Events

During the first quarter of 2022, there were two Major Events reported in PSE&G's service territory, each involving a State of Emergency related to snowstorms experienced in the region.

The first one occurred from January 6-12, 2022, and saw 11,999 PSE&G customers experience service interruptions, while the second State of Emergency occurred from January 28-February 4, 2022, and saw 40,277 PSE&G customers experience service interruptions. Between these two storms, neither brought flooding issues to PSE&G substations or switching stations.

The IM has received PSE&G's report on the performance of its investments from these Major Events and has reproduced the results in **Table 7 – Q1 2022 Major Event Performance** below.

Table 7 – Q1 2022 Major Event Performance

Circuit	5 Year Baseline SAIDI*	Report Quarter SAIDI*
ADA 8012	0.02574	0.00083
ALD 8012	0.37227	0.00059
ALD 8022	0.05448	0.00096
BEN 8011	**0.00163**	**0.02166**
BLO 4009		**0.03680**
BUS 8012	0.04422	0.00000
CED 8011	0.05594	0.00475
CED 8016	0.07119	0.00659
CIN 8009	0.14835	0.00089
CIN 8043	0.18459	0.00010
CLF 8015	**0.01520**	**0.06820**
CLK 8014	0.20056	0.00951
CLK 8023	0.00019	0.00000
CLK 8024	0.01526	0.00000
CLK 8042	0.35206	0.00033
COR 8042	0.05446	0.00000
CRX 8008	0.24596	0.00065
CUT 8004	0.18618	0.00071
CUT 8033	0.02286	0.00000
DEA 4009		**0.00043**
DOR 8012		**0.01776**
DOR 8015	0.02588	0.00153
EAT 8023		**0.04074**
FAW 8016	0.12332	0.01109
FAW 8023	0.02811	0.00060
FOR 4009		**0.00738**
FRA 8011		0.00000
GBK 8021	0.06208	0.00000
HID 8034	0.25737	0.00000
HOE 8037	**0.00573**	**0.02260**
HOE 8047	0.05561	0.01624
JAC 8022	0.04453	0.01036

Circuit	5 Year Baseline SAIDI*	Report Quarter SAIDI*
JAC 8023	0.05394	0.00221
JAC 8033	0.00350	0.00266
KIL 8012	0.21603	0.00000
KIL 8034	0.44870	0.00016
KIN 8011		**0.01061**
KIN 8014	0.00171	0.00031
KUS 8034	0.01739	0.00047
KUS 8045	0.02505	0.00000
LAF 8013	0.00125	0.00000
LAU 8011	0.30809	0.00157
LAU 8021	0.44101	0.00206
LAU 8025	0.02009	0.01377
LAU 8035	0.29567	0.00000
LAW 8023	0.01733	0.00049
LCE 8033	0.42672	0.00964
LEO 8004	**0.00027**	**0.03249**
LEO 8005	0.61152	0.00654
LEO 8042		0.00000
LEO 8043	0.07891	0.00037
LEV 8008	0.04412	0.00082
LEV 8016	**0.00021**	**0.00245**
LIT 8001	0.02586	0.01920
LUM 8014	0.29932	0.00000
MAD 8018	0.20763	0.00000
MAR 8002	0.04356	0.00220
MAR 8004	0.02404	0.00603
MAR 8013	0.36502	0.00000
MAY 8024	0.00558	0.00119
MCL 4008		0.00145
MEA 8021	0.06020	0.00000
MRO 8012	1.08732	0.00008
MRO 8013	0.46710	0.00000

Circuit	5 Year Baseline SAIDI*	Report Quarter SAIDI*
MTL 8013	0.02134	0.00000
MTL 8014	0.00035	0.00000
NED 8016	0.00729	0.00504
NEW 8025	0.00343	0.00000
NEW 8041	**0.00280**	**0.00550**
NEW 8042	0.05837	0.03241
NOT 8022	**0.00091**	**0.02638**
PEH 8004		**0.00053**
PIE 8013	0.02355	0.00465
PIE 8022		**0.00490**
POH 8015	0.12765	0.00000
RFL 8011	0.00742	0.00522
RFL 8012	**0.00235**	**0.03403**
SAD 8002		**0.00270**
SAD 8032		**0.01434**
SDH 8023	0.00860	0.00530
SDH 8026	0.01685	0.00003
SDH 8031	**0.01726**	**0.03019**
SMV 8011	0.00774	0.00231

Circuit	5 Year Baseline SAIDI*	Report Quarter SAIDI*
SMV 8014	0.06467	0.00549
SMV 8023	0.01943	0.00089
SOH 8022	0.16946	0.00000
SOS 8015	0.19304	0.02441
SPF 8014		**0.03536**
SPF 8016		**0.00078**
STP 8002	0.02921	0.01204
SUN 8013		0.00000
WAN 8014		0.00000
WAN 8015		**0.00056**
WAV 4004	0.09979	0.02798
WEW 8021	0.21824	0.00000
WEW 8042	0.01304	0.00163
WEW 8044	0.07375	0.00203
WFL 8034	0.04228	0.00690
WOR 8037	0.00017	0.00000
WOR 8039	0.18307	0.00068
		**-Calculated in minutes.*

In the circuit data in **Table 7** above, the "0.00000" indicates an outage, but the value is beyond five decimal points captured by PSE&G, while blank cells indicate no outage in the 5-year window. Additionally, all circuits impacted by this Major Event had received investments during either the original Energy Strong Program or through ES 2. As indicated above, there were 100 circuits impacted by these two Major Events, 73 of which had a current Major Event System Average Interruption Duration Index (SAIDI) better than the 5-year Major Event SAIDI average, while 18 circuits had no Major Event outage within the 5-year comparison window, leaving nine circuits that both had a prior Major Event outage within the past 5-years and had worse performance during these Major Events.

Additional information on the nine circuits that had worse performance during these Major Events than the 5-year Major Event SAIDI average is provided below in **Table 8 – Q1 2022 Major Event Additional Information on Selected Circuits** (note that some of these circuits had more than one incident during the Major Event, resulting in a total of 17 incidents from these nine circuits).

Table 8 – Q1 2022 Major Event Additional Information on Selected Circuits

Circuit	5-Year Baseline SAIDI*	Report Quarter SAIDI*	Customers Impacted	Outage Duration*
BEN 8021	0.00163	0.02166	673	80
CLF 8015	0.01520	0.06820	1,156	108
CLF 8015	0.01520	0.06820	324	138
HOE 8037	0.00573	0.02260	133	413
HOE 8037	0.00573	0.02260	1	1,250
LEO 8004	0.00027	0.03249	1,224	66
LEV 8016	0.00021	0.00245	610	10
NEW 8041	0.00280	0.00550	253	29
NEW 8041	0.00280	0.00550	253	25
NOT 8022	0.00091	0.02638	305	193

Circuit	5-Year Baseline SAIDI*	Report Quarter SAIDI*	Customers Impacted	Outage Duration*
NOT 8022	0.00091	0.02638	6	516
NOT 8022	0.00091	0.02638	4	516
NOT 8022	0.00091	0.02638	3	516
RFL 8012	0.00235	0.03403	1,880	45
SDH 8031	0.01726	0.03019	480	79
SDH 8031	0.01726	0.03019	384	79
SDH 8031	0.01726	0.03019	453	15
**-Calculated in minutes.*				

As indicated in **Table 8**, in addition to the original Energy Strong Program and ES 2 investments that increased sectionalizing of circuits to reduce the number of customers impacted by outages, the customer impact from a Major Event is also a function of the nature of the outages (extent of damage) and the location of damage relative to the various interrupting devices on the circuit, that is, reclosers or fuses. For some circuits, the 5-year baseline outage(s) were smaller or affected fewer customers, including different device operations (fuse with 10 customers vs. fuse with 150 customers) than the incident from the current Major Event being reported. Some circuits had more non-reclosing device operations in this Major Event (more fuse jobs) or more customers served by the circuit due to circuit rearrangements. Additionally, the circuits in **Table 8** with zero customers reflect the way the circuit is modeled in PSE&G's connectivity model and the restoration/isolation steps used to restore service (e.g. isolating a section of cable for repair, or a transformer with no assigned customers). The cause of the individual circuit incidents also varied, with some related to spacer cable issues (CLF 8015), some related to transformer failures (HOE 8037), some related to vegetation issues (LEV 8016 and NEW 8041), and some related to broken or damaged poles (NEW 8041 and NOT 8022).

III. Project Status

A. Electric Station Flood Mitigation

A summary of the subprogram plan as of the end of the first quarter of 2022 compared to the status as of the end of 2019, end of 2020, and end of 2021 is provided below in **Table 9 – ES 2 Electric Station Flood Mitigation Subprogram Milestone Schedule as of March 31, 2022**. Note that the Market Street and Ridgefield 4kV projects were previously placed in-service and closed out, thus there are no further updates to these projects (which have been further called out in italics in **Table 9**).

Table 9 – ES 2 Electric Station Flood Mitigation Milestone Schedule as of March 31, 2022

Project	Plan Status Point	2019		2020				2021				2022				2023				2024
		Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	
1. Academy Street	Dec. 2019		KO					C					IS		CO					
	Dec. 2020		KO		C									CO						
	Dec. 2021		KO		C						IS						CO			
	Mar. 2022		KO		C						IS						CO			
2. Clay Street	Dec. 2019	*Schedule Under Development*																		
	Dec. 2020			KO							C					IS				CO (Q2)
	Dec. 2021			KO							C				IS					CO (Q1)
	Mar. 2022			KO							C					IS				CO (Q1)

Project	Plan Status Point	2019		2020				2021				2022				2023				2024
		Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	
3. Front Street^	Dec. 2019	*Not in ES 2 Program*																		
	Dec. 2020	*Not in ES 2 Program*																		
	Dec. 2021								KO				C						IS	CO (Q2)
	Mar. 2022								KO				C						IS	CO (Q2)
4. Hasbrouck Heights	Dec. 2019		KO						C						IS		CO			
	Dec. 2020		KO									C					IS		CO	
	Dec. 2021		KO									C					IS	CO		
	Mar. 2022		KO									C				IS		CO		
5. Kingsland	Dec. 2019			KO				C			IS		CO							
	Dec. 2020			KO										C					IS	CO (Q2)
	Dec. 2021			KO											C		IS		CO	
	Mar. 2022			KO											C				IS	CO (Q2)
6. Lakeside Avenue	Dec. 2019*				KO				C										IS	CO (Q2)
	Dec. 2020						KO							C					IS	CO (Q2)
	Dec. 2021						KO							C					IS	CO (Q2)
	Mar. 2022						KO							C				IS		CO (Q1)
7. Leonia	Dec. 2019	*Schedule Under Development*																		
	Dec. 2020			KO		C									IS		CO			
	Dec. 2021			KO		C									IS		CO			
	Mar. 2022			KO		C									IS		CO			
8. Market Street	Dec. 2019			KO				C	OS		CO									
	Dec. 2020			KO					C	OS		CO								
	Dec. 2021			KO						C/OS	CO									
9. Meadow Road	Dec. 2019	*Schedule Under Development*																		
	Dec. 2020			KO											C				IS	CO (Q2)
	Dec. 2021			KO										C				IS		CO (Q1)
	Mar. 2022			KO										C				IS		CO (Q1)
10. Orange Valley	Dec. 2019	*Schedule Under Development*																		
	Dec. 2020					KO										C				IS (Q1); CO (Q3)
	Dec. 2021					KO										C				IS (Q1); CO (Q3)
	Mar. 2022					KO										C			IS	CO (Q2)
11. Ridgefield 13kV	Dec. 2019			KO	C										IS		CO			
	Dec. 2020			KO	C										IS		CO			
	Dec. 2021			KO	C										IS		CO			
	Mar. 2022			KO	C										IS		CO			
12. Ridgefield 4kV	Dec. 2019			KO						C	OS			CO						
	Dec. 2020			KO	C				OS		CO									
	Dec. 2021			KO	C				OS		CO									
13. State Street	Dec. 2019		KO					C								IS				CO (Q1)
	Dec. 2020		KO						C				IS							CO (Q1)
	Dec. 2021		KO						C					IS				CO		
	Mar. 2022		KO						C						IS		CO			
14. Toney's Brook	Dec. 2019			KO						C									IS	CO (Q2)
	Dec. 2020			KO										C			IS			CO (Q2)
	Dec. 2021			KO										C			IS			CO (Q2)
	Mar. 2022			KO										C			IS			CO (Q2)

December 31, 2023 - ES 2 Program End Date

Project	Plan Status Point	2019		2020				2021				2022				2023				2024
		Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	
15. Waverly	Dec. 2019	*Schedule Under Development*																		
	Dec. 2020			KO			C												IS	CO (Q2)
	Dec. 2021			KO			C													IS (Q3); CO (Q1 2025)
	Mar. 2022			KO			C													IS (Q1); CO (Q3)
16. Woodlynne	Dec. 2019		KO												C				IS	CO (Q2)
	Dec. 2020		KO												C				IS	CO (Q2)
	Dec. 2021		KO												C				IS	CO (Q2)
	Mar. 2022		KO								C								IS	CO (Q2)

Legend: KO = Kickoff; C = Construction; IS = Fully In-Service (major assets in-service); OS = Out-of-Service (if eliminated); CO = Closeout
-Actuals are indicated with an underline (Note: for the Market Street and Ridgefield 4kV projects, outside plant construction began in the first quarter of 2020, the construction milestone indicated on this chart reflects inside plant construction).
***-The Dec. 2019 Lakeside Avenue project schedule was based on the original raise and rebuild mitigation strategy; the current schedule reflects the proposed mitigation method change that contemplates relocating the substation.**
^-The Front Street project was proposed by PSE&G during the second quarter of 2021 to replace the cancelled Constable Hook project.

A summary of the subprogram status as of the end of the first quarter of 2022 is provided below in **Table 10 – ES 2 Electric Station Flood Mitigation Summary Status as of March 31, 2022**.

Table 10 – ES 2 Electric Station Flood Mitigation Summary Status as of March 31, 2022

Activity	Total # of Projects	Specific Projects
Kickoff Meeting	16	Academy Street; Clay Street; Front Street; Hasbrouck Heights; Kingsland; Lakeside Avenue; Leonia; Market Street; Meadow Road; Orange Valley; Ridgefield 13kV; Ridgefield 4kV; State Street; Toney's Brook; Waverly; Woodlynne
Key Drawing Review	16	Academy Street; Clay Street; Front Street; Hasbrouck Heights; Kingsland; Lakeside Avenue; Leonia; Market Street; Meadow Road; Orange Valley; Ridgefield 13kV; Ridgefield 4kV; State Street; Toney's Brook; Waverly; Woodlynne
Scope Locked	16	Academy Street; Clay Street; Front Street; Hasbrouck Heights; Kingsland; Lakeside Avenue; Leonia; Market Street; Meadow Road; Orange Valley; Ridgefield 4kV; Ridgefield 13kV; State Street; Toney's Brook; Waverly; Woodlynne
Major Equipment Purchase Orders (POs)	18*	Academy Street; Clay Street; Front Street*; Hasbrouck Heights; Kingsland; Lakeside; Leonia*; Meadow Road; Orange Valley; Ridgefield 13kV*; State Street; Toney's Brook; Waverly*; Woodlynne
Architect/ Engineer (A/E) Contract Award (or selection of PSE&G internal engineering)	16	Academy Street[1]; Clay Street[1]; Front Street[3]; Hasbrouck Heights[1]; Kingsland[2]; Lakeside Avenue[3]; Leonia[2]; Market Street[2]; Meadow Road[2]; Orange Valley[1]; Ridgefield 13kV[2]; Ridgefield 4kV[2]; State Street[2]; Toney's Brook[3]; Waverly[3]; Woodlynne[1]
Construction Start**	10	Academy Street; Clay Street; Hasbrouck Heights; Leonia; Market Street; Ridgefield 4kV; Ridgefield 13kV; State Street; Waverly; Woodlynne
In-Service	3	Academy Street; Market Street; Ridgefield 4kV
Partial In-Service	2	Leonia; Ridgefield 13kV

Activity	Total # of Projects	Specific Projects
**-Three of the listed projects (Front Street, Leonia, Ridgefield 13kV, and Waverly) have two switchgears, thus the current count reflects 18 switchgears at 14 substations. [1]-Indicates Burns & McDonnell is serving as the A/E. [2]-Indicates PSE&G internal resources are serving as the A/E. [3]-Indicates Black & Veatch is serving as the A/E. **-Includes inside plant (IP) and/or outside plant (OP) construction.*		

Beyond the key activities summarized in **Table 10** above, **Table 11 – ES 2 Electric Station Flood Mitigation Upcoming Activities for Q2 2022** summarizes the upcoming planned activities for each project during the second quarter of 2022, including any carryover of activities from earlier periods.

Table 11 – ES 2 Electric Station Flood Mitigation Upcoming Activities for Q2 2022

Station	Upcoming Activities for Q2 2022	Carryover Activities from Q1 2022
1. Academy Street	• Complete closeout report • Demo existing foundations, remove old equipment at existing Academy St. station	• Continue civil and electrical construction • Continue circuit cutovers
2. Clay Street	• Commence pile driving	• Major municipal licenses and permits issuance
3. Front Street	• Civil drawings Issued for Construction (IFC) • Civil and electrical POs issued • Start civil construction	• Continue engineering
4. Hasbrouck Heights	• Start civil foundations • Start electrical construction	• Continue civil construction
5. Kingsland	• Civil and electrical construction out for bid	• Continue engineering
6. Lakeside Avenue	• Civil PO issued • Major state licenses and permits issued	• Continue engineering
7. Leonia	• Complete demo of existing feeder rows • Receive switchgear #2 • Switchgear #2 circuits cutover to temporary switchgear	• Continue civil and electrical construction
8. Market Street	• Complete demolition and site remediation	• Continue demolition
9. Meadow Road	• Civil, controls, and electrical drawings IFC • Transition to 70% estimate	• Continue engineering
10. Orange Valley	• Controls drawings Issued for Review (IFR) • Civil and electrical drawings IFC • Site plan memorialization • Civil and electrical construction out for bid	• Continue engineering
11. Ridgefield 13kV	• Complete circuit cutovers to new switchgear #2 • Compete circuit cutovers from existing switchgear #1 to temporary switchgear • Demo existing switchgear #1	• Continue construction
12. Ridgefield 4kV	• Project complete	• Project complete
13. State Street	• Start civil foundations	• Continue construction
14. Toney's Brook	• Continue engineering	• Continue engineering
15. Waverly	• Receive phase 2 permits and hold pre-construction review with contractor • Start phase 2 civil and electrical construction • Set 26kV switchgear and commence commissioning	• Continue construction

Station	Upcoming Activities for Q2 2022	Carryover Activities from Q1 2022
16. Woodlynne	• Continue engineering	• Continue engineering

During the first quarter of 2022, PSE&G's switchgear vendor, Powercon, informed PSE&G that due to various material and sub-supplier delays, the major equipment deliveries may be impacted beyond the delay previously identified to the Ridgefield 13kV switchgear. As of the end of the first quarter of 2022, Powercon advised PSE&G that delivery delays were now expected for the Hamilton switchgear (delayed two months) and the Clay Street regulators (delayed five months), while also possible for equipment on the Paramus, Plainfield, Toney's Brook, Woodbury, and Woodlynne projects.[1] PSE&G was able to re-sequence the Hamilton schedule to mitigate the majority of this delay impact, while the Clay Street equipment was scheduled to be stored and has no schedule impact as a result at this time.

PSE&G receives weekly updates from Powercon on the current status of the deliveries, has initiated status calls to inquire further information on the current status, and has conducted site visits to gain further awareness on the status of this equipment. The overall status remains fluid, based on the current information from Powercon and this issue continues to be managed beyond the first quarter of 2022, but PSE&G has generally been able to mitigate any project impacts either from having the initial ship dates in advance of the project need dates, thereby building in float to the schedule, or by resequencing activities. One current exception is the Kingsland project, which saw its in-service date slip 94 days from June 30, 2023 to October 2, 2023 due to delays in the 13kV switchgear delivery on the Ridgefield 13kV project (for cost efficiencies, PSE&G plans to use the contingency switchgear from the Ridgefield 13kV project on Kingsland, which saves an estimated $1.7 million compared to if this option had not been available and is also the same approach that was used for the Meadow Road contingency switchgear that will serve as the permanent switchgear on Leonia).

The current project estimates are shown below in **Table 12 – ES 2 Electric Station Flood Mitigation Project Cost Status as of March 31, 2022**. As discussed in **Section II.B.**, during the first quarter of 2022, PSE&G decided to consolidate the R&C on the individual projects into one R&C balance for the entire subprogram, thus there is no estimated R&C amount at the project level. **Table 12** also shows the current estimate level based on PSE&G's estimating processes and as approved by the URB, the actual spend, and percentage of actuals to estimate as of the end of the first quarter of 2022.

Table 12 – ES 2 Electric Station Flood Mitigation Project Cost Status as of March 31, 2022

Project	Estimate Level	Base	Risk & Contingency*	Total	Current Forecast	Actuals to Date	% of Actuals to Estimate
1. Academy Street	Definitive	$9,300,000	$-	$9,300,000	$8,698,421	$6,260,799	67%
2. Clay Street	Conceptual	$30,800,000	$-	$30,800,000	$31,302,000	$8,846,983	29%
3. Front Street**	Study	$25,900,000	$-	$25,900,000	$25,693,360	$2,781,438	11%

[1] The Hamilton, Paramus, Plainfield, and Woodbury projects are all within the Electric Stipulated Base scope of the ES 2 Program.

Project	Estimate Level	Base	Risk & Contingency*	Total	Current Forecast	Actuals to Date	% of Actuals to Estimate
4. Hasbrouck Heights	Definitive	$19,300,000	$-	$19,300,000	$19,027,836	$9,779,630	51%
5. Kingsland	Study	$6,400,000	$-	$6,400,000	$6,427,155	$1,126,185	18%
6. Lakeside Avenue	Study	$39,400,000	$-	$39,400,000	$36,697,209	$1,525,371	4%
7. Leonia	Definitive	$24,900,000	$-	$24,900,000	$24,952,795	$16,979,539	68%
8. Market Street	Definitive	$29,100,000	$-	$29,100,000	$28,235,161	$27,820,378	96%
9. Meadow Road	Study	$7,200,000	$-	$7,200,000	$7,782,150	$1,331,494	19%
10. Orange Valley	Study	$14,700,000	$-	$14,700,000	$14,742,882	$909,541	6%
11. Ridgefield 13kV	Conceptual	$26,100,000	$-	$26,100,000	$27,245,211	$19,399,451	74%
12. Ridgefield 4kV	Definitive	$20,800,000	$-	$20,800,000	$20,707,403	$20,689,404	100%
13. State Street	Definitive	$19,600,000	$-	$19,600,000	$19,837,904	$9,584,815	49%
14. Toney's Brook	Conceptual	$16,200,000	$-	$16,200,000	$16,254,329	$1,664,826	10%
15. Waverly	Study	$36,200,000	$-	$36,200,000	$37,648,812	$7,412,639	21%
16. Woodlynne	Study	$21,300,000	$-	$21,300,000	$24,310,000	$3,735,353	18%
ES 2 Station Placeholder	N/A	$-	$41,800,000	$41,800,000	$-	$-	-
Subprogram Total		**$347,200,000**	**$41,800,000**	**$389,000,000**	**$349,562,629**	**$139,847,775**	**36%**

-As discussed in **Section II.B., during the first quarter of 2022, PSE&G made the decision to hold risk and contingency at the subprogram level, which resulted in updated estimates being prepared for each project to reflect this change and other project-specific updates as warranted.*

***-The Front Street project was proposed by PSE&G during the second quarter of 2021 to replace the cancelled Constable Hook project.*

Findings & Observations

- Nine of the sixteen Electric Station Flood Mitigation projects had movement in the forecasted in-service date during the first quarter of 2022, with five advancing and four slipping. The biggest changes came on the following projects:

- Waverly (advancing 196 days from September 17, 2024 to March 5, 2024), driven by improvements in the construction schedule following the site plan approval in December 2021;
- Kingsland (slipping 94 days from June 30, 2023 to October 2, 2023), driven by delays to the 13kV switchgear delivery on the Ridgefield 13kV project (Kingsland plans to use the contingency switchgear from the Ridgefield 13kV project), which effectively reversed the 96 day schedule advancement reported in the fourth quarter of 2022;
- State Street (slipping 87 days from September 23, 2022 to December 19, 2022), driven by an updated Southern Division OP schedule for when the first circuit will be ready for energization, which is a prerequisite to place the IP substation assets in-service;
- Clay Street (slipping 84 days from November 7, 2022 to January 30, 2023), driven by delays in securing the above grade structures and electric construction permits; and
- Lakeside Avenue (advancing 51 days from November 8, 2023 to September 18, 2023), driven by updates to the construction schedule that allowed installation of the switchgear foundation to commence in 2022 instead of 2023.

The forecasted in-service date shifts to the other four projects (Front Street, Hasbrouck Heights, Leonia, and Ridgefield 13kV) were between six days and 21 days and reflective of actual project conditions experienced in the first quarter of 2022.

- No change in completed projects during the first quarter of 2022, with three of the 16 projects previously put in-service (Market Street and Ridgefield during the second quarter of 2021 and Academy Street in the fourth quarter of 2021). The next project forecasted to be placed in-service are the Leonia, Ridgefield 13kV, and State Street projects, each forecasted to go in-service during the fourth quarter of 2022.
- In conjunction with the change how the projects' R&C on the subprogram is managed (shifting from project-level to subprogram-level), PSE&G also updated the base project estimates for the Academy Street, Clay Street, Front Street, Hasbrouck Heights, Kingsland, Orange Valley, Ridgefield 13kV, State Street, Waverly, and Woodlynne projects (with Hasbrouck Heights and State Street also advancing to the Definitive stage). Collectively these changes in base estimates resulted in a $15.0 million increase (with $12.3 million of that increase attributed to the Waverly ($6.8 million) and Woodlynne ($5.5 million) projects).
- The overall subprogram forecast as of the end of the first quarter of 2022 increased $1.7 million (or 0.5%) to $349.6 million from the status as of the end of 2021. The forecast continues to remain under the current subprogram estimate of $389.0 million (which includes $41.8 million of contingency and also matches the Stipulation amount of $389.0 million).
- With 40% of the subprogram forecast now spent (36% of the Stipulation amount), the IM has found nothing to date that would jeopardize the subprogram being completed on budget. However, the status of the later projects in this subprogram, and in particular Waverly, will have to continue to be closely followed to monitor if the projects can be completed within the ES 2 Program window. Other projects currently forecasted to be in-service in the final quarter of the Program (fourth quarter of 2023) include: Front Street, Kingsland, Orange Valley, and Woodlynne.

- Relative to the Waverly project, as of the end of the first quarter of 2022, the project continues to show a final in-service date in 2024, now at March 2024, which has advanced as PSE&G details the schedule following the site plan approval in December 2021. The Waverly project has multiple major asset in-service dates for the 26kV switchgear, 4kV switchgear, and three transformers, which are currently forecasted from September 2022 (26kV switchgear) to March 2024 (Transformer #3). PSE&G has informed the IM that the project team will continue to assess the project schedule and will be examining the potential to shorten durations and/or work activities concurrently to pull the final in-service date back into 2023. The IM will continue to review the proposed actions by PSE&G and report on the status in future IM quarterly reports,

1. Academy Street

During the first quarter of 2022, $131,061 was spent on the Academy Street project compared to a forecast of approximately $159,000, which brought the total spend to approximately $6.3 million. As part of the Electric Station Flood Mitigation subprogram re-estimating process that was completed in the first quarter of 2022, the Academy Street estimate was revised with the base estimate decreasing from $9.8 million to $9.3 million, which was the result of efficiencies gained in the construction and commissioning activities.

This project was placed in-service on October 19, 2021, and there were minimal activities performed during the first quarter of 2022 other than the continued circuit cutovers. The elimination of equipment at the old substation site and related demolition activities are expected to commence in the second quarter of 2022.

The actual spend by quarter for Academy Street as compared to the current approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023+
Actuals				*Forecast*			
$150,398	$4,224,550	$1,754,789	$131,061	$185,615	$206,354	$2,045,653	$-

Actuals to Date	Estimate	% of Actuals to Estimate
$6,260,799	$9,300,000	67%

2. Clay Street

During the first quarter of 2022, $5,044,642 was spent on the Clay Street project compared to a forecast of approximately $4.9 million, which brought the total spend to approximately $8.8 million. As part of the Electric Station Flood Mitigation subprogram re-estimating process that was completed in the first quarter of 2022, the Clay Street estimate was revised with the base estimate increasing from $30.3 million to $30.8 million, which was the result of the change in Transmission & Distribution (T&D) surcharge methodology. The current forecast of $31.3 million reflects changes in status, conditions, and assumptions since the time of the estimate update, including specifically an additional $0.5 million over the current estimate based on additional civil work required (e.g. enlarging two manholes, extra shifts).

The forecasted in-service date for the Clay Street project as of the end of the first quarter of 2022 slipped 84 days from the status as of the end of 2021. This shift was the result of delays in securing the above grade structures and electrical construction permits and eliminates the advancement in the forecasted in-service date gained during the fourth quarter of 2021.

The primary activities on the Clay Street project during the first quarter of 2022 included the submittal of the below grade permit package and the partial delivery of the switchgear (with the regulators expected to be delivered in May 2022).

The actual spend by quarter for Clay Street as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals				*Forecast*			
$116,409	$879,339	$2,806,593	$5,044,642	$5,964,696	$5,553,877	$5,147,098	$5,789,346

Actuals to Date	Estimate	% of Actuals to Estimate
$8,846,983	$30,800,000	29%

3. Front Street

During the first quarter of 2022, $429,607 was spent on the Front Street project compared to a forecast of approximately $465,000, which brought total spend to approximately $2.8 million. As part of the Electric Station Flood Mitigation subprogram re-estimating process that was completed in the first quarter of 2022, the Front Street estimate was revised with the base estimate increasing from $23.0 million to $25.9 million, which was the result of higher than estimated switchgear award ($2.1 million), higher than previously estimated construction supervision costs ($0.5 million), and utilizing an external A/E firm rather than in-house engineering as initially planned ($0.3 million). The switchgear was competitively bid and was awarded to the same vendor that was previously awarded the switchgear for other projects in the Program, suggesting current market conditions have contributed to the cost growth. Additionally, concerning the switch to an external A/E firm, PSE&G determined it did not have the internal resources to support the project schedule, thus after preliminary engineering was complete, it outsourced the detailed engineering scope.

The forecasted in-service date for the Front Street project as of the end of the first quarter of 2022 advanced 21 days from the status as of the end of 2021 to October 26, 2023.

The primary activities on the Front Street project during the first quarter of 2022 included:

- The continuation of the civil construction that commenced late in 2021;
- The receipt of the Soil Conservation District permit; and,
- Civil and electrical drawings IFR, and the civil and electrical contingency drawings IFC.

The actual spend by quarter for Front Street as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals				*Forecast*			
$-	$-	$2,351,832	$429,607	$785,609	$4,512,621	$1,982,573	$15,631,119

Actuals to Date	Estimate	% of Actuals to Estimate
$2,781,438	$25,900,000	11%

4. Hasbrouck Heights

During the first quarter of 2022, $4,323,599 was spent on the Hasbrouck Heights project compared to a forecast of approximately $4.5 million, which brought the total spend to approximately $9.8 million. As part of the Electric Station Flood Mitigation subprogram re-estimating process that was completed in the first quarter of 2022, the Hasbrouck Heights estimate advanced to the Definitive stage with a $1.2 million reduction to the base estimate (while the R&C was removed as discussed above), for a new estimate of $19.3 million. The total forecast for the Hasbrouck Heights project decreased approximately $1.4 million from the prior quarter for a current forecast of $19.0 million. The decrease was driven by lower than previously estimated dewatering costs based on soil conditions in the specific construction area.

The forecasted in-service date for the Hasbrouck Heights project as of the end of the first quarter of 2022 advanced eight days from the status as of the end of 2021 to January 24, 2023.

Notable activities completed during the first quarter of 2022 included:

- The delivery of regulator sections to complete the switchgear delivery;
- The pre-construction licensing and permitting compliance and construction requirements review with the contractor; and,
- Commencement of civil construction and demolition of the existing control house.

The actual spend by quarter for Hasbrouck Heights as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals				*Forecast*			
$149,848	$1,129,934	$4,176,249	$4,323,599	$2,141,254	$1,588,496	$2,148,686	$3,369,770

Actuals to Date	Estimate	% of Actuals to Estimate
$9,779,630	$19,300,000	51%

5. Kingsland

During the first quarter of 2022, $301,463 was spent on the Kingsland project compared to a forecast of approximately $291,000, which brought the total spend to approximately $1.1 million. As part of the Electric Station Flood Mitigation subprogram re-estimating process that was completed in the first quarter of 2022, the Kingsland estimate was revised with the base estimate increasing from $5.4 million to $6.4 million, which was the result of the change in T&D surcharge methodology.

The forecasted in-service date for the Kingsland project as of the end of the first quarter of 2022 slipped 94 days from the status as of the end of 2021 to October 2, 2023. This was driven by the delay to the 13kV switchgear delivery on the Ridgefield 13kV project as the Kingsland project plans to use the contingency switchgear from the Ridgefield 13kV project. This shift in the forecasted in-service date reverses the 96-day advancement gained during the fourth quarter of 2021.

During the first quarter of 2022, primary activity on the Kingsland project was the site plan submittal.

The actual spend by quarter for Kingsland as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals				*Forecast*			
$104,112	$209,667	$510,943	$301,463	$159,197	$147,083	$1,079,078	$3,915,613

Actuals to Date	Estimate	% of Actuals to Estimate
$1,126,185	$6,400,000	18%

6. Lakeside Avenue

During the first quarter of 2022, $351,720 was spent on the Lakeside Avenue project compared to a forecast of approximately $312,000. As part of the Electric Station Flood Mitigation subprogram re-estimating process that was completed in the first quarter of 2022, the Lakeside Avenue estimate was revised with no change to the base estimate (while the R&C was removed as discussed above). The total forecast for the Lakeside Avenue project decreased approximately $2.7 million from the prior quarter for a current forecast of $36.7 million. The decrease was driven by the civil construction bid being lower than previously estimated.

The forecasted in-service date for the Lakeside Avenue project as of the end of the first quarter of 2022 advanced 51 days from the status as of the end of 2021. This change was driven by an updated construction schedule that supported the commencement of the installation of the switchgear foundation in 2022 instead of 2023 as earlier planned, which allowed the in-service date to advance from November 2023 to September 2023.

Notable activities completed during the first quarter of 2022 included the IFC release of civil and electrical drawings, constructability reviews of the IP controls design drawing, and civil construction work out for bid.

The actual spend by quarter for Lakeside Avenue as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals				*Forecast*			
$148,943	$453,994	$570,713	$351,720	$433,537	$851,140	$312,218	$33,574,943

Actuals to Date	Estimate	% of Actuals to Estimate
$1,525,371	$39,400,000	4%

7. Leonia

During the first quarter of 2022, $1,789,112 was spent on the Leonia project compared to a forecast of approximately $1.5 million, which brought the total spend to approximately $17.0 million. As part of the Electric Station Flood Mitigation subprogram re-estimating process that was completed in the first quarter of 2022, the Leonia estimate was revised with no change to the base estimate (while the R&C was removed as discussed above).

The forecasted in-service date for the Leonia project as of the end of the first quarter of 2022 slipped six days from the status at the end of 2021.

Notable activities completed during the first quarter of 2022 included finishing the circuit cutovers on the 13kV switchgear #1 (which was placed in-service at the end of 2021) and the start of circuit cutovers from the existing switchgear #2 to the temporary switchgear.

The actual spend by quarter for Leonia as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals				*Forecast*			
$44,792	$6,033,379	$9,112,257	$1,789,112	$3,939,075	$1,119,964	$1,415,109	$1,499,108

Actuals to Date	Estimate	% of Actuals to Estimate
$16,979,539	$24,900,000	68%

8. *Market Street*

During the first quarter of 2022, $808,096 was spent on the Market Street project compared to a forecast of approximately $976,000, which brought the total spend to approximately $27.8 million. As part of the Electric Station Flood Mitigation subprogram re-estimating process that was completed in the first quarter of 2022, the Market Street estimate was revised with no change to the base estimate (while the R&C was removed as discussed above).

Notable activities conducted during the first quarter of 2022 included the receipt of the building demolition permit and the commencement of the building demolition. Demolition and site remediation activities are expected to be completed during the second quarter of 2022.

The actual spend by quarter for Market Street as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals				*Forecast*			
$251,193	$16,079,601	$10,681,487	$808,096	$325,784	$47,000	$42,000	$-

Actuals to Date	Estimate	% of Actuals to Estimate
$27,820,378	$29,100,00	96%

9. *Meadow Road*

During the first quarter of 2022, $288,050 was spent on the Meadow Road project compared to a forecast of $226,000, which brought the total spend to approximately $1.3 million. As part of the Electric Station Flood Mitigation subprogram re-estimating process that was completed in the first quarter of 2022, the Meadow Road estimate was revised with no change to the base estimate (while the R&C was removed as discussed above).

The forecasted in-service date for the Meadow Road project as of the end of the first quarter of 2022 remained unchanged from the status as of the end of 2021 at September 22, 2023.

The primary activity during the first quarter of 2022 was the continued advancement on detailed engineering, which commenced during the fourth quarter of 2021.

The actual spend by quarter for Meadow Road as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals				*Forecast*			
$63,128	$535,081	$445,234	$288,050	$141,114	$410,445	$1,365,600	$4,533,498

Actuals to Date	Estimate	% of Actuals to Estimate
$1,331,494	$7,200,000	19%

10. Orange Valley

During the first quarter of 2022, $111,565 was spent on the Orange Valley project compared to a forecast of approximately $116,000, which bought the total spend to approximately $910,000. As part of the Electric Station Flood Mitigation subprogram re-estimating process that was completed in the first quarter of 2022, the Orange Valley estimate was revised with the base estimate decreasing from $16.0 million to $14.7 million. This decrease to the base estimate was driven by lower than estimated A/E award (-$0.5 million, revised 4kV equipment relocation estimate from the Division (-$0.5 million), lower than estimated switchgear award ($-0.2 million), and lower carrying cost (-$0.1 million).

The forecasted in-service date for the Orange Valley project as of the end of the first quarter of 2022 remained unchanged from the status as of the end of 2021 at December 29, 2023.

During the first quarter of 2022, major activities on the Orange Valley project included the DEP permit submission, the IFR release of civil and electrical drawings, and constructability reviews of the civil and electrical design drawings.

The actual spend by quarter for Orange Valley as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals				*Forecast*			
$77,029	$362,895	$358,052	$111,565	$254,365	$173,034	$115,980	$13,289,963

Actuals to Date	Estimate	% of Actuals to Estimate
$909,541	$14,700,000	6%

11. Ridgefield 13kV

During the first quarter of 2022, $2,111,096 was spent on the Ridgefield 13kV project compared to a forecast of approximately $2.15 million, which brought the total spend to approximately $19.4 million. As part of the Electric Station Flood Mitigation subprogram re-estimating process that was completed in the first quarter of 2022, the Ridgefield 13kV estimate was revised as the project transitioned to the definitive estimate phase with the base estimate increasing by $0.8 million to $26.1 million. This increase in the base estimate was driven by required rebuilds of two additional manholes and more Division underground labor required for cable pulling and cutovers. The current forecast of $27.2 million reflects changes in status, conditions, and assumptions since the time of the estimate update, including specifically:

- More than anticipated dewatering and updated design of manhole modifications ($0.5 million); and,
- More Division effort required on manhole expansion and circuits cutovers due to difficulty of breaking back the duct bank (high strength concrete) and working around the energized circuits ($0.6 million).

The forecasted in-service date for the Ridgefield 13kV project as of the end of the first quarter of 2022 advanced seven days from the status as of the end of 2021 to December 13, 2022.

Notable activities completed during the first quarter of 2022 included the continued manhole modifications and circuit cutovers to the new switchgear #2.

The actual spend by quarter for Ridgefield 13kV as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals				*Forecast*			
$205,982	$6,232,692	$10,849,681	$2,111,096	$3,943,529	$1,655,900	$1,442,330	$804,000

Actuals to Date	Estimate	% of Actuals to Estimate
$19,399,451	$26,100,000	67%

12. Ridgefield 4kV

During the first quarter of 2022, $42,604 was spent on the Ridgefield 4kV project compared to a forecast of $48,000, which brought the total spend to approximately $20.7 million. The project was placed in-service on May 16, 2021.

The project is essentially complete now with final closeout activities performed during the first quarter of 2022.

The actual spend by quarter for Ridgefield 4kV as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals				*Forecast*			
$143,414	$11,239,534	$9,263,852	$42,604	$18,000	-	-	-

Actuals to Date	Estimate	% of Actuals to Estimate
$20,689,404	$20,800,000	100%

13. State Street

During the first quarter of 2022, $751,849 was spent on the State Street project compared to a forecast of approximately $636,000, which brought the total spend to approximately $9.6 million. As part of the Electric Station Flood Mitigation subprogram re-estimating process that was completed in the first quarter of 2022, the State Street estimate advanced to the Definitive stage with a $500,000 increase to the base estimate (while the R&C was removed as discussed above) for a new estimate of $19.6 million.

The forecasted in-service date for the State Street project as of the end of the first quarter of 2022 slipped 87 days from the status as of the end of 2021 to December 19, 2022. This shift was driven by an updated Southern Division OP schedule for when the first circuit will be ready for energization, which is needed to place the IP substation assets in-service. The initial plan assumed that an overhead route out of the station would be used for this circuit, however during field inspections and detailed engineering it was determined this route was not feasible due to an existing pole in the area that was not known of at the time of initial design. The updated route exits the station at a different side of the station that does not permit overhead electrical infrastructure, thus requiring installation of an underground manhole and duct bank system.

Notable activities performed on State Street during the first quarter of 2022 included the submittal of the test pit permit package and the test pit scope of work sent out for bid. The test pits will inform the engineering design of the 4kV manhole and ductbanks required to be installed through congested underground streets in Camden, New Jersey.

The actual spend by quarter for State Street as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals				*Forecast*			
$77,590	$662,148	$8,093,227	$751,849	$1,414,761	$1,146,801	$1,612,741	$6,078,786

Actuals to Date	Estimate	% of Actuals to Estimate
$9,584,815	$19,600,000	49%

14. Toney's Brook

During the first quarter of 2022, $432,853 was spent on the Toney's Brook project compared to a forecast of approximately $403,000, which brought the total spend to approximately $1.7 million. As part of the Electric Station Flood Mitigation subprogram re-estimating process that was completed in the first quarter of 2022, the Toney's Brooke estimate was revised with no change to the base estimate (while the R&C was removed as discussed above).

The forecasted in-service date for the Toney's Brook project as of the end of the first quarter of 2022 remains unchanged from the status as of the end of 2021 at April 21, 2023.

The primary activities on during the first quarter of 2022 involved the continued advancement of detailed engineering.

The actual spend by quarter for Toney's Brook as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals				*Forecast*			
$211,940	$373,096	$941,519	$138,270	$116,627	$994,981	$6,016,246	$7,461,650

Actuals to Date	Estimate	% of Actuals to Estimate
$1,664,826	$16,200,000	10%

15. Waverly

During the first quarter of 2022, $432,853 was spent on the Waverly project compared to a forecast of approximately $403,000, which brought the total spend to approximately $7.4 million. As part of the Electric Station Flood Mitigation subprogram re-estimating process that was completed in the first quarter of 2022, the Waverly estimate was revised with the base estimate increasing from $29.4 million to $36.2 million. This $6.8 million increase in the base estimate was driven by:

- Equipment awards higher than estimated ($2.9 million);
- Additional charges for site plan revisions and related extended project duration ($2.6 million), comprised of:
  - Additional engineering ($0.8 million);
  - Revised fencing and external façade improvements ($1.0 million); and,
  - Additional charges for extended project duration ($0.8 million).
- Change in T&D surcharge methodology ($1.1 million); and,
- Cost of laydown area higher than estimated ($0.2 million).

The current forecast of $37.6 million reflects changes in status, conditions, and assumptions since the time of the estimate update, including specifically:

- Civil construction PO awarded higher than estimated ($1.3 million); and,
- Cost of switchgear storage ($0.1 million).

The forecasted in-service date for the Waverly project as of the end of the first quarter of 2022 continued to advance as the project team details the construction schedule following the site plan approval in December 2021. The current forecasted in-service date advanced 196 days from the status as of the end of 2021 to March 5, 2024.

The primary activities performed during the first quarter of 2022 included the issuance of the Soil Conservation District permit, phase 2 electrical work awarded, and phase 3 civil work awarded.

The actual spend by quarter for Waverly as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals				*Forecast*			
$103,748	$2,460,815	$4,415,223	$432,853	$7,176,838	$2,542,671	$2,473,315	$18,043,349

Actuals to Date	Estimate	% of Actuals to Estimate
$7,412,639	$36,200,000	21%

16. Woodlynne

During the first quarter of 2022, $1,639,443 was spent on the Woodlynne project compared to a forecast of approximately $1.4 million, which brought the total spend to approximately $3.7 million. As part of the Electric Station Flood Mitigation subprogram re-estimating process that was completed in the first quarter of 2022, the Woodlynne estimate was revised with the base estimate increasing from $15.8 million to $21.3 million. This $5.5 million increase in the base estimate was driven by:

- Higher than estimated civil construction award ($3.9 million);
- Higher than estimated switchgear award ($0.8 million); and,
- Increased carrying cost ($0.8 million).

The current forecast of $24.3 million reflects changes in status, conditions, and assumptions since the time of the estimate update, including specifically:

- Material and civil construction POs higher than estimated and bids ($0.4 million); and,
- Revised Division estimate ($2.6 million).

The forecasted in-service date for the Woodlynne project as of the end of the first quarter of 2022 remains unchanged from the status as of the end of 2021 at October 10, 2023.

Design work continued to progress during the first quarter of 2022 and the civil construction work commenced later in the quarter.

The actual spend by quarter for Woodlynne as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals				*Forecast*			
$110,982	$993,298	$991,630	$1,639,443	$660,694	$1,078,409	$6,335,309	$12,500,235

Actuals to Date	Estimate	% of Actuals to Estimate
$3,735,353	$21,300,000	18%

B. Contingency Reconfiguration

During the first quarter of 2022, the final reclosers were installed and commissioned, completing this scope of the Contingency Reconfiguration subprogram. **Table 13 – ES 2 Program Recloser Status as of March 31, 2022** provides a summary of the recloser aspect of the Contingency Reconfiguration subprogram, indicating the number of units completed during the first quarter of 2022 and for the total program, showing the status of engineering, installation, and commissioning.

Table 13 – ES 2 Program Recloser Status as of March 31, 2022

Type	Engineering Packages Completed (1 recloser ea.)		Reclosers Installed		Reclosers Commissioned	
	Q1 Qty.	*Program Total*	*Q1 Qty.*	*Program Total*	*Q1 Qty.*	*Program Total*
13kV	6	954	21	954	22	954
4kV	-2	513	2	513	3	513
Total	4	1,467	23	1,467	25	1,467

As shown in **Table 13**, the final 23 reclosers were installed during the first quarter of 2022 along with the commissioning of 25 reclosers (which included two installed at the end of 2021). The reduction of two 4kV recloser engineering packages recorded during the first quarter of 2022 was the result of a reconciliation of the engineering packages, which identified two previously completed engineering packages in the Southern Division that were abandoned after completion of the engineering due to the location no longer being feasible as a result of a change in field conditions stemming from other completed projects that altered the original design condition. PSE&G also removed the costs associated with these two engineering packages from the ES 2 Program.

As previously discussed in prior IM reports, the Fuse Saver pilot program commenced in November 2020 and was primarily completed in January 2021. In total, this phase of the Fuse Saver pilot program included the installation and commissioning of 80 Fuse Saver devices with an additional 33 units installed during the second half of 2021 to allow PSE&G to capture additional cost and performance data from the existing inventory of Fuse Savers. During execution of the pilot program, PSE&G observed factors that will help it prepare for execution of the full Fuse Saver scope, including installation specifications (the remote control unit (RCU) must be placed directly below the Fuse Saver to avoid communications issues), and cost elements for some of the locations (new poles, traffic control, etc.). The observed experience from the 113 units installed in the pilot program saw communications issues present at 10 locations, with the external antenna addressing the communication issues at added cost of approximately $1,100 per unit (plus some additional labor to install the antenna). While monitoring performance of the installed Fuse Savers, PSE&G experienced other communication issues between the Fuse Savers and the RCU, wherein the Supervisory Control and Data Acquisition (SCADA) communication indicated a false open/close alarm on some of the devices. Siemens has provided a prototype Fuse Saver to address the communication issues, which PSE&G will monitor to ensure it addresses the issues prior to placing additional orders. Because of this, commencement of the full Fuse Saver scope was pushed to 2022 and is expected to commence during the second quarter of 2022.

The current forecasted completion date for the primary components that make up the Contingency Reconfiguration subprogram are provided in **Table 14 – ES 2 Contingency Reconfiguration Forecasted Completion Dates as of March 31, 2022**. This table also shows the forecasted final in-service dates as of the end of 2021 to show movement to the forecast as of the end of the first quarter of 2022.

Table 14 – ES 2 Contingency Reconfiguration Forecasted Completion Dates as of March 31, 2022

Scope & Division		Q4 2021 Forecasted Completion Date	Q1 2022 Forecasted Completion Date
Reclosers	Central	1/31/2022	1/31/2022 (Actual)
	Metro	12/31/2021	12/31/2021 (Actual)
	Palisades	2/28/2022	1/31/2022 (Actual)
	Southern	1/31/2022	1/31/2022 (Actual)
Fuse Savers	Central	9/30/2023	9/30/2023
	Metro	10/31/2023	10/31/2023
	Palisades	12/30/2023	11/30/2023
	Southern	9/30/2023	9/30/2023

As shown in **Table 14**, the Central, Palisades, and Southern Divisions completed their respective recloser scopes at the end of January 2022 (while the Metro Division had previously completed its recloser scope in December 2021). The forecasted in-service dates for the Fuse Saver scope remained unchanged from the prior quarter for three of the four Divisions, with the Palisades Division advancing its forecasted final in-service date to the end of November 2023, and each Division forecasted to complete this scope between September-November 2023.

The Contingency Reconfiguration subprogram costs through the end of the first quarter of 2022 are presented in **Table 15 – ES 2 Contingency Reconfiguration Costs as of March 31, 2022**.

Table 15 – Contingency Reconfiguration Costs as of March 31, 2022

Scope & Division		2019	2020	2021	Q1 2022	Total to Date	Forecast	% of Actuals to Forecast
		Actuals						
Reclosers	Central	$2,737,167	$12,050,820	$9,852,812	$880,537	$25,521,336	$25,521,336	100%
	Metro	$2,231,431	$10,726,610	$11,368,409	$150,325	$24,476,775	$24,476,776	100%
	Palisades	$2,515,569	$12,119,436	$8,280,522	($66,771)	$22,848,756	$22,848,756	100%
	Southern	$2,081,220	$12,405,684	$14,038,043	$530,051	$29,054,997	$29,054,997	100%
Fuse Savers	Central	$9,970	$789,937	$854,118	$249,268	$1,903,293	$10,376,485	18%
	Metro	$7,557	$561,915	$507,742	$160,801	$1,238,016	$11,787,531	11%
	Palisades	$7,468	$522,454	$577,113	$127,207	$1,234,242	$9,566,946	13%
	Southern	$9,792	$859,014	$578,217	$245,990	$1,693,013	$11,640,444	15%
Total		**$9,600,174**	**$50,035,871**	**$46,056,977**	**$2,277,408**	**$107,970,428**	**$145,273,272**	**74%**

As shown in **Table 15**, while the Contingency Reconfiguration subprogram forecast remained relatively unchanged from the prior quarter (in total, decreased approximately $500,000), the Central and Palisades Division forecasts for the Fuse Savers scope experienced more variance with the Central Division Fuse Savers scope decreasing by approximately $1.7 million and the Palisades Division Fuse Savers scope increasing by approximately $1.1 million. These forecast changes were driven by an adjustment to the number of Fuse Saver units assigned to each Division with the reallocation assigning a more equal number of units to each Division. In addition, the negative actuals recorded in the first quarter of 2022 in the Palisades Division for the reclosers scope was the net result of credits received for eight reclosers removed from the subprogram.

Findings & Observations:

- The final 23 reclosers on the subprogram were installed during the first quarter of 2022. With these final installations, the total number of reclosers installed in the ES 2 Program was 1,467 (954 13kV devices and 513 4kV devices).
- The status of the Fuse Savers scope of the subprogram remained relatively unchanged, with no installations in the period and no change in the forecasted final in-service dates for three of the four the Divisions, while the Palisades Division advanced its forecasted final in-service date approximately 30 days. The Fuse Savers costs incurred in the first quarter of 2022 related to advancing and completing more engineering packages in advance of the upcoming installations.
- The Contingency Reconfiguration subprogram forecast continued to remain relatively static as of the end of the first quarter of 2022 from the end of 2021, with the total forecast decreasing by approximately $494,000 (or 0.3%) to $145.3 million.

C. Grid Modernization – Communication System

The Stipulation identified the Grid Modernization – Communication System subprogram to include up to $72 million invested in installing a private wireless communications network to eliminate the use of dedicated phone lines for remote communication for both PSE&G and customer equipment. The overall network will provide coverage using both wireless and fiber technologies to all switching devices on the PSE&G system. The primary scopes within the Grid Modernization – Communication System include installation of the wireless network, fiber installations at selected stations, fiber cutovers at selected station with existing fiber to the PSE&G fiber network, and retrofitting existing reclosers and RTUs with updated routers. A summary of the status of these primary scopes of work as of the end of the first quarter of 2022 is as follows:

- Wireless network: placed in-service as of December 16, 2021; remaining work involves providing radios to support the installation of Fuse Savers.
- Fiber installations and cutovers: 27 out of 38 fiber installation projects completed and 11 out of 12 fiber cutover projects completed.
- Retrofitting existing reclosers: completed as of the fourth quarter of 2021 with a total of 2,318 retrofit reclosers installed.
- Retrofitting RTUs: 85 substation retrofits completed (75 during the first quarter of 2022) out of a current scope of 218 substations.

The retrofit RTU scope increased from 196 substations to 218 substations following PSE&G's determination to include not only substations served by Verizon plain old telephone service (POTS) (which represented the 196 substations), but also those served by Verizon 4G service (which represented the 22 additional stations). This brings the scope in alignment with PSE&G's objective of replacing all third party RTU communication services within its system.

As previously reported, the fiber scope includes installing fiber to electric substations and electric operations centers, in addition to cutting over stations with existing fiber service to the PSE&G fiber network. PSE&G preliminarily identified 41 installation projects and 12 cutovers for the subprogram, with three of 41 installation projects since removed due to the scheduled elimination of the targeted substations or the intended redundancy benefits not achievable after site review. The list of identified fiber installation and cutover projects is presented in **Table 16 – ES 2 Program Fiber Projects by Division as of March 31, 2022**.

Table 16 – ES 2 Program Fiber Projects by Division as of March 31, 2022

Division	Fiber Installation*	Fiber Cutover*
Central	Cranford; Elizabeth Sub HQ; Rahway; Hadley Road HQ; Roselle; Central HQ; Carteret; Edison; Keasby; Mechanic Street; First Street; Lehigh Avenue**	Elizabeth; Henry Street
Metro	East Orange; Metro HQ; Bloomfield; Central Avenue; Haldeon; Irvington; Irvington Sub HQ; Montclair; South Orange; Norfolk Street; Waverly**	-
Palisades	Bergen Point; Hackensack Sub HQ; Fort Lee; Harrison; Ridgewood; West New York; Palisades HQ; Culver Avenue; Morgan Street	Tonnelle Avenue; Spring Valley Road; Union City; Fairview; Polk Street; West Orange
Southern	Southern HQ; Princeton; Chauncey Street; Bordentown; Haddon Heights**; Thirty Second Street**	Delair; East Riverton; Riverside; Mount Holly
Total	***38 projects***	***12 projects***

**Projects underlined have been placed in-service.*
-Identified for removal from subprogram during Q2 2022 (see* ***Section IV*).*

During the first quarter of 2022, seven additional fiber installation projects (Central HQ, Culver Ave, Fort Lee, Hadley Road HQ, Haledon, Ridgewood, and West New York) and two additional fiber cutover projects (Fairview and Polk Street) were placed in-service. This brought the total projects in-service as of the end of the first quarter of 2022 to 27 for the fiber installation projects and 11 for the fiber cutover projects. **Table 17 – ES 2 Program Fiber Projects Status as of March 31, 2022** provides a summary of the status of the fiber installation and cutover projects within the subprogram as of the end of the first quarter of 2022 with the projects in italics representing those placed in-service.

Table 17 – ES 2 Program Fiber Projects Status as of March 31, 2022

Project Name	Q1 2022 Status
Fiber Installation Projects	
Bergen Point	*In-Service (Q1 2021)*
Bloomfield	Continued construction
Bordentown	*In-Service (Q3 2021)*
Carteret	IP work preparation underway; awaiting railroad permits
Central Ave	*In-Service (Q3 2021)*
Central HQ	*In-Service (Q1 2022)*
Chauncey Street	*In-Service (Q3 2021)*
Cranford	*In-Service (Q4 2020)*
Culver Ave	*In-Service (Q1 2022)*
East Orange	*In-Service (Q1 2021)*
Edison	IP work preparation underway; awaiting railroad permits
Elizabeth Sub HQ	*In-Service (Q1 2021)*
First Street	*In-Service (Q3 2021)*
Fort Lee	*In-Service (Q1 2022)*
Hackensack Sub HQ	*In-Service (Q4 2020)*
Haddon Heights	Preliminary engineering*
Hadley Rd HQ	*In-Service (Q1 2022)*
Haledon	*In-Service (Q1 2022)*
Harrison	*In-Service (Q3 2021)*
Irvington	*In-Service (Q4 2021)*
Irvington Sub HQ	*In-Service (Q4 2021)*
Keasbey	IP work preparation underway; awaiting railroad permits
Lehigh Avenue	Preliminary engineering*
Mechanic Street	IP work preparation underway; awaiting railroad permits
Metro HQ	*In-Service (Q1 2021)*
Montclair	Continued construction
Morgan Street	*In-Service (Q4 2021)*
Norfolk St	*In-Service (Q3 2021)*
Palisades HQ	IP work preparation underway; awaiting railroad permits
Princeton	*In-Service (Q3 2021)*
Rahway	*In-Service (Q1 2021)*
Ridgewood	*In-Service (Q1 2022)*
Roselle	*In-Service (Q2 2021)*
So Orange	*In-Service (Q3 2021)*
Southern HQ	*In-Service (Q4 2020)*
Thirty Second Street	Preliminary engineering*
Waverly	Preliminary engineering*
West New York	*In-Service (Q1 2022)*

Project Name	Q1 2022 Status
Fiber Cutover Projects	
Delair	*In-Service (Q4 2020)*
East Riverton	*In-Service (Q4 2020)*
Elizabeth	*In-Service (Q1 2021)*
Fairview	*In-Service (Q1 2022)*
Henry St	*In-Service (Q3 2021)*
Mount Holly	*In-Service (Q4 2020)*
Polk Street	*In-Service (Q1 2022)*
Riverside	*In-Service (Q4 2020)*
Spring Valley Rd	*In-Service (Q1 2021)*
Tonnelle Ave	*In-Service (Q4 2020)*
Union City	*In-Service (Q1 2021)*
West Orange	Completion dependent upon redundant link to Montclair substation being ready (two redundant fiber links required for each router to support reliability guidelines)
Substation Remote Terminal Unit (RTU) Cutovers	
Scope: 218 units	85 cutovers completed
-Project identified for removal from subprogram after the current reporting period, see **Section IV for additional information.*	

The Grid Modernization – Communication System subprogram costs through the end of the first quarter of 2022 are presented in **Table 18 – ES 2 Grid Modernization – Communication System Costs as of March 31, 2022**.

Table 18 – ES 2 Grid Modernization – Communication System Costs as of March 31, 2022

Scope & Division		2019	2020	2021	Q1 2022	Total to Date	Total Forecast	% of Actuals to Forecast
		Actuals						
Retrofit Reclosers	Central	$0	$884,278	$3,304,797	$215,275	$4,404,349	$6,700,030	66%
	Metro	$0	$818,620	$2,362,779	$135,374	$3,316,774	$5,593,403	59%
	Palisades	$0	$825,174	$3,115,474	$186,059	$4,126,707	$6,387,150	65%
	Southern	$0	$929,058	$3,862,816	$194,826	$4,986,700	$7,259,273	69%
Fiber	Central	$1,691	$2,418,851	$5,973,655	$1,581,263	$9,975,460	$10,727,513	93%
	Metro	$1,457	$1,866,697	$3,086,096	$1,576,328	$6,530,578	$7,717,563	85%
	Palisades	$1,582	$2,046,762	$3,603,134	$656,307	$6,307,785	$6,398,139	99%
	Southern	$4,731	$910,483	$2,466,477	$96,721	$3,478,412	$4,236,200	82%
	Cutovers*	$0	$876,502	$607,056	$851,293	$2,334,850	$3,249,145	72%
Wireless Network		$74,306	$6,035,441	$1,282,986	$61,558	$7,454,290	$7,875,891	95%
Bulk Purchase**		$0	$1,524,874	($520,766)	$641,029	$1,645,137	$0	-
Total		**$83,767**	**$19,136,741**	**$29,144,503**	**$6,196,033**	**$54,561,043**	**$66,144,306**	**82%**

**-Includes fiber communication cutovers and substation RTU cutovers (the latter of which began having spend in Q1 2021).*
***-The Bulk Purchase account is used for the purchase of bulk equipment, which is the then assigned to a specific Division when the equipment is released with a credit back to the Bulk Purchase account. Thus, this account is forecasted to have a $0 balance at the end of the ES 2 Program.*

As shown in **Table 18**, the total forecast for the Grid Modernization – Communication System subprogram increased to $66.1 million as of the end of the first quarter of 2022, up approximately $2.5

million from the $63.6 million forecast as of the end of 2021. This increase was primarily driven by the following factors:[2]

- Fiber – Central Division: forecast increased $1.2 million, comprised of:
  - Added Lehigh Avenue project to the subprogram scope/forecast: $0.5 million.
  - Added scope required for battery installation at Edison: $0.2 million.
  - Additional OP Division labor required: $0.3 million.
  - Updated vendor quotes on IP finishing work (Keasbey, Mechanic Street, and Edison): $0.2 million.
- Fiber – Palisades Division: forecast increased $0.2 million, comprised of West New York to Polk Street trailing underground chargers higher than initially forecasted.
- Fiber – Southern Division: forecast increased $0.9 million, comprised of:
  - Added Haddon Heights project to the subprogram scope/forecast: $0.7 million.
  - Higher project management costs than previously forecasted: $0.2 million.
- Substation RTU Cutovers: forecast increased $0.2 million, comprised of an increase in actual costs per unit driven by the complexity of antenna installation at certain stations with a need for Division labor not previously identified.

Findings & Observations:

- The retrofit substation RTU scope ramped up in the first quarter of 2022, with 75 substations completed during the quarter (and 85 total completed) out of a currently forecasted scope of 218 substations.
- Seven additional fiber installation projects and two additional fiber cutover projects were placed in-service during the first quarter of 2022, bringing the total number of projects in-service to 27 fiber installation projects and 11 fiber cutover projects. The fiber scope is expected to be completed by the end of 2022 (see also **Section IV** concerning changes to the fiber scope that occurred after the first quarter of 2022).
- The forecast for the Grid Modernization – Communication system subprogram increased by approximately $2.5 million from the status as of the end of 2021 to $66.1 million as of the end of the first quarter of 2022. The forecast increase was driven by higher costs in the current fiber projects (cost drivers on the individual projects included additional scope, additional labor requirements, and updated vendor quotes).

D. Grid Modernization – ADMS

The Grid Modernization – ADMS scope is split between three primary sections: DMS/DERMS, the OMS, and ADMS platform upgrades. The scope for each primary component of the Grid Modernization – ADMS subprogram and notable activities conducted during the first quarter of 2022 are presented as follows:

[2] Note: part of the forecast increase included adding the Lehigh Avenue and Haddon Heights projects to the subprogram forecast, these projects were subsequently removed from the subprogram during the second quarter of 2022 due to budgetary constraints, see **Section IV**.

DMS/DERMS

- Scope: Provide software and associated services to deploy a Smart Network in order to meet a subset of the ES 2 Program's objectives and use cases.
- Q1 2022 Activities:
  - Prepared and sent laptop to Open Systems International, Inc. (OSII) for use with testing.
  - Completed Sprint 14 & 15.
  - Completed schedule review.
  - Reorganized review of variance documentation with OSII.
- Forecasted Completion as of the end of the first quarter of 2022: 12/19/2022.

OMS

- Scope: Provide a single user interface for more efficient management of trouble orders and analysis of outage data through an integrated OMS, system interfaces, and geographic view of all integrated outage data and damage locations. OMS will include tools for dynamic visualization supporting incident management, damage location identification, dashboards, and the as-operated real-time view of PSE&G's network model. Field personnel also will have access to many of these tools as it relates to the incident(s) assigned to them via the Compass mobile crew application. 10 years' worth of existing OMS data will be migrated into the new system as well.
- Q1 2022 Activities:
  - Completed virtual private network (VPN) weather interface.
  - Completed onsite meetings to review SAP claims requirements and configurations.
  - Completed Sprint 12 and Sprint 12 retrospective.
  - Completed onsite visit for schedule planning for damage records, referrals, and reporting.
  - Completed reviews with cyber security.
  - Completed first and second round of converted data and feedback sessions.
  - Completed Sprint 13.
- Forecasted Completion as of the end of the first quarter of 2022: 4/30/2023.

ADMS Platform

- Scope: Replace, enhance, and expand the existing DSCADA platform elements inclusive of infrastructure components (servers and workstations) and applications (Monarch, Spectra, and Integra) to create an integrated ADMS platform.
- Q1 2022 Activities:
  - Completed System Acceptance Testing (SAT) and analysis of results.
  - Completed vulnerability testing.

  - Completed deconstruction of Edison Production rack.
  - Imaged workstations for Divisions in preparation for training.

- Actual In-Service Date: 1/28/2022.

The currently forecasted in-service dates for the OMS scopes slipped 128 days from the status as of the end of 2021. This shift in the forecasted completion of the OMS scope was the result of rescheduling the "go live" date due to delays in the OMS interface alignment with Mobile Work Management System (MWMS), which was driven by delays in the in-service date of the MWMS (which is not part of the ES 2 Program). The ADMS Platform was placed in-service on January 28, 2022.

The Grid Modernization – ADMS subprogram costs through the end of the first quarter of 2022 are presented in **Table 19 – ES 2 Grid Modernization – ADMS Costs as of March 31, 2022**.

Table 19 – ES 2 Grid Modernization – ADMS Costs as of March 31, 2022

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals				*Forecast*			
$36,213	$16,447,624	$9,854,442	$3,197,877	$2,764,836	$2,474,510	$6,673,902	$2,076,489

Actuals to Date	Forecast	% of Actuals to Forecast
$29,536,155	$43,525,894	68%

Findings & Observations:

- The first of three primary ADMS components was placed in-service during the first quarter of 2022 (the ADMS Platform). While the remaining DMS/DERMS and OMS are currently forecasted to be placed in-service in December 2022 and April 2023, respectively. The OMS scope was rescheduled during the first quarter of 2022 to account for delays to the MWMS (outside of ES 2, but interface alignment required to complete the OMS scope).
- The Grid Modernization – ADMS forecast as of the end of the first quarter of 2022 increased very slightly (approximately $32,000) from the end of 2022, with the total forecast remaining at $43.5 million.

E. Electric Stipulated Base

The Stipulation identified that the electric portion of the Stipulated Base include $100 million in investments at PSE&G's discretion towards electric Outside Plant-Higher Design Standards (OP-HDS) and/or electric stations life cycle subprograms described in the original ES 2 filing.[3] The OP-HDS scope is expected to commence in the summer of 2022 with detailed engineering on a number of circuits that meet the upgrade criteria and reflective of the circuit prioritization, the OP-HDS work is expected to continue through December 2023. In accordance with what the Stipulation provides, PSE&G plans to

[3] As noted in the Stipulation, the electric life cycle upgrades are part of the electric Stipulated Base to be recovered in the Company's next base rate case provided the investments are found to be prudent. The Stipulation also notes that should the 16 stations that comprise the Electric Station Flood Mitigation subprogram be completed for under the $389 million allocated for that subprogram, PSE&G may reallocate such unused funds to stations identified in the life cycle station upgrade portion of PSE&G's petition for accelerated recovery.

fund some of the life cycle station upgrades from the electric program accelerated investment, subject to funds available, after all Electric Station Flood Mitigation projects are funded at their final costs.

As reported in the IM 2020 Second Quarter Report, the initial four stations PSE&G selected for life cycle station upgrades went before the URB in June 2020 for Study level estimate approval and received approval for full funding. In the second quarter of 2021 a fifth station, State Street, was approved by the URB for its outside plant scope to be transferred from the related Electric Station Flood Mitigation project to the life cycle scope. These five stations and their current estimate compared to the actuals to date are provided in **Table 20 – ES 2 Life Cycle Station Upgrade Project Status as of March 31, 2022**.

Table 20 – ES 2 Life Cycle Station Upgrade Project Status as of March 31, 2022

Project	Estimate Level	Base	Risk & Contingency*	Total	Actuals to Date	% of Actuals to Estimate	Forecasted In-Service Date**
1. Hamilton	Study	$16,200,000	-	$16,200,000	$7,274,152	45%	10/28/2022 (↓ +16)
2. Paramus	Study	$20,500,000	-	$20,500,000	$8,861,478	43%	11/14/2022 (↑ -45)
3. Plainfield	Study	$22,700,000	-	$22,700,000	$5,948,906	26%	11/8/2022
4. Woodbury	Study	$17,800,000	-	$17,800,000	$3,625,514	20%	12/30/2022 (↓ +3)
5. State Street (OP)	Study	$19,700,000	-	$19,700,000	$607,150	3%	12/19/2022 (↑ -132)
R&C Balance	-	-	$3,100,000	$3,100,000	-	-	-

-As discussed in **Section II.B., during the first quarter of 2022, PSE&G made the decision to hold risk and contingency at the subprogram level, which resulted in updated estimates being prepared for each project to reflect this change and other project-specific updates as warranted.*

***-Reflects the in-service date of the last major asset (e.g. switchgear), certain activities may take place after this date to support the final in-service date (i.e. when all customers are cutover).*

(↑)-Indicates the forecasted in-service date advanced from the prior quarter.

(↓)-Indicates the forecasted in-service date slipped from the prior quarter.

As shown in **Table 20**, of the five life cycle station upgrade projects, the Paramus and State Street OP projects saw respective forecasted in-service dates advance during the first quarter of 2022, while the Hamilton and Woodbury projects saw their respective forecasted in-service dates slip during the first quarter of 2022. Additional details on each of these life cycle station upgrade projects is provided in the individual subsections that follow.

<u>Findings & Observations</u>:

- Construction continued on the Hamilton, Paramus, Plainfield, and Woodbury projects, while engineering continued to advance on the State Street OP project (which is expected to commence construction in the fourth quarter of 2022).
- There was movement in the forecasted in-service dates for four of the five life cycle upgrade projects during the first quarter of 2022. For Hamilton and Woodbury, the changes were relatively minor (slipping 16 days and 3 days, respectively). While the Paramus project advanced

45 days driven by better than planned construction progress and the State Street OP project advanced 132 days based on an updated schedule from Southern Division on the completion of the circuit, which is required to complete the project.

- The cost forecasts for the five life cycle upgrade projects collectively increased $1.3 million (or 1.3%) from the status as of the end of 2021 to a total forecast of $98.6 million as of the end of the first quarter of 2022. This increase was distributed fairly evenly across the individual projects.

1. Hamilton

During the first quarter of 2022, $3,770,758 was spent on the Hamilton project against a forecast of approximately $3.7 million. This brought total spend on the project to approximately $7.3 million through the end of the first quarter of 2022. The forecasted in-service date for the Hamilton project slipped 16 days from the status as of the end of 2021 to October 28, 2022.

Notable activities conducted during the first quarter of 2022 included the completion of the switchgear foundations and partial delivery of the switchgear (with regulators expected to be delivered in April 2022).

The actual spend by quarter for Hamilton as compared to the current URB approved estimate is provided below.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals				*Forecast*			
$0	$362,372	$3,141,022	$3,770,758	$3,315,653	$2,406,733	$2,269,989	$1,583,299

Actuals to Date	Estimate	Current Forecast	% of Actuals to Forecast
$7,274,152	$16,200,000	$16,849,828	45%

2. Paramus

During the first quarter of 2022, $952,513 was spent on the Paramus project against a forecast of approximately $922,000. This brought total spend on the project to approximately $8.9 million through the end of the first quarter of 2022. The forecasted in-service date for the Paramus project advanced from December 29, 2022, as of the end of 2021, to November 14, 2022, as of the end of the first quarter of 2022. This advancement in the forecasted in-service date was driven by construction progressing better than anticipated.

Notable activities conducted during the first quarter of 2022 on the Paramus project included:

- Pre-construction license and permit compliance/construction requirement review with contractor completed;
- All circuit cutovers completed on the contingency switchgear; and,
- Existing feeder row demolition commenced.

The actual spend by quarter for Paramus as compared to the current URB approved estimate is provided below.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals				*Forecast*			
$0	$840,200	$7,068,765	$952,513	$6,053,040	$1,458,915	$1,094,131	$3,510,574

Actuals to Date	Estimate	Current Forecast	% of Actuals to Forecast
$8,861,478	$20,500,000	$20,978,138	43%

3. Plainfield

During the first quarter of 2022, $1,682,480 was spent on the Plainfield project against a forecast of approximately $1.7 million. This brought total spend on the project to approximately $5.9 million through the end of the first quarter of 2022. The forecasted in-service date for the Plainfield project as of the end of the first quarter of 2022 remained unchanged from the prior quarter at November 8, 2022.

Notable activities conducted during the first quarter of 2022 included the award of the electrical construction scope of work, which is expected to commence in June/July 2022.

The actual spend by quarter for Plainfield as compared to the current URB approved estimate is provided below.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals				*Forecast*			
$0	$682,325	$3,584,101	$1,682,480	$6,147,328	$5,429,853	$1,710,404	$3,479,832

Actuals to Date	Estimate	Current Forecast	% of Actuals to Forecast
$5,948,906	$22,700,000	$22,716,323	26%

4. Woodbury

During the first quarter of 2022, $1,460,525 was spent on the Woodbury project against a forecast of approximately $1.1 million. The variance between forecasted and actual spend in the first quarter was driven by additional soil loadouts and more water sampling needed as well as contracted material handling and control work completed ahead of schedule. This brought the total spend on the project to approximately $3.6 million through the end of the first quarter 2022. The forecasted in-service date for the Woodbury project slipped from December 27, 2022 as of the end of 2021 to December 30, 2022 as of the end of the first quarter of 2022.

Notable activities conducted during the first quarter of 2022 included the start of preliminary civil manhole/conduit work.

The actual spend by quarter for Woodbury as compared to the current URB approved estimate is provided below.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals				*Forecast*			
$0	$551,165	$1,613,823	$1,460,525	$5,006,277	$3,307,944	$2,436,417	$3,958,921

Actuals to Date	Estimate	Current Forecast	% of Actuals to Forecast
$3,625,514	$17,800,000	$18,335,072	20%

5. State Street (Outside Plant)

During the first quarter of 2022, $395,903 was spent on the State Street (OP) project against a forecast of approximately $291,921. The variance between forecasted and actual spend in the first quarter was driven by the A/E completing more design and engineering work and more test pits completed than planned This brought the total spend on the project to approximately $607,000. The forecasted in-service date for the State Street OP project advanced from April 30, 2023, as of the end of 2021, to December 19, 2022, as of the end of the first quarter of 2022. This shift was driven by the Southern Division committing to completing the State Street OP 4kV circuit by the end of 2022.

Notable activities conducted during the first quarter of 2022 included the continuation of detailed engineering.

The actual spend by quarter for State Street (OP) as compared to the current URB approved estimate is provided below.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals				*Forecast*			
$0	$0	$211,247	$395,903	$884,618	$2,397,665	$1,969,139	$13,854,017

Actuals to Date	Estimate	Current Forecast	% of Actuals to Forecast
$607,150	$19,700,000	$19,712,589	3%

F. Gas M&R Station Upgrades

During the first quarter of 2022, three additional projects commenced construction activities (Camden, Central, and East Rutherford), while the Westampton project continued closeout and restoration activities following it being placed in-service in October 2021. **Table 21 – ES 2 Gas M&R Summary Status as of March 31, 2022** below provides the currently approved estimates for each project within the Gas M&R subprogram, along with the actuals to date and forecasted in-service dates.

Table 21 – ES 2 Gas M&R Summary Status as of March 31, 2022

Project	Estimate Level	Base	Risk & Contingency	Total Estimate	Actuals	% of Actuals to Estimate	Forecasted In-Service
1. Camden*	Study	$24,300,000	$5,000,000	$29,300,000	$5,812,073	20%	Dec 2022 (↑)
2. Central*	Study	$23,900,000	$5,100,000	$29,000,000	$12,016,345	41%	Nov 2023 (↓)
3. East Rutherford	Study	$13,800,000	$2,700,000	$16,500,000	$3,865,788	23%	Dec 2022 (↑)
4. Mount Laurel	Study	$9,400,000	$2,000,000	$11,400,000	$1,031,112	9%	Nov 2023 (↓)
5. Paramus*	Study	$11,500,000	$2,200,000	$13,700,000	$1,134,392	8%	Dec 2023
6. Westampton	Study	$9,100,000	$900,000	$10,000,000	$8,180,404	82%	Oct 2021
Subprogram Total		**$92,000,000**	**$17,900,000**	**$109,900,000**	**$32,040,114**	**29%**	**Dec 2023**

**-Included in the Stipulated Base.*
(↑)-Indicates the forecasted in-service date advanced from the prior quarter.
(↓)-Indicates the forecasted in-service date slipped from the prior quarter.

The in-service dates for the Central and Mount Laurel projects as of the end of the first quarter of 2022 slipped approximately 11 months to November 30, 2023, which was driven by a change in schedule priorities for 2022 work. This shift improves the balancing of the spend across the Program duration and avoids outage constraints that require the projects' in-service dates to occur prior the winter heating season. PSE&G anticipates no significant cost increases as a result of this shift in schedule prioritization. As previously reported, the Westampton project was placed in-service as of October 22, 2021.

Findings & Observations:

- The primary efforts to date on the subprogram continue to be primarily related to pre-construction planning efforts, including completing and submitting site plan packages, ordering long lead materials, and awarding the construction work. The Camden, Central, and East Rutherford projects each started the construction phase during the first quarter of 2022.
- The in-service dates of two projects (Central and Mount Laurel) shifted out approximately 11 months to November 2023, which reflected a change in the execution strategy of these projects to better balance the subprogram spend across the full Program and to avoid outage constraints. No meaningful cost impacts are anticipated as a result of this shift.
- The subprogram forecast increased from $107.8 million as of the end of 2021 to $128.3 million as of the end of the first quarter of 2022. The largest contributor for this increase was a $10.2 million increase to the Camden project forecast (while the Central, East Rutherford, and Mount Laurel projects each saw forecast increases of approximately $3.3 to $3.6 million). The forecast increase was driven by additional costs for materials, equipment, and construction based on purchase orders and bid proposals compared to the initial project estimates.
- The IM has found nothing to date that would jeopardize the subprogram being completed on time, particularly given the advancement of the final projects in the subprogram (Central, Mount Laurel, and Paramus). The continued cost pressures noted above have pushed the subprogram forecast to approximately $27.3 million above the Stipulation budget of $101 million.

1. Camden

During the first quarter of 2022, $2,791,701 was spent on the Camden project compared to a forecast of approximately $2.9 million, which brought the total spend to approximately $5.8 million. The forecasted in-service date for the Camden project as of the end of the first quarter of 2022 advanced 14 days from the status as of the end of 2021 to December 16, 2022.

Notable activities completed on the Camden project during the first quarter of 2022 included:

- Received foundation and structural permits;
- Awarded construction contract and held construction kickoff meeting;
- IFC mechanical drawings released; and,
- Site construction commenced.

The actual spend by quarter for Camden as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals				*Forecast*			
$13,326	$859,350	$2,147,696	$2,791,701	$10,015,027	$12,778,011	$6,840,283	$1,154,606

Actuals to Date	Estimate	Current Forecast	% of Actuals to Forecast
$5,812,073	$29,300,000	$36,600,000	16%

2. *Central*

During the first quarter of 2022, $7,112,617 was spent on the Central project compared to a forecast of approximately $7.5 million, which brought the total spend to approximately $12.0 million. The variance in first quarter spend was largely driven by later than expected receipt of final building drawings, which impacted the construction permits and the start of construction. The forecasted in-service date for the Central project as of the end of the first quarter of 2022 slipped 335 days from the status as of the end of 2021 to November 30, 2023 due to a reprioritization of the sequencing of the projects.

Notable activities completed on the Central project during the first quarter of 2022 included:

- Removed portions of existing underground pipelines due to interferences;
- Received majority of steel pipe and some fittings to the site;
- Set up laydown areas;
- Received IFC drawings from the building manufacturer;
- Installed safety fence along access road; and,
- Started demolition and civil work.

The actual spend by quarter for Central as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals				*Forecast*			
$6,869	$670,582	$4,226,277	$7,112,617	$6,629,415	$3,939,027	$2,447,316	$12,367,898

Actuals to Date	Estimate	Current Forecast	% of Actuals to Forecast
$12,016,345	$29,000,000	$37,400,000	32%

3. *East Rutherford*

During the first quarter of 2022, $1,551,290 was spent on the East Rutherford project compared to a forecast of approximately $1.3 million, which brought the total spend to approximately $3.9 million. The variance in first quarter spend was driven by the contractor mobilizing to site and receiving materials earlier than anticipated, which also locked in material pricing to avoid price increases. The forecasted in-service date for the East Rutherford project as of the end of the first quarter of 2022 advanced 14 days from the status as of the end of 2021 to December 16, 2022.

Notable activities completed on the East Rutherford project during the first quarter of 2022 included:

- IFC drawings received from A/E;
- Order placed for small diameter pipe and fittings;
- Began receiving materials on site;
- Installed site fence around perimeter and construction trailer delivered;
- Began performing test pits on site; and,
- Began submitting material test records for approval.

The actual spend by quarter for East Rutherford as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals				*Forecast*			
$9,010	$521,865	$1,783,623	$1,551,290	$5,547,595	$7,740,480	$3,843,635	$702,502

Actuals to Date	Estimate	Current Forecast	% of Actuals to Forecast
$3,865,788	$16,500,000	$21,700,000	18%

4. Mount Laurel

During the first quarter of 2022, $135,639 was spent on the Mount Laurel project compared to a forecast of approximately $96,000, which brought the total spend to approximately $1.0 million. The forecasted in-service date for the Mount Laurel project as of the end of the first quarter of 2022 slipped 335 days from the status as of the end of 2021 to November 30, 2023 due to a reprioritization of the sequencing of the projects.

Notable activities completed on the Mount Laurel project during the first quarter of 2022 included the conditional approval of the site plan by the township planning board.

The actual spend by quarter for Mount Laurel as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals				*Forecast*			
$5,965	$362,167	$527,341	$135,639	$58,457	$77,421	$102,058	$11,430,952

Actuals to Date	Estimate	Current Forecast	% of Actuals to Forecast
$1,031,112	$11,400,000	$12,700,000	8%

5. Paramus

During the first quarter of 2022, $94,755 was spent on the Paramus project compared to a forecast of approximately $140,000, which brought the total spend to approximately $1.1 million. The forecasted in-service date for the Paramus project as of the end of the first quarter of 2022 remains unchanged from the forecast as of the end of 2021 at December 29, 2023.

Notable activities completed on the Paramus project during the fourth quarter of 2021 included:

- Soil erosion permit approved; and,
- Paramus zoning board approved the project.

The actual spend by quarter for Paramus as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals				*Forecast*			
$8,842	$462,452	$568,344	$94,755	$150,612	$118,427	$694,206	$9,402,362

Actuals to Date	Estimate	Current Forecast	% of Actuals to Forecast
$1,134,392	$13,700,000	$11,500,000	10%

6. Westampton

During the first quarter of 2022, $178,124 was spent on the Westampton project compared to a forecast of approximately $130,000, which brought the total spend to approximately $8.2 million. The Westampton was placed in-service as of October 22, 2021, remaining activities include site restoration and final punch list items that will carry over into 2022.

During the first quarter of 2022, notable activities on the Westampton project included:

- New perimeter fence installed; and,
- Security cameras/security system installed.

The remaining items to closeout the project include corrosion protection work and final punch list items relating to site paving/grading. PSE&G expects these activities to be fully complete around July.

The actual spend by quarter for Westampton as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals				*Forecast*			
$8,395	$1,032,670	$6,961,216	$178,124	$187,876	$33,985	$34,045	$0

Actuals to Date	Estimate	Current Forecast	% of Actuals to Forecast
$8,180,404	$10,000,000	$8,436,311	97%

IV. Additional Information Following the end of the First Quarter of 2022

While the vast majority of this IM report is focused on the activities and status of the ES 2 Program during the first quarter of 2022, the timing of certain Program elements and information provided by PSE&G naturally carried over beyond the end of the calendar quarter. Such information will generally be covered in the next IM quarterly report but given the importance of some of this information as it pertains to the ES 2 Program, the IM has provided additional remarks to provide a more complete view of these mitigation changes based on the available information as of the date of this IM 2022 First Quarter Report.

Grid Modernization – Communication System

During the second quarter of 2022, PSE&G updated its fiber project listing based on the current status of scope and cost refinement across the projects and a prioritization of projects based on the available budget. As a result, four additional fiber projects were removed from the subprogram (Haddon Heights, Lehigh Avenue, Thirty-Second Street, and Waverly). Of these projects selected for removal, Waverly was the only one that was identified in the ES 2 filing and its removal was based on the determination that Waverly project under the Electric Station Flood Mitigation subprogram included fiber installation for the IP scope (with base capital funding provided for the OP scope). For the other three projects selected for removal, each was part of the additional locations reviewed by PSE&G for inclusion in the subprogram as part of the full review of all PSE&G substations and Operation Centers previously conducted (see Section IV.A. in the IM 2020 Third Quarter Report). Ultimately, the available budget did not allow these additional projects to be included within the ES 2 Program, though PSE&G has indicated to the IM that the Haddon Heights and Lehigh Avenue fiber projects will be executed outside of the ES 2 Program.

The Stipulation approved $72 million to be invested in the Grid Modernization – Communication System subprogram, but otherwise did not specify specific fiber projects. Following the earlier detailed review conducted by PSE&G to verify current status and communication needs and the current adjustment based on the available budget, the fiber scope now contains fiber installations at 27 distribution substations and eight Operation Centers, in addition to fiber cutovers to stations with existing fiber and the retrofitting of substation RTUs.

This complete list of fiber projects, including those originally proposed, those added (including those preliminarily added and later removed), and those removed, along with their corresponding cost data has been assembled in **Table 22 – ES 2 Fiber Project Status as of March 2023**.

Table 22 – ES 2 Fiber Project Status as of March 2023

Project Name	ES 2 Program Status	Budget*	Forecast	Actual
Bergen Point	Original	$750,000	$701,459	$702,777
Bloomfield	Original	$300,000	$1,482,687	$869,907
Bordentown	Added	$0	$682,285	$687,515
Carteret	Added	$0	$753,816	$974,932
Central Ave	Original	$480,000	$112,759	$113,360
Central HQ	Original	$570,000	$1,800,274	$1,881,116
Chauncey Street	Original	$840,000	$875,395	$870,023
Cranford	Original	$300,000	$357,876	$363,658
Culver Ave	Added	$0	$832,145	$861,758
East Orange	Original	$480,000	$1,143,568	$1,026,100
Edison	Added	$0	$1,070,066	$1,484,149
Elizabeth	Removed**	$210,000	$0	$0
Elizabeth Sub HQ	Original	$555,000	$749,712	$750,226
First Street	Original	$300,000	$618,118	$618,401
Fort Lee	Original	$480,000	$1,263,941	$1,262,214
Hackensack	Removed	$480,000	$0	$0
Hackensack Sub HQ	Original	$825,000	$595,412	$619,055
Haddon Heights	Added & Removed***	$0	$738,942	$0
Hadley Rd HQ	Added	$0	$1,460,786	$1,583,448
Haledon	Original	$300,000	$567,567	$610,260
Harrison	Original	$300,000	$576,805	$576,805
Howell Street	Added & Removed	$0	$0	$0
Irvington	Original	$300,000	$174,633	$175,166
Irvington Sub HQ	Original	$300,000	$601,657	$634,347
Keasbey	Original	$840,000	$784,856	$1,051,327
Lakeside	Removed	$570,000	$0	$0
Lehigh Avenue	Added & Removed***	$0	$818,014	$0

Project Name	ES 2 Program Status	Budget*	Forecast	Actual
Market Street	Removed	$390,000	$0	$0
Mechanic Street	Original	$1,200,000	$925,256	$1,047,867
Metro HQ	Original	$300,000	$582,568	$583,020
Montclair	Original	$840,000	$2,147,782	$2,696,966
Morgan Street	Added	$0	$518,181	$534,856
Nineteenth Ave.	Removed	$390,000	$0	$0
Norfolk St	Original	$300,000	$186,265	$187,317
Orange Valley	Removed	$300,000	$0	$0
Palisades HQ	Original	$255,000	$409,690	$616,105
Princeton	Original	$300,000	$1,132,137	$1,129,128
Rahway	Original	$390,000	$1,026,601	$1,075,955
Ridgewood	Original	$390,000	$483,367	$491,302
Roselle	Original	$390,000	$428,183	$430,033
So Orange	Original	$390,000	$312,099	$314,997
Southern HQ	Original	$570,000	$708,350	$672,201
State Street	Removed	$390,000	$0	$0
Thirty Second Street	Added & Removed	$0	$0	$0
Toney's Brook	Removed	$480,000	$0	$0
Waverly	Removed***	$300,000	$439,640	$0
West New York	Original	$300,000	$997,565	$930,181

*-Only the projects from the initial list had established budgets.
**-The Elizabeth Substation retained a fiber cutover scope that was executed as part of the ES 2 Program.
***-These projects were/will be completed outside of the ES 2 Program.

ENERGY STRONG PROGRAM

INDEPENDENT MONITOR

2022 FIRST QUARTER REPORT

APPENDIX A – DRAFT REPORT COMMENTS AND RESPONSES

APRIL 17, 2023

PEGASUS GLOBAL HOLDINGS, INC. ®

Questions & Comments to the IM 2022 First Quarter Report Formally Submitted to the IM

ID #	Question/Comment	IM Response	Report Changes
S-INF-1	**Reference Q1 2022 Report, Page 16** Please provide additional details explaining how PSE&G's plan to use the contingency switchgear from the Ridgefield 13kV project on the Kingsland project will result in cost efficiencies. Please also indicate when PSE&G expects to obtain the contingency switchgear to be used on the Ridgefield 13kV project.	The use of the Kingsland and Meadow Road switchgears as temporary (contingency) switchgears on the Ridgefield 13kV and Leonia projects, respectively, resulted in cost savings approximately equal to the purchase price of two 13kV sheltered aisle switchgears. Each project would have had to spend an additional $1.69 million (the actual price for the switchgears at Kingsland and Meadow Road) if PSE&G had not utilized the switchgears at Ridgefield 13kV and Leonia in this approach as these projects both required contingency switchgear to facilitate a construction sequence that maintained reliable supply to the customers.	**Section III.A.**
S-INF-2	**Reference Q1 2022 Report, Page 20, Front Street Substation** Regarding the Front Street Substation project: a. Please provide additional details about the "higher than estimated switchgear award ($2.1 million)", including the budgeted and actual cost of the switchgear. Please also describe the competitive bidding process utilized. b. Please explain why PSE&G elected to utilize an external A/E firm rather than in-house engineering as initially planned (resulting in an increase of $0.3 million).	The contract award price for the permanent switchgear was $5,540,793, with PSE&G adding a 10% management reserve to its cost account not part of the purchase order to cover unforeseen changes in scope (project complexities or field conditions). This was $1.2 million above PSE&G's estimate (with the contingency switchgear accounting for an additional $0.9 million above PSE&G's estimate). This appears to generally reflect market conditions as similar switchgear ordered earlier in the Program (pre-Covid 19) from the same vendor was approximately $1.4 million less than this current order. As with other switchgear procurements, PSE&G utilized a competitive bid process for the award of the Front Street switchgear. This included requests for quotations issued to three vendors, with two submitting bids (PowerCon and Powell). The evaluation criteria included: delivery date, cost, PSE&G specification, testing and commissioning, technical exceptions, installations support, warranty and other terms and conditions, training, previous project performance, and supplier diversity spend. Based on PSE&G's evaluation of the bids, it found Powell had a slightly more competitive commercial proposal (approximately $5.1 million against approximately $5.5 million), but PowerCon had a superior technical proposal. Additionally, while both vendors have past experience with PSE&G, Powell provided the Waverly 4kV switchgear, which saw approximately $300K in change	**Section III.A.3.**

ID #	Question/Comment	IM Response	Report Changes
		orders and were anticipated to be expected on this switchgear as well if Powell was awarded the work. Thus, based on the superior technical proposal and the past experience, PSE&G awarded this switchgear to PowerCon. Concerning the switch from internal resources to an external A/E, PSE&G determined it did not have the resources available to support the project schedule. PSE&G did perform the preliminary engineering on this project before outsourcing the detailed engineering.	
S-INF-3	**Reference Q1 2022 Report, Page 25, State Street Substation** Regarding the State Street Substation project, please provide additional details explaining why the first circuit will not be ready for energization when originally expected (resulting in a delay of 87 days).	When the project started field inspections and detailed engineering, it was determined that the initially planned overhead route was not feasible due to an existing overhead pole in the area that was not known at the time of the initial design. The updated route changes to exit the station at a different side of the station, which required installation of an underground manhole and duct bank system as overhead electrical infrastructure is not permitted on this side of the station.	**Section III.A.13.**
S-INF-4	**Reference Q1 2022 Report, Page 26, Waverly Substation** Regarding the Waverly Substation project: a. Please provide additional details about the "Additional charges for site plan revisions and related extended project duration ($2.6 million)". b. Please estimate the total costs associated with site plan revisions to date.	PSE&G's $2.6 million estimate of the costs resulting from the revised site plan is comprised of: additional engineering ($0.8 million), revised fencing and external façade improvements ($1.0 million), and additional charges for extended project duration ($0.8 million). Concerning the actual site plan revisions, based on the feedback received from the City of Newark Zoning Board and others involved in the community outreach, PSE&G redesigned the street facing frontages of the project to have a fence with a brick finish such that they appear to be walls, with the two entrances gates having a matching color scheme. The fences have locations for artwork to be placed with lighting for nighttime viewing. Additionally, the portions of the isolation walls that are visible were redesigned to match the brick and related features and finishes of the street facing fences. The new site plan also included the addition of street trees, shrubs and landscaping in the sidewalk area that will not interfere with the electric utilities.	**Section III.A.15.**
S-INF-5	**Reference Q1 2022 Report, Page 29, Contingency Reconfiguration Subprogram** Regarding the Fuse Savers scope, please indicate if there were any adjustments during Q1 2022 to the total number of Fuse Saver units to be installed.	During the first quarter of 2022, there was no change to the targeted number of Fuse Savers to be installed in the Program, which remained at 1,713 units. PSE&G's approach has been to review the actual cost data and related installation status information on a quarterly basis to update the installation plan and overall quantity of units planned for the Program.	No change

ID #	Question/Comment	IM Response	Report Changes
S-INF-6	**Reference Q1 2022 Report, Page 30, Grid Modernization – Communication System Subprogram** Regarding the Retrofit Substation Remote Terminal Unit (RTU) scope: a. What is attributed to the scope increasing from 196 substations (as indicating in the IM's Q4 2021 Report, Page 32) to 218 substations? b. Please compare the cost of the current scope to the cost of the originally budgeted scope.	The retrofit substation RTU scope increased from 196 to 218 to support PSE&G's objective of replacing all third party RTU communication service within its system rather than an earlier assumption to replace only those relying on plain old telephone service (POTS). The 196-unit scope was based on the substations served on Verizon POTS lines, while the 218-unit scope adds 22 other substations that are served by Verizon 4G service. The original budget for the substation RTU scope was $1,629,394 to replace 218 units. The actual costs per unit have increased by approximately 15% over the original budget driven by additional work to install antennas on the external of the control houses at some substations.	**Section III.C.**
S-INF-7	**Reference Q1 2022 Report, Page 32, Grid Modernization – Communication System Subprogram** Please provide the anticipated in-service date of the fiber cutover project "West Orange."	The West Orange project was successfully cutover to the TFI network on August 11, 2022.	No change
S-INF-8	Regarding the Grid Modernization – Communication System (Fiber Scope), please identify all locations added to the project scope (pursuant to the Record of Decision decisions in Section IV.A. of the IM 2020 Third Quarter Report) and provide their estimated costs. Please also identify all locations removed from the project scope and provide their originally budgeted costs.	This complete list of fiber projects, including those originally proposed, those added, and those removed, along with their corresponding cost data has been assembled and inserted into the body of the report at **Section IV.**	**Section IV.**
S-INF-9	**Reference Q1 2022 Report, Page 36, Table 20 – ES 2 Life Cycle Station Upgrade Project Status as of March 31, 2022** Please clarify if the risk and contingency associated with Electric Stipulated Base projects is included within the total risk and contingency for the Electric Station Flood Mitigation subprogram ($41.8 million). If not, please provide the risk and contingency associated with the Electric Stipulated Base project.	The R&C for the electric Stipulated Base life cycle projects is held under a subprogram placeholder as base funding. As of March 31, 2022, this base funding had a $3.1 million balance.	**Table 20**
S-INF-10	**Reference Q1 2022 Report, Page 38, Plainfield Substation**	The $20,978,138 forecast shown for Plainfield had incorrectly copied the Paramus forecast. The correct forecast for the Plainfield project as of the end of the first quarter of 2022 is $22,716,323. This represents an increase of approximately	**Section III.E.3.**

ID #	Question/Comment	IM Response	Report Changes
	What is attributed to the decrease in the forecasted cost of the Plainfield Substation project from $22,164,495 (See Q4 2021 Report, Page 38) to $20,978,138?	$500,000 from the end of 2022 and was largely the result of the electrical PO being higher than estimated, slightly offset by Division actuals being lower than estimated.	
S-INF-11	**Reference Q1 2022 Report, Page 39, Table 21 – ES 2 Gas M&R Summary Status as of March 31, 2022** With reference to the Gas M&R projects, please refer to Table 21 which indicates that the Camden M&R project is included in Stipulated Base. Please reconcile this with PSE&G's recent Energy Strong II cost recovery filing (BPU Docket Nos. ER22110669 and GR22110670), Filed November 1, 2022), in which PSE&G requested accelerated cost recovery of Camden M&R project expenditures placed in-service through January 31, 2023.	PSE&G initially projected to seek accelerated recovery on the Mount Laurel, East Rutherford, and Westampton M&R Stations based on the schedule forecasts that projected these stations to be the first three in-service in the subprogram. However, due to subsequent schedule changes, the Camden M&R station achieved in-service status ahead of Mount Laurel, therefore PSE&G is requesting cost recovery on Camden M&R station in this recent filing. This is consistent with the Stipulation that provides the first $50.5 million in Gas M&R investments to be recovered through the accelerated recovery, with any prudently incurred costs beyond $50.5 million being applied to the Stipulated Base.	No change
S-INF-12	Regarding the Central Gas M&R project, please provide additional details describing the need to increase the project scope from two (2) buildings to four (4) buildings (as discussed in S-INF-16 of the IM's Q4 2021 Report).	The design refinement resulted in a change of heater technology from water bath to the more efficient glycol heaters that provide for lower emissions. The reduced emissions facilitate obtaining the Title V Air Permit. This technology change also included replacement of four additional heaters that are near end of life, so PSE&G replaced them all, thus allowing the project to benefit from the improved technology. The original office level scope included the replacement of only one water bath heater. PSE&G also determined that use of two additional buildings would better address safety and other operational requirements/concerns. One of the additional buildings houses the circulating glycol heaters and the other houses the heat exchangers and the flow control equipment that balances the flow between the pipeline companies.	No change
S-INF-13	**Reference Q1 2022 Report, Page 43, Section IV. Additional Information Following the end of the First Quarter of 2022** Please indicate if the three (3) fiber projects removed from the Program (Haddon Heights, Lehigh Avenue, Thirty-Second Street) will be conducted outside of the Program.	PSE&G has indicated that the Haddon Heights and Lehigh Avenue projects are being executed outside of the ES 2 Program under base capital funding, but are scheduled to be completed within the Program window. The Thirty-Second Street project has been cancelled and will not be executed at this time.	**Section IV.**
RCR-IM-1	With reference to page 3 of the Independent Monitor's Draft First Quarter 2022 Report, please provide an update to the Kingsland switchgear delivery delay.	The reference on page 3 speaks to a delay to the switchgear #1 for the Ridgefield 13kV project, which impacts Kingsland as the contingency switchgear currently being used on the Ridgefield 13kV project will be the permanent switchgear for Kingsland once the switchgear #1 is received on the Ridgefield 13kV project.	No change

ID #	Question/Comment	IM Response	Report Changes
		Regarding the delivery status of switchgear #1 for the Ridgefield 13kV project, as of the end of the first quarter it was forecasted for delivery on July 22, 2022, with the actual delivery taking place on August 24, 2022 (or approximately one more month of delay from the status as of the end of the first quarter of 2022).	
RCR-IM-2	With reference to page 3 of the Independent Monitor's Draft First Quarter 2022 Report, please explain if the other projects are affected by major equipment deliveries and how this may increase individual project costs.	Due to the material and resource availability issues impacting Powercon, PSE&G's switchgear manufacturer, the outstanding switchgear deliveries are all at risk. As of the end of the first quarter of 2022, the following projects had open switchgear deliveries: Meadow Road, Ridgefield 13kV (switchgear #1), Lakeside, Leonia (switchgear #2), Clay Street, Toney's Brook, Waverly, Woodlynne, Orange Valley, Front Street (contingency and permanent switchgears). The 4kV life cycle station upgrade projects are similarly at risk with their open deliveries, which as of the end of the first quarter of 2022, was each of these projects (aside from the contingency switchgear on Paramus that was delivered in July 2021). The impacts from equipment delivery delays varies project to project depending on when the switchgear is needed to support the construction schedule (some of these deliveries were originally scheduled for storage due to being planned to be received well ahead of the need date). Additionally, as delivery delays are realized, the workarounds or mitigation options vary by project, with some more capable of absorbing impacts by resequencing or working activities in parallel when possible. PSE&G indicated to the IM that to date there have been no cost increases resulting from the major equipment delivery delays as PSE&G has been able to reprioritize deliveries with its vendor in addition to utilizing project float and/or shifting project schedules. There remains a risk for any project with open deliveries that the delivery date continues to shift out, which eventually can extend the project duration and lead to additional costs.	No change
RCR-IM-3	With reference to page 5 of the Independent Monitor's Draft First Quarter 2022 Report, please indicate how the project risk and contingency current risk registers are tracked.	The individual project risk registers are updated monthly by the project teams and reviewed by the subprogram and program leads, with the total R&C amounts aggregated and tracked at the subprogram level. During estimate transitions, if a project's base estimate increases, funding from the R&C placeholder is released to the project to fund the additional amount (likewise, if the base estimate decreases, the variance is returned to the R&C placeholder.	No change
RCR-IM-4	With reference to Table 12 ES 2 Electric Substation Flood Mitigation Project Cost Status as of March 31, 2022, please explain the increase in the projected cost of the Clay Street Substation from $30.8 to $31.3 million.	**Table 12** shows the current estimate and forecast for the Electric Station Flood Mitigation projects. For Clay Street, the current estimate (revised Conceptual level) is $30.8 million and was approved in January 2022, while the current forecast is $31.3 million and reflects the change in status, conditions, and	**Section III.A.2.**

ID #	Question/Comment	IM Response	Report Changes
		assumptions that have occurred since that last estimate update, including specifically: • Additional civil work required (enlarging two manholes, extra shifts) ($0.5 million).	
RCR-IM-5	With reference to Table 12 ES 2 Electric Substation Flood Mitigation Project Cost Status as of March 31, 2022, please explain the increase in the projected cost of the Ridgefield 13kV Substation from $26.1 to $27.2 million.	The $1.1 million forecast increase on the Ridgefield 13kV project reported during the first quarter of 2022 was driven by: • More than anticipated dewatering and updated design of manhole modifications ($0.5 million); and, • More Division effort required on manhole expansion and circuits cutovers due to difficult of breaking back the duct bank (high strength concrete) and working around the energized circuits ($0.6 million).	**Section IIIA.11.**
RCR-IM-6	With reference to Table 12 ES 2 Electric Substation Flood Mitigation Project Cost Status as of March 31, 2022, please explain the increase in the projected cost of the Waverly Substation from $36.2 to $37.6 million.	The $1.4 million forecast increase on the Waverly project reported during the first quarter of 2022 was driven by: • Civil construction PO awarded higher than estimated ($1.3 million); and, • Cost of switchgear storage ($0.1 million).	**Section III.A.15.**
RCR-IM-7	With reference to Table 12 ES 2 Electric Substation Flood Mitigation Project Cost Status as of March 31, 2022, please explain the increase in the projected cost of the Woodlynne Substation from $21.3 to $24.3 million.	The $3.0 million forecast increase on the Woodlynne project reported during the first quarter of 2022 was driven by: • Material and civil construction POs higher than estimated and bids ($0.4 million); and, • Revised Division estimate ($2.6 million).	**Section III.A.16.**
RCR-IM-8	With reference to page 18 of the Independent Monitor's Draft First Quarter 2022 Report, please explain the individual project updates to the Academy Street, Clay Street, Front Street, Hasbrouck Heights, Kingsland, Orange Valley, Ridgefield 13kV, State Street, Waverly, and Woodlynne projects (with Hasbrouck Heights and State Street also advancing to the Definitive stage) that collectively resulted in a $15.0 million increase.	The reference on page 18 reflects a summary of the updated estimates for these Electric Station Flood Mitigation projects that are individually discussed in greater detail within the respective project subsection under **Section III.A.** The IM notes that of the collective $15.0 million estimate increase on these projects, $12.3 million stemmed from two projects specifically: Waverly, which increased $6.8 million; and Woodlynne, which increased $5.8 million. Details of these updated project estimates are discussed within **Section III.A.15.** and **Section III.A.16.**, respectively.	No change
RCR-IM-9	With reference to page 28 of the Independent Monitor's Draft First Quarter 2022 Report, please explain how many installed Fuse Savers have experienced communication issues and have any remote control units been replaced and what are the costs with projected repairs or replacement.	In total, PSE&G installed 113 Fuse Savers during its pilot program, of which 10 locations experienced communication issues. PSE&G installed the modified external antenna at each of these 10 locations, which resolved the communication issues. Design of the standard RCU (enclosure and components) was modified to include the provision to install an external antenna in the field where needed (which has been at approximately 10% of the locations). The costs associated with the modified units are approximately $1,100 per unit and these units also require slightly longer installation times, but this is not tracked separately.	**Section III.B.**

<table>
<tr><th>ID #</th><th>Question/Comment</th><th>IM Response</th><th>Report Changes</th></tr>
<tr><td>RCR-IM-10</td><td>With reference to Table 12 – ES 2 Electric Station Flood Mitigation Project Cost Status as of March 31, 2022, please explain the change in the subprogram risk and contingency total for Academy Street, Clay Street, Front Street, Hasbrouck Heights, Kingsland, Lakeside Avenue, Leonia, Market Street, Meadow Road, Orange Valley, Ridgefield 13kV, Ridgefield 4kV, State Street, Toney's Brook, Waverly and Woodlynne Substations compared to Table 12 – ES 2 Electric Station Flood Mitigation Project Cost Status as of December 31, 2021 in Independent Monitor's Draft Fourth Quarter 2021 Report.</td><td>A summary of the Electric Station Flood Mitigation project estimate updates from the prior status as of the end of 2021 to the status as of the first quarter of 2022 is provided below:
<table><tr><th></th><th>Base</th><th>R&C</th><th>Total</th></tr><tr><td>As of Dec. 2021</td><td>$339,800,000*</td><td>$49,200,000</td><td>$389,000,000</td></tr><tr><td>As of Mar. 2022</td><td>$347,200,000</td><td>$41,800,000</td><td>$389,000,000</td></tr><tr><td colspan="4">*-included $3.7 million as a placeholder (to match the Stipulation budget of $389 million), this was absorbed by the R&C balance in the updated estimates.</td></tr></table>
Early in 2022 PSE&G instituted a change in the way it manages the R&C for the Electric Station Flood Mitigation projects shifting from each project maintaining its own R&C funds to managing the R&C at the subprogram level. Prior to this shift, the projects' R&C was updated at the time of an estimate transition (50% to 70% to 90%). This change allows PSE&G to manage the R&C month-to-month based on the current project risk registers, which are updated monthly by the project team and reviewed by the subprogram lead. When the individual projects go through an estimate transition any variance to the base estimate results in additional funds added to the R&C placeholder (if the base estimate decreased) or release of R&C to cover the increase in base.</td><td></td></tr>
<tr><td>RCR-IM-11</td><td>With reference to Table 20 ES 2 Life Cycle Station Upgrade Project Status as of March 31, 2022, please explain the subprogram risk and contingency total for Hamilton, Paramus, Plainfield, Woodbury and State Street Substations.</td><td>A summary of the Life Cycle Station Upgrade project estimate updates from the prior status as of the end of 2021 to the status as of the first quarter of 2022 is provided below:
<table><tr><th></th><th>Base</th><th>R&C</th><th>Total</th></tr><tr><td>As of Dec. 2021</td><td>$82,800,000</td><td>$19,600,000</td><td>$102,400,000</td></tr><tr><td>As of Mar. 2022</td><td>$96,900,000</td><td>$3,100,000</td><td>$100,000,000</td></tr></table>
For the purposes of internal budget allocations and authorizations, PSE&G has planned for a portion of the Life Cycle Station Upgrade projects to be funded through the Accelerated Recovery (Electric Station Flood Mitigation funding) as provided in the Stipulation ("If the Company determines the work on the 16 aforementioned substations identified in the flood mitigation subprogram can be completed under the $389 million investment ceiling associated with substations, PSE&G may reallocate any funds to those stations identified in the life cycle station upgrade portion of the petition for accelerated recovery.").</td><td>Table 20</td></tr>
</table>

ID #	Question/Comment	IM Response	Report Changes
PSEG-1	Please indicate circuit cutovers continued on the Academy Street project during the first quarter of 2022 and that circuit cutovers will be completed in the second quarter of 2022.	This activity has been added to the Academy Street project discussion.	**Section III.A.1.** and **Table 11**
PSEG-2	Please indicate in **Table 11** that the Waverly project upcoming activities for the second quarter of 2022 include setting the 26kV switchgear and start of commissioning.	This activity has been added to the Waverly project discussion.	**Table 11**

ENERGY STRONG 2 PROGRAM INDEPENDENT MONITOR 2022 SECOND QUARTER REPORT

PREPARED AND SUBMITTED BY

PEGASUS GLOBAL HOLDINGS, INC. ®

CONFIDENTIAL

JUNE 28, 2023

Table of Contents

Appendices

List of Acronyms and Abbreviations

Advanced Distribution Management Systems .... ADMS

Advanced Metering Interface .... AMI

Allowance for Funds Used During Construction .... AFUDC

Architect and Engineer .... A/E

Board of Public Utilities .... BPU

Construction Work In Progress .... CWIP

Costs of Removal .... COR

Distribution Management System .... DMS

Distributed Energy Resource Management System .... DERMS

Distribution Supervisory Control and Data Acquisition .... D-SCADA

Energy Strong 2 .... ES 2

Fault Protection Analysis .... FPA

Gas Metering & Regulating .... Gas M&R

Geographic Information System .... GIS

Henkels & McCoy .... H&M

Independent Monitor .... IM

Industrial Site Recovery Act .... IRSA

Inside Plant .... IP

Issued for Construction .... IFC

Liquid Propane Air .... LPA

Mobile Work Management System .... MWMS

Open Systems International Inc. .... OSII

Outage Management System .... OMS

Outside Plant .... OP

Outside Plant-Higher Design Standards .... OP-HDS

Project & Construction .... P&C

Protective Distribution System .... PDS

Public Service Electric & Gas .... PSE&G

Purchase Order .... PO

Quality Assurance System .... QAS

Record of Decision .... ROD

Remote Terminal Unit .... RTU

Risk and Contingency .... R&C

Supervisory Control and Data Acquisition .... SCADA

Transmission Fiber Infrastructure .... TFI

Utility Review Board .... URB

Value of Loss Load .... VOLL

I. Executive Summary

Public Service Electric & Gas's (PSE&G's) Energy Strong 2 (ES 2) Program was established from a Stipulation that the involved parties agreed to in August 2019, as approved by a Board of Public Utilities (BPU) Order dated September 11, 2019, with an effective date of September 21, 2019. The Stipulation provided the ES 2 Program would be comprised of five primary subprograms: Electric Station Flood Mitigation; Contingency Reconfiguration; Grid Modernization – Communications; Grid Modernization – Advanced Distribution Management Systems (ADMS); and Gas Metering & Regulating (Gas M&R) Station Upgrades. In addition, a Stipulated Base spend was established that includes both an electric component (higher outside plant design standards and station life cycle upgrades) and a gas component (overlapping with the Gas M&R subprogram). This report contains the Independent Monitor's (IM's) findings and observations on the ES 2 Program elements and other information on the Program's status as of the second quarter of 2022.

During the second quarter of 2022, the bulk of the spend within the ES 2 Program was within the subprograms with larger individual projects (Electric Station Flood Mitigation, Electric Stipulated Base, and Gas M&R). Within the Electric Station Flood Mitigation subprogram, eight projects remain in construction as of the end of the second quarter of 2022 (with Market Street completing its construction scope and Front Street commencing construction during the quarter). Four of these projects are forecasted to be placed in-service during the fourth quarter of 2022, with the remaining stations forecasted to be completed in 2023 or early 2024. Within the Electric Stipulated Base scope, four of the five projects are in construction (with pre-construction activities underway on the other project, State Street Outside Plant (OP)), all five of these projects remain forecasted to go in-service during the fourth quarter of 2022. On the Gas M&R subprogram, three of the projects continued construction during the second quarter of 2022, each of these three projects is forecasted to go in-service during the fourth quarter of 2022. This will leave the Mount Laurel and Paramus projects as the two remaining projects in the subprogram (following the earlier completion of the Westampton project). Updated project estimates were also prepared for the Gas M&R projects during the second quarter of 2022, which saw the overall subprogram estimate increase by $18.9 million as driven by scope and execution refinement, with larger impacts realized from limited front-end planning performed on the stations at the time of the ES 2 filing.

Within the other subprograms, Fuse Saver installations recommenced in the Contingency Reconfiguration subprogram following the earlier pilot program conducted in 2020-2021. The Fuse Saver installations are expected to continue through the end of 2023, with 1,641 units currently forecasted for this scope of work. Within the Grid Modernization – Communication System subprogram, primary efforts during the second quarter of 2022 continued to focus on completing the remaining fiber installations (seven remaining as of the end of the quarter) and the remaining substation remote terminal unit (RTU) retrofits (48 remaining as of the end of the quarter). A new Grid Modernization – Communication System subprogram estimate was also completed during the second quarter of 2022, with the fiber installation scope estimate increasing $3.0 million from the prior estimate based on the higher costs observed on completed projects and the wireless network and retrofits scope decreasing by $1.3 million from the prior estimate based on an updated number of radios planned for the subprogram. Within the Grid Modernization – ADMS subprogram, go-live was achieved on the ADMS platform in June 2022, the quality assurance system (QAS) environment was built in the Outage Management System (OMS) scope, and additional patches were competed in the Distribution Management System (DMS)/Distributed Energy Resource Management System (DERMS) scope. An updated estimate was also prepared for the Grid

Modernization – ADMS subprogram during the second quarter of 2022, which resulted in the subprogram estimate increasing by $13.6 million from the prior estimate, with the increase driven by scope updates, extended schedules/resource requirements, and additional risk and contingency (R&C).

Table 1 – ES 2 Subprogram & Stipulated Base Status as of June 30, 2022 below provides the spend to date on the subprograms within the ES 2 Program and Stipulated Base compared to the total forecast, Stipulation budget, and forecasted completion for each.

Table 1 – ES 2 Subprogram & Stipulated Base Status as of June 30, 2022

Subprogram	Q2 Spend	Total Spend to Date*	Total Forecast*	% of Actuals to Forecast	Forecasted Completion**	Stipulation Budget***
Electric Station Flood Mitigation	**$17,828,688**	**$157,676,463**	**$358,158,627**	**44%**	**Feb 2024**	**$389M**
Contingency Reconfiguration	**$2,123,126**	**$110,093,554**	**$145,612,679**	**76%**	**Dec 2023**	**$145M**
Grid Modernization – Communications	**$3,225,559**	**$57,786,702**	**$66,279,811**	**87%**	**Dec 2023**	**$64.3M**
Grid Modernization – ADMS	**$8,230,861**	**$37,767,016**	**$53,479,258**	**71%**	**Dec 2022**	**$42.7M**
Electric Stipulated Base	**$13,592,008**	**$39,909,208**	**$99,102,305**	**40%**	**Dec 2023**	**$100M**
Gas M&R Station Upgrades^	**$19,389,664**	**$51,429,779**	**$104,273,652**	**49%**	**Dec 2023**	**$101M**
Total*	**$64,389,907**	**$454,662,622**	**$826,906,331**	**55%**	**Feb 2024**	**$842M**

-Note: total figures may not fully align due to rounding. Additionally, the total forecast R&C in its forecasts for these projects. See **Table 11 and **Table 20** for the Electric Station Flood Mitigation and Gas M&R project estimates, respectively, with base costs and R&C shown.*
***-Final in-service date.*
****-Following the $7.7 million transfer in July 2021 from the Grid Modernization – Communications subprogram to the Grid Modernization – ADMS subprogram.*
^-Includes both the ES 2 projects and the Stipulated Base gas projects.

Given the prominence of the Electric Station Flood Mitigation subprogram, which represents over half of the total ES 2 Program spending (before the Stipulated Base consideration), a summary of the projects within this subprogram is provided below in **Table 2 – ES 2 Electric Station Flood Mitigation Status as of June 30, 2022**.

Table 2 – ES 2 Electric Station Flood Mitigation Status as of June 30, 2022

Project	Total Estimate (rounded)	Actuals	% of Actuals to Estimate	Forecasted In-Service Date*
1. Academy Street	$9,300,000	$6,404,971	69%	**10/19/2021**
2. Clay Street	$30,800,000	$10,783,240	35%	1/30/2023
3. Front Street^	$25,900,000	$3,670,971	14%	11/8/2023 (↓+13)
4. Hasbrouck Heights	$19,300,000	$11,967,537	62%	12/23/2022 (↑-32)
5. Kingsland	$6,400,000	$1,665,091	26%	10/4/2023 (↓+2)
6. Lakeside Avenue	$39,400,000	$1,756,207	5%	9/18/2023
7. Leonia	$24,900,000	$20,947,894	84%	12/13/2022 (↓+28)
8. Market Street	$29,100,000	$28,022,997	96%	**6/25/2021**
9. Meadow Road	$7,200,000	$1,652,591	23%	9/22/2023
10. Orange Valley	$14,700,000	$1,186,155	8%	12/29/2023
11. Ridgefield 13kV	$26,100,000	$21,957,130	84%	12/13/2022

Project	Total Estimate (rounded)	Actuals	% of Actuals to Estimate	Forecasted In-Service Date*
12. Ridgefield 4kV	$20,800,000	$20,703,809	100%	**5/16/2021**
13. State Street	$19,600,000	$10,631,628	54%	12/19/2022
14. Toney's Brook	$16,200,000	$2,294,598	14%	4/17/2023 (↑-4)
15. Waverly	$36,200,000	$8,949,013	25%	2/27/2024 (↑-7)
16. Woodlynne	$21,300,000	$5,082,698	24%	10/10/2023

-Reflects the in-service date of the last major asset (e.g. switchgear), certain activities may take place after this date to support the final in-service date (i.e. when all customers are cutover).* ***Bold* *dates indicate the actual in-service date.*

(↑)-*Indicates the forecasted in-service date advanced from the prior quarter.*

(↓)-*Indicates the forecasted in-service date slipped from the prior quarter.*

^- *The Front Street project was proposed by PSE&G during the second quarter of 2021 to replace the cancelled Constable Hook project.*

During the second quarter of 2022, there were no updated estimates approved for the Electric Station Flood Mitigation projects. The projects that are active in construction (Clay Street, Front Street, Hasbrouck Heights, Leonia, Ridgefield 13kV, State Street, Waverly, and Woodlynne) had the highest spend during the quarter. **Table 2** also shows that six of the sixteen projects had movement during the second quarter of 2022 in the forecasted in-service date, with three advancing and three slipping. Of these six projects, four had the forecasted in-service dates change by less than two weeks (Front Street, Kingsland, Toney's Brook, and Waverly). While the Hasbrouck Heights forecasted in-service date advanced 32 days from the prior quarter, driven by resequencing construction activities and better than expected progress, and the Leonia forecasted in-service date slipped 28 days, driven by delays to the 13kV switchgear #2 delivery that slipped from mid-May to an actual delivery of June 16, 2022. As previously reported, the Waverly final in-service date had improved following the receipt of the approved site plan, but remains outside the Program end date following the earlier site plan delays due to slips in the forecasted delivery of the 4kV switchgear for the project, with a current forecasted in-service date of February 27, 2024.

The IM has found nothing to date that would jeopardize the overall ES 2 Program being completed on budget, although most individual subprograms are forecasted near or above their Stipulation budgets. Additionally, schedule challenges, particularly on the Waverly substation and other projects with forecasted in-service dates near the Program end date that are at risk due to the delays on the switchgear deliveries will continue to warrant further monitoring by the IM to identify if the ES 2 Program will be completed within the defined timeline. At this time, the following projects have forecasted in-service dates near the end of the Program end date and have open switchgear deliveries: Front Street, Lakeside Avenue, Orange Valley, Waverly, and Woodlynne. For Waverly specifically, the forecasted delivery date for the 4kV switchgear slipped 11 days from the status as of the end of the prior quarter. As previously discussed, on a monthly basis, PSE&G reviews the project schedules and assesses opportunities to improve the schedule based on the current status and information available, including the current delivery projections for the remaining switchgear.

As per N.JA.C. Section 14:3-2A.5(c)2, the IM reports are to address:

i. *The effectiveness of Infrastructure Investment Program investments in meeting project objectives;*

ii. *The cost-effectiveness and efficiency of investments;*
iii. *The appropriateness of cost assignments; and*
iv. *Any other information required by the Board.*

The IM focuses the majority of the discussion within each report on these primary objectives, after introducing summarized the findings on these areas in the IM 2021 Third Quarter Report, the IM will continue to provide a summary on these areas for each report with an emphasis on new information relative to the current reporting period. These summarized findings are as follows:

- **Effectiveness of ES 2 investments in meeting project objectives**: The objectives for each subprogram within the ES 2 were defined within PSE&G's ES 2 filing and confirmed by the Stipulation. The overall objectives focused on improving system resiliency, reliability, and hardening through rebuilding or replacing selected substations, installing smart control and monitoring devices on distribution circuits (reclosers, fuse savers, etc.), installing ADMS and a new communication system, and rebuilding selected Gas M&R stations. Within **Section III** of this report, the IM provides a review of the status of the efforts performed to meet these objectives for each subprogram. During the second quarter of 2022, the following projects/scopes were placed in-service and/or completed:
    - Electric Station Flood Mitigation: Academy Street, Market Street, and Ridgefield 4kV previously placed in-service. Next projects forecasted to go in-service are the Hasbrouck Heights, Leonia, Ridgefield 13kV, and State Street projects, each forecasted to go in-service by the end of 2022.
    - Contingency Reconfiguration: Fuse Saver installations recommenced in May 2022 with 13 units installed during the quarter (126 units installed on the Program in total out of a currently planned scope of 1,641 units).
    - Grid Modernization – Communication System: 85 substation RTU retrofits completed (bringing the total to 170 out of a total scope of 218 substations); seven fiber projects and one fiber cutover project remaining.
    - Electric Stipulated Base: Hamilton's substation battery was placed in-service during the quarter. Each life cycle station upgrade project is forecasted to go in-service by the end of 2022.
    - Gas M&R: Westampton previously placed in-service in October 2021, the next stations forecasted for completion are the Camden and East Rutherford stations planned to go in-service by the end of 2022.

- **Cost-effectiveness and efficiency of investments**: To assess the cost effectiveness and efficiency of ES 2 investments, the IM began with a review of the initial scope, estimate, and related planning documents for each project to establish a baseline to monitor progress against as the work advances. As the Program execution advances, the IM continues to evaluate actual costs against the initial estimates and current forecasts, including seeking additional information relating to any variances identified. While the overall Program's current cost forecast is below the Stipulation amount, the IM has observed cost increases realized on specific projects or aspects of the Program and found the majority of these increases stem from scope evolution and/or more detailed estimates from the time of the ES 2 filing, as well as the more recent changes in general market conditions (e.g. Covid-19 impacts, supply chain issues, etc.). The updated subprogram forecasts as of the end of the second quarter of 2022 compared to the end of the prior quarter were as follows:

- Electric Station Flood Mitigation: subprogram forecast increased approximately $8.6 million (or 2.5%) to approximately $358.2 million.
- Contingency Reconfiguration: subprogram forecast increased approximately $339,000 (or 0.2%) to approximately $145.6 million.
- Grid Modernization – Communication System: subprogram forecast increased approximately $136,000 (or 0.2%) to approximately $66.3 million.
- Grid Modernization – ADMS: subprogram forecast increased approximately $10.0 million (or 22.9%) to approximately $53.4 million.
- Electric Stipulated Base: subprogram forecast increased approximately $0.5 million (or 0.5%) to approximately $99.1 million.
- Gas M&R: subprogram forecast decreased approximately $24.1 million (or -18.7%) to approximately $104.3 million.

As shown above, the biggest subprogram forecast changes during the second quarter of 2022 were in the Electric Station Flood Mitigation, Grid Modernization – ADMS, and Gas M&R subprograms. Within the Electric Station Flood Mitigation subprogram, this increase was primarily on the Clay Street, Kingsland, Orange Valley, and Waverly projects, each seeing construction awards higher than estimated, slightly offset by a scope reduction on the Lakeside Avenue project. Within the Grid Modernization – ADMS subprogram, the forecast increase reflected an updated estimate that detailed the scope and interface complexities in the project. Within the Gas M&R subprogram, the forecast decrease primarily reflected PSE&G removing the LPA scope on the Camden and Central projects from the ES 2 Program.

- **Appropriateness of cost assignments**: The IM receives and reviews recurring data concerning the accumulation of costs within the Program. Based on that review, the IM submits follow-up questions to the Company regarding that data for the reporting period. Such follow-up questions generally focus on the following aspects:
    - Review of any unusual changes in cost elements from period-to-period, including but not limited to allowance for funds used During construction (AFUDC), cost of removal (COR), and the allocation of overheads.
    - Review spend on capital accounts, such as Construction Work in Progress (CWIP) as it relates to overall spend, AFUDC, and COR.
    - Verify cost accumulations and classifications appear to be in accordance with Generally Accepted Accounting Principles (GAAP), to the extent the IM has access to such information.
    - Review and investigation of prior period adjustments and/or corrections to capital accounts.
    - Engage the Company's Internal Audit group on specific areas to audit, review, and assess – particularly for areas in which the IM has limited or no visibility (proprietary data, accounting systems, etc.).

Through the above steps, the IM tracks and monitors how the Company is recording costs to support the finding that the cost assignments appear to be appropriately applied. These cost items are discussed further within **Section II.C.** of this IM report.

As noted in the IM 2020 First Quarter Report, the IM conducts its assessment in accordance with Generally Accepted Government Auditing Standards (GAGAS, or more commonly referred to as the "Yellow Book" standards). The Yellow Book provides a framework for conducting performance management reviews/audit engagements with competence, integrity, objectivity, and independence that result in information used for oversight, accountability, transparency, and improvements of the audited programs and operations. On April 19, 2023, a draft IM 2022 Second Quarter Report was submitted to PSE&G, BPU Staff, and Rate Counsel. Per the Yellow Book, the transmittal of a draft report is intended to allow for review and comment by the audited entity and others to develop a fair, complete, and objective report. A summary of the comments on the draft report and the IM's responses are provided in **Appendix A – Draft Report Comments and Responses**. This **Appendix A** also identifies specific sections within this IM 2022 Second Quarter Report that have been edited, supplemented with additional information, or otherwise revised in response to the comments received.

II. Program Status

A. Key Decisions

In order to capture formalized key decisions regarding the ES 2 Program, PSE&G completes a "Record of Decision" (ROD) that includes a description of the decision; alternatives considered; the decision made; and rationale for the decision. The RODs are assessed by the IM as they are completed to review their impact to the Program. In addition, the IM may request PSE&G complete a ROD to formalize a decision if such a decision has not yet been formalized through the ROD process.

During the second quarter of 2022, there were no additional RODs issued. The current and pending RODs as of the date of this IM 2022 Second Quarter Report are presented below in **Table 3 – ES 2 Records of Decisions**.

Table 3 – ES 2 Records of Decisions

Subprogram	Record of Decision	IM Comments
Electric Station Flood Mitigation	Academy Street & State Street Change in Mitigation Method	Reasonable and appropriate *(See Section B.1. in the IM 2020 First Quarter Report)*
Electric Station Flood Mitigation	Engineering Support for Energy Strong Program Projects	Reasonable and appropriate *(See Section B.2. in the IM 2020 First Quarter Report)*
Grid Modernization – Communication System	Wireless Communication Network	Reasonable and appropriate *(See Section II.A.1. in the IM 2020 Third Quarter Report)*
Grid Modernization – Communication System	Substation Communication Center	Reasonable and appropriate *(See Section II.A.2. in the IM 2020 Third Quarter Report)*
Grid Modernization – Communication System	Fiber Scope	Reasonable and appropriate *(See Section IV.A. in the IM 2020 Third Quarter Report)*
Electric Station Flood Mitigation	Constable Hook, Lakeside, & Orange Valley Change in Mitigation Method	Reasonable and appropriate *(See Sections II.A.3. and IV.B. in the IM*

Subprogram	Record of Decision	IM Comments
		2020 Third Quarter Report and additional discussion in Section II.A.1. and Section IV.B. of the IM 2020 Fourth Quarter Report)
Grid Modernization – Communication System	Communication Retrofit of Replacement and non-ES-II Units	Reasonable and appropriate *(See Section II.A.2. in the IM 2020 Fourth Quarter Report)*
Electric Station Flood Mitigation	Market Street Radioactive Soil Testing and Handling	Reasonable and appropriate *(See Section II.A.3. in the IM 2020 Fourth Quarter Report)*
Electric Station Flood Mitigation	Transfer of Clay Street Wastewater Wall Scope from ES2FM to Clay Street 69kV Project	Reasonable and appropriate *(See Section IV.A. in the IM 2020 Fourth Quarter Report)*
Contingency Reconfiguration	Energy Strong II Electric Program – Contingency Reconfiguration Subprogram, 13kV and 4kV Reclosers	Reasonable and appropriate *(See Section IV.A. in the IM 2021 First Quarter Report and Section II.A.1. in the IM 2021 Second Quarter Report)*
Grid Modernization – ADMS	Outage Management System (OMS) Implementation	Reasonable and appropriate *(See Section IV.A. in the IM 2021 First Quarter Report and Section II.A.2. the IM 2021 Second Quarter Report)*

B. Program Management

Beginning in July 2020, the IM began participating in a bi-weekly call with PSE&G to review its bi-weekly ES 2 Program Dashboard. As with the original Energy Strong Program, the Dashboard provides a mechanism for PSE&G to monitor and control activities to be completed in order to achieve key near-term milestones, including a focus on recently completed activities, any key issues, and other key metrics (e.g. installation targets) as appropriate. These calls have proven to be an effective way for the IM to stay informed on current and upcoming activities and to allow a venue for discussions between the IM and PSE&G on these activities and status updates and continue to be held on a recurring basis.

C. Cost Assignments

1. Costs of Removal (COR)

Costs of Removal (COR) generally include costs for such activities as environmental removal, removal of inside station equipment, structures, foundations, towers and fixtures, conductors and other electrical devices, poles and fixtures, transformers, plant demolition, foundations, and removal of underground conduit and other wiring. Generally, COR are charged to Accumulated Depreciation and are amortized and recovered through a component of depreciation expense. The specific method and amount of recovery is determined in gas and electric rate cases before the BPU.

Table 4 – ES 2 Program Costs of Removal as of June 30, 2022, below itemizes the charges to COR for the second quarter of 2022, the first quarter of 2022 (for comparative purposes), total COR for the years 2021, 2020, 2019, and total ES 2 Program COR to date. These amounts do not reflect any salvage value reductions, which have been *de minimis* in the ES 2 program through June 30, 2022.

Table 4 – ES 2 Program Costs of Removal as of June 30, 2022

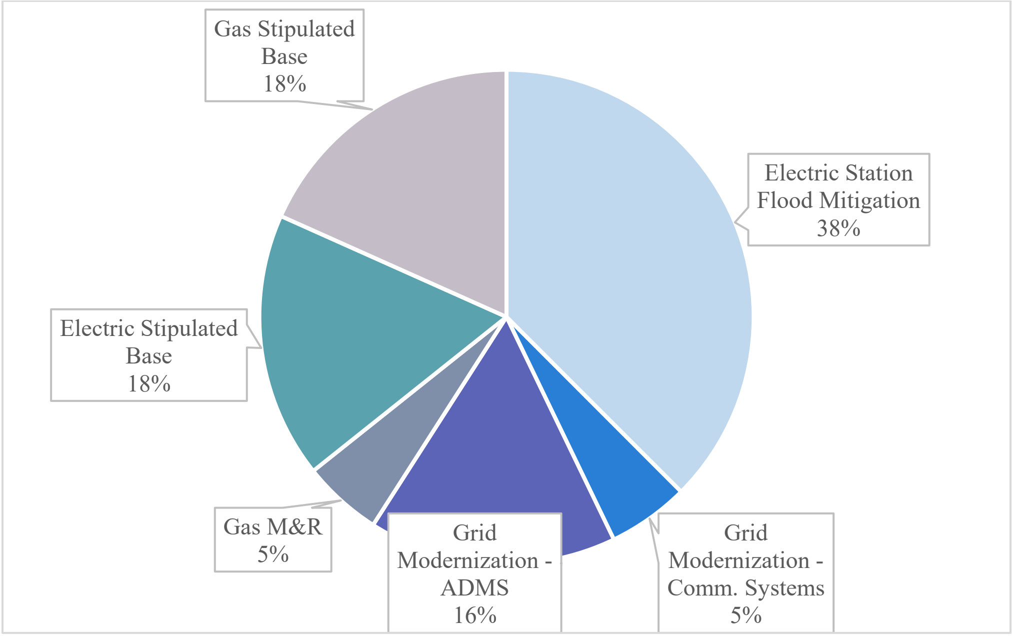
Subprogram	Q2 2022	Q1 2022	Total 2022 (YTD)	Total 2021	Total 2020	Total 2019 (Q4)	Total COR
	(in $ thousands)						
Electric Station Flood Mitigation	$595.7	$873.4	$1,469.1	$5,558.7	$1,021.1	$0	**$8,048.9**
Contingency Reconfiguration	$35.7	$229.3	$265.0	$2,250.2	$2,198.9	$431.0	**$5,145.1**
Grid Modernization – Communications	$14.0	$11.0	$25.0	$137.8	$24.4	$0	**$187.2**
Grid Modernization – ADMS	$0	$0	$0	$0	$0	$0	**$0**
Electric Stipulated Base	$340.5	$370.0	$710.5	$150.0	$0	$0	**$860.5**
Gas M&R Station Upgrades	$0	($0.4)	($0.4)	$148.9	$0	$0	**$148.5**
Gas Stipulated Base	$0	$431.5	$431.5	$196.1	$0	$0	**$627.6**
Total	**$985.9**	**$1,914.8**	**$2,900.7**	**$8,441.7**	**$3,244.4**	**$431.0**	**$15,017.8**

The COR charges incurred on the Program for the second quarter of 2022 primarily reflect: (i) approximately $0.2 million of COR activities at the Ridgefield 13kV substation project for demolition of the bus system, disconnect switch, and feeder rows; (ii) approximately $0.2 million at the Leonia substation project for foundation demolition and underground cable removal; and (iii) approximately $150,000 of foundation and feeder row removal costs at the Paramus lifecycle project under the Electric Stipulated Base.

2. Construction Work-in-Progress (CWIP) & In-Service Transfers

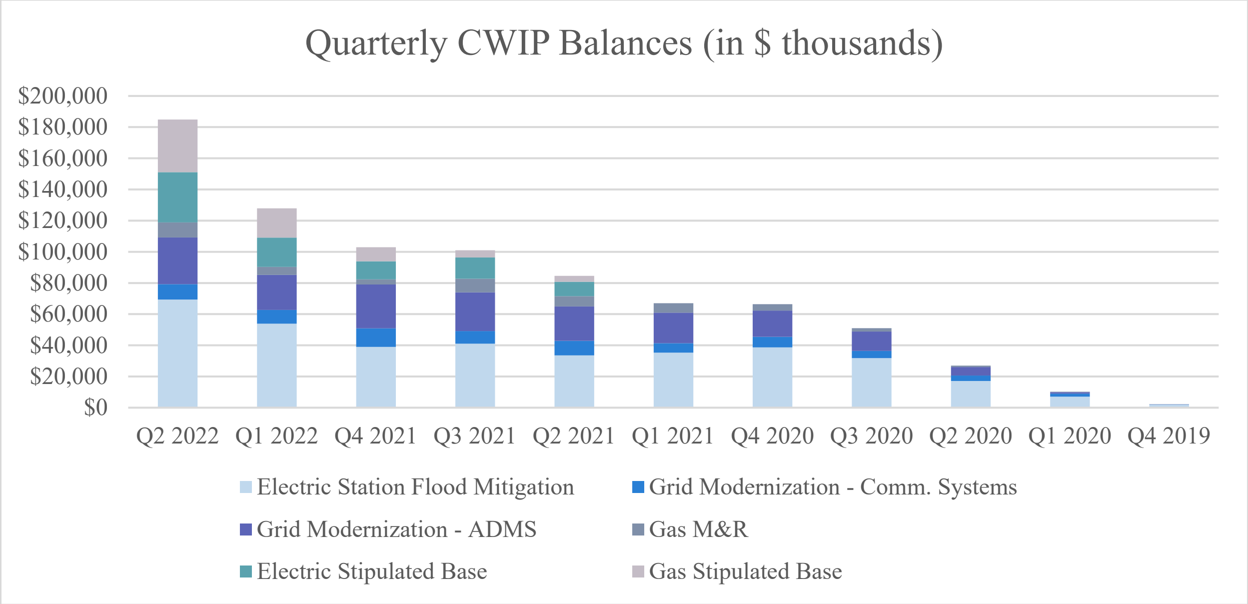
As of June 30, 2022, the ES 2 CWIP balance was $184.9 million, compared to $127.9 million as of the end of the prior quarter. The largest components of CWIP as of June 30, 2022 were the Hasbrouck ($12.4 million), State Street ($11.1 million), Clay Street ($11.0 million), and Waverly ($9.7 million) Electric Station Flood Mitigation projects; the Central ($18.8 million) and Camden ($13.7 million) Gas Stipulated Base M&R projects; the Hamilton ($10.5 million) and Plainfield ($7.9 million) substations under the Electric Stipulated Base; and, work associated with the ADMS subprogram ($30.0 million). The Electric Station Flood Mitigation subprogram comprises the largest component of total end of period CWIP outstanding, as depicted in **Figure 1 – ES 2 CWIP as of June 30, 2022** below.

Figure 1 – ES 2 CWIP as of June 30, 2022



In addition, **Figure 2 – ES 2 CWIP Balances by Subprogram as of June 30, 2022** below depicts the composition of end-of-quarter CWIP balances by subprogram for the second quarter of 2022, the first quarter of 2022, and each quarter of 2021 and 2020, and the fourth quarter of 2019.

Figure 2 – ES 2 CWIP Balances by Subprogram as of June 30, 2022



	Q2 2022	Q1 2022	Q4 2021	Q3 2021	Q2 2021	Q1 2021	Q4 2020	Q3 2020	Q2 2020	Q1 2020	Q4 2019
Electric Station Flood Mitigation	$69,358	$ 53,834	$ 38,947	$ 41,077	$ 33,531	$ 35,299	$ 38,727	$ 31,860	$ 17,149	$ 7,101	$ 1,987
Grid Modernization - Comm. Systems	$ 9,872	$ 8,847	$ 11,991	$ 8,077	$ 9,343	$ 6,026	$ 6,760	$ 4,529	$ 3,508	$ 1,908	$ 75
Grid Modernization - ADMS	$30,010	$ 22,534	$ 28,057	$ 24,817	$ 22,085	$ 19,600	$ 16,837	$ 12,502	$ 5,428	$ 969	$ 36
Gas M&R	$ 9,642	$ 5,086	$ 3,338	$ 8,735	$ 6,574	$ 6,123	$ 4,032	$ 2,149	$ 951	$ 291	$ 53
Electric Stipulated Base	$32,179	$ 18,841	$ 11,560	$ 13,645	$ 9,280	$ -	$ -	$ -	$ -	$ -	$ -
Gas Stipulated Base	$33,854	$ 18,757	$ 9,042	$ 4,691	$ 3,808	$ -	$ -	$ -	$ -	$ -	$ -

Transfers from CWIP to plant in service were minimal during the second quarter of 2022, totaling approximately $0.1 million. Total ES 2 transfers from CWIP have been $86 million through June 30, 2022. It should be noted that work related to certain assets, such as the reclosers under the Contingency Reconfiguration subprogram, generally can be completed without being recorded through CWIP. As such, no AFUDC is recorded on these expenditures. This accounting treatment is in accord with generally accepted accounting principles and the Company's accounting policies.

3. Allowance for Funds Used During Construction (AFUDC)

The amount of quarterly AFUDC recorded by the Company for each ES 2 subprogram during the second and first quarters of 2022, total 2022 to date, total AFUDC for the years 2021, 2020 and 2019, and total ES 2 AFUDC accrued to date, is shown below **Table 5 – ES 2 Program AFUDC as of June 30, 2022**.

Table 5 – ES 2 Program AFUDC as of June 30, 2022

Subprogram	Q2 2022	Q1 2022	Total 2022 (YTD)	Total 2021	Total 2020	Total 2019 (Q4)	Total AFUDC
	(in $ thousands)						
Electric Station Flood Mitigation	$944.5	$759.0	$1,703.5	$2,281.2	$936.5	$9.9	**$4,931.1**
Contingency Reconfiguration	$0	$0	$0	$0	$0	$0	**$0**
Grid Modernization – Communications	$123.1	$115.6	$238.7	$386.9	$184.3	$0.2	**$810.1**
Grid Modernization – ADMS	$438.9	$385.7	$824.6	$1,365.6	$352.7	$0.1	**$2,543.0**
Electric Stipulated Base	$383.9	$230.0	$613.9	$524.6	$44.0	$0	**$1,182.5**
Gas M&R Station Upgrades (incl. Stip. Base)	$395.6	$208.3	$603.9	$470.0	$70.0	$0.2	**$1,144.1**
Total	**$2,286.0**	**$1,698.6**	**$3,984.6**	**$5,028.3**	**$1,587.5**	**$10.4**	**$10,610.8**

AFUDC accrued for ES 2 projects during the second quarter of 2022 increased over AFUDC accrued during the first quarter of 2022 as the result of increases in total average CWIP balances across all subprograms.

During the first quarter of each year, the AFUDC rate is reviewed for possible reset as it applies to the current year based on updated capital structure and component cost data. For the year 2022, the new AFUDC rate was calculated to be 6.92%, using the capital structure and component costs as of January 31, 2022. This rate is higher than the 2021 rate of 6.81%, primarily due to a zero balance of short-term in the 2022 calculation (vs. a $44 million balance of short-term debt in 2021), and also to an 8% reduction in the Company's amount of long-term debt outstanding (lowering the debt component of the capital structure from 45.5% to 44.8%), and a reduction in the embedded cost of long-term debt, both as used in the AFUDC calculation. In calculating the 2022 AFUDC rate, the Company used (i) a 3.63% embedded cost of long-term debt (vs. 3.85% in 2021), (ii) no short-term debt, and (iii) a cost of equity of 9.60% (unchanged from 2021).

Subsequent to the annual reset calculation referred to above, and during the course of each year, the AFUDC rate is also recalculated as it applies to each fiscal quarter. If the recalculated rate changes by 25 basis points from the rate then in effect, the rate is reset and retroactively applied to January 1 of that year. For the second quarter of 2022, based on data as of June 30, 2022, the recalculated weighted average

AFUDC accrual rate (6.92%) did not meet this criterion to warrant changing from the annual rate (6.92%) in effect. Therefore, AFUDC was accrued during the second quarter of 2022 at the calculated rate of 6.92%.

The IM observes that the Company's calculation of the AFUDC rate and its application is in accordance with both PSE&G's accounting policy and Plant Instruction 3(17) of the Federal Regulatory Commission's Uniform Systems of Accounts prescribed for public utilities.

The IM also notes that the relevant AFUDC information as it relates to second quarter 2022 ES 2 project costs is consistent with the applicable dictates of the Stipulation entered into with respect to these Energy Strong projects. The IM will continue to review future ES 2 AFUDC accruals for consistency with relevant provisions of the Stipulation for accounting and reporting purposes only, and not as a party to, or in expressing an opinion concerning, any rate proceedings.

4. Allocated Overheads

PSE&G follows a philosophy of allocating overhead costs, whether at the Service Company or from utility support organizations, to the operating company or unit receiving the benefit, and ultimately, if appropriate, settling costs to individual assets. Where possible, services are charged directly to the entity receiving the benefit, but where direct charging of costs is not feasible, cost allocations from the Service Company to operating companies are prescribed in a BPU-approved schedule issued pursuant to a BPU order in July 2003. This Order was amended by a BPU Order dated June 8, 2022, allowing the company to transfer certain employees to the PSE&G Service Company in an effort to better support transmission growth opportunities and projects. This action had no impact on existing overhead allocations. The Stipulation requires the Company to follow its current practices with regard to capitalized overheads.

For ES 2 electric and gas distribution projects, allocated overhead costs should primarily come from utility-related labor costs associated with administrative and supervisory personnel, labor and other costs associated with bargaining unit personnel, fringe benefits, materials handling costs, payroll taxes and depreciation expense. Shown below in **Table 6 – ES 2 Program Overhead Allocations as of June 30, 2022** are the allocated overhead costs charged to ES 2 subprograms for the second and first quarters of 2022 (for comparative purposes), 2022 year-to-date, total 2021, total 2020, total 2019, and total ES 2 Program allocated overheads to date.

Table 6 – ES 2 Program Overhead Allocations as of June 30, 2022

Subprogram	Q2 2022	Q1 2022	Total 2022 (YTD)	Total 2021	Total 2020	Total 2019 (Q4)	Total Overhead Allocations
	(in $ thousands)						
Electric Station Flood Mitigation	$2,208	$2,185	$4,393	$14,368	$14,023	$287	**$33,071**
Contingency Reconfiguration	$795	$843	$1,638	$14,420	$17,109	$3,415	**$36,582**
Grid Modernization – Communications	$717	$1,802	$2,519	$9,171	$3,625	$12	**$15,327**
Grid Modernization – ADMS	$124	$76	$200	$501	$426	$11	**$1,138**
Electric Stipulated Base	$1,275	$1,449	$2,724	$2,123	$259	$0	**$5,106**

Subprogram	Q2 2022	Q1 2022	Total 2022 (YTD)	Total 2021	Total 2020	Total 2019 (Q4)	Total Overhead Allocations
	(in $ thousands)						
Gas M&R Station Upgrades (incl. Stip. Base)	$339	$197	$536	$735	$291	$15	**$1,577**
Total	**$5,458**	**$6,552**	**$12,010**	**$41,318**	**$35,733**	**$3,740**	**$92,801**

The overwhelming majority of overhead costs allocated to ES 2 projects during the second quarter of 2022 are costs allocated from areas that support all utility distribution and transmission projects, including ES 2 projects. More specifically, most (approximately 83%) of the second quarter allocated costs reflect labor costs of supervisory, administrative and operations planning personnel, labor and other costs from bargaining unit personnel, and fringe benefits associated with these labor costs. The decrease in overhead costs for the second quarter of 2022 from the first quarter of 2022 reflects primarily the decrease in spend on outside services and labor on Grid Modernization projects.

D. System Performance

1. Current Reporting Quarter Major Events

During the second quarter of 2022, there were no Major Events reported in PSE&G's service territory.

III. Project Status

A. Electric Station Flood Mitigation

A summary of the subprogram plan as of the end of the second quarter of 2022 compared to the status as of the end of 2019, end of 2020, and end of 2021 is provided below in **Table 7 – ES 2 Electric Station Flood Mitigation Subprogram Milestone Schedule as of June 30, 2022**. Note that the Market Street and Ridgefield 4kV projects were previously placed in-service and closed out, thus there are no further updates to these projects (which have been further called out in italics in **Table 7**).

Table 7 – ES 2 Electric Station Flood Mitigation Milestone Schedule as of June 30, 2022

Project	Plan Status Point	2019		2020				2021				2022				2023					2024
		Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4		
1. Academy Street	Dec. 2019		KO					C					IS		CO					*December 31, 2023 - ES 2 Program End*	
	Dec. 2020		KO		C									CO							
	Dec. 2021		KO		C						IS						CO				
	Jun. 2022		KO		C						IS		CO								
2. Clay Street	Dec. 2019	*Schedule Under Development*																			
	Dec. 2020			KO							C					IS					CO (Q2)
	Dec. 2021			KO							C				IS						CO (Q1)
	Jun. 2022			KO							C					IS					CO (Q1)
3. Front Street^	Dec. 2019	*Not in ES 2 Program*																			
	Dec. 2020	*Not in ES 2 Program*																			
	Dec. 2021								KO				C						IS		CO (Q2)
	Jun. 2022								KO				C						IS		CO (Q2)

Project	Plan Status Point	2019		2020				2021				2022				2023					2024
		Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	*December 31, 2023 - ES 2 Program End Date*	
4. Hasbrouck Heights	Dec. 2019		KO						C						IS		CO				
	Dec. 2020		KO									C					IS		CO		
	Dec. 2021		KO									C					IS	CO			
	Jun. 2022		KO									C			IS			CO			
5. Kingsland	Dec. 2019			KO				C			IS		CO								
	Dec. 2020			KO										C					IS		CO (Q2)
	Dec. 2021			KO											C		IS		CO		
	Jun. 2022			KO									C						IS		CO (Q2)
6. Lakeside Avenue	Dec. 2019*				KO				C										IS		CO (Q2)
	Dec. 2020						KO							C					IS		CO (Q2)
	Dec. 2021						KO							C					IS		CO (Q2)
	Jun. 2022						KO							C				IS			CO (Q1)
7. Leonia	Dec. 2019	*Schedule Under Development*																			
	Dec. 2020			KO		C									IS		CO				
	Dec. 2021			KO		C									IS		CO				
	Jun. 2022			KO		C									IS		CO				
8. Market Street	Dec. 2019			KO				C	OS		CO										
	Dec. 2020			KO					C	OS		CO									
	Dec. 2021			KO						C/OS	CO										
9. Meadow Road	Dec. 2019	*Schedule Under Development*																			
	Dec. 2020			KO											C				IS		CO (Q2)
	Dec. 2021			KO										C				IS			CO (Q1)
	Jun. 2022			KO											C			IS			CO (Q1)
10. Orange Valley	Dec. 2019	*Schedule Under Development*																			
	Dec. 2020					KO										C					IS (Q1); CO (Q3)
	Dec. 2021					KO										C					IS (Q1); CO (Q3)
	Jun. 2022					KO									C				IS		CO (Q2)
11. Ridgefield 13kV	Dec. 2019			KO	C										IS		CO				
	Dec. 2020			KO	C										IS		CO				
	Dec. 2021			KO	C										IS		CO				
	Jun. 2022			KO	C										IS		CO				
12. Ridgefield 4kV	Dec. 2019			KO						C	OS			CO							
	Dec. 2020			KO	C				OS		CO										
	Dec. 2021			KO	C				OS		CO										
13. State Street	Dec. 2019		KO					C								IS					CO (Q1)
	Dec. 2020		KO						C				IS								CO (Q1)
	Dec. 2021		KO						C					IS				CO			
	Jun. 2022		KO						C						IS		CO				
14. Toney's Brook	Dec. 2019			KO						C									IS		CO (Q2)
	Dec. 2020			KO										C			IS				CO (Q2)
	Dec. 2021			KO										C			IS				CO (Q2)
	Jun. 2022			KO										C			IS		CO		

Project	Plan Status Point	2019		2020				2021				2022				2023					2024
		Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4		
15. Waverly	Dec. 2019	*Schedule Under Development*																		*December 31, 2023 - ES 2 Progr*	
	Dec. 2020			<u>KO</u>			<u>C</u>												IS		CO (Q2)
	Dec. 2021			<u>KO</u>			<u>C</u>														IS (Q3); CO (Q1 2025)
	Jun. 2022			<u>KO</u>			<u>C</u>														IS (Q1); CO (Q3)
16. Woodlynne	Dec. 2019		<u>KO</u>												C				IS		CO (Q2)
	Dec. 2020		<u>KO</u>												C				IS		CO (Q2)
	Dec. 2021		<u>KO</u>												C				IS		CO (Q2)
	Jun. 2022		<u>KO</u>									<u>C</u>							IS		CO (Q2)

<u>Legend</u>: KO = Kickoff; C = Construction; IS = Fully In-Service (major assets in-service); OS = Out-of-Service (if eliminated); CO = Closeout
-Actuals are indicated with an underline (Note: for the Market Street and Ridgefield 4kV projects, outside plant construction began in the first quarter of 2020, the construction milestone indicated on this chart reflects inside plant construction).
***-The Dec. 2019 Lakeside Avenue project schedule was based on the original raise and rebuild mitigation strategy; the current schedule reflects the proposed mitigation method change that contemplates relocating the substation.**
^-The Front Street project was proposed by PSE&G during the second quarter of 2021 to replace the cancelled Constable Hook project.

A summary of the subprogram status as of the end of the second quarter of 2022 is provided below **Table 8 – ES 2 Electric Station Flood Mitigation Summary Status as of June 30, 2022**.

Table 8 – ES 2 Electric Station Flood Mitigation Summary Status as of June 30, 2022

Activity	Total # of Projects	Specific Projects
Kickoff Meeting	16	Academy Street; Clay Street; Front Street; Hasbrouck Heights; Kingsland; Lakeside Avenue; Leonia; Market Street; Meadow Road; Orange Valley; Ridgefield 13kV; Ridgefield 4kV; State Street; Toney's Brook; Waverly; Woodlynne
Key Drawing Review	16	Academy Street; Clay Street; Front Street; Hasbrouck Heights; Kingsland; Lakeside Avenue; Leonia; Market Street; Meadow Road; Orange Valley; Ridgefield 13kV; Ridgefield 4kV; State Street; Toney's Brook; Waverly; Woodlynne
Scope Locked	16	Academy Street; Clay Street; Front Street; Hasbrouck Heights; Kingsland; Lakeside Avenue; Leonia; Market Street; Meadow Road; Orange Valley; Ridgefield 4kV; Ridgefield 13kV; State Street; Toney's Brook; Waverly; Woodlynne
Major Equipment Purchase Orders (POs)	18*	Academy Street; Clay Street; Front Street*; Hasbrouck Heights; Kingsland; Lakeside; Leonia*; Meadow Road; Orange Valley; Ridgefield 13kV*; State Street; Toney's Brook; Waverly*; Woodlynne
Architect/ Engineer (A/E) Contract Award (or selection of PSE&G internal engineering)	16	Academy Street[1]; Clay Street[1]; Front Street[3]; Hasbrouck Heights[1]; Kingsland[2]; Lakeside Avenue[3]; Leonia[2]; Market Street[2]; Meadow Road[2]; Orange Valley[1]; Ridgefield 13kV[2]; Ridgefield 4kV[2]; State Street[2]; Toney's Brook[3]; Waverly[3]; Woodlynne[1]
Construction Start**	11	Academy Street; Clay Street; Front Street; Hasbrouck Heights; Leonia; Market Street; Ridgefield 4kV; Ridgefield 13kV; State Street; Waverly; Woodlynne
In-Service	3	Academy Street; Market Street; Ridgefield 4kV

Activity	Total # of Projects	Specific Projects
Partial In-Service	2	Leonia; Ridgefield 13kV
-Three of the listed projects (Front Street, Leonia, Ridgefield 13kV, and Waverly) have two switchgears, thus the current count reflects 18 switchgears at 14 substations.* *[1]-Indicates Burns & McDonnell is serving as the A/E.* *[2]-Indicates PSE&G internal resources are serving as the A/E.* *[3]-Indicates Black & Veatch is serving as the A/E.* *-Includes projects that have commenced inside plant and/or outside plant construction; also maintains identification of projects that have since completed construction (generally those that are shown as in-service).*		

Beyond the key activities summarized in **Table 8** above, **Table 9 – ES 2 Electric Station Flood Mitigation Upcoming Activities for Q3 2022** summarizes the upcoming planned activities for each project during the third quarter of 2022, including any carryover of activities from earlier periods.

Table 9 – ES 2 Electric Station Flood Mitigation Upcoming Activities for Q3 2022

Station	Upcoming Activities for Q3 2022	Carryover Activities from Q2 2022
1. Academy Street	• Complete fiber cutover to new station	• Demo existing foundations, remove old equipment at existing Academy St. station
2. Clay Street	• Commence phase 1 civil work	• Commence pile driving
3. Front Street	• Manhole/trench work for contingency switchgear	• Continued civil construction (contingency switchgear)
4. Hasbrouck Heights	• Continued civil/electrical construction • Switchgear commissioning	• Switchgear assembly
5. Kingsland	• Commencing civil and electrical construction	• Issue electrical PO
6. Lakeside Avenue	• Commence civil construction	• Continued engineering
7. Leonia	• Install lightning mast, continued construction	• Complete switchgear #2 assembly
8. Market Street	*Project complete*	
9. Meadow Road	• Commence civil construction	• Civil and electrical POs issued
10. Orange Valley	• Issue civil and electrical POs • Commence civil construction	• Civil and electrical construction out for bid
11. Ridgefield 13kV	• Commence electrical construction	• Demo existing switchgear #1 (foundations)
12. Ridgefield 4kV	*Project complete*	
13. State Street	• Relay testing and commissioning switchgear	• Continued construction
14. Toney's Brook	• Commence civil construction	• Prepare for construction
15. Waverly	• Commissioning new switchgear • Demolition of existing switchgear	• Continued construction • Switchgear assembly
16. Woodlynne	• Continued engineering	• Continued engineering

As discussed in the IM 2022 First Quarter Report, PSE&G's switchgear vendor, Powercon, informed PSE&G that due to various material and sub-supplier delays, the remaining major equipment deliveries may continue to see impacts. PSE&G continues to receive weekly updates from Powercon on the current status of the deliveries and PSE&G's management visited Powercon's site in May 2022 with additional onsite visits planned. Powercon is exploring options to improve its production floor efficiencies and ordering supplies earlier to potentially alleviate further impacts. PSE&G has requested more detailed and frequent status updates from Powercon to better inform its project planning, including details of Powercon's production schedules and information from its sub-vendors/suppliers. The status of the major equipment deliveries for the Electric Station Flood Mitigation projects is presented in **Table 10 – Electric Station Flood Mitigation Major Switchgear Deliveries as of June 30, 2022**.

Table 10 – Electric Station Flood Mitigation Switchgear Deliveries as of June 30, 2022

Station	Description	Delivery Status as of Q1 2022	Delivery Status as of Q2 2022
1. Academy Street	13kV switchgear	***11/7/2020***	***11/7/2020***
2. Clay Street	4kV switchgear	6/16/2022	8/30/2022
3. Front Street	4kV switchgear	5/22/2023	5/22/2023
	4kV cont. switchgear	7/18/2022	7/17/2022
4. Hasbrouck Heights	4kV switchgear	***11/30/2021***	***11/30/2021***
5. Kingsland	13kV switchgear[1]	***9/30/2020***	***9/30/2020***
6. Lakeside Avenue	4kV switchgear	1/26/2023	1/26/2023
7. Leonia	13kV switchgear #1	***5/24/2021***	***5/24/2021***
	13kV switchgear #2	5/15/2022	***6/16/2022***
	13kV cont. switchgear[2]	***10/16/2020***	***10/16/2020***
8. Market Street	Elimination project		
9. Meadow Road	13kV switchgear[2]	1/3/2023	2/14/2023
10. Orange Valley	4kV switchgear	6/14/2023	5/29/2023
11. Ridgefield 13kV	13kV switchgear #1	7/22/2022	8/2/2022
	13kV switchgear #2	***4/27/2021***	***4/27/2021***
	13kV cont. switchgear[1]	***9/30/2020***	***9/30/2020***
12. Ridgefield 4kV	Elimination project		
13. State Street	4kV switchgear	***12/15/2021***	***12/15/2021***
14. Toney's Brook	4kV switchgear	12/21/2022	12/20/2022
15. Waverly	26kV switchgear	***4/30/2021***	***4/30/2021***
	4kV switchgear	7/25/2022	8/5/2022
16. Woodlynne	4kV switchgear	9/21/2022	11/22/2022

Note: bold/italicized dates indicate actual delivery dates.
[1]The Kingsland 13kV switchgear was delivered to the Ridgefield 13kV site where it is being used as the contingency/temporary switchgear for that project before its permanent installation on the Kingsland project.
[2]The Meadow Road project will use the Leonia project's 13kV contingency switchgear as its permanent switchgear.

As shown in **Table 10**, as of the end of the second quarter of 2022, there were 10 switchgear deliveries outstanding for the subprogram, with one actual delivery realized during the quarter (the 13kV switchgear #2 for Leonia, which was received later than scheduled and led to the in-service date shift discussed in **Section III.A.7.**). The forecasted delivery dates for the remaining switchgear saw varying degrees of movement from the status at the end of the first quarter of 2022, with four of the 10 units seeing virtually no change, three seeing movement of less than one month (including Orange Valley's 4kV switchgear advancing), and three experiencing more significant slips, with Clay Street, Meadow Road, and Woodlynne each seeing the associated equipment delivery dates slip between 42 and 75 days, however this did not cause a change to the forecasted in-service dates for these projects at this time.

The current project estimates and forecasts are shown below in **Table 11 – ES 2 Electric Station Flood Mitigation Project Cost Status as of June 30, 2022**. As discussed in the IM 2022 First Quarter Report, PSE&G decided to consolidate the R&C on the individual projects into one R&C balance for the entire subprogram, thus there is no estimated R&C amount at the project level. Additionally, R&C funds are released when projects transition estimate levels and during the second quarter of 2022 there were no updated estimates in the subprogram, thus the R&C balance remained unchanged from the prior quarter. **Table 11** also shows the current estimate level based on PSE&G's estimating processes and as approved by its Utility Review Board (URB), the actual spend, and percentage of actuals to estimate as of the end of the second quarter of 2022.

Table 11 – ES 2 Electric Station Flood Mitigation Project Cost Status as of June 30, 2022

Project	Estimate Level	Base	Risk & Contingency*	Total	Current Forecast	Actuals to Date	% of Actuals to Estimate
1. Academy Street	Definitive	$9,300,000	$-	$9,300,000	$8,499,311	$6,404,971	69%
2. Clay Street	Conceptual	$30,800,000	$-	$30,800,000	$33,614,140	$10,783,240	35%
3. Front Street**	Study	$25,900,000	$-	$25,900,000	$26,155,627	$3,670,971	14%
4. Hasbrouck Heights	Definitive	$19,300,000	$-	$19,300,000	$18,923,124	$11,967,537	62%
5. Kingsland	Study	$6,400,000	$-	$6,400,000	$8,502,960	$1,655,091	26%
6. Lakeside Avenue	Study	$39,400,000	$-	$39,400,000	$34,900,034	$1,756,207	5%
7. Leonia	Definitive	$24,900,000	$-	$24,900,000	$25,116,227	$20,947,894	84%
8. Market Street	Definitive	$29,100,000	$-	$29,100,000	$28,291,584	$28,022,997	96%
9. Meadow Road	Study	$7,200,000	$-	$7,200,000	$8,285,425	$1,652,591	23%
10. Orange Valley	Study	$14,700,000	$-	$14,700,000	$17,022,378	$1,186,155	8%
11. Ridgefield 13kV	Conceptual	$26,100,000	$-	$26,100,000	$27,990,304	$21,957,130	84%
12. Ridgefield 4kV	Definitive	$20,800,000	$-	$20,800,000	$20,703,808	$20,703,809	100%
13. State Street	Definitive	$19,600,000	$-	$19,600,000	$19,838,101	$10,631,628	54%
14. Toney's Brook	Conceptual	$16,200,000	$-	$16,200,000	$16,250,526	$2,294,598	14%
15. Waverly	Study	$36,200,000	$-	$36,200,000	$39,911,783	$8,949,013	25%
16. Woodlynne	Conceptual	$21,300,000	$-	$21,300,000	$24,153,365	$5,082,698	24%
ES 2 Station Placeholder	N/A	$-	$41,800,000	$41,800,000	$-	$-	-

Project	Estimate Level	Base	Risk & Contingency*	Total	Current Forecast	Actuals to Date	% of Actuals to Estimate
Subprogram Total		**$347,200,000**	**$41,800,000**	**$389,000,000**	**$358,158,627**	**$157,676,463**	**41%**
**-As discussed in Section II.B. of the IM 2022 First Quarter Report, PSE&G made the decision to hold risk and contingency at the subprogram level, which resulted in updated estimates being prepared for each project to reflect this change and other project-specific updates as warranted.*							
***-The Front Street project was proposed by PSE&G during the second quarter of 2021 to replace the cancelled Constable Hook project.*							

Findings & Observations

- No change in completed projects during the second quarter of 2022, with three of the 16 projects previously put in-service (Market Street and Ridgefield during the second quarter of 2021 and Academy Street in the fourth quarter of 2021). The next projects forecasted to be placed in-service are the Hasbrouck Heights, Leonia, Ridgefield 13kV, and State Street projects, each forecasted to go in-service during the fourth quarter of 2022.
- Six of the remaining thirteen Electric Station Flood Mitigation projects had movement in the forecasted in-service date during the second quarter of 2022, with three advancing and three slipping. For four of those projects, the change was less than two weeks, with the biggest changes involving the following projects:
  - Hasbrouck Heights (advancing 32 days from January 23, 2023 to December 23, 2022); and
  - Leonia (slipping 28 days from November 15, 2022 to December 13, 2022).
- The overall subprogram forecast as of the end of the second quarter of 2022 increased $8.6 million (or 2.5%) to $358.2 million from the status as of the prior quarter. The forecast continues to remain under the current subprogram estimate and Stipulation amount of $389.0 million (which includes $41.8 million in R&C). The change in the subprogram forecast was predominantly driven by changes to the project forecasts on five of the projects, including:
  - Kingsland (increased $2.1 million to $8.5 million): driven by civil and electrical construction awards higher than estimated and an increased quantity of piles based on the final design.
  - Lakeside Avenue (decreased $1.8 million to $34.9 million): electrical construction award lower than estimated (driven by scope reduction) and the transfer of the 4kV bus scope to the 69kV transmission project.
  - Clay Street (increased $2.3 million to $33.6 million): electrical construction award higher than estimated; equipment procurement higher than estimated; scope increases; and construction schedule recovery.
  - Waverly (increased $2.3 million to $39.9 million): civil construction award higher than estimated.
  - Orange Valley (increased $2.3 million to $17.0 million): civil construction award higher than estimated.

- With 44% of the subprogram forecast now spent (41% of the Stipulation amount), the IM has found nothing to date that would jeopardize the subprogram being completed on budget as even with some cost pressures on certain projects, there is adequate R&C remaining in the subprogram. However, the schedule status of the later projects in this subprogram, and in particular Waverly, will continue to be closely followed by the IM to monitor if the projects can be completed within the ES 2 Program window. At this time, the primary risk to the project schedule is the major equipment deliveries, followed by resource availability to support schedule requirements. Other projects currently forecasted to be in-service in the final quarter of the Program (fourth quarter of 2023) include: Front Street, Kingsland, Orange Valley, and Woodlynne.
- Concerning the major equipment deliveries, the primary issues appear to be continued supply chain challenges stemming from the Covid-19 and post-pandemic marketplace impacts, particularly with the sub-vendors to the switchgear manufacturer. In response to these unforeseen challenges, PSE&G has sought and received additional information and more frequent updates from its manufacturer, including conducting site visits to the fabrication facility. Based on the current information it receives, PSE&G assesses the project schedules and determines if there is any expected schedule impact from the delivery delays, and if so, if resequencing of activities or accelerating work is an option to recover the schedule. The IM is monitoring PSE&G's efforts in this regard to recover the schedule slippage and minimize any impacts to the overall Program completion.
- Relative to the Waverly project, as of the end of the second quarter of 2022, the project continues to show a final in-service date in 2024, now at February 2024, which has continued to show improvements as PSE&G details the schedule following the site plan approval in December 2021. The Waverly project has multiple major asset in-service dates for the 26kV switchgear, 4kV switchgear, and three transformers, which are currently forecasted from September 2022 (26kV switchgear) to February 2024 (Transformer #3). PSE&G has informed the IM that the project team will continue to assess the project schedule and will be examining the potential to shorten durations and/or work activities concurrently to pull the final in-service date back into 2023. The IM will continue to monitor the PSE&G efforts in this regard and will report on any recovery actions taken and how those actions assist in reducing the current slippage.

1. Academy Street

During the second quarter of 2022, $144,172 was spent on the Academy Street project compared to a forecast of approximately $135,000, which brought the total spend to approximately $6.4 million.

This project was placed in-service on October 19, 2021, and there were minimal activities performed during the second quarter of 2022. The elimination of equipment at the old substation site and related demolition activities are expected to commence and be completed in the second half of 2022.

The actual spend by quarter for Academy Street as compared to the current approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals					*Forecast*		
$150,398	$4,224,550	$1,754,789	$131,061	$144,172	$103,424	$1,948,915	$42,000

Actuals to Date	Estimate	% of Actuals to Estimate
$6,404,971	$9,300,000	69%

2. Clay Street

During the second quarter of 2022, $1,936,258 was spent on the Clay Street project compared to a forecast of approximately $2.7 million, which brought the total spend to approximately $10.8 million. The variance in forecasted to actual spend during the second quarter of 2022 was attributed to civil pile driving delayed (from May-June to June-July) due to the T3 contingency not being completed in April as initially planned and less foundation and duct bank work completed in June 2022 than originally planned. Part of this impact stemmed from a work standdown in June 2022 that was instituted in response to a reliability incident where the underground contractor excavating for new duct banks hit an obstruction (concrete at the top of an existing duct bank), which damaged two of the four pipes in the duct bank. This incident resulted in no injuries or customers impacted, and during the standdown PSE&G and the contractor reviewed safety and excavation procedures. Ultimately this had an approximate 10-day impact to the construction work on the project.

The forecast for the Clay Street project increased approximately $2.3 million from the prior quarter to a forecast of approximately $33.6 million as of the end of the second quarter of 2022. This forecast increase was driven by:

- Electrical construction award higher than estimated: $900,000;
- Construction schedule recovery due to permitting delays: $600,000;
- A/E procured equipment higher than estimated: $400,000;
- Addition of Human Machine Interface (HMI) to switchgear: $200,000; and,
- Requirement for a contingency capacitor bank: $200,000.

Despite less work completed in June 2022 than planned, the forecasted in-service date for the Clay Street project as of the end of the second quarter of 2022 remains unchanged from the status as of the end of the first quarter of 2022 at January 30, 2023.

The primary activities on the Clay Street project during the second quarter of 2022 included the receipt of the below grade construction permit and commencement of pile driving and civil works, which both began in June 2022.

The actual spend by quarter for Clay Street as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals					*Forecast*		
$116,409	$879,339	$2,806,593	$5,044,642	$1,936,258	$7,016,356	$6,276,325	$9,538,218

Actuals to Date	Estimate	% of Actuals to Estimate
$10,783,240	$30,800,000	35%

3. Front Street

During the second quarter of 2022, $889,533 was spent on the Front Street project compared to a forecast of approximately $904,000, which brought total spend to approximately $3.7 million. The forecasted in-service date for the Front Street project as of the end of the second quarter of 2022 slipped 13 days from the status as of the end of the first quarter of 2022 to November 8, 2023.

The primary activities on the Front Street project during the second quarter of 2022 included:

- Start of civil construction inside plant (IP) to prepare for the contingency switchgear;
- Final vendor controls drawings received (for the permanent switchgear); and,
- Electrical construction PO issued (with electrical construction expected to commence in August 2022).

The actual spend by quarter for Front Street as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals					*Forecast*		
$-	$-	$2,351,832	$429,607	$889,533	$4,980,522	$1,873,016	$16,631,118

Actuals to Date	Estimate	% of Actuals to Estimate
$3,670,971	$25,900,000	14%

4. Hasbrouck Heights

During the second quarter of 2022, $2,187,907 was spent on the Hasbrouck Heights project compared to a forecast of approximately $2.3 million, which brought the total spend to approximately $12.0 million. The forecasted in-service date for the Hasbrouck Heights project as of the end of the second quarter of 2022 advanced 32 days from the status as of the end of the first quarter of 2022 to December 23, 2022. This forecasted in-service date advancement was driven by a combination of re-sequencing the civil and electrical construction activities and better than expected electrical construction progress.

Notable activities completed during the second quarter of 2022 included:

- Commencement of electrical construction;
- Start of civil foundations and other civil IP work (grounding grid, trenches); and,
- Setting the switchgear.

The actual spend by quarter for Hasbrouck Heights as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals					*Forecast*		
$149,848	$1,129,934	$4,176,249	$4,323,599	$2,187,907	$1,702,906	$2,320,722	$2,931,960

Actuals to Date	Estimate	% of Actuals to Estimate
$11,967,537	$19,300,000	62%

5. Kingsland

During the second quarter of 2022, $538,096 was spent on the Kingsland project compared to a forecast of approximately $512,000, which brought the total spend to approximately $1.7 million. The forecast for the Kingsland project increased approximately $2.1 million from the prior quarter to a forecast of approximately $8.5 million as of the end of the second quarter of 2022. This forecast increase was driven by:

- Civil construction award higher than estimated: $1,500,000;
- Increase in piles based on final design: $300,000; and,
- Electrical construction award higher than estimated: $300,000.

The forecasted in-service date for the Kingsland project as of the end of the second quarter of 2022 remained nearly unchanged from the status as of the end of the first quarter of 2022, with two-day slip to October 4, 2023.

During the second quarter of 2022, primary activity on the Kingsland project was the civil and electrical work going out for bid, with the civil PO issued in June 2022. Civil and electrical construction are expected to commence in the third quarter of 2022.

The actual spend by quarter for Kingsland as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals					*Forecast*		
$104,112	$209,667	$510,943	$301,463	$538,906	$390,263	$2,357,731	$4,089,875

Actuals to Date	Estimate	% of Actuals to Estimate
$1,665,091	$6,400,000	26%

6. Lakeside Avenue

During the second quarter of 2022, $230,836 was spent on the Lakeside Avenue project compared to a forecast of approximately $159,000. The forecasted in-service date for the Lakeside Avenue project as of the end of the second quarter of 2022 remained unchanged from the status as of the end of the first quarter of 2022 at September 18, 2023.

Notable activities completed on the Lakeside Avenue project during the second quarter of 2022 included the civil PO being issued. Civil construction is expected to commence in the third quarter of 2022, followed by electrical construction commencing in the fourth quarter of 2022.

The actual spend by quarter for Lakeside Avenue as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project. The forecast for the Lakeside Avenue project decreased $1.8 million from the status as of the prior quarter to $34.9 million (shown in **Table 11**), which was driven by electrical construction award lower than estimated (in turn driven by scope reduction as initially planned elevated stairs and rigging of the switchgear was no longer required) and the transfer of the 4kV bus scope to the 69kV transmission project (based on the sections transferred being tied to the high-side bushings of the 69/4kV transformers, and as such considered a transmission asset under PSE&G's practices).

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals					*Forecast*		
$148,943	$453,994	$570,713	$351,720	$230,836	$2,263,003	$1,656,432	$29,224,392

Actuals to Date	Estimate	% of Actuals to Estimate
$1,756,207	$39,400,000	5%

7. Leonia

During the second quarter of 2022, $3,968,355 was spent on the Leonia project compared to a forecast of approximately $3.98 million, which brought the total spend to approximately $20.9 million. The forecasted in-service date for the Leonia project as of the end of the second quarter of 2022 slipped 28 days from the status at the end of the first quarter of 2022 to December 13, 2022. This forecasted in-service date slip was driven by delivery delays on the switchgear.

Notable activities completed on the Leonia project during the second quarter of 2022 included:

- Completed the demolition of the existing feeder rows;
- Switchgear #2 circuits cutover to the temporary switchgear;
- Start of demolition of existing switchgear #2; and,
- The new switchgear #2 was received at site and set.

The actual spend by quarter for Leonia as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals					*Forecast*		
$44,792	$6,033,379	$9,112,257	$1,789,112	$3,968,355	$1,190,086	$1,147,384	$1,830,862

Actuals to Date	Estimate	% of Actuals to Estimate
$20,947,895	$24,900,000	84%

8. Market Street

During the second quarter of 2022, $202,619 was spent on the Market Street project compared to a forecast of approximately $221,000, which brought the total spend to approximately $28.0 million. The Market Street substation was taken out of service as of June 25, 2021.

Notable activities conducted during the second quarter of 2022 included the completion of civil demolition and the associated Industrial Site Recovery Act (IRSA) compliance activities.

The actual spend by quarter for Market Street as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals					*Forecast*		
$251,193	$16,079,601	$10,681,487	$808,096	$202,619	$181,588	$51,000	$36,000

Actuals to Date	Estimate	% of Actuals to Estimate
$28,022,997	$29,100,00	96%

9. Meadow Road

During the second quarter of 2022, $321,098 was spent on the Meadow Road project compared to a forecast of $273,000, which brought the total spend to approximately $1.7 million. The forecasted in-service date for the Meadow Road project as of the end of the second quarter of 2022 remained unchanged from the status as of the end of the first quarter of 2022 at September 22, 2023.

The primary activities conducted on the Meadow Road project during the second quarter of 2022 included:

- Civil, electrical, and controls drawings issued for construction (IFC); and
- Civil and electrical construction out for bid.

Civil construction is expected to commence in the third quarter of 2022, while electrical construction is currently forecasted to being in early 2023.

The actual spend by quarter for Meadow Road as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals					*Forecast*		
$63,128	$535,081	$445,234	$288,050	$321,098	$573,894	$1,415,692	$4,643,248

Actuals to Date	Estimate	% of Actuals to Estimate
$1,652,591	$7,200,000	23%

10. Orange Valley

During the second quarter of 2022, $276,614 was spent on the Orange Valley project compared to a forecast of approximately $241,000, which bought the total spend to approximately $1.2 million. The forecasted in-service date for the Orange Valley project as of the end of the second quarter of 2022 remained unchanged from the status as of the end of the first quarter of 2022 at December 29, 2023.

During the second quarter of 2022, major activities on the Orange Valley project included the civil and electrical work being issued for bid and the IFC release of the civil and electrical drawing packages. Civil construction is anticipated to commence in the third quarter of 2022, while electrical construction is currently forecasted to start in early 2023.

The actual spend by quarter for Orange Valley as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals					*Forecast*		
$77,029	$362,895	$358,052	$111,565	$276,614	$376,925	$708,865	$14,750,433

Actuals to Date	Estimate	% of Actuals to Estimate
$1,186,155	$14,700,000	8%

11. Ridgefield 13kV

During the second quarter of 2022, $2,557,679 was spent on the Ridgefield 13kV project compared to a forecast of approximately $2.5 million, which brought the total spend to approximately $22.0 million. The forecasted in-service date for the Ridgefield 13kV project as of the end of the second quarter of 2022 remained unchanged from the status as of the end of the first quarter of 2022 at December 13, 2022.

Notable activities performed during the second quarter of 2022 included:

- Relay setting information delivered to the IP construction relay group;
- New Switchgear #2 all circuit cutover completed;
- Existing switchgear #1 circuits cutover to the temporary switchgear;
- Completed demolition of the existing switchgear #1; and,
- Started civil construction for the new switchgear #1.

The actual spend by quarter for Ridgefield 13kV as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals					*Forecast*		
$205,982	$6,232,692	$10,849,681	$2,111,096	$2,557,679	$3,412,979	$1,816,195	$804,000

Actuals to Date	Estimate	% of Actuals to Estimate
$21,957,130	$26,100,000	84%

12. Ridgefield 4kV

During the second quarter of 2022, $14,405 was spent on the Ridgefield 4kV project compared to a forecast of $13,000, which held the total spend at approximately $20.7 million. The project was placed in-service on May 16, 2021.

The project is essentially complete now with final closeout activities performed during the first quarter of 2022 that included some trailing costs in the second quarter of 2022.

The actual spend by quarter for Ridgefield 4kV as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals					*Forecast*		
$143,414	$11,239,534	$9,263,852	$42,604	$14,405	-	-	-

Actuals to Date	Estimate	% of Actuals to Estimate
$20,703,809	$20,800,000	100%

13. State Street

During the second quarter of 2022, $1,046,814 was spent on the State Street project compared to a forecast of approximately $1.07 million, which brought the total spend to approximately $10.6 million. The forecasted in-service date for the State Street project as of the end of the second quarter of 2022 remained unchanged from the status as of the end of the first quarter of 2022 at December 19, 2022.

Notable activities performed on State Street during the second quarter of 2022 included the continued advancement of civil and electrical construction.

The actual spend by quarter for State Street as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals					*Forecast*		
$77,590	$662,148	$8,093,227	$751,849	$1,046,814	$1,199,012	$1,885,426	$6,122,034

Actuals to Date	Estimate	% of Actuals to Estimate
$10,631,629	$19,600,000	54%

14. Toney's Brook

During the second quarter of 2022, $629,773 was spent on the Toney's Brook project compared to a forecast of approximately $110,000, which brought the total spend to approximately $2.3 million. The variance in forecasted to actual spend during the second quarter of 2022 was attributed to early delivery of steel platforms and standard shape structures that had previously been forecasted to arrive in July 2022.

The forecasted in-service date for the Toney's Brook project as of the end of the second quarter of 2022 advanced four days from the status as of the end of the first quarter of 2022 to April 17, 2023.

The primary activities on during the second quarter of 2022 involved preparations for construction, with civil and electrical construction both forecasted to commence in the third quarter of 2022.

The actual spend by quarter for Toney's Brook as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals					*Forecast*		
$211,940	$373,096	$941,519	$138,270	$629,773	$793,356	$5,704,738	$7,457,834

Actuals to Date	Estimate	% of Actuals to Estimate
$2,294,598	$16,200,000	14%

15. Waverly

During the second quarter of 2022, $1,536,375 was spent on the Waverly project compared to a forecast of approximately $1.5 million, which brought the total spend to approximately $8.9 million.

The forecasted in-service date for the Waverly project as of the end of the second quarter of 2022 continued to achieve advancements as the project team details the construction schedule following the site plan approval in December 2021. The current forecasted in-service date advanced seven days from the status as of the end of the first quarter of 2022 to February 27, 2024.

The primary activities performed during the second quarter of 2022 included:

- Construction permits approved;
- Start of civil construction;
- 26kV switchgear set on foundation; and,
- Start of electrical construction.

The 26kV switchgear is currently forecasted to be placed in-service in September 2022.

The actual spend by quarter for Waverly as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals					*Forecast*		
$103,748	$2,460,815	$4,415,223	$432,853	$1,536,375	$8,643,675	$2,258,298	$20,060,797

Actuals to Date	Estimate	% of Actuals to Estimate
$8,949,014	$36,200,000	25%

16. Woodlynne

During the second quarter of 2022, $1,347,345 was spent on the Woodlynne project compared to a forecast of approximately $1.4 million, which brought the total spend to approximately $5.1 million. The forecasted in-service date for the Woodlynne project as of the end of the second quarter of 2022 remains unchanged from the status as of the end of the first quarter of 2022 at October 10, 2023.

The primary activities performed on the Woodlynne project during the second quarter of 2022 involved the continuation of civil construction that commenced in late February 2022. Electrical construction is currently forecasted to commence in early 2023.

The actual spend by quarter for Woodlynne as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals					*Forecast*		
$110,982	$993,298	$991,630	$1,639,443	$1,347,345	$972,053	$5,617,958	$12,480,656

Actuals to Date	Estimate	% of Actuals to Estimate
$5,082,698	$21,300,000	24%

B. Contingency Reconfiguration

During the first quarter of 2022, the final reclosers were installed and commissioned, completing this scope of the Contingency Reconfiguration subprogram and with the remaining work involving the installation of Fuse Saver devices. **Table 12 – ES 2 Program Fuse Saver Status as of June 30, 2022** provides a summary of the Fuse Saver scope of the Contingency Reconfiguration subprogram, indicating the number of units completed during the second quarter of 2022 and for the total program, showing the status of engineering, installation, and commissioning out of a total scope of 1,641 units. This represents a reduction of 72 units in the forecasted number of units for the Program from the status as of the end of the first quarter of 2022 and follows PSE&G's approach on forecasting the Fuse Saver scope based on a quarterly review of the actual cost data and related installation status information to inform the installation plan. PSE&G continues seeking to optimize the number of Fuse Savers installed in alignment with the overall budget for the subprogram.

Table 12 – ES 2 Program Fuse Saver Status as of June 30, 2022

Type	Engineering Packages Completed (1 Fuse Saver ea.)	Fuse Savers Installed	Fuse Savers Commissioned
Q2 Qty.	170	13	12
Program Total to Date	417	126	125
Remaining	1,224	1,515	1,516

The installation of Fuse Savers recommenced in May 2022, following the earlier installations performed as part of the Fuse Saver pilot program in 2020-2021. As shown in **Table 12**, installations in the second quarter of 2022 were limited to 13 devices, which was the result of a hold placed on installations after a technical issue was observed on a couple devices and installations not being performed in periods when a D-SCADA freeze was initiated. The technical issue involved voltage observed when the unit was in the open position, PSE&G sent back two units to Siemens for testing, which determined that the root cause was ghost or induced voltage (due to close proximity to a live conductor). PSE&G assessed potential safety hazards when the devices are in the open configuration and is considering a change in the measuring instrument, but cleared the installations to continue.

Regarding the D-SCADA freeze, PSE&G implemented a D-SCADA freeze in late April/early May 2022 and again in mid-June 2022, which was needed to support the Platform go-live milestone achieved in the Grid Modernization – ADMS subprogram. This was identified ahead of implementation of the D-SCADA freeze, but nonetheless resulted in an approximate two-week period where installations were not available. As a result, PSE&G intends to add more installations than initially planned in the third and fourth quarters of 2022 and also push some installations into 2023, though expects no significant cost impacts as a result of this shift.

The current forecasted completion date for the primary components that make up the Contingency Reconfiguration subprogram are provided in **Table 13 – ES 2 Contingency Reconfiguration Forecasted Completion Dates as of June 30, 2022**. This table also shows the forecasted final in-service dates as of the end of the first quarter of 2022 to show movement to the forecast as of the end of the second quarter of 2022.

Table 13 – ES 2 Contingency Reconfiguration Forecasted Completion Dates as of June 30, 2022

Scope & Division		Q1 2022 Forecasted Completion Date	Q2 2022 Forecasted Completion Date
Reclosers	Central	1/31/2022 (Actual)	1/31/2022 (Actual)
	Metro	12/31/2021 (Actual)	12/31/2021 (Actual)
	Palisades	1/31/2022 (Actual)	1/31/2022 (Actual)
	Southern	1/31/2022 (Actual)	1/31/2022 (Actual)
Fu	Central	9/30/2023	12/30/2023

Scope & Division		Q1 2022 Forecasted Completion Date	Q2 2022 Forecasted Completion Date
	Metro	10/30/2023	12/30/2023
	Palisades	12/30/2023	12/30/2023
	Southern	9/30/2023	12/30/2023

As shown in **Table 13**, the forecasted in-service dates for the Fuse Saver scope slipped for the Central, Metro, and Southern Divisions based on adjusted monthly distribution to account for the delays in installation encountered in the second quarter of 2022 as discussed above.

The Contingency Reconfiguration subprogram costs through the end of the second quarter of 2022 are presented in **Table 14 – ES 2 Contingency Reconfiguration Actual Costs as of June 30, 2022**.

Table 14 – Contingency Reconfiguration Actual Costs as of June 30, 2022

Scope & Division		2019	2020	2021	Q1 2022	Q2 2022	Total to Date
		Actuals					
Reclosers	Central	$2,737,167	$12,050,820	$9,852,812	$880,537	$45,064	$25,566,400
	Metro	$2,231,431	$10,726,610	$11,368,409	$150,325	($31,771)	$24,445,004
	Palisades	$2,515,569	$12,119,436	$8,280,522	($66,771)	$2,816	$22,851,572
	Southern	$2,081,220	$12,405,684	$14,038,043	$530,051	$4,112	$29,059,110
Fuse Savers	Central	$9,970	$789,937	$854,118	$249,268	$433,473	$2,336,767
	Metro	$7,557	$561,915	$507,742	$160,801	$298,329	$1,536,344
	Palisades	$7,468	$522,454	$577,113	$127,207	$656,533	$1,890,775
	Southern	$9,792	$859,014	$578,217	$245,990	$714,570	$2,407,583
Total		**$9,600,174**	**$50,035,871**	**$46,056,977**	**$2,277,408**	**$1,824,151**	**$110,093,555**

Table 15 – Contingency Reconfiguration Forecasted Costs as of June 30, 2022 examines the forecast as of the end of the second quarter of 2022 for each Division's Fuse Saver scope compared to the total actual costs incurred through the end of the second quarter of 2022.

Table 15 – Contingency Reconfiguration Forecasted Costs as of June 30, 2022

Scope & Division		Total to Date	Forecast	Remaining Forecast	% of Actuals to Forecast
Reclosers	Central	$25,566,400	$25,575,700	$9,300	100%
	Metro	$24,445,004	$24,445,004	-	100%
	Palisades	$22,851,572	$22,851,571	-	100%
	Southern	$29,059,110	$29,059,110	-	100%
Fuse Savers	Central	$2,336,767	$10,532,401	$8,195,635	22%
	Metro	$1,536,344	$11,677,063	$10,140,719	13%
	Palisades	$1,890,775	$9,776,369	$7,885,594	19%
	Southern	$2,407,583	$11,695,459	$9,287,876	21%
Total		**$110,093,555**	**$145,612,679**	**$35,519,124**	**76%**

As shown in **Table 15**, the overall Contingency Reconfiguration subprogram was spent 76% of its current forecast. With the total forecast as of the end of the second quarter of 2022 increasing $339,407 from the status as of the end of the prior quarter.

<u>Findings & Observations</u>:

- Progress on the Fuse Savers scope of the subprogram began to ramp-up following the completion of the reclosers scope in the first quarter of 2022, but was limited due to a D-SCADA freeze and a technical issue encountered (and resolved) during the quarter. During the second quarter of 2022, an additional 170 Fuse Saver engineering packages were completed, 13 units installed, and 12 units commissioned; with a total of 125 units commissioned as of the end of the second quarter of 2022 out of a current scope of 1,641 units.

- The slower than planned progress during the second quarter contributed to revised in-service dates for the Fuse Saver scope of work following the adjustment of the monthly installation targets, with each Division now forecasted to complete the Fuse Savers scope by December 2023.

- The Contingency Reconfiguration subprogram forecast continued to remain relatively static as of the end of the second quarter of 2022, with the total forecast increasing by approximately $339K (or less than 0.0%) to $145.6 million. This is slightly above the Stipulation budget of $145.0 million.

C. Grid Modernization – Communication System

The Stipulation identified the Grid Modernization – Communication System subprogram to include up to $72 million invested in installing a private wireless communications network to eliminate the use of dedicated phone lines for remote communication for both PSE&G and customer equipment. The overall network will provide coverage using both wireless and fiber technologies to all switching devices on the PSE&G system. The primary scopes within the Grid Modernization – Communication System include installation of the wireless network, fiber installations at selected stations, fiber cutovers at selected station with existing fiber to the PSE&G fiber network, and retrofitting existing reclosers and RTUs with updated routers. A summary of the status of these primary scopes of work as of the end of the second quarter of 2022 is as follows:

- Wireless network: placed in-service as of December 16, 2021; remaining work involves providing radios to support the installation of Fuse Savers in the Contingency Reconfiguration subprogram.

- Fiber installations and cutovers: 27 out of 34 fiber installation projects completed and 11 out of 12 fiber cutover projects completed.

- Retrofitting existing reclosers: completed as of the fourth quarter of 2021 with a total of 2,318 retrofit reclosers installed.

- Retrofitting RTUs: 170 substation retrofits completed (85 during the second quarter of 2022) out of a current scope of 218 substations.

PSE&G has planned the Grid Modernization – Communication System scope of work by grouping the wireless network and retrofit components into one estimate for approval before its URB and having a separate estimate for the fiber installations and cutovers scope. During the second quarter of 2022, PSE&G transitioned these estimates to the Definitive stage, which were approved by its URB in June 2022. **Table 16 – Grid Modernization – Communication System Estimate** shows the current Definitive stage estimate compared to the earlier Study and Office stage estimates.

Table 16 – Grid Modernization – Communication System Estimate

Scope	Item	Description	Cost
Fiber Installations & Cutovers	***Office Estimate***		***$23,400,000***
	New Fiber Scope Refinement	Substation and Operation Center fiber installation scope and estimates modified to align with current communication needs	$7,900,000
	Project Management, Licensing & Permitting, Engineering	Reduction in scope of Distribution Stations with existing fiber that still required communications to be cutover	($3,800,000)
	Study Estimate		***$27,500,000***
	Outside Plant Estimates	Actual costs higher than estimated for contracted work ($1.6 million) and work performed with internal resources ($0.9 million) based on scope and estimate refinement	$2,500,000
	Inside Plant Estimates	Office level estimates further refined	$2,200,000
	Changed Routes	Route changed in order to provide simplified design and avoid extensive inspections and permitting associated with original OP routes for Montclair (+$1.3 million) and Bloomfield (-$0.4 million).	$900,000
	Fiber Cutovers	Increase due to scope and estimate refinement	$300,000
	Scope Reduction	32nd Street, Howell Street, Waverly, Haddon Heights, and Lehigh Avenue stations removed from ES 2 Program	($2,900,000)
	Definitive Estimate		***$30,500,000***
Wireless Network & Retrofits	***Office Estimate***		***$48,600,000***
	FirstNet Wireless Network Solution	Selection of FirstNet as the wireless network solution in lieu of original plan to build a solely owned and operated private network	($13,500,000)
	Conceptual Estimate		***$35,100,000***
	Radio Reduction	387-unit reduction related to Fuse Savers, Retrofits, and Reclosers – including material and labor	($1,300,000)
	Definitive Estimate		***$33,800,000***
Total Grid Modernization – Communication System Definitive Estimate			**$64,300,000**

As shown in **Table 16**, since the initial Office estimate, the Grid Modernization – Communication System subprogram has seen cost adjustments primarily related to scope refinements and updated cost data. Overall, PSE&G has managed the subprogram to maintain its overall funding level (following the earlier transfer of $7.7 million to the Grid Modernization – ADMS subprogram), though cost pressures, particularly on the fiber installation projects have led the current forecast of $66.3 million to be slightly above the Definitive estimate of $64.3 million. PSE&G assessed the issues encountered to date with the Grid Modernization – Communication System subprogram and identified the following challenges and lessons learned:

- Changes in electric system and fiber communication availability at locations between the ES 2 filing and the BPU approval of the Program.
- Inadequate site investigations resulted in critical items being left out of initial scope definitions of IP (station batteries, facilities upgrade) and OP (underground/overhead splices) for various stations.
- Significant increase in construction duration resulting from time taken to obtain railroad permits and flaggers; lead time for scheduling Transmission Fiber Infrastructure (TFI) commissioning

resources; new outages required for splicing into fiber communication circuits supporting transmission line.
- Budget for ES 2 fiber projects was fixed with zero R&C.
- Lack of comprehensive review and updating of location requirements, grouping, and prioritizing locations for new fiber installation.

As previously reported, the fiber scope includes installing fiber to electric substations and electric operations centers, in addition to cutting over stations with existing fiber service to the PSE&G fiber network. PSE&G preliminarily identified 41 installation projects and 12 cutovers for the subprogram, with three of 41 installation projects were previously removed due to the scheduled elimination of the targeted substations or the intended redundancy benefits not achievable after site review. During the second quarter of 2022, PSE&G assessed the remaining budget for the fiber scope and determined it would remove four additional projects from the planned list due to budgetary constraints (in addition to one of the removed stations, Waverly, having the IP fiber installation included as part of the Electric Station Flood Mitigation project at the substation). The list of identified fiber installation and cutover projects is presented in **Table 17 – Fiber Projects by Division as of June 30, 2022**.

Table 17 – Fiber Projects by Division as of June 30, 2022

Division	Fiber Installation*	Fiber Cutover*
Central	Cranford; Elizabeth Sub HQ; Rahway; Hadley Road HQ; Roselle; Central HQ; Carteret; Edison; Keasby; Mechanic Street; First Street; Lehigh Avenue**	Elizabeth; Henry Street
Metro	East Orange; Metro HQ; Bloomfield; Central Avenue; Haldeon; Irvington; Irvington Sub HQ; Montclair; South Orange; Norfolk Street; Waverly**	-
Palisades	Bergen Point; Hackensack Sub HQ; Fort Lee; Harrison; Ridgewood; West New York; Palisades HQ; Culver Avenue; Morgan Street	Tonnelle Avenue; Spring Valley Road; Union City; Fairview; Polk Street; West Orange
Southern	Southern HQ; Princeton; Chauncey Street; Bordentown; Haddon Heights**; 32nd Street**	Delair; East Riverton; Riverside; Mount Holly
Total	***38 projects***	***12 projects***
**Projects underlined have been placed in-service. **-Identified for removal from subprogram during Q2 2022.*		

During the second quarter of 2022 no additional fiber installation or fiber cutover projects were placed in-service. Thus, the total projects in-service as of the end of the second quarter of 2022 remained at 27 for the fiber installation projects and 11 for the fiber cutover projects. **Table 18 – ES 2 Program Fiber Projects Status as of June 30, 2022** provides a summary of the status of the fiber installation and cutover projects within the subprogram as of the end of the second quarter of 2022 with the projects in italics representing those placed in-service.

Table 18 – ES 2 Program Fiber Projects Status as of June 30, 2022

Project Name	Q2 2022 Status
Fiber Installation Projects	
Bergen Point	*In-Service (Q1 2021)*
Bloomfield	Continued construction; township permit required to complete OP installation; verbal approval received in June 2022

Project Name	Q2 2022 Status
Bordentown	*In-Service (Q3 2021)*
Carteret	IP construction underway; submitted engineer-stamped drawings to railroad agencies
Central Ave	*In-Service (Q3 2021)*
Central HQ	*In-Service (Q1 2022)*
Chauncey Street	*In-Service (Q3 2021)*
Cranford	*In-Service (Q4 2020)*
Culver Ave	*In-Service (Q1 2022)*
East Orange	*In-Service (Q1 2021)*
Edison	IP work preparation underway; awaiting railroad permits
Elizabeth Sub HQ	*In-Service (Q1 2021)*
First Street	*In-Service (Q3 2021)*
Fort Lee	*In-Service (Q1 2022)*
Hackensack Sub HQ	*In-Service (Q4 2020)*
Haddon Heights	Removed from subprogram
Hadley Rd HQ	*In-Service (Q1 2022)*
Haledon	*In-Service (Q1 2022)*
Harrison	*In-Service (Q3 2021)*
Irvington	*In-Service (Q4 2021)*
Irvington Sub HQ	*In-Service (Q4 2021)*
Keasbey	IP work preparation underway; railroad permits received for one of two OP runs
Lehigh Avenue	Removed from subprogram
Mechanic Street	Railroad permits received; Division scheduling work and railroad flaggers
Metro HQ	*In-Service (Q1 2021)*
Montclair	OP splices completed; TFI checklist submitted; router cut-in scheduled for July 2022
Morgan Street	*In-Service (Q4 2021)*
Norfolk St	*In-Service (Q3 2021)*
Palisades HQ	IP work preparation underway; railroad permit received, Contractor scheduling safety training and flagger support
Princeton	*In-Service (Q3 2021)*
Rahway	*In-Service (Q1 2021)*
Ridgewood	*In-Service (Q1 2022)*
Roselle	*In-Service (Q2 2021)*
So Orange	*In-Service (Q3 2021)*
Southern HQ	*In-Service (Q4 2020)*
Thirty Second Street	Removed from subprogram
Waverly	Removed from subprogram
West New York	*In-Service (Q1 2022)*
Fiber Cutover Projects	
Delair	*In-Service (Q4 2020)*
East Riverton	*In-Service (Q4 2020)*
Elizabeth	*In-Service (Q1 2021)*
Fairview	*In-Service (Q1 2022)*
Henry St	*In-Service (Q3 2021)*
Mount Holly	*In-Service (Q4 2020)*
Polk Street	*In-Service (Q1 2022)*
Riverside	*In-Service (Q4 2020)*
Spring Valley Rd	*In-Service (Q1 2021)*
Tonnelle Ave	*In-Service (Q4 2020)*
Union City	*In-Service (Q1 2021)*

Project Name	Q2 2022 Status
West Orange	Rack installation completed; in-service dependent upon Montclair substation being placed in-service (achieved in late June 2022), TFI checklist submitted and router cut-in scheduled for July 2022.
Substation Remote Terminal Unit (RTU) Cutovers	
Scope: 218 units	85 cutovers completed
-Project identified for removal from subprogram after the current reporting period, see **Section IV for additional information.*	

The Grid Modernization – Communication System subprogram costs by major period through the end of the second quarter of 2022 are presented in **Table 19 – ES 2 Grid Modernization – Communication System Actual Costs as of June 30, 2022**, while **Table 20 – ES 2 Grid Modernization – Communication System Forecasts as of June 30, 2022** provides the current forecasts as of the end of the second quarter of 2022 compared to the actual costs.

Table 19 – ES 2 Grid Modernization – Communication System Actual Costs as of June 30, 2022

Scope & Division		2019	2020	2021	Q1 2022	Q2 2022	Total to Date
		Actuals					
Retrofit Reclosers	Central	$0	$884,278	$3,304,797	$215,275	$186,505	$4,590,854
	Metro	$0	$818,620	$2,362,797	$135,374	$192,271	$3,509,045
	Palisades	$0	$825,174	$3,115,474	$186,059	$184,718	$4,311,425
	Southern	$0	$929,058	$3,862,816	$194,826	$193,249	$5,179,949
Fiber	Central	$1,691	$2,418,851	$5,973,655	$1,581,263	$681,857	$10,657,317
	Metro	$1,457	$1,866,697	$3,086,096	$1,576,328	$347,002	$6,877,580
	Palisades	$1,582	$2,046,762	$3,603,134	$656,307	$93,875	$6,401,660
	Southern	$4,731	$910,483	$2,466,477	$96,721	$33,229	$3,511,641
	Cutovers	$0	$876,502	$479,927	$49,907	$8,735	$1,415,071
Wireless Network		$74,306	$6,035,441	$1,282,986	$61,558	$99,655	$7,553,946
Substation RTU Cutovers		$0	$0	$127,129	$801,385	$920,534	$1,849,048
Bulk Purchase*		$0	$1,524,874	($520,766)	$641,029	$283,929	$1,929,066
Total		**$83,767**	**$19,136,741**	**$29,144,503**	**$6,196,033**	**$3,225,559**	**$57,786,601**
**-The Bulk Purchase account is used for the purchase of bulk equipment, which is the then assigned to a specific Division when the equipment is released with a credit back to the Bulk Purchase account. Thus, this account is forecasted to have a $0 balance at the end of the ES 2 Program.*							

Table 20 – ES 2 Grid Modernization – Communication System Forecasts as of June 30, 2022

Scope & Division		Total to Date	Total Forecast	% of Actuals to Forecast
		Actuals		
Retrofit Reclosers	Central	$4,590,854	$6,639,697	69%
	Metro	$3,509,045	$5,553,635	63%
	Palisades	$4,311,425	$6,363,959	68%
	Southern	$5,179,949	$7,189,013	72%
Fiber	Central	$10,657,317	$11,237,905	95%
	Metro	$6,877,580	$7,613,808	90%
	Palisades	$6,401,660	$6,640,530	96%
	Southern	$3,511,641	$3,451,015	102%
	Cutovers	$1,415,071	$1,437,071	98%
Wireless Network		$7,553,946	$8,045,603	94%
Substation RTU Cutovers		$1,849,048	$2,107,575	88%
Bulk Purchase*		$1,929,066	$-	-

Scope & Division	Total to Date *Actuals*	Total Forecast	% of Actuals to Forecast
Total	**$57,786,601**	**$66,279,811**	**87%**
**-The Bulk Purchase account is used for the purchase of bulk equipment, which is the then assigned to a specific Division when the equipment is released with a credit back to the Bulk Purchase account. Thus, this account is forecasted to have a $0 balance at the end of the ES 2 Program.*			

As shown in **Table 19**, actual costs incurred in the second quarter of 2022 were roughly half that incurred in the first quarter of 2022, which reflected much less work performed in the fiber scope due to the few projects remaining while the retrofit reclosers scope essentially mirrored the progress and costs seen in the first quarter of 2022. The forecasts shown in **Table 20** remained relatively unchanged from the status as of the end of the first quarter of 2022, with an overall forecast increase of approximately $136,000 (or a 0.2% increase).

Findings & Observations:

- The retrofit substation RTU scope continued to advance in the second quarter of 2022 following the ramp up in the first quarter of 2022, with an additional 85 substations completed during the quarter, bringing the total to 170 substations completed out of a currently forecasted scope of 218 substations.
- No additional fiber installation of fiber cutover projects were completed during the second quarter of 2022, leaving the total number of projects in-service at 27 for the fiber installation projects and 11 for the fiber cutover projects. The fiber scope still is expected to be completed by the end of 2022.
- The forecast for the Grid Modernization – Communication system subprogram remained relatively unchanged from the status as of the end of the first quarter of 2022, with an overall forecast increase of approximately $136,000 (or a 0.2% increase) to $66.3 million.
- PSE&G transitioned the two primary estimates generated for the subprogram (fiber installation & cutovers and wireless network & retrofits) to the Definitive stage. The fiber scope estimate increased by $3.0 million from the prior estimate, driven primarily by higher than estimated construction costs and scope changes. While the wireless network & retrofits scope estimate decreased by $1.3 million from the prior estimate due to a reduction in the number of radio units expected to be installed in the subprogram (that was in turn driven by a reduction in reclosers, Fuse Savers, and retrofit reclosers).
- Following the updated estimate, PSE&G identified the challenges and lessons learned from the subprogram's execution. With cost pressures driven by changes in the status of the sites from the ES 2 filing to the approval of the Program, further exacerbated by inadequate site investigations that left required items out of the initial scope and no R&C within the initial budget. Scheduling commissioning resources and railroad flaggers was also identified as a challenge to project execution. These identified lessons learned were drivers to the increased costs, particularly in the fiber scope, and demonstrate some of the challenges in executing a group of similar, smaller sized projects that despite relatively common scopes (installing fiber), have unique station-specific requirements that are not identified until detailed engineering and site inspections take place.

D. Grid Modernization – ADMS

The Grid Modernization – ADMS scope is split between three primary sections: DMS/DERMS, the OMS, and ADMS platform upgrades. The scope for each primary component of the Grid Modernization – ADMS subprogram and notable activities conducted during the second quarter of 2022 are presented as follows:

DMS/DERMS

- Scope: Provide software and associated services to deploy a Smart Network in order to meet a subset of the ES 2 Program's objectives and use cases.
- Q2 2022 Activities:
  - Completed and provided Supervisory Control and Data Acquisition (SCADA) keys to Open Systems International Inc. (OSII) (forecast module).
  - Completed testing Fault Protection Analysis (FPA) module in Protective Distribution System (PDS).
  - Completed work on patching plan for FPA.
  - Compiled information for end user training.
  - Completed patch DERMS PDS.
- Forecasted Completion as of the end of the second quarter of 2022: 12/19/2022 (unchanged from Q1).

OMS

- Scope: Provide a single user interface for more efficient management of trouble orders and analysis of outage data through an integrated OMS, system interfaces, and geographic view of all integrated outage data and damage locations. OMS will include tools for dynamic visualization supporting incident management, damage location identification, dashboards, and the as-operated real-time view of PSE&G's network model. Field personnel also will have access to many of these tools as it relates to the incident(s) assigned to them via the Compass mobile crew application. Ten (10) years' worth of existing OMS data will be migrated into the new system as well.
- Q2 2022 Activities:
  - Completed converted data and feedback sessions.
  - Combined PDS for Configuration.
  - Received code review approvals for Interfaces from Arch Review Board.
  - Attended onsite Mobile Work Management System (MWMS) Discovery Workshops and revised analysis.
  - Completed buildout of QAS environment.
  - Approved code review for SAP archive Job Dip.

  - Approved design review for SAP claims and Geographic Information System (GIS) smart notes.
  - Configured Compass PDS as part of Sprint 15.
  - Identified variances in PDS environment and escalated to OSII.
- Forecasted Completion as of the end of the second quarter of 2022: 4/30/2023 (unchanged from Q1).

ADMS Platform

- Scope: Replace, enhance, and expand the existing D-SCADA platform elements inclusive of infrastructure components (servers and workstations) and applications (Monarch, Spectra, and Integra) to create an integrated ADMS platform.
- Q2 2022 Activities:
  - Completed training for Divisions and Relay Chiefs.
  - Completed Division workstations and monitor setups for cutover.
  - Completed buildout of management servers configuration.
  - Completed vulnerability migration.
  - Attempted go-live on 5/11/2022, identified and remediated defects and initiated go-live freeze on 6/15/2022, which was completed on 6/23/2022.
- Actual In-Service Date: 1/28/2022.

During the second quarter of 2022, PSE&G transitioned the Grid Modernization – ADMS subprogram estimate to the Definitive level. **Table 21 – Grid Modernization – ADMS Subprogram Estimate** shows the current Definitive stage estimate compared to the earlier Study and Office stage estimates.

Table 21 – Grid Modernization – ADMS Subprogram Estimate

Item	Description		Cost
Office Estimate			***$35,000,000***
Additional Interface and Hardware Requirements	During preliminary design, additional system integration and architecture requirements were identified since the original ES 2 filing		$5,400,000
Performance Testing	Due to lessons learned from Tropical Storm Isaias, additional performance testing scope was added to the project		$2,300,000
Conceptual Estimate			***$42,700,000***
OMS Scope Changes	*Detail of OMS Scope Changes*		$7,500,000
	Additional system architects – incremental need regarding amount of integration; underestimated due to intricacies with Mulesoft and various interfaces (SAP, Advanced Metering Interface (AMI), MWMS, Visualizations, etc.); outsourced original architect and acquired additional architect to meet the level of effort required	*$700,000*	
	Additional Distribution Operations Subject Matter Experts – Quality control; ex-Operational staff to test system; omitted from prior scope/estimates	*$400,000*	

Item	Description		Cost
	Additional Project Manager – required to manage complex infrastructure, systems integration, and compliance	*$400,000*	
	Additional GIS resources – due to availably challenges with current staff	*$500,000*	
	Additional Engineer and Architect – needed to support Platform integration with OMS; scope omitted from prior estimates	*$500,000*	
	Additional Project Coordinator – to assist Project Manager with coordinating deliverables and requirements due to increased level of effort needed to effectively manage execution	*$200,000*	
	Additional Controller – outsourced replacement for prior PSE&G controller	*$200,000*	
	Energy Cloud Governance – oversee and manage cross-program dependencies; implement best program management	*$1,100,000*	
	Organizational Change Management – right-sizing to program magnitude	*$500,000*	
	OSII scope changes – related to OMS, Visualizations, Compass, etc.; enhanced performance testing	*$2,600,000*	
	Additional Hardware	*$200,000*	
	Platform Delay – additional costs for rework and additional work required due to Platform delay	*$200,000*	
MWMS Delay	Due to the MWMS delay, schedules adjusted for alignment and resources extended		$3,300,000
R&C	Additional R&C		$2,800,000
Definitive Estimate			***$56,300,000***

As shown in **Table 21**, the Grid Modernization – ADMS subprogram estimate has increased $21.3 million since the initial Office level estimate. The changes summarized above that drove the cost increases generally relate to improving the product quality to match the company needs (including updated security requirements and application interfaces), enhancing the testing, additional staffing/program management, additional R&C, and impacts from the MWMS delay. PSE&G assessed the issues encountered to date with the Grid Modernization – ADMS subprogram and identified the following challenges and lessons learned:

- R&C should be included when estimating large and complex IT initiatives.
- IT projects differ from construction projects regarding risks and dependencies.
- Large and complex IT projects with significant dependencies on in-flight projects need greater levels of oversight/governance.
- Lack of project organization with understanding future projects within portfolio/strategy.
- Deficiency of proper resources in place and understanding future technologies.
- Organization change management is necessary when releasing new large and complex projects to gain user acceptance.

The Grid Modernization – ADMS subprogram costs through the end of the second quarter of 2022 are presented in **Table 22 – ES 2 Grid Modernization – ADMS Costs as of June 30, 2022**.

Table 22 – ES 2 Grid Modernization – ADMS Costs as of June 30, 2022

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals					*Forecast*		
$36,213	$16,447,624	$9,854,442	$3,197,877	$8,230,861	$3,235,879	$6,055,743	$6,420,617

Actuals to Date	Forecast	% of Actuals to Forecast
$37,767,018	$53,479,258	71%

Findings & Observations:

- The first of three primary ADMS components (the ADMS Platform) was placed in-service during the first quarter of 2022, with work in the second quarter of 2022 involving continued training and preparing workstations. The remaining DMS/DERMS and OMS scopes are continued to be forecasted to be placed in-service in December 2022 and April 2023, respectively.
- During the second quarter of 2022, PSE&G transitioned the Grid Modernization – ADMS subprogram estimate to the Definitive level, which saw the estimate increase by $13.6 million from the Conceptual level estimate (including an additional $2.8 million in R&C). The bulk of the estimate increase was attributed to scope and standardization changes reflecting the complexity of the OMS scope and aligning with updated security requirements and application interfaces. The subprogram forecast as of the end of the second quarter of 2022 similarly increased from the prior quarter, with the total forecast now at $53.5 million.
- Based on the challenges experienced in planning and estimating the ADMS scope of work, PSE&G appropriately identified lessons learned that will help it plan and prepare for future IT-type projects that differ in approach from typical construction projects. While both construction projects and IT/software projects can both be extremely complex, with many interfaces and different stakeholders among the common complexities, IT/software projects often have a higher degree of dynamism, or rate of change, compared to typical construction projects that can require different project management approaches.

E. Electric Stipulated Base

The Stipulation identified that the electric portion of the Stipulated Base include $100 million in investments at PSE&G's discretion towards electric Outside Plant-Higher Design Standards (OP-HDS) and/or electric stations life cycle subprograms described in the original ES 2 filing.[1] The OP-HDS scope continues to advance engineering ahead of construction commencing in the third quarter of 2022; the OP-HDS work is expected to continue through December 2023. The OP-HDS scope currently contemplates upgrades to approximately 40-50 circuit miles and replacement of approximately 700 poles. Initial selection of circuits for OP-HDS investments is based on the Value of Loss Load (VOLL) based on the highest annual VOLL from 2010-2020 over the baseline performance, while final circuit selection will reflect the VOLL rankings with the execution requirements driven by field conditions in an effort to maximize the customer benefit.

As reported in the IM 2020 Second Quarter Report, the initial four stations PSE&G selected for life cycle station upgrades went before the URB in June 2020 for Study level estimate approval and received approval for full funding. In the second quarter of 2021 a fifth station, State Street, was approved by the URB for its outside plant scope to be transferred from the related Electric Station Flood Mitigation project

[1] As noted in the Stipulation, the electric life cycle upgrades are part of the electric Stipulated Base to be recovered in the Company's next base rate case provided the investments are found to be prudent. The Stipulation also notes that should the 16 stations that comprise the Electric Station Flood Mitigation subprogram be completed for under the $389 million allocated for that subprogram, PSE&G may reallocate such unused funds to stations identified in the life cycle station upgrade portion of PSE&G's petition for accelerated recovery.

to the life cycle scope. During the second quarter of 2022, PSE&G advanced the Hamilton, Plainfield, and Woodbury project estimates to the Definitive level. The five life cycle station upgrade projects and their current estimate compared to the actuals to date are provided in **Table 23 – ES 2 Life Cycle Station Upgrade Project Status as of June 30, 2022**.

Table 23 – ES 2 Life Cycle Station Upgrade Project Status as of June 30, 2022

Project	Estimate Level	Base	Risk & Contingency*	Total	Actuals to Date	% of Actuals to Estimate	Forecasted In-Service Date**
1. Hamilton	Definitive	$16,800,000	-	$16,800,000	$10,363,391	62%	10/5/2022 (↑ -23)
2. Paramus	Conceptual	$20,500,000	-	$20,500,000	$14,804,042	72%	11/3/2022 (↑ -11)
3. Plainfield	Definitive	$22,600,000	-	$22,600,000	$8,631,746	38%	11/28/2022 (↓ +20)
4. Woodbury	Definitive	$18,100,000	-	$18,100,000	$5,402,352	30%	12/30/2022
5. State Street (OP)	Study	$19,700,000	-	$19,700,000	$707,678	4%	12/19/2022
ES 2 Station Placeholder	-	-	$2,300,000	$2,300,000	-	-	-

**-As discussed in the IM 2022 First Quarter Report, during the first quarter of 2022, PSE&G made the decision to hold R&C at the subprogram level.*
***-Reflects the in-service date of the last major asset (e.g. switchgear), certain activities may take place after this date to support the final in-service date (i.e. when all customers are cutover).*
(↑)-*Indicates the forecasted in-service date advanced from the prior quarter.*
(↓)-*Indicates the forecasted in-service date slipped from the prior quarter.*

As shown in **Table 23**, of the five life cycle station upgrade projects, the Plainfield project saw its forecasted in-service date advance during the second quarter of 2022, while the Hamilton and Woodbury projects saw their respective forecasted in-service dates slip during the second quarter of 2022. Overall, these shifts in forecasted in-service dates were relatively minor, with all five of the life cycle station upgrade projects still forecasted for completion by the end of 2022. The R&C balance as of the end of the second quarter of 2022 decreased by $0.8 million from the prior quarter, with these R&C funds being allocated to the base estimate for Hamilton ($600K) and Woodbury ($300K), slightly offset by a reduction to the base estimate for Plainfield (-$100K) with those funds returning to the R&C balance. Additional details on each of these life cycle station upgrade projects is provided in the individual subsections that follow.

Similar to the Electric Station Flood Mitigation subprogram, the life cycle station upgrade projects within the Electric Stipulated Base have started to experience delays to the forecasted delivery dates of the major equipment. The status of the major equipment deliveries for the Electric Stipulated Base projects is presented in **Table 24 – Electric Station Flood Mitigation Major Switchgear Deliveries as of June 30, 2022**.

Table 24 – Electric Station Flood Mitigation Switchgear Deliveries as of June 30, 2022

Station	Description	Delivery Status as of Q1 2022	Delivery Status as of Q2 2022
1. Hamilton	4kV switchgear	4/5/2022	***4/5/2022***
2. Paramus	4kV switchgear	5/16/2022	***5/31/2022***
	4kV cont. switchgear	***7/8/2021***	***7/8/2021***
3. Plainfield	4kV switchgear	7/27/2022	8/26/2022
4. Woodbury	4kV switchgear	7/20/2022	7/20/2022
Note: bold/italicized dates indicate actual delivery dates.			

As shown in **Table 24**, the Hamilton and Paramus projects received their respective 4kV switchgears during the second quarter of 2022 (with Paramus having previously received a contingency switchgear to support the construction plan). For the remaining deliveries, both Plainfield and Woodbury are forecasted for the third quarter of 2022, with the Plainfield delivery slipping approximately one month from the status as of the end of the prior quarter.

Findings & Observations:

- Construction continued on the Hamilton, Paramus, Plainfield, and Woodbury projects, while engineering continued to advance on the State Street OP project (which is expected to commence construction in the fourth quarter of 2022).
- There was little movement in the forecasted in-service dates for three of the five life cycle upgrade projects during the second quarter of 2022, with Hamilton and Paramus slipping 23 and 11 days, respectively, and Plainfield advancing 20 days. Each of the five life cycle upgrade projects is currently forecasted to be in-service during the fourth quarter of 2022.
- The cost forecasts for the five life cycle upgrade projects collectively increased by approximately $0.5 million (or 0.5%) from the status as of the end of the first quarter of 2022 to a total forecast of $99.1 million as of the end of the second quarter of 2022. This increase was predominantly accounted for within the Paramus and Plainfield projects, while the Woodbury project saw a forecast decrease and Hamilton and the State Street OP projects had very minor forecast changes.
- Updated estimates were approved during the second quarter of 2022 on the Hamilton, Plainfield, and Woodbury projects, each of which advanced to the Definitive estimate stage and each saw the base estimate increase by $100K to $600K, with the primary drivers relating to higher than estimated construction costs.

1. Hamilton

During the second quarter of 2022, $3,089,239 was spent on the Hamilton project against a forecast of approximately $3.1 million. This brought total spend on the project to approximately $10.4 million through the end of the second quarter of 2022. The forecasted in-service date for the Hamilton project advanced 23 days from the status as of the end of the first quarter of 2022 to October 5, 2022. This forecasted in-service date advancement was driven by commissioning starting earlier than expected due to better than expected construction progress.

Notable activities performed during the second quarter of 2022 included the delivery of the regulators to complete the Powercon switchgear delivery and the commencement of electrical construction with the substation’s battery being placed in-service in May 2022.

During the second quarter of 2022, PSE&G advanced the Hamilton estimate to the Definitive stage, which resulted in the base estimate increasing by $600K to $16.8 million. This increase was driven by:

- $0.3 million: higher than estimated Division costs for design change on manholes and cable work;
- $0.2 million: higher testing and commissioning costs based on refined scope for underground cutover work;
- $0.2 million: higher than previously estimated bill of materials award. And,
- ($0.1 million): lower carrying costs based on actual trend.

The actual spend by quarter for Hamilton as compared to the current URB approved estimate is provided below.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals					***Forecast***		
$0	$362,372	$3,141,022	$3,770,758	$3,089,239	$2,115,676	$2,342,184	$2,089,733

Actuals to Date	Estimate	Current Forecast	% of Actuals to Forecast
$10,363,392	$16,800,000	$16,910,986	61%

2. Paramus

During the second quarter of 2022, $5,942,564 was spent on the Paramus project against a forecast of approximately $6.2 million. This brought total spend on the project to approximately $14.8 million through the end of the second quarter of 2022. The forecasted in-service date for the Paramus project advanced from November 14, 2022, as of the end of the first quarter of 2022, to November 3, 2022, as of the end of the second quarter of 2022.

Notable activities conducted during the second quarter of 2022 on the Paramus project included the commencement of IP civil and electrical construction, which included:

- Civil construction efforts included installation of foundations, duct banks, conduits and cable tray, and the grounding grid.
- Electrical construction efforts included the assembly of the 4kV switchgear (delivered at the end of May 2022) and the start of prepping and pulling cable to the new switchgear.

The actual spend by quarter for Paramus as compared to the current URB approved estimate is provided below.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals					***Forecast***		
$0	$840,200	$7,068,765	$952,513	$5,942,564	$1,711,285	$1,217,431	$3,597,807

Actuals to Date	Estimate	Current Forecast	% of Actuals to Forecast
$14,804,042	$20,500,000	$21,330,565	69%

3. Plainfield

During the second quarter of 2022, $2,682,840 was spent on the Plainfield project against a forecast of approximately $3.1 million. This brought total spend on the project to approximately $8.6 million through the end of the second quarter of 2022. The forecasted in-service date for the Plainfield project as of the end of the second quarter of 2022 slipped 20 days from the status as of the prior quarter to November 28, 2022. This forecasted in-service date slip was driven by delivery delays on the switchgear.

Notable activities conducted during the second quarter of 2022 included:

- Installation of new manholes;
- Installation of foundations and duct banks; and,
- Completion of the demolition of the existing feeder rows (started in the first quarter of 2022).

During the second quarter of 2022, PSE&G advanced the Plainfield estimate to the Definitive stage, which resulted in the base estimate decreasing by $100K to $22.6 million. This decrease was driven by:

- $0.9 million: Civil and electrical construction awards higher than previously estimated ($0.2 million and $0.7 million, respectively); and,
- ($1.0 million): Lower than estimated actual costs for Division overhead (-$0.6 million) and updated underground estimate based on current construction sequence (-$0.4 million).

The actual spend by quarter for Plainfield as compared to the current URB approved estimate is provided below.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals					*Forecast*		
$0	$682,325	$3,584,101	$1,682,480	$2,682,840	$8,827,318	$1,803,873	$3,785,103

Actuals to Date	Estimate	Current Forecast	% of Actuals to Forecast
$8,631,745	$22,600,000	$23,048,040	37%

4. Woodbury

During the second quarter of 2022, $1,776,838 was spent on the Woodbury project against a forecast of approximately $1.6 million. This brought the total spend on the project to approximately $5.4 million through the end of the second quarter 2022. The forecasted in-service date for the Woodbury project as of the end of the second quarter of 2022 remained unchanged from the status as of the end of the prior quarter at December 30, 2022.

Notable activities conducted during the second quarter of 2022 included:

- Completion of the duct banks from the station property line to OP manholes;
- Completion of the switchgear foundation;
- Installation of cable trench;
- Installation of the grounding grid; and,
- Site restoration and installation of station driveways.

During the second quarter of 2022, PSE&G advanced the Woodbury estimate to the Definitive stage, which resulted in the base estimate increasing by $300K to $18.1 million. This increase was driven by:

- $1.2 million: higher than estimated civil construction award ($1.1 million) and electrical supervision estimate ($0.1 million);
- $0.4 million: higher engineering estimate due to additional design and engineering needed for guidelines, SCADA updates, manhole access, and perimeter wall updates;
- $0.3 million: higher than estimated award for station wiring; and,
- ($1.6 million): Division estimate refinement after field verifications and preliminary engineering completed.

The actual spend by quarter for Woodbury as compared to the current URB approved estimate is provided below.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals					***Forecast***		
$0	$551,165	$1,613,823	$1,460,525	$1,776,838	$6,444,584	$2477,880	$3,775,253

Actuals to Date	Estimate	Current Forecast	% of Actuals to Forecast
$5,402,351	$18,100,000	$18,100,069	30%

5. *State Street (Outside Plant)*

During the second quarter of 2022, $101,527 was spent on the State Street (OP) project against a forecast of approximately $572,000. The variance between forecasted and actual spend in the second quarter was driven by delays in reaching an agreement with Camden County on restoration efforts, which caused permit delays and delays to the test pits work. The County had requested PSE&G use concrete and doweling for the temporary patching of the roadways following the test pits, but PSE&G advised the County that it would be installing manholes and duct banks in this area in the immediate future, which would make use of concrete for the temporary patching excessive. After additional discussions, the County and PSE&G reached an agreement to forego the use of concrete for the temporary patching (with a provision that if there is a failure, any repair would utilize concrete). PSE&G expects no additional costs associated with this effort, but the delay in permit approval is expected to affect the schedule, which is being evaluated. As of the end of the second quarter of 2022, the forecasted in-service date for the State Street OP project remained unchanged from the status as of the prior quarter at December 19, 2022.

Notable activities conducted during the second quarter of 2022 included the continuation of detailed engineering and outreach to the local municipalities concerning the underground work (test pits) that are expected to commence in the third quarter of 2022.

The actual spend by quarter for State Street (OP) as compared to the current URB approved estimate is provided below.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals					***Forecast***		
$0	$0	$211,247	$395,903	$100,527	$1,529,615	$2,933,398	$14,541,955

Actuals to Date	Estimate	Current Forecast	% of Actuals to Forecast
$707,677	$19,700,000	$19,712,645	4%

F. Gas M&R Station Upgrades

During the second quarter of 2022, PSE&G submitted updated estimates for each of the Gas M&R projects for approval by the URB. As part of this effort, the Camden, Central, East Rutherford, and Mount Laurel projects advanced the Conceptual level estimate, while Paramus and Westampton remained at the Study and Definitive stages, respectively. **Table 25 – ES 2 Gas M&R Summary Status as of June 30, 2022** below provides these newly approved estimates for each project within the Gas M&R subprogram, along with the actuals to date and forecasted in-service dates.

Table 25 – ES 2 Gas M&R Summary Status as of June 30, 2022

Project	Estimate Level	Base	Risk & Contingency	Total Estimate	Actuals	% of Actuals to Estimate	Forecasted In-Service
1. Camden*	Conceptual	$18,500,000	$3,300,000	$21,800,000	$13,467,350	62%	Dec 2022
2. Central*	Conceptual	$31,400,000	$5,500,000	$36,900,000	$19,046,123	52%	Nov 2023
3. East Rutherford	Conceptual	$21,700,000	$4,300,000	$26,000,000	$8,279,623	32%	Dec 2022
4. Mount Laurel	Conceptual	$12,700,000	$3,100,000	$15,800,000	$1,073,372	7%	Nov 2023
5. Paramus*	Study	$11,500,000	$8,400,000	$19,900,000	$1,250,390	6%	Dec 2023
6. Westampton	Definitive	$8,400,000	$-	$8,400,000	$8,312,921	99%	*Oct 2021 (actual)*
Subprogram Total		**$104,200,000**	**$24,600,000**	**$128,800,000**	**$51,429,779**	**40%**	**Dec 2023**

**-Included in the Stipulated Base.*
(↑)-*Indicates the forecasted in-service date advanced from the prior quarter.*
(↓)-*Indicates the forecasted in-service date slipped from the prior quarter.*

Collectively, the updated estimates resulted in the overall subprogram estimate increasing by $18.9 million, or 17%, from the prior estimates. While details of the individual estimate changes are discussed within the individual project discussions that follow, PSE&G reviewed its estimating process including conducting a deep dive into the drivers to the changes from the Office level estimates and found:

- The original ES 2 filing estimates were completed in January 2018 and included seven projects totaling $136 million. The Stipulation as approved in September 2019 provided six stations at a total of $101 million, which saw the lowest priority station eliminated along with R&C being reduced from 60% to 35% and an additional 15% cut from the subprogram.
- There was insufficient investigation in the development of the projects during front-end planning to support the BPU filing (i.e. project scope not locked, lack of constructability review, final site layout incomplete).
- The upfront scope development did not consider design and execution refinement, resulting in deviation from the preliminary scope as formal scope lockdown for these projects did not occur.
- The R&C was insufficient and did not cover the final scope definition thereby leading to cost increases throughout the estimate phases.
- Front-end planning activities were not completed, nor were all stage gates met when Study level estimate were developed by the project teams with A/E firm assistance and submitted to the URB.
- Comparative estimates were not developed to support the review of the A/E estimates to ensure consistency.

- Scope items, such as Liquid Propane Air (LPA) systems at Camden and Central, scrubber improvements at Central and line strainers at each site were added, expanding upon the original BPU filing scope to take advantage of the mobilization on these projects, and then later carved out upon further evaluation, ensuring alignment with the filing.
- A more experienced project team executed ES 1, which were less complex stations, mitigating potential impacts due to lack of front-end planning within the existing processes. The current ES 2 stations are more complex and being managed by a less experienced project team, highlighting the need for a more formalized front-end planning process.
- Due to Covid-19, material price inflation as per market conditions contributed to increased material costs.

PSE&G also identified actions to implement to avoid this issue in the future, including:

- Evaluate and modify the existing Gas M&R project origination process:
  - Implement changes to the more closely model the electric project origination process.
  - Further develop gas expertise to perform feasibility analyses, further develop the design, and perform constructability analyses.
  - Better define project scope in the origination process to minimize undocumented scope evolution.
- Develop and expand Gas M&R expertise in the Projects & Construction (P&C) estimating group:
  - P&C estimating group has expanded to include gas projects.
  - Project teams have supplied the P&C estimating group with information as prices are received (materials, construction, etc.).
  - Benchmark with Gas Construction estimating group, Gas Asset Management and A/E firms subject matter experts to expand and support the gas estimating program.
- Implement the modified project origination process and expanded expertise.
- For future programs, if the settlement value is materially different than the filing, there needs to be a review to see if the original project scope is still achievable under the proposed settlement amount.

In consideration of the above, the IM has reviewed PSE&G's recommendations to award for the construction contractor scope of the Gas M&R projects awarded to date (all except Mt. Laurel and Paramus). A summary of this review is provided as follows:

- <u>Camden</u>: Henkels & McCoy (H&M) selected as the construction contractor after receiving the highest evaluated score (combined technical, commercial, and supplemental aspects) of the three contractors that submitted bids. H&M had the second lowest price (1.4% above the lowest bid, but 21.5% below the highest bid), but had a higher overall score due to their experience with similarly complex projects and their ability to meet the schedule and resource requirements.

- <u>Central</u>: H&M selected as the construction contractor after receiving the highest evaluated score of the three contractors that submitted bids. In addition to having the requisite experience and capabilities, H&M was the lowest bidder on this project (12.5% and 59% below the other bidders).

- <u>East Rutherford</u>: J. Fletcher Creamer selected as the construction contractor after receiving the highest evaluated score of the four contractors that submitted bids. In addition to having the requisite experience and capabilities, J. Fletcher Creamer was the lowest bidder on this project (52% to 102% below the other bidders).

- Westampton: H&M selected as the construction contractor after receiving the highest evaluated score of the five contractors that submitted bids. In addition to having the requisite experience and capabilities, H&M was the lowest bidder on this project (3.5% to 84% below the other bidders).

Relative to the forecasted in-service dates shown in **Table 25**, as of the end of the second quarter of 2022, the forecasted in-service dates for the remaining Gas M&R projects remained unchanged from the status as of the end of the prior quarter. As previously reported, the Westampton project was placed in-service as of October 22, 2021.

Findings & Observations:

- The six projects that comprise the Gas M&R subprogram continues to advance at various stages of development or delivery. During the second quarter of 2022, construction continued to advance on the Camden, Central, and East Rutherford projects, while the Mount Laurel and Paramus projects continued pre-construction activities including advancing design efforts and receiving the interconnection agreement with Transco. The Westampton project was previously put in-service in October 2021, while punch list items and site restoration activities continued in the second quarter of 2022.

- There were no changes to the forecasted in-service dates of the Gas M&R projects during the second quarter of 2022. The next projects to be completed are the Camden and East Rutherford projects, which are forecasted to be placed in-service by the end of 2022.

- PSE&G updated the estimates for each of the Gas M&R projects during the second quarter of 2022, resulting in the overall subprogram estimate increasing by $18.9 million. While the Camden and Westampton project estimates decreased, the other stations within the subprogram saw estimate increases ranging from $4.4 million to $9.5 million. The estimate increases were generally related to design evolution, scope refinement, and current market conditions, which were more impactful due to the reduction in R&C from the original ES 2 filing to the approved Stipulation (reducing R&C from 60% to 35%). Despite these estimate increases, the overall subprogram forecast was reduced to $104.3 million (from $128.3 million as of the end of the first quarter of 2022) and remains below the current total estimate of $128.8 million, with the difference between the forecast and the estimate primarily reflecting the R&C funds.

- With the significant increase in the updated project estimates, the IM finds that PSE&G appropriately assessed why and how the project cost estimates have changed since the filing including identifying lessons learned and actions to be taken on future initiatives. Generally speaking, the increases were driven by scope refinement and market conditions, further exacerbated by the budget and R&C reduction from the ES 2 filing to the approved Stipulation.

- The IM has found nothing to date that would jeopardize the subprogram being completed on time, however, the current forecast of $104.3 million exceeds the Stipulation budget of $101.0 million.

1. Camden

During the second quarter of 2022, $7,655,276 was spent on the Camden project compared to a forecast of approximately $9.1 million, which brought the total spend to approximately $13.5 million. The variance in forecasted to actual spend in the second quarter of 2022 was attributed to delayed delivery of material to site due to availability from the sub-vendors. Despite these material delays, PSE&G has held the forecasted in-service date for the Camden project at December 16, 2022 by re-sequencing certain activities and implementing contingency plans such as working with Transco to tie-in on their facility upstream of the pressure regulators and using a valve to connect to the new M&R station, this allows the old station to remain operating until the new station is ready and can make the cutover without taking a two to three day outage. PSE&G anticipates this contingency plan will require minor amounts of additional piping and minimal valve costs, but should not have a material impact on the project cost.

Notable activities on the Camden project during the second quarter of 2022 included:

- Contractor mobilized and began receiving materials;
- Soil conservation measures installed;
- Excavation for building footings and foundations;
- Pipe fabrication;
- Steel erection for regulator, heater, and control buildings;
- Installation of meter runs in the regulator building.

The actual spend by quarter for Camden as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project. During the second quarter of 2022, PSE&G submitted the Conceptual estimate for the Camden project to its URB for approval. This updated estimate saw the overall estimate decrease by $7.5 million ($5.8 million in the base estimate and $1.7 million in R&C) from the previously approved Study level estimate, with the changes driven by:

- $3.6 million – changes in site plan due to required site remediation resulted in approximately 70% more pipe and conduit. There was a limited portion of the site that was remediated prior to the start of the project, while the project had a requirement to avoid the non-remediated areas, which resulted in the layout of the buildings not being optimized to minimize the pipe routing.
- $3.3 million – due to the new compressor sizing requiring additional load, the existing 5kV transformers were not adequate and required replacement of equipment, associated switchgear, and an additional 30x42 foot raised platform to house the equipment.
- $2.9 million – additional schedule coordination needed to meet site remediation deadline requirements required additional resources.
- $1.7 million – building size increase based on final piping design; additional steel and prices higher than estimated.
- $0.8 million – higher than estimated mobilization/demobilization costs based on actual bids; asbestos abatement of M&R building and onsite security.
- $0.6 million – updated R&C based on current risk register.
- ($18.1 million) – removal of LPA components from ES 2 project scope (includes valves, piping, buildings, construction costs, engineering, testing and commissioning).
- ($2.3 million) – adjustment to R&C to remove risk items associated with LPA scope.

As much of this updated estimate involves impacts associated with the LPA scope, PSE&G also presented an estimate to its URB that documented the changes from the $15.4 million Office level estimate to the current $21.8 million Conceptual estimate to present a summarized view of the changes to the current ES 2 project scope (i.e. no LPA scope adjustments, addition or removal). The cost drivers from the earlier Office level estimate to the current Conceptual estimate were:

- $2.9 million – changes in site plan due to required site remediation that impacted the building location relative to inlet/outlet piping and resulted in additional piping and conduit required.

- $2.4 million – additional schedule coordination needed to meet site remediation deadline requirements (added resources, premium time).
- $1.8 million – building size increased based on final piping design; additional steel required and prices higher than estimated.
- $1.4 million – other construction: Higher mobilization/demobilization costs based on actual contractor bids; Asbestos abatement of M&R building.
- ($2.1 million) – drawdown of R&C based on current risk register.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals					*Forecast*		
$13,326	$859,350	$2,147,696	$2,791,701	$7,655,276	$1,862,886	$2,978,844	$191,919

Actuals to Date	Estimate	Current Forecast	% of Actuals to Forecast
$13,467,350	$21,800,000	$18,500,999	73%

2. Central

During the second quarter of 2022, $7,029,778 was spent on the Central project compared to a forecast of approximately $7.4 million, which brought the total spend to approximately $19.0 million. The forecasted in-service date for the Central project as of the end of the second quarter of 2022 remains at November 30, 2023, unchanged from the status as of the end of the first quarter of 2022.

Notable activities on the Central project during the second quarter of 2022 included:

- Excavated footings and foundations for regulator and heat exchanger/flow control buildings;
- Started forming and pouring foundations;
- Pipe fabrication;
- Steel erection for regulator, heater, and control buildings;
- Started installation of meter runs in regulator building;
- Set SCADA building in place.

The actual spend by quarter for Central as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project. During the second quarter of 2022, PSE&G submitted the Conceptual estimate for the Central project to its URB for approval. This updated estimate saw the overall estimate increase by $7.9 million ($7.5 million in the base estimate and $0.4 million in R&C) from the previously approved Study level estimate, with the changes driven by:

- $6.6 million – design evolution of building configuration/foundations caused modifications to: inlet/outlet header configurations, overpressure protection, piping, electrical, conduits, and refinement of material/equipment specifications.
- $3.0 million – based on final IFC piping design and building layout, LPA injection points required relocation needing additional valves, material, foundations, demolition, and pipe supports.
- $1.8 million – Transco scrubber: final design flow exceeds existing scrubber capacity, requiring a new and larger scrubber with additional piping, valves, and foundation.
- $1.6 million – station by-pass: relocated away from proposed regulation building to allow access in case of station emergency.

- $0.5 million – shift in-service date: additional mobilization and demobilization of the construction contractor and associated carrying costs to shift in-service from 2022 to 2023.
- $2.4 million – updated R&C.
- ($5.0 million) – removal of LPA components from ES 2 project scope (includes valves, piping, buildings, construction costs, engineering, and testing and commissioning).
- ($1.0 million) – adjustment to R&C to remove risk items associated with LPA scope.
- ($1.0 million) – removal of scrubber components from ES 2 project scope (includes scrubber equipment, valves, piping, construction costs, and engineering).
- ($0.2 million) – adjustment to R&C to remove risk items associated with scrubber scope.
- ($0.8 million) – updated R&C based on current risk register.

As much of this updated estimate involves impacts associated with the LPA scope, PSE&G also presented an estimate to its URB that documented the changes from the $19.7 million Office level estimate to the current $36.9 million Conceptual estimate to present a summarized view of the changes to the current ES 2 project scope (i.e. no LPA scope adjustments, addition or removal). The cost drivers from the earlier Office level estimate to the current Conceptual estimate were:

- $6.9 million – construction: based on actual bids & PO for construction costs; includes additional pipe supports, foundations, gas main tie-ins, pipe prefabrications, additional electrical and instrumentation, and current market conditions.
- $5.4 million – building/foundation & mechanical: driven by design evolution of the building configuration/foundations; increasing the building count from two to four buildings and increasing the number of heater replacements from one to five. This design evolution led to modifications to: inlet/outlet header configurations, additional foundations; overpressure protection, piping, electrical, instrumentation, conduits, and refinement of material/equipment specifications.
- $3.0 million – procurement: driven by procurement of two additional buildings and four heaters required for final design and increases due to market conditions.
- $1.6 million – station by-pass: relocated away from the proposed regulation building to allow access in case of station emergency.
- $1.2 million – project management, licensing & permitting, and engineering: increase due to actual spend to date and estimate to complete.
- $0.5 million – shift in-service date: additional mobilization and demobilization of the construction contractor and associated carrying costs to shift in-service from 2022 to 2023.
- ($1.4 million) – update of R&C based on current risk register.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals					*Forecast*		
$6,869	$670,582	$4,226,277	$7,112,617	$7,029,778	$3,671,463	$1,479,499	$7,203,120

Actuals to Date	Estimate	Current Forecast	% of Actuals to Forecast
$19,046,122	$36,900,000	$31,400,204	61%

3. East Rutherford

During the second quarter of 2022, $4,413,835 was spent on the East Rutherford project compared to a forecast of approximately $4.8 million, which brought the total spend to approximately $8.3 million. The forecasted in-service date for the East Rutherford project as of the end of the second quarter of 2022 remains unchanged from the status as of the end of the prior quarter at December 16, 2022.

Notable activities on the East Rutherford project during the second quarter of 2022 included:

- Set up frac tank for ground water management;
- Excavated for temporary bypass lines and installed hot taps for temporary bypass;
- Completed hazardous abatement in regulator building;
- Initiated station outage;
- Completed demolition of regulator building and removal of all existing yard pipe;
- Prepared for pile driving;
- Continued pipe fabrication;
- Installed water filtering equipment.

The actual spend by quarter for East Rutherford as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project. During the second quarter of 2022, PSE&G submitted the Conceptual estimate for the East Rutherford project to its URB for approval. This updated estimate saw the overall estimate increase by $9.5 million ($7.9 million in the base estimate and $1.6 million in R&C) from the previously approved Study level estimate, with the changes driven by:

- $3.3 million – outage constraint: construction contractor sequencing and durations were longer than anticipated and required additional resources; construction limited by winter heating season.
- $1.6 million – design evolution: changed from one large heater to two smaller heaters to facilitate maintenance of heater tubes; increased piping wall thickness to mitigate high noise levels; upgraded temporary regulator skids to allow additional operational controls during construction.
- $0.5 million – design required upgrade to electrical service from 200a/120vac to 400a/480vac to support additional equipment and includes the separation of the currently shared Transco/PSE&G electrical service to the station. This requirement stemmed from the Interconnection Agreement between Transco and PSE&G that called for PSE&G to provide power to Transco and by utilizing a separate service disconnect, it ensures that an electrical shutdown by either Transco or PSE&G will not impact the other party, improving the safety and reliability of the station as a result.
- $2.0 million – building footprint: increased costs associated with regulator and control buildings, including materials, building erection, piles, foundations, and fit out of instrumentation and controls.
- $0.5 million – environmental: based on samples taken during detail design, the building/piping will require lead/asbestos/PCB abatement; higher than anticipated water table requires additional dewatering.
- $1.6 million – updated R&C based on current risk register.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals					*Forecast*		
$9,010	$521,865	$1,783,623	$1,551,290	$4,413,835	$9,523,474	$3,194,450	$702,502

Actuals to Date	Estimate	Current Forecast	% of Actuals to Forecast
$8,279,623	$26,000,000	$21,700,048	38%

4. Mount Laurel

During the second quarter of 2022, $42,260 was spent on the Mount Laurel project compared to a forecast of approximately $58,000, which brought the total spend to approximately $1.1 million. The forecasted in-service date for the Mount Laurel project as of the end of the second quarter of 2022 remained unchanged from the status as of the end of the prior quarter at November 30, 2023.

Notable activities on the Mount Laurel project during the second quarter of 2022 included PSE&G receiving updated pricing from construction contractors and PSE&G receiving the interconnection agreement from Transco.

The actual spend by quarter for Mount Laurel as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project. During the second quarter of 2022, PSE&G submitted the Conceptual estimate for the Mount Laurel project to its URB for approval. This updated estimate saw the overall estimate increase by $4.4 million ($3.3 million in the base estimate and $1.1 million in R&C) from the previously approved Study level estimate, with the changes driven by:

- $1.9 million – construction bid: direct impacts to construction contractor based on current market conditions since original estimate.
- $0.7 million – material price increase: increase in material costs and shipping based on current quotes received.
- $0.7 million – project management/oversight: additional project management, oversight, and carrying costs to shift in-service from 2022 to 2023.
- $1.1 million – updated R&C based on current risk register.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals					*Forecast*		
$5,965	$362,167	$527,341	$135,639	$42,260	$77,419	$118,261	$11,430,951

Actuals to Date	Estimate	Current Forecast	% of Actuals to Forecast
$1,073,372	$15,800,000	$12,700,000	8%

5. Paramus

During the second quarter of 2022, $115,998 was spent on the Paramus project compared to a forecast of approximately $150,000, which brought the total spend to approximately $1.3 million. The forecasted in-service date for the Paramus project as of the end of the second quarter of 2022 remains unchanged from the forecast as of the end of the prior quarter at December 29, 2023.

Notable activities on the Paramus project during the second quarter of 2022 included:

- Engineer developed and submitted 70% drawings for review; and,
- RFP issued for major equipment items.

The actual spend by quarter for Paramus as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project. During the second quarter of 2022, PSE&G submitted an updated Study level estimate for the Paramus project to its URB for approval. This updated estimate saw the overall estimate increase by $6.2 million (entirely within R&C, no increase to the base estimate) from the previously approved Study level estimate, with the changes driven by the current risk register and the experience of other more advanced projects in the ES 2 Program.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals					*Forecast*		
$8,842	$462,452	$568,344	$94,755	$115,998	$120,754	$726,505	$9,402,362

Actuals to Date	Estimate	Current Forecast	% of Actuals to Forecast
$1,250,390	$19,900,000	$11,500,011	11%

6. Westampton

During the second quarter of 2022, $132,517 was spent on the Westampton project compared to a forecast of approximately $191,000, which brought the total spend to approximately $8.3 million. The Westampton was placed in-service as of October 22, 2021, remaining activities include site restoration and final punch list items that continued to be performed in 2022.

During the second quarter of 2022, notable activities on the Westampton project included:

- Completed installation of cathodic protection components; and,
- Continuing to work through punch list items.

The remaining items to closeout the project include corrosion protection work and final punch list items relating to site paving/grading. PSE&G expects these activities to be fully complete around July.

The actual spend by quarter for Westampton as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project. A revised Definitive estimate was submitted by PSE&G and approved by its URB in the second quarter of 2022. As the project was essentially complete at this time, the updated estimate removed the remaining R&C ($900K) and reduced the base estimate to reflect the actual costs (reducing the base estimate by $700K).

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals					*Forecast*		
$8,395	$1,032,670	$6,961,216	$178,124	$132,517	$123,562	$35,903	$-

Actuals to Date	Estimate	Current Forecast	% of Actuals to Forecast
$8,312,921	$8,400,000	$8,472,386	98%

ENERGY STRONG PROGRAM

INDEPENDENT MONITOR

2022 SECOND QUARTER REPORT

APPENDIX A – DRAFT REPORT COMMENTS AND RESPONSES

JUNE 28, 2023

PEGASUS GLOBAL HOLDINGS, INC. ®

Questions & Comments to the IM 2022 Second Quarter Report Formally Submitted to the IM

ID #	Question/Comment	IM Response	Report Changes
S-INF-1	**<u>Reference Q1 2022 Report, S-INF-3</u>** Regarding the State Street Substation project, the IM's Q1 2022 Report state that the initially planned overhead route was no longer feasible due to an existing overhead pole in the area that was not known at the time of the initial design, and the updated route requires the installation of an underground manhole and duct bank system. a. Please estimate the cost increases associated with this scope change. b. Please provide additional details explaining how the existing overhead pole caused the initially planned overhead route to become infeasible. c. Please indicate if the Company considered other overhead alternatives before opting for an underground route. d. Please explain why the existing overhead pole was not identified during field inspections.	Regarding the State Street project: a. PSE&G estimates the costs associated with the overhead route design change is approximately $370,000, with a total cost of approximately $870,000 for this circuit 4005/tie feeder. b. The initial planned route for the circuit 4005/tie feeder was based on an Office level overhead design/scope that was not confirmed in the field at the time. During field inspections in the detailed design phase, it was discovered that an existing pole line already occupied the intended route along Cooper Street. c. Three overhead routers were evaluated by PSE&G (Cooper Street, Federal/Market, and Right-of-way to Route 30). d. The existing overhead pole was identified during field inspections that occurred in the detailed design phase.	No change
S-INF-2	**<u>Reference Q2 2022 Report, Page 4, Cost-Effectiveness and Efficiency of Investments</u>** Please discuss the cost-effectiveness of the Contingency Reconfiguration subprogram given that the total anticipated number of recloser and fuse saver installations has decreased significantly from originally budgeted totals.	The initial scope and estimate to the actual installed scope and final costs can serve as a baseline in evaluating the cost-effectiveness and efficiency of executing the work, but consideration also must be given to the underlying drivers and reasons for any changes in scope or cost. Each month PSE&G reviews the actual cost per unit and hours per unit on the installations and assesses any variances from its estimate and assumptions to inform the forecast at completion. Below the IM discusses the primary changes from the initial scope and estimate to final installed units and costs for the Fuse Savers and reclosers, respectively. <u>Fuse Savers</u> In the ES 2 filing, PSE&G identified 3,282 circuits where customers are served from overhead facilities on a branch line as candidates to receive reclosing devices (Fuse Savers). At the time of the ES 2 filing, PSE&G	No change

ID #	Question/Comment	IM Response	Report Changes
		estimated installation of these devices would range between $11,721 for single-phase devices and $18,262 for two-phase devices. The Black & Veatch "Electric Cost-Benefit Analysis" study attached to PSE&G's ES 2 filing noted that *"PSE&G currently does not have any of these devices installed; therefore, some work is required to develop a construction standard and training to ensure the workforce is familiar with the construction and operation of the reclosing devices."* The construction standard and training was developed through implementation of the Fuse Saver pilot program that commenced in November 2020 and was primarily completed in January 2021 (PSE&G installed 80 devices in this initial period, then opted to install the remaining units in inventory to capture additional cost and performance data, resulting in a total of 113 units installed as of the end of 2021). The actual costs observed through the Fuse Saver pilot program actuals saw single phase devices average $35,216 and two-phase devices average $48,031, significantly higher than the estimate at the time of the ES 2 filing. The cost increases were primarily driven by: • The ES 2 filing estimate not including management costs, tree trimming, storage, or traffic control costs; • Higher material costs than estimated, including pole replacements at multiple locations (pole replacement costs not included in the initial estimate assumptions, adds approximately $10,000 in costs); and, • Average labor hours 4x higher than the ES 2 filing estimate and increased labor rates since filing. PSE&G's approach on forecasting the Fuse Saver scope during its execution is based on a quarterly review of the actual cost data and related installation status information to inform and update the installation plan. PSE&G continues seeking to optimize the number of Fuse Savers installed in alignment with the overall budget for the subprogram. For example, given the added costs of the pole replacements, PSE&G considered attempting to avoid such locations, but in many cases the existing equipment and height/spacing requirements on the pole required installation of a new pole. <u>Reclosers</u> In the ES 2 filing, PSE&G identified 1,190 circuits as candidates for recloser investments, comprised of 690 13kV circuits and 500 4kV circuits.	

ID #	Question/Comment	IM Response	Report Changes
		PSE&G's approach to this scope was to update the circuit list on a recurring basis through the execution of the Program to reflect changes to the system (either work already completed or work planned in the near-term). This effort included conducting detailed reviews of the system to identify cost effective opportunities to include other circuits in the Program following the same cost/benefit process utilized in the ES 2 filing. Ultimately, PSE&G installed a total of 1,467 reclosers through the ES 2 Program, which included 954 13kV circuits and 513 4kV circuits, representing an increase of 277 units from what was initially planned.	
S-INF-3	**<u>Reference Q2 2022 Report, Page 18</u>** Regarding the cost reductions associated with the Lakeside Avenue project: a. Please provide additional information about the scope reduction associated with the electrical construction award, including estimated cost savings. b. Please explain why the 4kV bus scope was transferred to the 69kV transmission project and provide the estimated Energy Strong II cost savings.	Regarding the drivers to the cost forecast reduction on the Lakeside Avenue project: a. The project initially planned for elevated stair rails and rigging of the switchgear that was no longer required. This resulted in a contract price that was approximately $1.5 million lower than what was estimated with that initial scope. b. PSE&G transferred the 4kV bus scope based on its practice for delineation of the transmission/distribution systems interconnection point at the high side bushing on the transmission/distribution transformer. The sections of the 4kV bus scope (bus work and steel supports) transferred to the 69kV transmission project are tied to the high-side bushings of the three 69/4kV transformers, which is classified as a transmission asset. PSE&G estimates the costs associated with this transferred scope are approximately $300,000.	**Section III.A.6.**
S-INF-4	**<u>Reference Q2 2022 Report, Page 18</u>** Please provide additional information about the scope increases on the Clay Street substation project and this associated cost increases.	The detail of this cost forecast increase has been added to the discussion on the Clay Street project within **Section III.A.2.**	**Section III.A.2.**
S-INF-5	**<u>Reference Q2 2022 Report, Page 28, Contingency Reconfiguration Subprogram</u>** Regarding the Fuse Saver projects: a. What is attributed to the scope being reduced from 1,713 units (<u>See</u> Q1 2022 Report, S-INF-5) to 1,641 units? b. Of the 1,641 total forecasted units, how many are expected to require an external antenna to address communication issues?	Regarding the Fuse Saver scope of work: a. PSE&G's approach on forecasting the number of Fuse Savers to be installed during the Program continues to follow a quarterly review of the actual cost data and related installation status information to update the installation plan and overall quantity of units planned for the Program to align with the established budget for this scope of work. b. Based on the units installed to date, PSE&G estimates that approximately 10% of the locations will require the modified external antenna.	**Section III.B.**

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	c. Please explain why the delay in Fuse Saver installations associated with the Company's D-SCADA freeze could not be reasonably foreseen during the scheduling process. Please also indicate if additional D-SCADA freezes are expected to occur within the remainder of Energy Strong II.	c. The D-SCADA freeze was identified ahead of its implementation, however it still resulted in an approximate two-week period in which installations were unavailable. The other major factor that influenced Fuse Saver installations during the second quarter of 2022 was the technical issues encountered on two of the first devices installed following the earlier pilot program (*see also* RCR-IM-15). There are no ES 2 related D-SCADA production system freezes planned or contemplated for the remainder of the Program.	
S-INF-6	**<u>Reference Q2 2022 Report, Page 29, Grid Modernization – Communication System Subprogram</u>** Regarding the Retrofit Substation Remote Terminal Unit (RTU) scope: a. Please identify the projects removed from the program and explain how PSE&G determined that the projects are no longer necessary. b. Please discuss PSE&G's rationale to include not only substations served by Verizon plain old telephone service (POTS) (which represented 196 substations), but also those served by Verizon 4G service (which represented 22 additional stations). (<u>See</u> Q1 2022 Report, S-INF-6).	Regarding the Retrofit Substation RTU scope: a. No stations have been removed from the Retrofit Substation RTU scope. b. The intent of PSE&G was to replace the RTUs relying on third-party communication, which included both the Verizon POTS and Verizon 4G service. Previously, PSE&G removed the substations served by the Verizon 4G service from the subprogram following an initial assumption that only the RTUs served by Verizon POTS would be replaced that was later clarified to include all third-party services.	No change
S-INF-7	**<u>Reference Q2 2022 Report, Page 30, Grid Modernization – Communication System Subprogram</u>** Regarding the identified challenges and lessons learned for the Grid Modernization – Communication System subprogram, please discuss if these issues (including inadequate site investigations and lack of comprehensive review and updating location requirements, grouping, and prioritizing locations for new fiber installation) specifically contributed to any cost increases that would not have otherwise occurred absent these issues.	Given the variety of factors that influenced the execution of the fiber projects within the Grid Modernization – Communication System subprogram (including executing through the Covid-19 pandemic), it would be difficult to parse out specific cost impacts stemming from specific issues encountered in the execution of the fiber projects. For example, one of the issues identified by PSE&G was inadequate site investigations that resulted in required items being left out of the initial scope definitions. This led to cost increases as the missing scope items were identified and included in the projects, but they were nonetheless requirements for the project to achieve its intended objectives. From the IM's perspective, there are elements of these issues/lessons learned that potentially caused cost inefficiencies, such as the lack of a comprehensive review to update location requirements and group projects for potential efficiencies. However, other issues encountered were more related to typical project execution risks, such as the increased time to	No change

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		obtain railroad permits and lead time for scheduling commissioning resources, and with this scope of work having a fixed budget with no R&C, any realized risks inherently led to cost increases.	
S-INF-8	**Reference Q2 2022 Report, Pages 32-33, Tables 19 and 20** Please clarify if the spending for "Retrofit reclosers" also includes spending for retrofitting RTUs. If not, please explain the significant amount of forecasted spending, given that retrofitting of reclosers was completed in Q4 2021.	The Grid Modernization – Communication System subprogram is responsible for the procurement, handling, delivery and oversight of the Fuse Saver radios being installed within the Contingency Reconfiguration subprogram. The current spend for the Retrofit reclosers scope relates to materials (radios and kitting) and associated project management costs for the Fuse Saver scope. The specific costs related to the Substation RTU scope have been split out in **Table 19** and **Table 20**.	**Table 19 & Table 20**
S-INF-9	**Reference Q2 2022 Report, Page 34, Grid Modernization – Communication System Subprogram** Regarding the Grid Modernization – Communication System subprogram, please provide additional details about the fiber scope changes which contributed to a cost increase of $3 million.	The details of the transition of the fiber installation and cutovers scope from the Office level estimate to Study level estimate to the current Definitive level estimate are shown on **Table 16**. In summary, the drivers of the current $3.0 million estimate increase are: • OP estimates: $2.5 million – actual costs higher than estimated. • IP estimates: $2.2 million – refinement of Office level estimates. • Changed routes: $0.9 million – routes for Montclair (+$1.3 million) and Bloomfield (-$0.4 million) projects changed to provide simplified designs and avoid extensive inspections and permitting associated with the original OP routes. • Fiber cutovers: $0.3 million – increase due to scope and estimate refinement. • Scope reduction: ($2.9 million) – removal of selected projects from the subprogram. The specific scope refinement related to changes made to meet updated system communication requirements.	No change
S-INF-10	**Reference Q2 2022 Report, Page 35, Grid Modernization – ADMS Subprogram** Regarding the ADMS project, it is noted that the scope of work includes the replacement of existing D-SCADA elements inclusive of infrastructure components (servers and workstations) and applications (Monarch, Spectra, and Integra). Please discuss if any equipment deployed within the Company's system will become obsolete as a result of the ADMS implementation.	The infrastructure for Common Gate Interface (CGI) – Outage Management System (OMS) will be obsolete and retired after OSI OMS go live. The associated CAD infrastructure will also be obsolete after DWMS CAD for electric and gas operations is completely replaced by MWMS, which is expected by mid-2024. For the Platform, DSCADA-Legacy hardware was decommissioned as part of the hardware upgrade involved with the Platform scope and implementation.	No change

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S-INF-11	**Reference Q2 2022 Report, Page 37, Grid Modernization – ADMS Subprogram** Regarding the identified challenges and lessons learned for the Grid Modernization – ADMS subprogram: a. Please discuss if these issues (including lack of project organization with understanding future projects within portfolio/strategy and deficiency of proper resources) specifically contributed to any cost increases that would not otherwise have occurred absent these issues. b. Please discuss if these issues are expected to have any implications on the functionality of the ADMS.	The issues identified and encountered with the execution of the Grid Modernization – ADMS subprogram generally relate to the first-of-a-kind nature of this scope of work, the limited project definition at the time of the ES 2 filing, and the decision to incorporate lessons learned from Topical Storm Isaias shortly after operational planning for the project had completed. **Table 21** summarizes the evolution of the Grid Modernization – ADMS subprogram estimate from the initial $35.0 Office level estimate through the $42.7 million Conceptual level estimate to the current $56.3 million Definitive level estimate. In further examining these cost drivers, the IM has grouped them into the following primary categories: • Scope changes/design evolution: $10.5 million; • Project execution/resources: $4.5 million; • Schedule impacts: $3.5 million; and, • R&C: $2.8 million. Concerning the identified challenges and lessons learned and if those specifically contributed to any cost increases that otherwise would not have occurred, it is the IM's view that the majority of these costs would likely have been incurred for delivery of the final scope of work (considering the scope evolution, including lessons learned from Tropical Storm Isaias, that also drove changes to the schedule and resource requirements). Importantly, these issues will not have impacts on the functionality of the ADMS, which will also benefit from the updated scope and lessons learned incorporated from Tropical storm Isaias).	
S-INF-12	**Reference Q2 2022 Report, Page 38, Electric Stipulated Base** Regarding the Outside Plant-Higher Design Standards (OP-HDS) projects within Electric Stipulated Base: a. It is indicated that circuits will be selected based upon Value of Lost Load (VOLL). Please discuss if the circuits' reliability metrics will also be considered. b. Please provide the estimated costs of the currently contemplated OP-HDS scope.	Regarding the OP-HDS scope: a. The VOLL metric combines the customer minutes interrupted reliability metrics with the economic cost impact on the affected customers to estimate the value to customers of improved circuit performance. b. While PSE&G is preparing and advancing the OP-HDS work, at this time it has incurred no costs within the ES 2 Program. While PSE&G intends to use any remaining funds from the Life Cycle projects towards the OP-HDS scope of work, in early 2023 PSE&G also transferred some of this work to its Infrastructure Advancement Program that has a similar scope.	No change

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S-INF-13	**<u>Reference Q2 2022 Report, Page 42, State Street (Outside Plant)</u>** Please provide additional details about the "delays in reaching an agreement with the County on restoration efforts", including any additional costs resulting from the eventual agreement.	Camden County requested PSE&G use concrete and doweling for temporary patching in the roadways after the test pits on the State Street OP project were completed. PSE&G met with the County to advise them that the manhole and duct bank installation would closely follow completion of the test pits and that would make the temporary patching requested by the County to go beyond typical restoration efforts considering the project would be excavating in the same locations in the near future. After further negotiations with the County, an agreement was reached to forego the use of concrete for the temporary patching (with the provision that if there is a failure, any repair would utilizing concrete). PSE&G expects no additional costs associated with this effort, but the delay in reaching a resolution on this did affect the project schedule.	**Section III.E.5.**
S-INF-14	**<u>Reference Q2 2022 Report, Page 43, Gas M&R Station Upgrades</u>** Regarding the Gas M&R Station Upgrades, please indicate if all six (6) projects will incorporate a change in heater technology from water bath to more efficient glycol heaters. Please also discuss any cost increases associated with this scope change.	PSE&G implemented a change in heater technology at the Camden, Central, and Paramus stations. This change from water bath to more efficient glycol heaters was only made at facilities where all of the heaters warranted life cycle replacement, as such this was not considered a scope change.	No change
S-INF-15	**<u>Reference Q2 2022 Report, Page 43, Gas M&R Station Upgrades</u>** Regarding the cost increases for the Gas M&R Station Upgrade projects from the Office level estimates: a. Please discuss if the identified issues and lessons learned (including insufficient investigations in the development of the projects during front-end planning, lack of formal scope lockdown, lack of comparative estimates, and a lesser experienced project team) specifically contributed to any cost increases that would not have otherwise occurred absent these issues. b. Please indicate if PSE&G incorporated these lessons learned before proceeding with the Gas M&R station upgrades approved in PSE&G's Infrastructure Advancement Program (approved June 29, 2022 in Docket Nos. EO21111211 and GO21111212).	The challenges encountered and the resulting lessons learned resulted in cost increases to the Gas M&R projects that largely would have been required to complete the objectives of improving the reliability, safety, and environmental performance of the stations as they generally related to lack of scope definition and related upfront planning and are less tied to the actual execution of the projects. For example, on the Central M&R project that went from an Office level estimate of $15.4 million to a Conceptual level estimate of $36.9 million, the cost increase detailed in **Section III.F.2.** can be primarily attributed to the complexity of the station that has three pipeline companies feeding the station (essentially creating three mini-stations on one site) that required extensive coordination for construction, outages, and testing and commissioning, including the use of a station by-pass. In addition, the end-of-life condition of the station's heaters resulted in the need for two additional buildings and four additional heaters from the initial scope. On top of that, the general market conditions during and after the Covid-19 pandemic have led to higher than expected cost increases for labor, equipment, and material. The lessons learned identified by PSE&G largely focus on enhancing the project origination and estimating processes, including performing a review if the settlement	No change

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		value is materially different than what was initially filed. For the ES 2 Program, PSE&G's estimate for the six projects ultimately approved for the Program was $119.3 million, however, the Stipulation budget was established at $101.0 million (combined accelerated and stipulated base funding). As a result, the original R&C amounts were reduced along with an arbitrary cut to align with the Stipulation budget. PSE&G has informed the IM that the identified lessons learned have been incorporated into the Company's planning and execution of the Gas M&R projects within the Infrastructure Advancement Program.	
S-INF-16	**<u>Reference Q2 2022 Report, Page 46, Camden M&R Station</u>** Regarding the cost increase of $3.6 million on the Camden M&R Station project associated with site plan changes: a. Please provide additional details explaining how the required site remediation resulted in approximately 70% more pipe and conduit being necessary. b. Please provide additional details about the required site remediation, including how this relates to the Camden M&R Station project.	Regarding the $3.6 million cost increase on the Camden M&R project associated with site plan changes: a. This was due to the limited area of the site that was remediated prior to the project and the need for the project to avoid the non-remediated areas, which resulted in the layout of the buildings not being optimized to minimize the pipe routing. b. The portion of the site where the M&R station is being built has already been remediated. The remainder of the site will remediated after completion of the Camden M&R project.	**Section III.F.1.**
S-INF-17	**<u>Reference Q2 2022 Report, Page 46, Camden M&R Station</u>** Regarding the cost increase of $3.3 million on the Camden M&R Station project associated with the new compressor sizing, please compare the new compressor sizing to that of the prior compressor and rationalize the need for a higher capability compressor.	The referenced $3.3 million increase associated with the compressor were removed from the ES 2 project scope as part of PSE&G removing the LPA scope from the Gas M&R projects (referenced by the $18.1 million reduction noted in the estimate discussion). With this scope adjustment, PSE&G also presented an updated estimate to its URB that has been added to this discussion on the Camden M&R project estimate.	**Section III.F.1.**
S-INF-18	**<u>Reference Q2 2022 Report, Page 47, Central M&R Station</u>** Regarding the cost increase of $3.0 million on the Central M&R Station project associated with the relocation of Liquid Propane Air (LPA) injection points, please clarify if these costs were removed from Energy Strong II similarly to the other LPA components.	The estimated $3.0 million increase associated with the relocation of the LPA injection points was removed from the ES 2 project similar to the other LPA components.	**Section III.F.2.**
S-INF-19	**<u>Reference Q2 2022 Report, Page 47, Central M&R Station</u>**	Regarding the noted $1.0 million cost decrease on the Central M&R project estimate associated with removal of the scrubber components from the ES 2 project scope:	No change

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	Regarding the cost decrease of $1.0 million on the Central M&R Station project due to the removal of scrubber components from Energy Strong II project scope: a. Please explain the Company's rationale for removing the scrubber components from the program. b. Please indicate if the scrubber components will also be removed from the program for the other M&R Station projects. c. Please clarify if the cost increase of $1.8 million associated with the Transco scrubber will also be removed from the program.	a. PSE&G removed the scrubber components from the ES 2 project scope as the replacement of the scrubber was not identified in the filing documents. b. The scrubber components will not be removed from the other ES 2 Gas M&R projects as they were listed components in the filing documents for those projects. c. PSE&G has removed costs associated with the Transco scrubber components from the ES 2 Program.	
S-INF-20	**<u>Reference Q2 2022 Report, Page 48, East Rutherford M&R Station</u>** Regarding the cost increase of $0.5 million on the East Rutherford M&R Station project associated with the electrical service upgrade, please explain the need to separate the shared Transco/PSE&G electrical service.	The Interconnection Agreement between Transco and PSE&G specifically requires PSE&G to provide power to Transco. By providing Transco with a separate service disconnect, it ensures that an electrical shutdown by either Transco or PSE&G will not impact service to the other and improves the safety and reliability of the station as a result.	**Section III.F.3.**
RCR-IM-1	With reference to page 3 of the Independent Monitor's Draft Second Quarter 2022 Report, please provide an update to the Leonia switchgear delivery delay.	The Leonia 13kV switchgear #2 was delivered on June 16, 2022 (as shown in **Table 10**).	**Section I.**
RCR-IM-2	With reference to page 3 of the Independent Monitor's Draft Second Quarter 2022 Report, please identify the "certain individual subprograms … forecasted near or above their Stipulation budgets."	The current subprogram forecasts and ES 2 Program budgets are shown in **Table 1**, which indicates the Grid Modernization – Communication System, Grid Modernization – ADMS, Gas M&R, and Contingency Reconfiguration subprograms have current forecasts above the Program budget. Overall, the total ES 2 Program forecast of approximately $826.9 million represents 98% of the $842 million Program budget (including the accelerated recovery and stipulated base funding mechanisms).	**Section I.**
RCR-IM-3	With reference to page 3 of the Independent Monitor's Draft Second Quarter 2022 Report, please identify the "other projects with forecasted in-service dates near the Program end date that are at risk due to the delays on the switchgear deliveries[.]"	The Electric Station Flood Mitigation subprogram projects with forecasted in-service dates near the end of the Program end date of December 2023 and with open switchgear deliveries as of the end of the second quarter of 2022 included (with the current in-service forecast indicated in parentheses): Front Street (11/8/2023); Lakeside Avenue (9/18/2023); Orange Valley (12/29/2023); Waverly (2/27/2024); and Woodlynne (10/10/2023).	**Section I.**
RCR-IM-4	With reference to page 3 of the Independent Monitor's Draft Second Quarter 2022 Report, please indicate whether other	The forecasted in-service date for the Waverly substation project was originally planned for the fourth quarter of 2023, but after the initial site	**Section I.**

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	supply chain issues in addition to the 4 kV switchgear delivery delays are contributing to the February 27, 2024 forecasted in-service date for the Waverly substation.	plan was rejected in March 2021, this shifted the entire project out by approximately one year to the end of 2024 (based on the timeline around resubmitting the site plan). In September 2021, the revised site plan was submitted to the Newark Planning Board and approved in December 2021. With the revised site plan approved earlier than planned, it advanced the forecasted in-service date to September 2024 by shifting the construction activities forward as supported by the improved permit dates. During the first quarter of 2022, the project team continued to detail and analyze the construction schedule for opportunities, which led to the in-service date to improve to March 2024. During the second quarter of 2022, progress advanced largely on or ahead of schedule, which contributed to the in-service date advancing seven days to February 27, 2024. The Waverly project also has multiple in-service dates, from the 26kV switchgear (forecasted for September 2022), the 4kV switchgear, T1, and T2 (forecasted for October 2023), and the T3 (forecasted for February 2024). While the 4kV switchgear delivery accounted for the 11 day slip to the forecasted in-service date from the first to second quarter of 2022, the primary driver to the current in-service date for Waverly was the impact from requiring a revised site plan as detailed above.	
RCR-IM-5	With reference to page 4 of the Independent Monitor's Draft Second Quarter 2022 Report, please confirm that only 13 fuse saver units were installed during the 2022 Second Quarter, leaving 1,515 units to be installed by December 31, 2023 as part of the Contingency Reconfiguration subprogram.	This status of the Fuse Savers as of the end of the second quarter of 2022 is confirmed, with 13 devices installed during the second quarter for a total of 126 devices installed during the Program out of a forecast of 1,516 devices.	No change
RCR-IM-6	With reference to Figure 2 – ES 2 CWIP Balances by Subprogram as of June 30, 2022, please explain the discrepancy between the $69.3 million Q2 2022 subtotal for Electric Station Flood Mitigation, while a preceding paragraph on page 8 notes a CWIP Electric Station Flood Mitigation costs for "Hasbrouck ($12.4 million), State Street ($11.1 million), Clay Street ($11.0 million), and Waverly ($9.7 million)" of $44.2 million in total for the same subprogram.	The referenced text concerning the CWIP balances for the Electric Station Flood Mitigation subprogram highlights the individual projects with the highest CWIP balances, but does not detail every project within the subprogram. The CWIP balances as of the end of the second quarter of 2022 for each substation projects is provided as follows: **Project** — **Q2 2022 CWIP Balance** Academy Street — $- Clay Street — $11,047,959 Front Street — $3,796,963 Hasbrouck Heights — $12,352,213	No change

<table>
<tr><th>ID #</th><th>Question/Comment</th><th>IM Response</th><th>Report Changes</th></tr>
<tr><td></td><td></td><td>
<table>
<tr><td>Kingsland</td><td>$1,754,738</td></tr>
<tr><td>Lakeside Avenue</td><td>$1,860,702</td></tr>
<tr><td>Leonia</td><td>$4,668,986</td></tr>
<tr><td>Market Street</td><td>$149,782</td></tr>
<tr><td>Meadow Road</td><td>$1,777,667</td></tr>
<tr><td>Orange Valley</td><td>$1,268,318</td></tr>
<tr><td>Ridgefield 13kV</td><td>$2,284,652</td></tr>
<tr><td>Ridgefield 4kV</td><td>$-</td></tr>
<tr><td>State Street</td><td>$11,081,551</td></tr>
<tr><td>Toney's Brook</td><td>$2,452,994</td></tr>
<tr><td>Waverly</td><td>$9,641,079</td></tr>
<tr><td>Woodlynne</td><td>$5,220,160</td></tr>
<tr><td>Total</td><td>$69,357,695</td></tr>
</table>
</td><td></td></tr>
<tr><td>RCR-IM-7</td><td>With reference to Table 9 – ES 2 Electric Substation Flood Mitigation Upcoming Activities for Q3 2022, please explain the inclusion of the switchgear assembly at Hasbrouck Heights when there was no mention of this activity in the Draft First Quarter 2022 Report, Table 11 – ES 2 Electric Station Flood Mitigation Upcoming Activities for Q2 2022 on page 15, for this substation.</td><td>In the IM 2022 First Quarter Report, the upcoming activities on the Hasbrouck Heights project planned for the second quarter of 2022 were identified as the start of civil foundations and the start of electrical construction. The electrical construction activities at the end of the second quarter of 2022 primarily involved the switchgear assembly, which is why this activity was highlighted in Table 9.</td><td>No change</td></tr>
<tr><td>RCR-IM-8</td><td>With reference to page 15 of the Independent Monitor’s Draft Second Quarter 2022 Report, concerning communications provided by PSE&G’s switchgear vendor, Powercon, please explain the “more detailed and frequent status updates from Powercon” referred to in the Draft Second Quarter 2022 Report regarding remaining major equipment deliveries beyond “receiv[ing] weekly updates from Powercon on the current status of the deliveries and PSE&G’s management” onsite visits to the vendor.</td><td>Concerning the additional information from Powercon, PSE&G requested and has received details in Powercon’s production schedules and information from the sub-vendors/suppliers.</td><td>Section III.A.</td></tr>
<tr><td>RCR-IM-9</td><td>With reference to Table 10 – ES 2 Electric Substation Flood Mitigation Switchgear Deliveries as of June 30, 2022, please explain why the Ridgefield 13 kV cont. switchgear is</td><td>The 13kV contingency switchgear for Ridgefield 13kV shows a September 30, 2020 delivery date as this is when this switchgear was delivered to the project. This switchgear will also be the permanent switchgear for</td><td>No change</td></tr>
</table>

ID #	Question/Comment	IM Response	Report Changes
	shown with delivery date in bold of September 30, 2020 when it is the "Kingsland 13kV switchgear [] delivered to the Ridgefield 13kV site where it is being used as the contingency/temporary switchgear for that project before its permanent installation on the Kingsland project[]" and will be removed.	Kingsland following its use as a contingency switchgear for the Ridgefield 13kV project.	
RCR-IM-10	With reference to Table 11 – ES 2 Electric Substation Flood Mitigation Project Cost Status as of June 30, 2022, on page 16 and the Findings and Observations on page 18, please specify the costs for each subcategory noted "[1] electrical construction award higher than estimated; [2] equipment procurement higher than estimated; [3] scope increases; and [4] construction schedule recovery" contributing to the $2.3 million increase in the projected cost of the Clay Street Substation from $30.8 to $33.6 million.	The detail of this cost forecast increase has been added to the discussion on the Clay Street project within **Section III.A.2.**	**Section III.A.2.**
RCR-IM-11	With reference to Table 11 – ES 2 Electric Substation Flood Mitigation Project Cost Status as of June 30, 2022, on page 16 and the Findings and Observations on page 18, please specify the costs for each subcategory noted "[1] civil and electrical construction awards higher than estimated and [2] an increased quantity of piles based on the final design" contributing to the $2.1 million increase in the projected cost of the Kingsland Substation from $6.4 to $8.5 million.	The detail of this cost forecast increase has been added to the discussion on the Kingsland project within **Section III.A.5.**	**Section III.A.5.**
RCR-IM-12	With reference to Table 11 – ES 2 Electric Substation Flood Mitigation Project Cost Status as of June 30, 2022, on page 16 and the Findings and Observations on page 18, please specify the costs for each subcategory noted "[1] civil and electrical construction awards higher than estimated and [2] an increased quantity of piles based on the final design" contributing to the $2.1 million increase in the projected cost of the Kingsland Substation from $6.4 to $8.5 million.	The detail of this cost forecast increase has been added to the discussion on the Kingsland project within **Section III.A.5.**	**Section III.A.5.**
RCR-IM-13	With reference to page 19 of the Independent Monitor's Draft Second Quarter 2022 Report, please explain what the other "[p]art of this impact" contributing the variance for Clay Street substation between forecasted second quarter spending of $2.7 million and actual spending of $1.9 million, including any delays in April and May 2022.	The second quarter of 2022 cost forecast to actual variance on Clay Street was driven by civil piling work shifting from a planned May-June execution to June-July due to the T3 contingency not being completed in April 2022 as initially planned and less foundation and duct bank work completed in June 2022 than was planned due to a safety standdown, which resulted in an approximate 10-day impact to the construction schedule.	**Section III.A.2.**

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RCR-IM-14	With reference to page 18 of the Independent Monitor's Draft Second Quarter 2022 Report, please explain the individual project updates to the Academy Street, Clay Street, Front Street, Hasbrouck Heights, Kingsland, Orange Valley, Ridgefield 13kV, State Street, Waverly, and Woodlynne projects (with Hasbrouck Heights and State Street also advancing to the Definitive stage) that collectively resulted in a $15.0 million increase.	This description appears to reference the IM's First Quarter 2022 Report, where the updated estimates to the Electric Station Flood Mitigation projects resulted in an overall $15.0 million increase to the overall base estimate for the subprogram. Details of these estimate updates were discussed within the individual project sections under Section III.A. of this report. During the second quarter of 2022 there were no updates to the estimates for the projects within the Electric Station Flood Mitigation subprogram, though the subprogram forecast increased by $8.6 million as detailed in the Findings & Observations in **Section III.A.**.	No change
RCR-IM-15	With reference to page 27 of the Independent Monitor's Draft Second Quarter 2022 Report, please explain how many installed Fuse Savers experienced communication issues other than the two units returned to Siemens for testing, have any remote control units been replaced, and what are the costs with projected repairs or replacement.	PSE&G has encountered communication issues on approximately 10% of the installed Fuse Savers (including 10 devices of the 113 installed in the pilot program). The costs associated with the RCU modifications to address the communication issues are approximately $1,100 per unit in material and also slightly longer installation times, though the installation costs are not tracked separately for the devices with and without the modification. The devices returned to Siemens for testing in the second quarter of 2022 did not have communication issues, but instead encountered a voltage reading when in the open position that was determined to be ghost/induced voltage stemming from the device's proximity to a live conductor and not an issue with the device itself.	No change
RCR-IM-16	With reference to page 27 of the Independent Monitor's Draft Second Quarter 2022 Report, please explain how many of the 1,515 remaining to be installed Fuse Savers does PSE&G intend to install than "initially planned in the third and fourth quarters of 2022" and at what additional cost.	There is no material cost impact expected from this shift, essentially following the installations delays encountered during the second quarter of 2022 (as discussed in **Section III.B.**), PSE&G shifted the balance of the installations originally planned for the second quarter of 2022 across the installations planned for the remainder of the year. In total, during the second quarter of 2022, PSE&G commissioned 12 Fuse Savers in this period out of a target of 168.	No change
RCR-IM-17	With reference to Table 15 – Contingency Reconfiguration Forecasted Cost of June 30, 2022 and the findings and observations on page 28 of the Independent Monitor's Draft Second Quarter 2022 Report, please explain how "each Division [is] now forecasted to complete the Fuse Savers scope by December 2023" when as of June 30, 2022 $8.1 million, 19 percent of the $43.9 million forecasted budget	The current end of 2023 forecasted completion for the Fuse Saver scope of work reflects a slight slip from the forecast as of the end of the first quarter of 2022 (as shown in **Table 13**). This slip reflects the limited installations conducted in the second quarter of 2022 due to the technical issues and D-SCADA freeze discussed in **Section III.B.**. PSE&G continues to establish quarterly installation targets with the Divisions, which are then split into monthly targets with forecasts updated bi-weekly, which supports completing this scope of work by the end of	No change

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	for Fuse Saver installations and out of 1,641 total projected units, 125 units have been commissioned.	2023 (as of the end of the first quarter of 2023, 957 units had been commissioned).	
RCR-IM-18	With reference the findings and observations on page 28 of the Independent Monitor's Draft Second Quarter 2022 Report, please explain what accounted for the Contingency Reconfiguration subprogram forecast increasing by $339,000, to a total of $145.6 million, above the Stipulation budget of $145.0 million.	The updated forecast for the Contingency Reconfiguration continues to reflect the actual costs and field conditions encountered to date as based on the currently projected number of units (Fuse Savers and reclosers) to be installed as part of the subprogram with PSE&G continuing to seek to optimize the number of units installed against the subprogram budget. For example, PSE&G's initial assumption was for 1,713 Fuse Savers to be installed as part of this subprogram, based on the actual costs incurred through the end of the second quarter of 2022, the planned number of Fuse Savers was reduced to 1,641 units after the costs per unit increased (due to a combination of higher labor, higher traffic control, and higher project management costs). Overall, the subprogram forecast has remained fairly constant since the third quarter of 2021, fluctuating between $145.3 million and $145.8 million in this time.	No change
RCR-IM-19	With reference to the findings and observations for Grid Modernization – Communications System on page 34 of the Independent Monitor's Draft Second Quarter 2022 Report, please explain the "inadequate site investigations that left required items out of the initial scope and no R&C within the initial budget" that PSE&G noted affected the Grid Modernization – Communications System subprogram budget.	The initial fiber estimates reflected a scope that essentially included just the fiber installation itself, PSE&G identified through the first batch of projects completed that certain stations had other scope elements required to complete the fiber installation, such as battery rack space, redundant feeders, and/or similar items that had not been included in the initial project estimates. Similarly, execution of the work identified other site-specific issues, such as on the Edison project where blocked conduit contributed to an approximate $40,000 cost increase. Because these site-specific items were not identified earlier in the estimating process, they contributed to cost increases realized during execution of these projects. Additionally, because there was no R&C budget for the subprogram, any realized risks (such as missing scope or site conditions) contributed to direct cost increases rather than being absorbed by R&C funds. The approach of not including R&C funds for a group of smaller, repetitive type projects is not unusual, but does mean with a fixed budget that the overall number of projects delivered may be reduced as a result of any cost increases realized. The IM also agrees with PSE&G's decision to include R&C for future fiber installation efforts as the site-specific nature of this work and required interfaces (transmission, railroads, etc.) can lead to deviations from the initial budget assumptions and having R&C funding	No change

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		ensures the initially targeted scope of the overall program is more likely to be achieved when these types of issues are encountered. *See also* **S-INF-7**.	
RCR-IM-20	With reference to Table 21 – Grid Modernization – ADMS Subprogram Estimate on page 36, please add subtotals in a separate column for OMS Scope Changes that contributed to the $21.3 million subprogram budget increase.	The subtotals for the OMS scope changes were originally listed in Table 21 next to the scope change descriptions, but for clarity Table 21 has been revised to better show these values.	**Table 21**
RCR-IM-21	With reference to Table 23 – ES 2 Life Cycle Station Upgrade Project Status as of June 30, 2022 on page 38, please explain whether the subprogram risk and contingency total if $2.3 million for Hamilton, Paramus, Plainfield, Woodbury and State Street substations represents a change in total compared the risk and contingency total (not shown) in Table 20 – ES 2 Life Cycle Station Upgrade Project Status as of March 31, 2022 in Independent Monitor's Draft First Quarter 2022 Report on page 36.	As of the end of the first quarter of 2022, the R&C balance for the Life Cycle Station Upgrade projects was $3.1 million. As of the end of the second quarter of 2022, the R&C balance was reduced to $2.3 million (with the $0.9 million of R&C allocated during the second quarter of 2022 going to Hamilton ($600K), Woodbury ($300K), and offset by a reduction in the base estimate to Plainfield (-$100K) with those funds returning to the R&C balance. The IM also notes the R&C balance was added to Table 20 in the IM's First Quarter 2022 Final Report.	**Section III.E.**
Rate Counsel 5/3/2023 Letter	Rate Counsel continues to note that the budget for Electric stipulated base has been set to $100 million for the life cycle subprogram. In the report for this quarter, Pegasus continued to provide Study level estimates for the five substations (Hamilton, Paramus, Plainfield, Woodbury, and State Street). (See Table 23, p. 38). The current Study level estimate for the subprogram increased by $800,000 to $97.7 million. Pegasus notes that "[d]uring the second quarter of 2022, PSE&G advanced the Hamilton, Plainfield, and Woodbury project estimates to the Definitive level." Much of the increase is attributed to advancement of Hamilton to the definitive stage with a $600,000 increase to $16.8 million and a revised forecast of $16.9 million. (p. 40).	The IM notes that only the State Street OP project remains at the Study level estimate, the other projects have either advanced to the Conceptual level (Paramus) or Definitive level (Hamilton, Plainfield, and Woodbury). The total subprogram estimate of $97.7 million is correct, but does not include the $2.3 million in R&C funds.	No change
Rate Counsel 5/3/2023 Letter	The current forecast for the Electric Flood mitigation program increased from $349.56 million in the First Quarter 2022 Report to $358.15 million in the Second Quarter Report. The IM notes the "forecast continues to remain under the current subprogram estimate and Stipulation amount of $389.0 million (which includes $41.8 million in R&C). (p. 18). Rate Counsel notes the R&C subtotal of $41.8 million remains unchanged since PSE&G discontinued providing individual project risk and	PSE&G updates the project forecasts and the project risk registers on a monthly basis, but release of R&C funds is tied to the projects going through estimate transitions. During the second quarter of 2022, none of the Electric Station Flood Mitigation projects reached an estimate transition, thus no R&C funds were released during the quarter and the R&C balance remained unchanged from the status as of the end of the first quarter of 2022. To appreciate the availability of R&C funds, the variances between the project estimates and forecasts can be reviewed, as the forecasts offer a leading indicator in the periods between estimate	**Section III.A.**

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	contingency costs as reported in the First Quarter 2022 Report, although the IM reports further delays in the completion dates with "three projects slipping" and the "overall subprogram forecast as of the end of the second quarter of 2022 increased $8.6 million (or 2.5%) to $358.2 million from the status as of the prior quarter."(p. 17) Rate Counsel is interested in learning how the risk and contingency estimate total of $41.80 million remains unchanged from the First Quarter 2022 Report when the subprogram forecast was $347.20 million.	transitions on if additional R&C funding will likely be required at the next estimate transition. Under this approach, and with the data from **Table 11**, it shows that the Electric Station Flood Mitigation subprogram has a current forecast of $358.2 million that is approximately $11.0 million above the current Base estimate for the subprogram, suggesting if the current trends hold approximately $11.0 million of R&C will be released.	
Rate Counsel 5/3/2023 Letter	In the First Quarter 2022 Report, the IM noted that PSE&G reported that the completion date for Kingsland had slipped 94 days (from June 30, 2023 to October 2, 2023), "driven by delays to the 13kV switchgear delivery on the Ridgefield 13kV project (Kingsland plans to use the contingency switchgear from the Ridgefield 13kV project)." In the Second Quarter 2022, the IM notes that switchgear delivery delays affect: • Clay Street - 4kV switchgear (delayed 76 days) • Leonia - 13kV switchgear #2 (delayed 33 days) • Ridgefield 13kV - 13kV switchgear #1(delayed 12 days) • Waverly – 4kV switchgear (delayed 12 days) As the IM notes in Table 10 – Electric Station Flood Mitigation Switchgear Deliveries as of June 30, 2022, p. 15, of the two switchgear deliveries scheduled for the second quarter 2022, as noted in the First Quarter 2022 Report, only one switchgear delivery is reported for the second quarter 2022 in the Second Quarter 2022 Report. As the IM notes "as of the end of the second quarter of 2022, there were 10 switchgear deliveries outstanding for the subprogram[.]" Table 10 – Electric Station Flood Mitigation Switchgear Deliveries as of June 30, 2022 indicates six switchgear deliveries are scheduled in 2022 and 4 are scheduled in 2023. Rate Counsel is interested in understanding if the Company has adequate resources and planning contingencies to address the impact of further delays in equipment deliveries affecting multiple	The remaining switchgear deliveries continue to present a risk to the completion of the projects in the Electric Station Flood Mitigation and Electric Station Life Cycle subprograms, including the slip for the Clay Street switchgear that had previously been expected to be received in the second quarter of 2022. While the shifting delivery dates have added challenges to delivering the projects, PSE&G has attempted to mitigate these impacts by resequencing or advancing other work where possible and meeting with the Divisions at least monthly to review the current schedules and availability of resources. PSE&G and its Divisions schedule the Division resources based on the current equipment delivery dates and related items required to support the project schedule.	No change

ID #	Question/Comment	IM Response	Report Changes
	substations and address unforeseen situations beyond those reported in the Second Quarter 2022 Report.		
Rate Counsel 5/3/2023 Letter	In the Second Quarter 2022 Report, the IM reports that PSE&G continues to forecast work completion for six (Front Street, Kingsland, Lakeside Avenue, Meadow Road, Orange Valley and Woodlynne) of sixteen substation projects in the ES 2 Electric Station Flood Mitigation program during the third and fourth quarters of 2023, while the completion date for a seventh project (Waverly) remains outside the program end date of December 31, 2023. The IM noted that PSE&G continues to forecast that the Orange Valley substation work is scheduled for completion on December 29, 2023 and that the Waverly substation project is now scheduled for completion on February 27, 2024, an improvement of a week from the March 5, 2024 date provided in the First Quarter 2022 Report. The completion date for Front Street has slipped nearly two weeks to November 11, 2023, and the IM reports spending was 14 percent, $3.67 million of the total estimate of $25.9 million. The scheduled completion date for the Orange Valley substation is near the program end date of December 31, 2023, and the IM reports spending is $1.18 million, 8 percent of the total estimate of $14.7 million. The completion date for Lakeside Avenue is September 18, 2023, and actual spending is 5 percent, $1.75 million of the total estimate of $39.4 million. The scheduled completion date for the Waverly substation is after the program end date of December 31, 2023, and the IM reports spending is twenty-five percent, $8.94 million, of total estimate of $36.2 million. Rate Counsel is interested in understanding how PSE&G plans to manage work for six substation projects (Front Street, Kingsland, Lakeside Avenue, Meadow Road, Orange Valley and Woodlynne) in the third and fourth quarters of 2023, and if any accelerated work will impact current budgets for the delayed substation work in the ES 2 Electric Station Flood Mitigation program.	Concerning the six Electric Station Flood Mitigation project currently forecasted to go in-service during the third and fourth quarters of 2023, PSE&G continues to update the project schedules on a monthly basis to reflect the current status including the current forecasted delivery dates for projects with open switchgear deliveries and has also sought out additional information from its vendor (production schedules, sub-vendor statuses, etc.). Based on this updated information, the project teams evaluate any opportunities to improve the schedule and coordinate to ensure resources are available to meet the project needs. While having six of the 16 Electric Station Flood Mitigation projects go in-service over a two-quarter period represents a significant effort, particularly for testing and commissioning resources, PSE&G's planning and efforts to date have demonstrated this level of effort is achievable as in a six-week period at the end of 2022, PSE&G successfully placed four of the Electric Station Flood Mitigation projects in-service.	No change

ID #	Question/Comment	IM Response	Report Changes
Rate Counsel 5/3/2023 Letter	In the Second Quarter 2022 Report, the IM reports that PSE&G Outside Plant-Higher Design Standards (OP-HDS) scope "scope currently contemplates upgrades to approximately 40-50 circuit miles and replacement of approximately 700 poles." (p. 38). Prior quarterly reports have not included such detail. The IM notes that "[i]nitial selection of circuits for OP-HDS investments is based on … the highest annual [Value of Loss Load] (VOLL) from 2010-2020 over the baseline performance, while final circuit selection will reflect the VOLL rankings … driven by field conditions." The Rate Counsel is interested in understanding what specific "field conditions" PSE&G is planning on using for OP-HDS selection criteria. (p. 38).	Final circuit selection for the OP-HDS scope involves consideration of the actual field conditions where impacts from other projects may have resulted in a change to the actual field conditions on the circuit and may warrant no longer including particular circuits in the scope of work as a result. The IM also notes that in early 2023, PSE&G made the decision to transition the OP-HDS work planned for the ES 2 Program to its Infrastructure Advancement Program (under the Open Wire to Spacer project) due to limited funding available in the Electric Stipulated Base portion of the ES 2 Program.	No change
Rate Counsel 5/3/2023 Letter	The forecast for the Grid Modernization – Communication system subprogram remained relatively unchanged from the status as of the end of the first quarter of 2022, with an overall forecast increase of approximately $136,000 (or a 0.2% increase) to $66.3 million. (p. 34) Rate Counsel is interested in understanding what risk & contingency level for the Grid Modernization – Communication would PSE&G have assigned retrospectively based on lessons learned from the "inadequate site investigations that left required items out of the initial scope and no R&C within the initial budget."	Industry standards from AACE provide that there are a broad range of methodologies for estimating contingency amounts. The factors considered include, but are not limited to, the following: • Portfolio, program, or project type: scope, size, complexity, level of technology. • Risk type: strategic versus tactical, systemic versus project-specific. • Project phase: estimate confidence level. • Base estimate methodology: methods, tools, and data used to develop the base estimate. • Skills and knowledge: of the involved participants, both in preparing the estimate and in executing the work. The approach of not including R&C funds for a group of smaller, repetitive type projects is not unusual, but does mean with a fixed budget that the overall number of projects delivered may be reduced from what was initially estimated as a result of any cost increases or risks realized. The IM also agrees with PSE&G's decision to include R&C for future fiber installation efforts as the site-specific nature of this work and required interfaces (transmission, railroads, etc.) can lead to deviations from the initial budget assumptions and having R&C funding ensures the initially targeted scope of the overall program is more likely to be achieved when these types of issues are encountered. *See also* S-INF-7 and RCR-IM-19.	No change

ENERGY STRONG 2 PROGRAM INDEPENDENT MONITOR 2022 THIRD QUARTER DRAFT REPORT

PREPARED AND SUBMITTED BY

PEGASUS GLOBAL HOLDINGS, INC. ®

CONFIDENTIAL

NOVEMBER 13, 2023

Table of Contents

Appendices

List of Acronyms and Abbreviations

Advanced Distribution Management Systems..ADMS

Allowance for Funds Used During Construction..AFUDC

Architect/Engineer..A/E

Board of Public Utilities...BPU

Construction Work In Progress...CWIP

Costs of Removal..COR

Distribution Management System..DMS

Distributed Energy Resource Management System...DERMS

Distribution Supervisory Control and Data Acquisition.......................................DSCADA

Energy Strong 2...ES 2

Gas Metering & Regulating...Gas M&R

Generally Accepted Accounting Principles..GAAP

Geographic Information System...GIS

Human-Machine Interface..HMI

Independent Monitor...IM

Inside Plant..IP

Issued for Bid..IFB

Issued for Construction..IFC

Liquid Propane Air..LPA

New Jersey Department of Environmental Protection..NJDEP

Open Systems International Inc...OSI

Outage Management System...OMS

Outside Plant..OP

Outside Plant-Higher Design Standards..OP-HDS

Public Service Electric & Gas...PSE&G

Purchase Order..PO

Quality Assurance System...QAS

Record of Decision .... ROD

Remote Terminal Unit .... RTU

Request for Information .... RFI

Risk and Contingency .... R&C

Supervisory Control and Data Acquisition .... SCADA

Utility Review Board .... URB

I. Executive Summary

Public Service Electric & Gas's (PSE&G's) Energy Strong 2 (ES 2) Program was established from a Stipulation that the involved parties agreed to in August 2019, as approved by a Board of Public Utilities (BPU) Order dated September 11, 2019, with an effective date of September 21, 2019. The Stipulation provided the ES 2 Program would be comprised of five primary subprograms: Electric Station Flood Mitigation; Contingency Reconfiguration; Grid Modernization – Communications; Grid Modernization – Advanced Distribution Management Systems (ADMS); and Gas Metering & Regulating (Gas M&R) Station Upgrades. In addition, a Stipulated Base spend was established that includes both an electric component (higher outside plant design standards and station life cycle upgrades) and a gas component (overlapping with the Gas M&R subprogram). This report contains the Independent Monitor's (IM's) findings and observations on the ES 2 Program elements and other information on the Program's status as of the third quarter of 2022.

During the third quarter of 2022, the bulk of the spend within the ES 2 Program continued to be in the largest subprogram, Electric Station Flood Mitigation, with spend in the quarter up approximately $11.8 million from the prior quarter driven by five additional projects commencing construction, which brought all projects in the subprogram past the start of construction milestone. Spend also ramped up in the Contingency Reconfiguration subprogram where the Fuse Savers scope of work had its first full quarter of implementation. Within the other subprograms, the Grid Modernization – Communication System subprogram placed two additional fiber installation projects and one fiver cutover project in-service, with all of the fiber cutover projects and 29 of the 34 fiber installation projects now completed in the ES 2 Program. The Grid Modernization – Communication System also completed the retrofit substation remote terminal unit (RTU) scope, with an additional 48 substations completed in the third quarter of 2022, for a total of 218 substation retrofits completed in the Program. The Grid Modernization – ADMS subprogram completed sprint 21 in the Distribution Management System (DMS)/Distributed Energy Resource Management System (DERMS) scope and completed the Quality Assurance System (QAS) build and configuration for the Outage Management System (OMS) scope. The Gas M&R subprogram continued to advance construction on the Camden and East Rutherford, both forecasted to be in-service by the end of 2022 and both also having updated estimates approved during the third quarter of 2022 that resulted to no overall change in the subprogram estimate. The Hamilton, Paramus, Plainfield, and Woodbury projects in the Electric Stipulated Base scope continued construction during the third quarter of 2022, while the State Street (Outside Plant) project performed test pits ahead of the manhole and conduit work. The Outside Plant-Higher Design Standards (OP-HDS) work under the Electric Stipulated Base also commenced in the third quarter, though at this time PSE&G is performing this work outside of the ES 2 Program due to the forecasts for the life cycle station upgrade projects currently consuming the entirety of the Electric Stipulated Base budget.

Major equipment (primarily switchgear) deliveries continue to be a primary risk item for the Electric Station Flood Mitigation and Electric Stipulated Base projects with open deliveries. During the third quarter of 2022, switchgear deliveries were received on the Front Street, Ridgefield 13kV, Plainfield, and Woodbury projects. This completes the deliveries for the Electric Stipulated Base projects and leaves eight remaining for the Electric Station Flood Mitigation projects.

Table 1 – ES 2 Subprogram & Stipulated Base Status as of September 30, 2022 below provides the spend to date on the subprograms within the ES 2 Program and Stipulated Base compared to the total forecast and forecasted completion for each.

Table 1 – ES 2 Subprogram & Stipulated Base Status as of September 30, 2022

Subprogram	2022 Q3 Spend	Total Spend to Date*	Total Forecast*	% of Actuals to Forecast	Forecasted Completion**	Stipulation Funding Amount***
Electric Station Flood Mitigation	**$29,627,767**	**$187,304,228**	**$356,924,105**	**52%**	**Apr 2024**	**$389M**
Contingency Reconfiguration	**$7,708,933**	**$117,802,488**	**$147,615,838**	**80%**	**Dec 2023**	**$145M**
Grid Modernization – Communications	**$3,391,702**	**$61,178,303**	**$66,564,461**	**92%**	**Dec 2023**	**$64.3M**
Grid Modernization – ADMS	**$3,194,435**	**$40,961,453**	**$60,907,462**	**67%**	**Jun 2023**	**$42.7M^**
Electric Stipulated Base	**$19,163,528**	**$59,072,735**	**$100,582,790**	**59%**	**Dec 2023**	**$100M**
Gas M&R Station Upgrades^^	**$24,947,158**	**$76,376,937**	**$110,272,385**	**69%**	**Dec 2023**	**$101M^^^**
Total*	**$88,033,523**	**$542,696,145**	**$842,867,041**	**64%**	**Apr 2024**	**$842M**

-Note: total figures may not fully align due to rounding. Additionally, the total forecast includes only the base cost for the Electric Station Flood Mitigation and Gas M&R subprograms as PSE&G does not include risk and contingency (R&C) in its forecasts for these projects. See **Table 11 and **Table 23** for the Electric Station Flood Mitigation and Gas M&R project estimates, respectively, with base costs and R&C shown.*
***-Final in-service date.*
****-Following the $7.7 million transfer in July 2021 from the Grid Modernization – Communications subprogram to the Grid Modernization – ADMS subprogram.*
^-PSE&G has increased the funding for the Grid Modernization – ADMS subprogram by $13.6 million over the Stipulation amount to a total of $56.3 million (including $2.8 million in R&C).
^^-Includes both the ES 2 projects and the Stipulated Base gas projects.
^^^-PSE&G has increased the funding for the Gas M&R subprogram by $27.8 million over the Stipulation amount to a total of $128.8 million (including $24.6 million in R&C). This R&C balance is currently at $19.1 million as of the end of the third quarter of 2022.

Given the prominence of the Electric Station Flood Mitigation subprogram, which represents over half of the total ES 2 Program spending (before the Stipulated Base consideration), a summary of the projects within this subprogram is provided below in **Table 2 – ES 2 Electric Station Flood Mitigation Status as of September 30, 2022**.

Table 2 – ES 2 Electric Station Flood Mitigation Status as of September 30, 2022

Project	Total Estimate (rounded)	Actuals	% of Actuals to Estimate	Forecasted In-Service Date*
1. Academy Street	$9,300,000	$6,519,897	70%	**10/19/2021**
2. Clay Street	$30,800,000	$13,021,870	39%	3/23/2023 (↓+52)
3. Front Street^	$25,900,000	$9,558,510	37%	1/9/2024 (↓+62)
4. Hasbrouck Heights	$19,300,000	$13,926,106	72%	11/18/2022 (↑-35)
5. Kingsland	$8,700,000	$2,219,794	26%	11/6/2023 (↓+33)
6. Lakeside Avenue	$39,400,000	$3,292,610	8%	2/28/2024 (↓+163)
7. Leonia	$24,900,000	$22,304,216	90%	11/16/2022 (↑-27)
8. Market Street	$29,100,000	$28,140,833	97%	**6/25/2021**
9. Meadow Road	$7,200,000	$2,035,052	25%	9/28/2023 (↓+6)
10. Orange Valley	$14,700,000	$2,227,908	15%	2/2/2024 (↓+35)
11. Ridgefield 13kV	$26,100,000	$25,524,755	98%	12/8/2022 (↑-5)
12. Ridgefield 4kV	$20,800,000	$20,703,808	100%	**5/16/2021**

Project	Total Estimate (rounded)	Actuals	% of Actuals to Estimate	Forecasted In-Service Date*
13. State Street	$19,600,000	$11,609,902	59%	12/16/2022 (↑-3)
14. Toney's Brook	$16,200,000	$3,034,991	19%	5/26/2023 (↓+39)
15. Waverly	$36,200,000	$17,197,448	43%	4/30/2024 (↓+63)
16. Woodlynne	$24,000,000	$5,986,596	25%	10/10/2023

-Reflects the in-service date of the last major asset (e.g. switchgear), certain activities may take place after this date to support the final in-service date (i.e. when all customers are cutover).* ***Bold* *dates indicate the actual in-service date.*

(↑)-*Indicates the forecasted in-service date advanced from the prior quarter.*

(↓)-*Indicates the forecasted in-service date slipped from the prior quarter.*

^- The Front Street project was proposed by PSE&G during the second quarter of 2021 to replace the cancelled Constable Hook project.

As indicated in **Table 2**, the projects that previously started construction (Academy Street, Leonia, Market Street, Ridgefield 13kV, Ridgefield 4kV, and Waverly) continue to have the highest total spend to date. Additionally, six of the stations (Clay Street, Kingsland, Meadow Road, Ridgefield 4kV, Waverly, and Woodlynne) had new estimates approved by the PSE&G's Utility Review Board (URB) in during the third quarter of 2022. Overall, the updated estimates resulted in an increase to the base estimate of $12.5 million that was offset by a release of R&C funds to result in the total subprogram estimate remaining at $389.0 million. **Table 2** also shows that all of the remaining projects aside from Woodlynne had movement in the forecasted in-service date during the third quarter of 2022, with four advancing and eight slipping. Of these twelve projects, three of the projects (Meadow Road, Ridgefield 13kV, and State Street) had forecasted in-service dates change by less than one week. The largest changes to forecasted in-service dates were on the Lakeside Avenue, Waverly, and Front Street projects that each saw slips to their respective forecasted in-service date of at least 60 days, with Lakeside and Front Street impacted by continued delays to their switchgear deliveries and Waverly impacted by manhole rework required prior to the 26kV switchgear energization and the need for Y-buses prior to the 26kV circuit cutovers that will increase the overall duration of the cutovers. As a result of these continued schedule changes, four projects now have forecasted in-service dates in early 2024 (Front Street, Lakeside Avenue, Orange Valley, and Waverly). While PSE&G continues to assess opportunities to regain the schedule on these projects, each of these projects has an open switchgear delivery that continues to present a risk to the project schedule.

The current cost forecast for the Electric Station Flood Mitigation subprogram of $356.9 million decreased approximately $1.2 million from the prior quarter and continues to be below the Stipulation budget of $389.0 million. However, schedule challenges, particularly on the projects with open switchgear deliveries and forecasted in-service dates near the Program end date will continue to warrant further monitoring by the IM to determine if the projects can be completed within the defined Program timeline. PSE&G continues to work with its switchgear vendor to receive updated information on the status of the remaining deliveries and has also instructed the vendor to prioritize certain deliveries in order to maximize support of the project schedules.

As per N.JA.C. Section 14:3-2A.5(c)2, the IM reports are to address:

i. *The effectiveness of Infrastructure Investment Program investments in meeting project objectives;*

ii. *The cost-effectiveness and efficiency of investments;*
iii. *The appropriateness of cost assignments; and*
iv. *Any other information required by the Board.*

The IM focuses the majority of the discussion within each report on these primary objectives, after introducing summarized the findings on these areas in the IM 2021 Third Quarter Report, the IM will continue to provide a summary on these areas for each report with an emphasis on new information relative to the current reporting period. These summarized findings are as follows:

- **Effectiveness of ES 2 investments in meeting project objectives**: The objectives for each subprogram within the ES 2 were defined within PSE&G's ES 2 filing and confirmed by the Stipulation. The overall objectives focused on improving system resiliency, reliability, and hardening through rebuilding or replacing selected substations, installing smart control and monitoring devices on distribution circuits (reclosers, fuse savers, etc.), installing ADMS and a new communication system, and rebuilding selected Gas M&R stations. Within **Section III** of this report, the IM provides a review of the status of the efforts performed to meet these objectives for each subprogram. During the third quarter of 2022, the following projects/scopes were placed in-service and/or completed:
    - Electric Station Flood Mitigation: Academy Street, Market Street, and Ridgefield 4kV previously placed in-service in 2021. The next projects forecasted to go in-service are the Hasbrouck Heights, Leonia, Ridgefield 13kV, and State Street projects, each of which continues to be forecasted to go in-service by the end of 2022.
    - Contingency Reconfiguration: Following the completion of the recloser scope in early 2022, the Fuse Saver installations continued with 286 units installed during the quarter (412 units installed on the Program in total out of a currently planned scope of 1,574 units).
    - Grid Modernization – Communication System: the final 48 substation RTU retrofits were completed during the quarter (bringing the total to 218 substations in the Program); the final fiber cutover project was completed out of 12 total projects; and, two additional fiber projects were completed, leaving five projects remaining out of a total scope of 34 projects.
    - Electric Stipulated Base: Three of the five life cycle projects remain forecasted to go in-service by the end of 2022; the other two projects have shifted to 2023 forecasted in-service dates based on updated equipment delivery schedules and design changes.
    - Gas M&R: Westampton previously placed in-service in October 2021, the next stations forecasted for completion are the Camden and East Rutherford stations that continue to be forecasted to go in-service by the end of 2022.

- **Cost-effectiveness and efficiency of investments**: To assess the cost effectiveness and efficiency of ES 2 investments, the IM began with a review of the initial scope, estimate, and related planning documents for each project to establish a baseline to monitor progress against as the work advances. As the Program execution advances, the IM continues to evaluate actual costs against the initial estimates and current forecasts, including seeking additional information relating to any variances identified. The overall Program's current cost forecast now is slightly above the Stipulation amount, reflecting the cost increases that as observed by the IM has largely stemmed from scope evolution and/or more detailed estimates from the time of the ES 2 filing, as well as the more recent changes in general market conditions (e.g. Covid-19 impacts, supply chain issues, etc.). The updated subprogram forecasts as of the end of the third quarter of 2022 compared to the end of the prior quarter were as follows:

- Electric Station Flood Mitigation: subprogram forecast decreased approximately $1.2 million (or -0.3%) to approximately $356.9 million.
- Contingency Reconfiguration: subprogram forecast increased approximately $2.0 million (or 1.4%) to approximately $147.6 million.
- Grid Modernization – Communication System: subprogram forecast increased approximately $285K (or 0.4%) to approximately $66.6 million.
- Grid Modernization – ADMS: subprogram forecast increased approximately $7.4 million (or 13.9%) to approximately $60.9 million.
- Electric Stipulated Base: subprogram forecast increased approximately $1.5 million (or 1.5%) to approximately $100.6 million.
- Gas M&R: subprogram forecast increased approximately $6.0 million (or 5.8%) to approximately $110.3 million.

As shown above, the biggest subprogram forecast changes during the second quarter of 2022 were in the Grid Modernization – ADMS and Gas M&R subprograms. Within the Grid Modernization – ADMS subprogram, the forecast increase reflected the impacts associated with a change from one OMS production release to two releases. Within the Gas M&R subprogram, the forecast increase primarily relates to the scope changes and related execution requirements identified through the development of detailed design for the Camden and East Rutherford projects.

- **Appropriateness of cost assignments**: The IM receives and reviews recurring data concerning the accumulation of costs within the Program. Based on that review, the IM submits follow-up questions to the Company regarding that data for the reporting period. Such follow-up questions generally focus on the following aspects:
  - Review of any unusual changes in cost elements from period-to-period, including but not limited to allowance for funds used during construction (AFUDC), cost of removal (COR), and the allocation of overheads.
  - Review spend on capital accounts, such as Construction Work in Progress (CWIP) as it relates to overall spend, AFUDC, and COR.
  - Verify cost accumulations and classifications appear to be in accordance with Generally Accepted Accounting Principles (GAAP), to the extent the IM has access to such information.
  - Review and investigation of prior period adjustments and/or corrections to capital accounts.
  - Engage the Company's Internal Audit group on specific areas to audit, review, and assess – particularly for areas in which the IM has limited or no visibility (proprietary data, accounting systems, etc.).

Through the above steps, the IM tracks and monitors how the Company is recording costs to support the finding that the cost assignments appear to be appropriately applied. These cost items are discussed further within **Section II.C** of this IM report.

As noted in the IM 2020 First Quarter Report, the IM conducts its assessment in accordance with Generally Accepted Government Auditing Standards (GAGAS, or more commonly referred to as the "Yellow Book" standards). The Yellow Book provides a framework for conducting performance management reviews/audit engagements with competence, integrity, objectivity, and independence that result in information used for oversight, accountability, transparency, and improvements of the audited programs and operations. On September 7, 2023, a draft IM 2022 Third Quarter Report was submitted to PSE&G, BPU Staff, and Rate Counsel. Per the Yellow Book, the transmittal of a draft report is intended to allow for review and comment by the audited entity and others to develop a fair, complete, and objective report. A summary of the comments on the draft report and the IM's responses are provided in **Appendix A – Draft Report Comments and Responses**. This **Appendix A** also identifies specific sections within this IM 2022 Third Quarter Report that have been edited, supplemented with additional information, or otherwise revised in response to the comments received.

II. Program Status

A. Key Decisions

In order to capture formalized key decisions regarding the ES 2 Program, PSE&G completes a "Record of Decision" (ROD) that includes a description of the decision; alternatives considered; the decision made; and rationale for the decision. The RODs are assessed by the IM as they are completed to review their impact to the Program. In addition, the IM may request PSE&G complete a ROD to formalize a decision if such a decision has not yet been formalized through the ROD process.

The current and pending RODs as of the date of this IM 2022 Third Quarter Report are presented below in **Table 3 – ES 2 Records of Decisions**.

Table 3 – ES 2 Records of Decisions

Subprogram	Record of Decision	IM Comments
Electric Station Flood Mitigation	Academy Street & State Street Change in Mitigation Method	Reasonable and appropriate *(See Section B.1. in the IM 2020 First Quarter Report)*
Electric Station Flood Mitigation	Engineering Support for Energy Strong Program Projects	Reasonable and appropriate *(See Section B.2. in the IM 2020 First Quarter Report)*
Grid Modernization – Communication System	Wireless Communication Network	Reasonable and appropriate *(See Section II.A.1. in the IM 2020 Third Quarter Report)*
Grid Modernization – Communication System	Substation Communication Center	Reasonable and appropriate *(See Section II.A.2. in the IM 2020 Third Quarter Report)*
Grid Modernization – Communication System	Fiber Scope	Reasonable and appropriate *(See Section IV.A. in the IM 2020 Third Quarter Report)*
Electric Station Flood Mitigation	Constable Hook, Lakeside, & Orange Valley Change in Mitigation Method	Reasonable and appropriate *(See Sections II.A.3. and IV.B. in the IM 2020 Third Quarter Report and*

Subprogram	Record of Decision	IM Comments
		additional discussion in Section II.A.1. and Section IV.B. of the IM 2020 Fourth Quarter Report)
Grid Modernization – Communication System	Communication Retrofit of Replacement and non-ES-II Units	Reasonable and appropriate *(See Section II.A.2. in the IM 2020 Fourth Quarter Report)*
Electric Station Flood Mitigation	Market Street Radioactive Soil Testing and Handling	Reasonable and appropriate *(See Section II.A.3. in the IM 2020 Fourth Quarter Report)*
Electric Station Flood Mitigation	Transfer of Clay Street Wastewater Wall Scope from ES2FM to Clay Street 69kV Project	Reasonable and appropriate *(See Section IV.A. in the IM 2020 Fourth Quarter Report)*
Contingency Reconfiguration	Energy Strong II Electric Program – Contingency Reconfiguration Subprogram, 13kV and 4kV Reclosers	Reasonable and appropriate *(See Section IV.A. in the IM 2021 First Quarter Report and Section II.A.1. in the IM 2021 Second Quarter Report)*
Grid Modernization – ADMS	Outage Management System (OMS) Implementation	Reasonable and appropriate *(See Section IV.A. in the IM 2021 First Quarter Report and Section II.A.2. the IM 2021 Second Quarter Report)*

During the third quarter of 2022, there were no additional RODs issued.

B. Program Management

Beginning in July 2020, the IM began participating in a bi-weekly call with PSE&G to review its bi-weekly ES 2 Program Dashboard. As with the original Energy Strong Program, the Dashboard provides a mechanism for PSE&G to monitor and control activities to be completed in order to achieve key near-term milestones, including a focus on recently completed activities, any key issues, and other key metrics (e.g. installation targets) as appropriate. These calls have proven to be an effective way for the IM to stay informed on current and upcoming activities and to allow a venue for discussions between the IM and PSE&G on these activities and status updates and continue to be held on a recurring basis.

During the third quarter of 2022, PSE&G hosted the IM for meetings with subprogram personnel to review the status of the Program to date and outlook going forward. The meetings were conducted at PSE&G's Edison Training Center, which also allowed a visit to the ADMS training room to see the ADMS Platform in use in a simulated environment. In addition, site visits were conducted at the Ridgefield 13kV and State Street substations and the Westampton Gas M&R station.

C. Cost Assignments

1. Costs of Removal (COR)

Costs of Removal (COR) generally include costs for such activities as environmental removal, removal of inside station equipment, structures, foundations, towers and fixtures, conductors and other electrical devices, poles and fixtures, transformers, plant demolition, foundations, and removal of underground conduit and other wiring. Generally, COR are charged to Accumulated Depreciation and are amortized and recovered through a component of depreciation expense. The specific method and amount of recovery is determined in gas and electric rate cases before the BPU.

Table 4 – ES 2 Program Costs of Removal as of September 30, 2022, below itemizes the charges to COR for the third quarter of 2022, the second quarter of 2022 (for comparative purposes), total COR to date for 2022, total COR for the years 2021, 2020, 2019, and total ES 2 Program COR to date. These amounts do not reflect any salvage value reductions, which have been *de minimis* in the ES 2 program through September 30, 2022 (approximately $0.3 million).

Table 4 – ES 2 Program Costs of Removal as of September 30, 2022

Subprogram	Q3 2022	Q2 2022	Q1 2022	Total 2022 (YTD)	Total 2021	Total 2020	Total 2019 (Q4)	Total COR
	(in $ thousands)							
Electric Station Flood Mitigation	$397.2	$595.7	$873.4	$1,866.3	$5,558.7	$1,021.1	$0	**$8,446.1**
Contingency Reconfiguration	$213.5	$35.7	$229.3	$478.5	$2,250.2	$2,198.9	$431.0	**$5,358.6**
Grid Modernization – Communications	$5.3	$14.0	$11.0	$30.3	$137.8	$24.4	$0	**$192.5**
Grid Modernization – ADMS	$0	$0	$0	$0	$0	$0	$0	**$0**
Electric Stipulated Base	$183.1	$340.5	$370.0	$893.6	$150.0	$0	$0	**$1,043.6**
Gas M&R Station Upgrades	$763.0	$0	($0.4)	$762.6	$148.9	$0	$0	**$911.5**
Gas Stipulated Base	$0	$0	$431.5	$431.5	$196.1	$0	$0	**$627.6**
Total	**$1,562.1**	**$985.9**	**$1,914.8**	**$4,462.8**	**$8,441.7**	**$3,244.4**	**$431.0**	**$16,579.9**

Approximately half of the $1.6 million in COR activities in the third quarter of 2022 related to activities at the East Rutherford M&R project for demolition and removal costs associated with the regulator building and foundation, heaters, and yard piping.

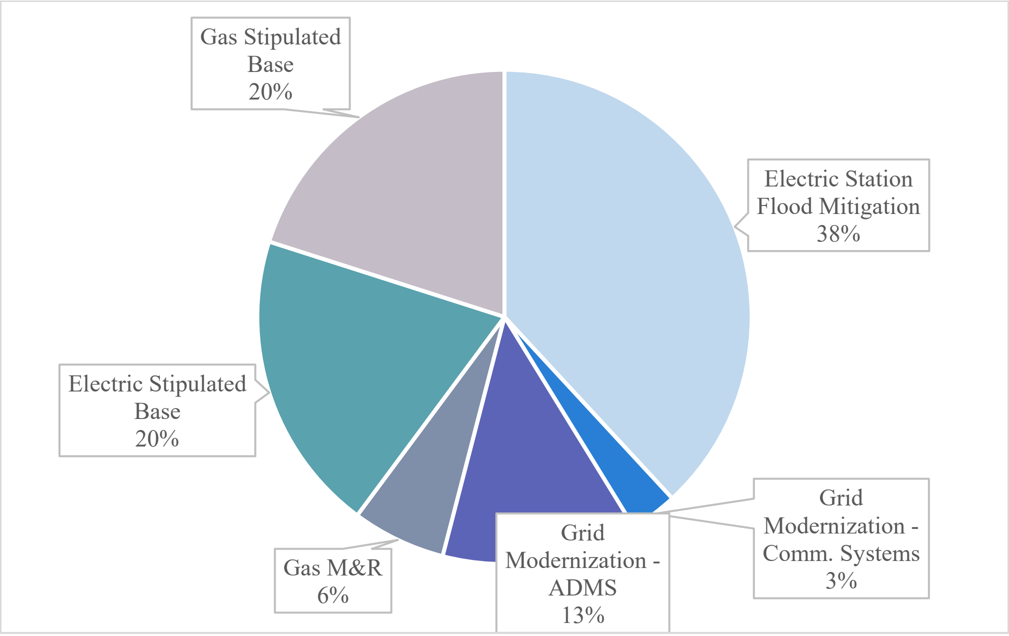
2. Construction Work-in-Progress (CWIP) & In-Service Transfers

As of September 30, 2022, the ES 2 CWIP balance was $260.7 million, compared to $184.9 million as of June 30, 2022. This is the highest balance of CWIP to date in the ES 2 program. The largest components of CWIP as of September 30, 2022 were within:

- The Electric Station Flood Mitigation projects, including: Hasbrouck Heights ($14.6 million), State Street ($12.2 million), Clay Street ($13.5 million), and Waverly ($18.0 million).
- The Gas M&R projects, including: East Rutherford ($14.2 million), Central ($23.7 million), and Camden ($27.2 million) (the latter of which is part of the Gas Stipulated Base).
- The Lifecycle Station Upgrade projects under Electric Stipulated Base, including: Hamilton ($13.1 million) and Plainfield ($16.4 million).
- The ADMS subprogram ($33.4 million).

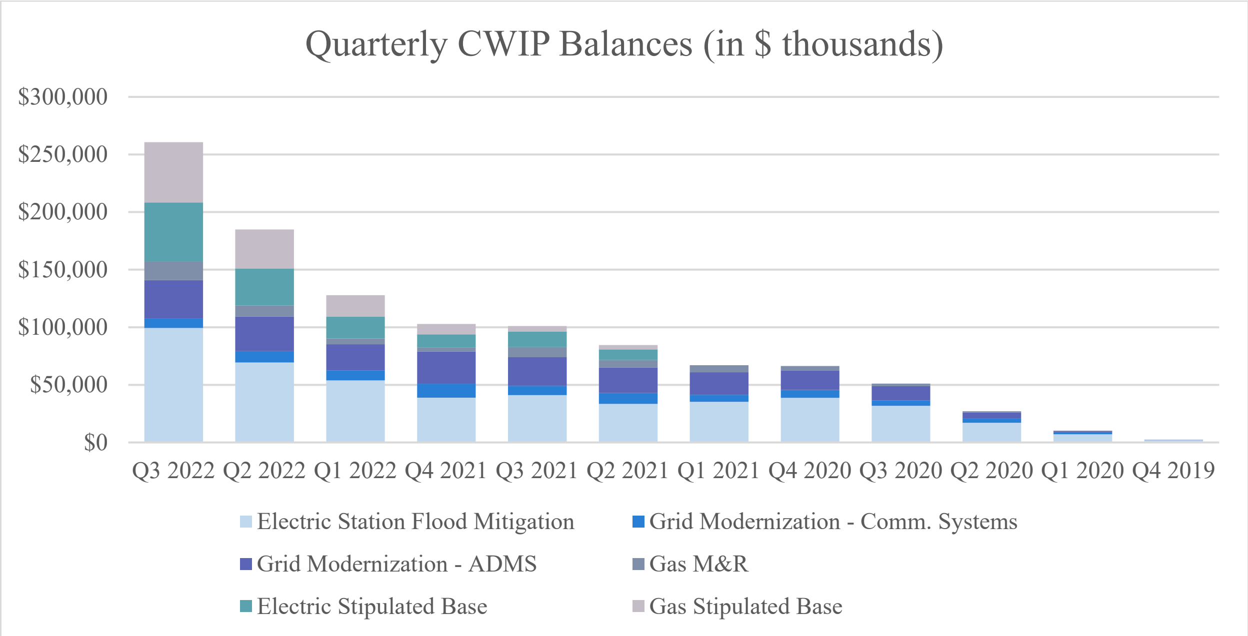
The Electric Station Flood Mitigation subprogram comprises the largest component of total end of period CWIP outstanding, as depicted in **Figure 1 – ES 2 CWIP as of September 30, 2022** below.

Figure 1 – ES 2 CWIP as of September 30, 2022



In addition, the **Figure 2 – ES 2 CWIP Balances by Subprogram as of September 30, 2022** below depicts the composition of end-of-quarter CWIP balances by subprogram for the third, second and first quarters of 2022, and each quarter of 2021 and 2020, and the fourth quarter of 2019.

Figure 2 – ES 2 CWIP Balances by Subprogram as of September 30, 2022



	Q3 2022	Q2 2022	Q1 2022	Q4 2021	Q3 2021	Q2 2021	Q1 2021	Q4 2020	Q3 2020	Q2 2020	Q1 2020	Q4 2019
Electric Station Flood Mitiga	$99,393	$69,358	$ 53,834	$ 38,947	$ 41,077	$ 33,531	$ 35,299	$ 38,727	$ 31,860	$ 17,149	$ 7,101	$ 1,987
Grid Modernization - Comm.	$ 8,080	$ 9,872	$ 8,847	$ 11,991	$ 8,077	$ 9,343	$ 6,026	$ 6,760	$ 4,529	$ 3,508	$ 1,908	$ 75
Grid Modernization - ADMS	$33,396	$30,010	$ 22,534	$ 28,057	$ 24,817	$ 22,085	$ 19,600	$ 16,837	$ 12,502	$ 5,428	$ 969	$ 36
Gas M&R	$15,984	$ 9,642	$ 5,086	$ 3,338	$ 8,735	$ 6,574	$ 6,123	$ 4,032	$ 2,149	$ 951	$ 291	$ 53
Electric Stipulated Base	$51,540	$32,179	$ 18,841	$ 11,560	$ 13,645	$ 9,280	$ -	$ -	$ -	$ -	$ -	$ -
Gas Stipulated Base	$52,329	$33,854	$ 18,757	$ 9,042	$ 4,691	$ 3,808	$ -	$ -	$ -	$ -	$ -	$ -

Transfers from CWIP to plant in service were $3.1 million during the third quarter of 2022, the majority of which was attributed to placing several Grid Modernization fiber projects in service during the third quarter. Total ES 2 transfers from CWIP have been $89 million through September 30, 2022. It should be noted that work related to certain assets, such as the reclosers under the Contingency Reconfiguration subprogram, generally can be completed without being recorded through CWIP. As such, no AFUDC is recorded on these expenditures. This accounting treatment is in accord with generally accepted accounting principles and the Company's accounting policies.

3. Allowance for Funds Used During Construction (AFUDC)

The amount of quarterly AFUDC recorded by the Company for each ES 2 subprogram during the third, second, and first quarters of 2022, total 2022 to date, total AFUDC for the years 2021, 2020 and 2019, and total Energy Strong AFUDC accrued to date, is shown below in **Table 5 – ES 2 Program AFUDC as of September 30, 2022**.

Table 5 – ES 2 Program AFUDC as of September 30, 2022

Subprogram	Q3 2022	Q2 2022	Q1 2022	Total 2022 (YTD)	Total 2021	Total 2020	Total 2019 (Q4)	Total AFUDC
	(in $ thousands)							
Electric Station Flood Mitigation	$1,285.1	$944.5	$759.0	$2,988.6	$2,281.2	$936.5	$9.9	**$6,216.2**
Contingency Reconfiguration	$0	$0	$0	$0	$0	$0	$0	**$0**
Grid Modernization – Communications	$98.5	$123.1	$115.6	$327.2	$386.9	$184.3	$0.2	**$898.6**
Grid Modernization – ADMS	$536.9	$438.9	$385.7	$1,361.5	$1,365.6	$352.7	$0.1	**$3,079.9**
Electric Stipulated Base	$645.0	$383.9	$230.0	$1,258.9	$524.6	$44.0	$0	**$1,827.5**
Gas M&R Station Upgrades (incl. Stip. Base)	$733.8	$395.6	$208.3	$1,337.7	$470.0	$70.0	$0.2	**$1,877.9**
Total	**$3,229.3**	**$2,286.0**	**$1,698.6**	**$7,283.9**	**$5,028.3**	**$1,587.5**	**$10.4**	**$13,910.1**

AFUDC accrued for ES 2 projects during the third quarter of 2022 increased over AFUDC accrued during the second quarter of 2022 as the result of increases in total average CWIP balances across almost all subprograms.

During the first quarter of each year, the AFUDC rate is reviewed for possible reset as it applies to the current year based on updated capital structure and component cost data. For the year 2022, the new AFUDC rate was calculated to be 6.92%, using the capital structure and component costs as of January 31, 2022. This rate is higher than the 2021 rate of 6.81%, primarily due to a zero balance of short-term in the 2022 calculation (vs. a $44 million balance of short-term debt in 2021), and also to an 8% reduction in the Company's amount of long-term debt outstanding (lowering the debt component of the capital structure from 45.5% to 44.8%), and a reduction in the embedded cost of long-term debt, both as used in the AFUDC calculation. In calculating the 2022 AFUDC rate, the Company used (i) a 3.63% embedded cost of long-term debt (vs. 3.85% in 2021), (ii) no short-term debt, and (iii) a cost of equity of 9.60% (unchanged from 2021).

Subsequent to the annual reset calculation referred to above, and during the course of each year, the AFUDC rate is also recalculated as it applies to each fiscal quarter. If the recalculated rate changes by 25 basis points from the rate then in effect, the rate is reset and retroactively applied to January 1 of that year. For the third quarter of 2022, based on data as of September 30, 2022, the recalculated weighted average AFUDC accrual rate (6.92%) did not meet this criterion to warrant changing from the annual rate (6.92%) in effect. Therefore, AFUDC was accrued during the third quarter of 2022 at the calculated rate of 6.92%.

The IM observes that the Company's calculation of the AFUDC rate and its application is in accordance with both PSE&G's accounting policy and Plant Instruction 3(17) of the Federal Regulatory Commission's Uniform Systems of Accounts prescribed for public utilities.

The IM also notes that the relevant AFUDC information as it relates to third quarter 2022 ES 2 project costs is consistent with the applicable dictates of the Stipulation entered into with respect to these Energy Strong projects. The IM will continue to review future ES 2 AFUDC accruals for consistency with relevant provisions of the Stipulation for accounting and reporting purposes only, and not as a party to, or in expressing an opinion concerning, any rate proceedings.

4. Allocated Overheads

PSE&G follows a philosophy of allocating overhead costs, whether at the Service Company or from utility support organizations, to the operating company or unit receiving the benefit, and ultimately, if appropriate, settling costs to individual assets. Where possible, services are charged directly to the entity receiving the benefit, but where direct charging of costs is not feasible, cost allocations from the Service Company to operating companies are prescribed in a BPU-approved schedule issued pursuant to a BPU order in July 2003. This Order was amended by a BPU Order dated June 8, 2022, allowing the company to transfer certain employees to the PSE&G Service Company in an effort to better support transmission growth opportunities and projects. This action had no impact on existing overhead allocations. The Stipulation requires the Company to follow its current practices with regard to capitalized overheads.

For ES 2 electric and gas distribution projects, allocated overhead costs should primarily come from utility-related labor costs associated with administrative and supervisory personnel, labor and other costs associated with bargaining unit personnel, fringe benefits, materials handling costs, payroll taxes and depreciation expense. Shown below in **Table 6 – ES 2 Program Overhead Allocations as of September 30, 2022** are the allocated overhead costs charged to ES 2 subprograms for the first three quarters of 2022, total 2022 year to date, total 2021, total 2020, total 2019 and total ES 2 Program allocated overheads to date.

Table 6 – ES 2 Program Overhead Allocations as of September 30, 2022

Subprogram	Q3 2022	Q2 2022	Q1 2022	Total 2022 (YDT)	Total 2021	Total 2020	Total 2019 (Q4)	Total Overhead Allocations
	(in $ thousands)							
Electric Station Flood Mitigation	$3,324	$2,208	$2,185	$7,717	$14,368	$14,023	$287	**$36,395**
Contingency Reconfiguration	$3,037	$795	$843	$4,675	$14,420	$17,109	$3,415	**$39,619**

Subprogram	Q3 2022	Q2 2022	Q1 2022	Total 2022 (YDT)	Total 2021	Total 2020	Total 2019 (Q4)	Total Overhead Allocations
	(in $ thousands)							
Grid Modernization – Communications	$553	$717	$1,802	$3,073	$9,171	$3,625	$12	**$15,881**
Grid Modernization – ADMS	$50	$124	$76	$250	$501	$426	$11	**$1,188**
Electric Stipulated Base	$2,751	$1,275	$1,449	$5,476	$2,123	$259	$0	**$7,858**
Gas M&R Station Upgrades (incl. Stip. Base)	$435	$339	$197	$971	$735	$291	$15	**$2,012**
Total	**$10,149**	**$5,458**	**$6,552**	**$22,159**	**$41,318**	**$35,733**	**$3,740**	**$102,950**

The overwhelming majority of overhead costs allocated to ES 2 projects during the third quarter of 2022 are costs allocated from areas that support all utility distribution and transmission projects, including ES 2 projects. More specifically, most (approximately 77%) of the third quarter allocated costs reflect labor costs of supervisory, administrative and operations planning personnel, labor and other costs from bargaining unit personnel, and fringe benefits associated with these labor costs. The increase in overhead costs for the third quarter of 2022 from the second quarter of 2022 reflects (i) an increase in construction activities at a number of Electric Station Flood Mitigation and Electric Stipulated Base projects, which resulted in higher labor costs and outside services subject to surcharge (including contract labor), and (ii) an increase in the number of installed fuse savers in the Contingency Reconfiguration subprogram, which increased the spend on labor and materials subject to surcharge. The major categories of overhead costs incurred in the second and third quarters of 2022 by subprogram are provided below in **Table 7 – Q2 and Q3 2022 Overhead Cost Comparison**.

Table 7 – Q2 and Q3 2022 Overhead Cost Comparison

Overhead Category*	Electric Station Flood Mitigation	Contingency Reconfiguration	Grid Modernization – Communications	Grid Modernization – ADMS	Electric Stipulated Base	Gas M&R (incl Stip. Base)	Total
Q2 2022 (in $ thousands)							
AMCS	$102	$19	$31	$2	$70	$43	$268
Fleet	$89	$69	$41	$8	$43	$0	$250
Fringe	$370	$115	$91	$41	$171	$116	$903
Labor & Outside Services	$1,081	$199	$303	$22	$732	$117	$2,453
Labor Only	$319	$256	$168	$27	$150	$0	$921
Material Handling	$31	$37	$6	$0	$15	$5	$93
Payroll Tax	$91	$30	$23	$10	$41	$29	$224
Toolkit and Other Services	$72	$22	$17	$7	$35	$25	$179

Overhead Category*	Electric Station Flood Mitigation	Contingency Reconfiguration	Grid Modernization – Communications	Grid Modernization – ADMS	Electric Stipulated Base	Gas M&R (incl Stip. Base)	Total
Vehicle Depreciation	$52	$49	$37	$6	$18	$4	$167
Other	$0	$0	$0	$0	$0	$0	$0
Total	**$2,208**	**$795**	**$717**	**$124**	**$1,275**	**$339**	**$5,458**
Q3 2022 (in $ thousands)							
AMCS	$176	$76	$26	$0.3	$167	$71	$517
Fleet	$115	$277	$34	$0.6	$99	$5	$530
Fringe	$499	$416	$53	$30	$291	$142	$1,431
Labor & Outside Services	$1,824	$746	$264	$2	$1,634	$112	$4,581
Labor Only	$384	$948	$123	$3	$346	$19	$1,824
Material Handling	$46	$204	$3	$0	$19	$13	$284
Payroll Tax	$114	$100	$12	$7	$67	$33	$334
Toolkit and Other Services	$109	$83	$14	$5	$75	$33	$319
Vehicle Depreciation	$57	$188	$24	$0.7	$53	$7	$329
Other	$0	$0	$0	$0	$0	$0	$0
Total	**$3,324**	**$3,037**	**$553**	**$50**	**$2,751**	**$435**	**$10,149**

*Asset Management & Centralized Services (AMCS): labor and fringes, material, contractor, consultant or other business expenses from several areas within AMCS that provide general support to Electric, Transmission, and Gas's O&M, Capital, Third Party, and Affiliate work.
Fleet: Bargaining unit personnel that maintain the vehicles for each Division.
Fringe: Costs associated with other fringe costs, pensions, and other post-employment benefits.
Labor & Outside Services: Labor and fringes, material, other business expenses associated with administrative and general costs.
Labor Only: Travel, fuel, personal protection equipment and troubleshooter labor costs specifically related to the support of the T&D Bargaining Unit work force allocated over all T&D work.
Material Handling: Costs associated with the materials handling process.
Payroll Tax: Costs associated with payroll tax.
Toolkit and Other Services: Costs associated with purchase of personal protective equipment and personal hand tools for Bargaining Unit employees and are utilized to perform O&M, Capital, Third Party, Affiliate, and deferred work activities.
Vehicle Depreciation: Depreciation expense associated with vehicle usage in each Division.

D. System Performance

1. Current Reporting Quarter Major Events

During the third quarter of 2022, there were no Major Events reported in PSE&G's service territory.

III. Project Status

A. Electric Station Flood Mitigation

A summary of the subprogram plan as of the end of the third quarter of 2022 compared to the status as of the end of 2019, end of 2020, and end of 2021 is provided below in **Table 8 – ES 2 Electric Station Flood Mitigation Subprogram Milestone Schedule as of September 30, 2022**. Note that the Academy, Market Street, and Ridgefield 4kV projects were previously placed in-service and closed out, thus there are no further updates to these projects (which have been further called out in italics in **Table 8**).

Table 8 – ES 2 Electric Station Flood Mitigation Milestone Schedule as of September 30, 2022

Project	Plan Status Point	2019		2020				2021				2022				2023					2024
		Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4		
1. Academy Street	Dec. 2019		KO					C					IS		CO					*December 31, 2023 - ES 2 Program End Date*	
	Dec. 2020		KO		C									CO							
	Dec. 2021		KO		C						IS						CO				
	Sep. 2022		KO		C						IS		CO								
2. Clay Street	Dec. 2019	*Schedule Under Development*																			
	Dec. 2020			KO							C					IS					CO (Q2)
	Dec. 2021			KO							C				IS						CO (Q1)
	Sep. 2022			KO							C					IS					CO (Q1)
3. Front Street^	Dec. 2019	*Not in ES 2 Program*																			
	Dec. 2020	*Not in ES 2 Program*																			
	Dec. 2021								KO				C						IS		CO (Q2)
	Sep. 2022								KO				C								IS (Q1); CO (Q2)
4. Hasbrouck Heights	Dec. 2019		KO						C						IS		CO				
	Dec. 2020		KO									C					IS		CO		
	Dec. 2021		KO									C					IS	CO			
	Sep. 2022		KO									C			IS			CO			
5. Kingsland	Dec. 2019			KO				C			IS		CO								
	Dec. 2020			KO										C					IS		CO (Q2)
	Dec. 2021			KO											C		IS		CO		
	Sep. 2022			KO										C					IS		CO (Q2)
6. Lakeside Avenue	Dec. 2019*				KO				C										IS		CO (Q2)
	Dec. 2020						KO							C					IS		CO (Q2)
	Dec. 2021						KO							C					IS		CO (Q2)
	Sep. 2022						KO							C				IS			IS (Q1); CO (Q3)
7. Leonia	Dec. 2019	*Schedule Under Development*																			
	Dec. 2020			KO		C									IS		CO				
	Dec. 2021			KO		C									IS		CO				
	Sep. 2022			KO		C									IS		CO				
8. Market Street	Dec. 2019			KO				C	OS		CO										
	Dec. 2020			KO					C	OS		CO									
	Dec. 2021			KO						C/OS	CO										
9. Meadow Road	Dec. 2019	*Schedule Under Development*																			
	Dec. 2020			KO											C				IS		CO (Q2)
	Dec. 2021			KO										C				IS			CO (Q1)
	Sep. 2022			KO										C				IS			CO (Q1)

Project	Plan Status Point	2019		2020				2021				2022				2023				2024
		Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	
10. Orange Valley	Dec. 2019	*Schedule Under Development*																		
	Dec. 2020					KO										C				IS (Q1); CO (Q3)
	Dec. 2021					KO										C				IS (Q1); CO (Q3)
	Sep. 2022					KO								C						IS (Q1); CO (Q2)
11. Ridgefield 13kV	Dec. 2019			KO	C										IS		CO			
	Dec. 2020			KO	C										IS		CO			
	Dec. 2021			KO	C										IS		CO			
	Sep. 2022			KO	C										IS		CO			
12. Ridgefield 4kV	Dec. 2019			KO						C	OS			CO						
	Dec. 2020			KO	C				OS		CO									
	Dec. 2021			KO	C				OS		CO									
13. State Street	Dec. 2019		KO					C								IS				CO (Q1)
	Dec. 2020		KO						C				IS							CO (Q1)
	Dec. 2021		KO						C					IS				CO		
	Sep. 2022		KO						C						IS				CO	
14. Toney's Brook	Dec. 2019			KO						C									IS	CO (Q2)
	Dec. 2020			KO										C			IS			CO (Q2)
	Dec. 2021			KO										C			IS			CO (Q2)
	Sep. 2022			KO										C			IS		CO	
15. Waverly	Dec. 2019	*Schedule Under Development*																		
	Dec. 2020			KO			C												IS	CO (Q2)
	Dec. 2021			KO			C													IS (Q3); CO (Q1 2025)
	Sep. 2022			KO			C													IS (Q2); CO (Q4)
16. Woodlynne	Dec. 2019		KO												C				IS	CO (Q2)
	Dec. 2020		KO												C				IS	CO (Q2)
	Dec. 2021		KO												C				IS	CO (Q2)
	Sep. 2022		KO								C								IS	CO (Q1)

December 31, 2023 - ES 2 Program End Date

Legend: KO = Kickoff; C = Construction; IS = Fully In-Service (major assets in-service); OS = Out-of-Service (if eliminated); CO = Closeout
-Actuals are indicated with an underline (Note: for the Market Street and Ridgefield 4kV projects, outside plant construction began in the first quarter of 2020, the construction milestone indicated on this chart reflects inside plant construction).
***-The Dec. 2019 Lakeside Avenue project schedule was based on the original raise and rebuild mitigation strategy; the current schedule reflects the proposed mitigation method change that contemplates relocating the substation.**
^-The Front Street project was proposed by PSE&G during the second quarter of 2021 to replace the cancelled Constable Hook project.

A summary of the subprogram status as of the end of the third quarter of 2022 is provided below **Table 9 – ES 2 Electric Station Flood Mitigation Summary Status as of September 30, 2022**.

Table 9 – ES 2 Electric Station Flood Mitigation Summary Status as of September 30, 2022

Activity	Total # of Projects	Specific Projects
Kickoff Meeting	16	Academy Street; Clay Street; Front Street; Hasbrouck Heights; Kingsland; Lakeside Avenue; Leonia; Market Street; Meadow Road; Orange Valley; Ridgefield 13kV; Ridgefield 4kV; State Street; Toney's Brook; Waverly; Woodlynne

Activity	Total # of Projects	Specific Projects
Key Drawing Review	16	Academy Street; Clay Street; Front Street; Hasbrouck Heights; Kingsland; Lakeside Avenue; Leonia; Market Street; Meadow Road; Orange Valley; Ridgefield 13kV; Ridgefield 4kV; State Street; Toney's Brook; Waverly; Woodlynne
Scope Locked	16	Academy Street; Clay Street; Front Street; Hasbrouck Heights; Kingsland; Lakeside Avenue; Leonia; Market Street; Meadow Road; Orange Valley; Ridgefield 4kV; Ridgefield 13kV; State Street; Toney's Brook; Waverly; Woodlynne
Major Equipment Purchase Orders (POs)	18*	Academy Street; Clay Street; Front Street*; Hasbrouck Heights; Kingsland; Lakeside; Leonia*; Meadow Road; Orange Valley; Ridgefield 13kV*; State Street; Toney's Brook; Waverly*; Woodlynne
Architect/ Engineer (A/E) Contract Award (or selection of PSE&G internal engineering)	16	Academy Street[1]; Clay Street[1]; Front Street[3]; Hasbrouck Heights[1]; Kingsland[2]; Lakeside Avenue[3]; Leonia[2]; Market Street[2]; Meadow Road[2]; Orange Valley[1]; Ridgefield 13kV[2]; Ridgefield 4kV[2]; State Street[2]; Toney's Brook[3]; Waverly[3]; Woodlynne[1]
Construction Start**	16	Academy Street; Clay Street; Front Street; Hasbrouck Heights; Lakeside; Leonia; Kingsland; Market Street; Meadow Road; Orange Valley; Ridgefield 4kV; Ridgefield 13kV; State Street; Toney's Brook; Waverly; Woodlynne
In-Service	3	Academy Street; Market Street; Ridgefield 4kV
Partial In-Service	2	Leonia; Ridgefield 13kV

**-Three of the listed projects (Front Street, Leonia, Ridgefield 13kV, and Waverly) have two switchgears, thus the current count reflects 18 switchgears at 14 substations.*
[1]-Indicates Burns & McDonnell is serving as the A/E.
[2]-Indicates PSE&G internal resources are serving as the A/E.
[3]-Indicates Black & Veatch is serving as the A/E.
***-Includes projects that have commenced inside plant (IP) and/or outside plant (OP) construction; also maintains identification of projects that have since completed construction (generally those that are shown as in-service).*

Beyond the key activities summarized in **Table 9** above, **Table 10 – ES 2 Electric Station Flood Mitigation Planned Activities for Q4 2022** summarizes the upcoming planned activities for each project for the fourth quarter of 2022, including any carryover of activities from earlier periods.

Table 10 – ES 2 Electric Station Flood Mitigation Planned Activities for Q4 2022

Station	Planned Activities for Q4 2022	Carryover Activities from Q3 2022
1. Academy Street	• Demolition of old station	• Demo existing foundations, remove old equipment at existing Academy St. station
2. Clay Street	• Start electrical construction	• Continue civil construction
3. Front Street	• Commission and energize contingency switchgear	• Continue to prepare the contingency switchgear
4. Hasbrouck Heights	• Energize switchgear and place in-service	• Switchgear commissioning
5. Kingsland	• Start electrical construction	• Continue civil construction
6. Lakeside Avenue	• Start switchgear foundations	• Commence civil construction
7. Leonia	• Energize switchgear and place in-service	• Continue commissioning of switchgear #2
8. Market Street	*Project complete*	
9. Meadow Road	• Install foundations, conduit, grounding, and cable trench	• Continue civil construction
10. Orange Valley	• Install duct banks, start switchgear foundation	• Continue civil construction

Station	Planned Activities for Q4 2022	Carryover Activities from Q3 2022
11. Ridgefield 13kV	• Energize switchgear and place in-service	• Continue commissioning new switchgear #1
12. Ridgefield 4kV	*Project complete*	
13. State Street	• Energize switchgear and place in-service	• Continue commissioning switchgear
14. Toney's Brook	• Install grounding grid, conduit, bus supports • Start electrical construction	• Continue civil construction
15. Waverly	• Demo existing 26kV switchgear • Cutovers to new 26kV switchgear	• Install new 26kV cables • Manhole construction
16. Woodlynne	• Continued civil construction	• Continued ductbank and manhole construction

As discussed in the IM 2022 First Quarter Report, PSE&G's switchgear vendor, Powercon, informed PSE&G that due to various material and sub-supplier delays, the remaining major equipment deliveries may continue to see impacts. Powercon continues to explore options to improve its production floor efficiencies and ordering supplies earlier to potentially alleviate further impacts. PSE&G has requested more detailed and frequent status updates from Powercon to better inform its project planning. The status of the major equipment deliveries for the Electric Station Flood Mitigation projects is presented in **Table 11 – Electric Station Flood Mitigation Major Switchgear Deliveries as of September 30, 2022**.

Table 11 – Electric Station Flood Mitigation Switchgear Deliveries as of September 30, 2022

Station	Description	Delivery Status as of Q2 2022	Delivery Status as of Q3 2022
1. Academy Street	13kV switchgear	***11/7/2020***	***11/7/2020***
2. Clay Street	4kV switchgear	8/30/2022	10/3/2022
3. Front Street	4kV switchgear	5/22/2023	8/15/2023
	4kV cont. switchgear	7/17/2022	***8/25/2022***
4. Hasbrouck Heights	4kV switchgear	***11/30/2021***	***11/30/2021***
5. Kingsland	13kV switchgear[1]	***9/30/2020***	***9/30/2020***
6. Lakeside Avenue	4kV switchgear	1/26/2023	6/30/2023
7. Leonia	13kV switchgear #1	***5/24/2021***	***5/24/2021***
	13kV switchgear #2	***6/16/2022***	***6/16/2022***
	13kV cont. switchgear[2]	***10/16/2020***	***10/16/2020***
8. Market Street	Elimination project		
9. Meadow Road	13kV switchgear[2]	2/14/2023	2/14/2023
10. Orange Valley	4kV switchgear	5/29/2023	8/15/2023
11. Ridgefield 13kV	13kV switchgear #1	8/2/2022	***8/24/2022***
	13kV switchgear #2	***4/27/2021***	***4/27/2021***
	13kV cont. switchgear[1]	***9/30/2020***	***9/30/2020***
12. Ridgefield 4kV	Elimination project		
13. State Street	4kV switchgear	***12/15/2021***	***12/15/2021***
14. Toney's Brook	4kV switchgear	12/20/2022	12/20/2022
15. Waverly	26kV switchgear	***4/30/2021***	***4/30/2021***
	4kV switchgear	8/5/2022	10/31/2022
16. Woodlynne	4kV switchgear	11/22/2022	2/6/2023

Station	Description	Delivery Status as of Q2 2022	Delivery Status as of Q3 2022
Note: bold/italicized dates indicate actual delivery dates. [1]The Kingsland 13kV switchgear was delivered to the Ridgefield 13kV site where it is being used as the contingency/temporary switchgear for that project before its permanent installation on the Kingsland project. Delivery of the switchgear to the Kingsland site will follow the Ridgefield 13kV project being placed in-service, which is forecasted for December 2022 with the disassembly of the contingency/temporary switchgear and delivery to Kingsland expected in the first quarter of 2023. [2]The Meadow Road project will use the Leonia project's 13kV contingency switchgear as its permanent switchgear.			

As indicated in **Table 11**, during the third quarter of 2022, there were two additional switchgear deliveries received (the contingency 4kV switchgear for Front Street and the 13kV switchgear #1 for Ridgefield 13kV), leaving eight deliveries remaining for the subprogram. Of the remaining eight deliveries, two had the forecasted delivery date unchanged from the prior quarter, while the other six all slipped between approximately three weeks and 155 days, continuing to reflect the challenges Powercon is experiencing and continuing to impact the forecasted in-service dates for these projects.

The current project estimates are shown below in **Table 12 – ES 2 Electric Station Flood Mitigation Project Cost Status as of September 30, 2022**. As discussed in the IM 2022 First Quarter Report, PSE&G decided to consolidate the R&C on the individual projects into one R&C balance for the entire subprogram, thus there is no estimated R&C amount at the project level. **Table 12** also shows the current estimate level based on PSE&G's estimating processes and as approved by the URB, the actual spend, and percentage of actuals to estimate as of the end of the third quarter of 2022.

Table 12 – ES 2 Electric Station Flood Mitigation Project Cost Status as of September 30, 2022

Project	Estimate Level	Base	Risk & Contingency*	Total	Current Forecast	Actuals to Date	% of Actuals to Estimate
1. Academy Street	Definitive	$9,300,000	$-	$9,300,000	$7,997,585	$6,519,897	70%
2. Clay Street	Definitive	$33,600,000	$-	$33,600,000	$33,613,927	$13,021,870	39%
3. Front Street**	Study	$25,900,000	$-	$25,900,000	$27,500,832	$9,558,510	37%
4. Hasbrouck Heights	Definitive	$19,300,000	$-	$19,300,000	$19,073,778	$13,926,106	72%
5. Kingsland	Conceptual	$8,700,000	$-	$8,700,000	$8,993,293	$2,219,794	26%
6. Lakeside Avenue	Study	$39,400,000	$-	$39,400,000	$32,706,175	$3,292,610	8%
7. Leonia	Definitive	$24,900,000	$-	$24,900,000	$25,680,491	$22,304,216	90%
8. Market Street	Definitive	$29,100,000	$-	$29,100,000	$28,308,684	$28,140,833	97%
9. Meadow Road	Conceptual	$7,200,000	$-	$8,300,000	$8,406,000	$2,035,052	25%
10. Orange Valley	Study	$14,700,000	$-	$14,700,000	$14,903,289	$2,227,908	15%

Project	Estimate Level	Base	Risk & Contingency*	Total	Current Forecast	Actuals to Date	% of Actuals to Estimate
11. Ridgefield 13kV	Conceptual	$26,100,000	$-	$26,100,000	$28,244,833	$25,524,755	98%
12. Ridgefield 4kV	Definitive	$20,700,000	$-	$20,700,000	$20,703,808	$20,703,809	100%
13. State Street	Definitive	$19,600,000	$-	$19,600,000	$19,837,904	$11,609,902	59%
14. Toney's Brook	Conceptual	$16,200,000	$-	$16,200,000	$16,250,514	$3,034,991	19%
15. Waverly	Conceptual	$39,900,000	$-	$39,900,000	$40,738,565	$17,197,448	43%
16. Woodlynne	Definitive	$24,000,000	$-	$24,000,000	$23,964,496	$5,986,596	25%
ES 2 Station Placeholder	N/A	$-	$29,300,000	$29,300,000	$-	$-	-
Subprogram Total		**$359,700,000**	**$29,300,000**	**$389,000,000**	**$356,924,105**	**$187,304,230**	**48%**

**-As discussed in Section II.B. of the IM 2022 First Quarter Report, PSE&G made the decision to hold risk and contingency at the subprogram level, which resulted in updated estimates being prepared for each project to reflect this change and other project-specific updates as warranted.*

***-The Front Street project was proposed by PSE&G during the second quarter of 2021 to replace the cancelled Constable Hook project.*

Findings & Observations

- No change in completed projects during the third quarter of 2022, with three of the 16 projects previously put in-service (Market Street and Ridgefield during the second quarter of 2021 and Academy Street in the fourth quarter of 2021). The next projects forecasted to be placed in-service are the Hasbrouck Heights, Leonia, Ridgefield 13kV, and State Street projects, each continues to advance towards a forecasted in-service date in the fourth quarter of 2022.
- Five additional projects commenced construction during the third quarter of 2022 (Kingsland, Lakeside Avenue, Meadow Road, Orange Valley, and Toney's Brook), with that all projects in the subprogram have passed the construction start milestone.
- Twelve of the remaining thirteen Electric Station Flood Mitigation projects had movement in the forecasted in-service date during the third quarter of 2022, with four advancing and eight slipping. For three of those projects, the change was less than one week, while the biggest changes involved the following projects:
    - Lakeside Avenue (slipping 163 days to February 28, 2024);
    - Waverly (slipping 62 days to April 20, 2024);
    - Front Street (slipping 62 days to January 9, 2024); and,

  - Clay Street (slipping 52 days to March 23, 2023).

  Of those four projects, all but Clay Street had switchgear delivery delays (while Clay Street had combined impacts from a safety incident, weather impacts, and additional test pits required). As previously discussed, PSE&G updates the schedule on a monthly basis based on the current data and information available and assesses opportunities to improve the schedule as part of this process.

- The overall subprogram forecast as of the end of the third quarter of 2022 decreased $1.2 million (or -0.3%) to $356.9 million from the status as of the prior quarter. The forecast continues to remain under the current subprogram estimate and Stipulation amount of $389.0 million (which includes $29.3 million in R&C). The change in the subprogram forecast was predominantly driven by changes to the project forecasts on four of the projects, including:
  - Front Street (increased $1.3 million to $27.5 million): driven by an updated Division forecast for bringing six circuits from OP to IP, additional handling of contingency feeder rows, and additional costs for contingency wire checker and contingency disassembly.
  - Lakeside Avenue (decreased $2.2 million to $32.7 million): driven by lower OP Division cost stemming from 15% decrease in the linear footage of underground cable required and removing the contingency no longer required.
  - Orange Valley (decreased $2.2 million to $27.5 million): driven by a reallocation of civil and electrical costs between the Orange Valley and Orange Heights projects.
  - Waverly (increased $827K to $40.7 million): driven by more civil work required to rebuild a manhole and escalation in A/E procured steel and cable trench prices.
- With 52% of the subprogram forecast now spent (48% of the Stipulation amount), the IM has found nothing to date that would jeopardize the subprogram being completed on budget as even with some cost pressures on certain projects, there is adequate R&C remaining in the subprogram. However, the schedule status of the later projects in this subprogram, and in particular those with open switchgear deliveries currently forecasted for 2023 will have to continue to be closely followed to monitor if the projects can be completed within the ES 2 Program window. At this time, the primary risk to the project schedule is those major equipment deliveries, followed by resource availability to support schedule requirements and weather-related impacts. Delays to the switchgear deliveries have caused the forecasted in-service dates for Front Street, Lakeside Avenue, Orange Valley, and Waverly to slip into 2024. While the resource risk is primarily within the Metro Division (potentially impacting Lakeside, Clay Street, Waverly, Orange Valley, and Tone's Brook) and Southern Divisions (potentially impacting State Street, Woodlynne, and Woodbury).
- Regarding the projects with remaining switchgear deliveries, PSE&G continues to meet regularly with its vendor to receive updated information as to the status of these deliveries. PSE&G has also worked with the vendor to re-prioritize certain deliveries to optimize the project schedules and advanced the in-service date if possible. During the third quarter of 2022 the 4kV contingency switchgear was received at Front Street and 13kV switchgear #1 was received at Ridgefield 13kV. Of the remaining eight switchgear deliveries, six of the eight saw the forecasted delivery date slip from the status as of the end of the prior quarter (while the other two remained constant).

1. Academy Street

During the third quarter of 2022, $114,926 was spent on the Academy Street project compared to a forecast of approximately $71,000, which brought the total spend to approximately $6.5 million.

This project was placed in-service on October 19, 2021, and in the third quarter of 2022 the final circuit was cutover to the switchgear. The demolition of the old substation is expected to commence in October 2022, with the PO associated with this work issued in August 2022.

The actual spend by period for Academy Street as compared to the current forecast and URB approved estimate is provided below along with the forecasted spend through the end of the project. The Academy Street forecast decreased approximately $500,000 during the third quarter of 2022, which was the result of the civil and electrical demolition POs being lower than estimated.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals						*Forecast*	
$150,398	$4,224,550	$1,754,789	$131,061	$144,172	$114,926	$1,435,688	$42,000

Estimate & Forecast		Actuals to Date	% of Actuals to Estimate & Forecast
Estimate	$9,300,000	$6,519,897	70%
Forecast	$7,997,585		82%

2. Clay Street

During the third quarter of 2022, $2,238,630 was spent on the Clay Street project compared to a forecast of approximately $3.0 million, which brought the total spend to approximately $13.0 million. The variance in forecasted to actual spend during the third quarter of 2022 was largely driven by the delivery of the feeder rows being delayed from September to October 2022.

The forecasted in-service date for the Clay Street project as of the end of the third quarter of 2022 slipped 52 days from the status as of the end of the prior quarter to March 23, 2023. The slip in forecasted in-service date was the combined result of a safety incident on the project, weather impacts in the outside plant civil work that delayed the installation of the switchgear building foundation, and a requirement for additional test pits to confirm the OP underground design.

The primary activities on the Clay Street project during the third quarter of 2022 included the continued advancement of the civil construction, with foundation and duct bank installations performed during the quarter, and the start of work on the switchgear building.

The actual spend by period for Clay Street as compared to the current forecast and URB approved estimate is provided below along with the forecasted spend through the end of the project. During the third quarter of 2022, the Clay Street project transitioned to the Definitive level estimate, which resulted in the base estimate increasing from $30.8 million to $33.6 million. This $2.8 million increase was driven by:

- Electrical construction award higher than estimated ($0.8 million);
- Higher revised Division estimate ($0.7 million);
- Project schedule recovery ($0.6 million);

- Higher A/E procured equipment award ($0.4 million);
- Addition of Human-Machine Interface (HMI) to the switchgear PO ($0.2 million); and
- Addition of a contingency capacitor bank ($0.1 million).

Regarding the "project schedule recovery" item listed above, this was comprised primarily in additional construction contractor costs (approximately $475K), with the remainder related to civil and electrical supervision costs. These efforts recovered three months in the project schedule from the six-month delay encountered.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals						***Forecast***	
$116,409	$879,339	$2,806,593	$5,044,642	$1,936,258	$2,238,630	$8,640,123	$11,987,934

Estimate & Forecast		Actuals to Date	% of Actuals to Estimate & Forecast
Estimate	$33,600,000	$13,021,870	39%
Forecast	$33,613,927		39%

3. Front Street

During the third quarter of 2022, $5,887,539 was spent on the Front Street project compared to a forecast of approximately $5.4 million, which brought total spend to approximately $9.6 million. The higher than forecasted spend during the third quarter of 2022 was attributed to higher than forecasted overhead labor involved with bringing the six circuits from OP to IP.

The forecasted in-service date for the Front Street project as of the end of the third quarter of 2022 slipped 62 days from the status as of the end of the prior quarter to January 9, 2024. This change in the forecasted in-service date was the result of delays to the Powercon switchgear delivery from May 2023 to August 2023, which pushed the project's critical path out.

The primary activities on the Front Street project during the third quarter of 2022 included:

- Contingency switchgear delivered;
- Civil and electrical drawings issued for construction (IFC); and,
- Commencement of electrical construction (for the contingency switchgear).

The actual spend by period for Front Street as compared to the current forecast and URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals						***Forecast***	
$-	$-	$2,351,832	$429,607	$889,533	$5,887,539	$2,385,947	$15,556,375

Estimate & Forecast		Actuals to Date	% of Actuals to Estimate & Forecast
Estimate	$25,900,000	$9,558,510	37%
Forecast	$27,500,832		35%

4. Hasbrouck Heights

During the third quarter of 2022, $1,958,570 was spent on the Hasbrouck Heights project compared to a forecast of approximately $2.2 million, which brought the total spend to approximately $13.9 million. The forecasted in-service date for the Hasbrouck Heights project as of the end of the third quarter of 2022 advanced 35 days from the status as of the end of the prior quarter to November 18, 2022. This advancement in the forecasted in-service date was driven by electrical construction and relay work progressing faster than expected.

Notable activities completed on the Hasbrouck Heights project during the third quarter of 2022 included:

- Switchgear set on the foundation;
- Civil construction completed;
- Commencement of switchgear commissioning;
- Delivery of regulator/reactors (partial).

The actual spend by period for Hasbrouck Heights as compared to the current forecast and URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals						*Forecast*	
$149,848	$1,129,934	$4,176,249	$4,323,599	$2,187,907	$1,958,570	$1,912,016	$3,235,656

Estimate & Forecast		Actuals to Date	% of Actuals to Estimate & Forecast
Estimate	$19,300,000	$13,926,106	72%
Forecast	$19,073,778		73%

5. Kingsland

During the third quarter of 2022, $554,703 was spent on the Kingsland project compared to a forecast of approximately $1.0 million, which brought the total spend to approximately $2.2 million. The variance in forecasted to actual spend during the third quarter of 2022 was attributed to less electrical work performed than planned in September due to delays on outstanding requests for information.

The forecasted in-service date for the Kingsland project as of the end of the third quarter of 2022 slipped 35 days from the status as of the prior quarter to November 6, 2023. This slip to the forecasted in-service date was driven by resource availability constraints within the Division and intricacies in sequencing the cutovers of the circuits.

The primary activities on the Kingsland project during the third quarter of 2022 included:

- Electrical PO issued;
- Construction permits received;
- Pre-construction licenses and permit review meeting held; and,
- Commencement of civil construction.

The actual spend by period for Kingsland as compared to the current forecast and URB approved estimate is provided below along with the forecasted spend through the end of the project. During the third quarter of 2022, the Kingsland project transitioned to the Conceptual estimate level, which resulted in the base estimate increasing from $6.4 million to $8.7 million. This $2.3 million increase was driven by:

- Unforeseen contaminated soil ($0.9 million);
- Final civil design required additional piles ($0.6 million);
- Contingency plan required for station reliability during outages ($0.6 million);
- Extended project duration: shift from Q2 2023 to Q4 2023 in-service ($0.4 million); and,
- Lower licensing and permitting needs: (-$0.2 million).

Regarding the extended project duration noted above, this was calculated based on additional carrying costs for 2023 ($25k/month) and an additional five months in 2024 for post in-service closeout ($20k/month). These carrying costs cover typical project management activities and resources (e.g. project manager, staff engineer, cost engineer, scheduler, etc.).

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals						*Forecast*	
$104,112	$209,667	$510,943	$301,463	$538,906	$554,703	$1,924,615	$4,848,885

Estimate & Forecast		Actuals to Date	% of Actuals to Estimate & Forecast
Estimate	$8,700,000	$2,219,794	26%
Forecast	$8,993,293		25%

6. Lakeside Avenue

During the third quarter of 2022, $1,536,403 was spent on the Lakeside Avenue project compared to a forecast of approximately $1.4 million. The forecasted in-service date for the Lakeside Avenue project as of the end of the third quarter of 2022 slipped 163 days from the status as of the end of the prior quarter to February 28, 2024, which was the result of a delay to the anticipated switchgear delivery from April 2023 to July 2023.

Notable activities completed on the Lakeside Avenue project during the third quarter of 2022 included:

- Electrical PO issued;
- Pre-construction licenses and permits review meeting held; and,
- Commencement of civil construction, beginning with manhole and duct bank installations.

The actual spend by period for Lakeside Avenue as compared to the current forecast and URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals						*Forecast*	
$148,943	$453,994	$570,713	$351,720	$230,836	$1,536,403	$2,101,547	$27,312,018

Estimate & Forecast		Actuals to Date	% of Actuals to Estimate & Forecast
Estimate	$39,400,000	$3,292,610	8%
Forecast	$32,706,175		10%

7. Leonia

During the third quarter of 2022, $1,356,322 was spent on the Leonia project compared to a forecast of approximately $1.3 million, which brought the total spend to approximately $22.3 million. The forecasted in-service date for the Leonia project as of the end of the third quarter of 2022 advanced 27 days from the status at the end of the prior quarter to November 16, 2022.

Notable activities completed on the Leonia project during the third quarter of 2022 included:

- Continued installation of the new switchgear #2, including installation of the firewall, pulling cable, and manhole/conduit work; and,
- Commencement of commissioning the new switchgear #2.

The actual spend by period for Leonia as compared to the current forecast and URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals						*Forecast*	
$44,792	$6,033,379	$9,112,257	$1,789,112	$3,968,355	$1,356,322	$1,591,776	$1,784,499

Estimate & Forecast		Actuals to Date	% of Actuals to Estimate & Forecast
Estimate	$24,900,000	$22,304,217	90%
Forecast	$25,680,491		87%

8. Market Street

During the third quarter of 2022, $117,836 was spent on the Market Street project compared to a forecast of approximately $203,000, which brought the total spend to approximately $28.1 million. The Market Street substation was taken out of service as of June 25, 2021.

The final punch list items and site cleanup activities were completed at the end of the second quarter of 2022, remaining costs including those incurred during the third quarter of 2022 relate to final and trailing costs related to this closeout work.

The actual spend by period for Market Street as compared to the current forecast and URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals						*Forecast*	
$251,193	$16,079,601	$10,681,487	$808,096	$202,619	$117,836	$121.852	$46,000

Estimate & Forecast		Actuals to Date	% of Actuals to Estimate & Forecast
Estimate	$29,100,000	$28,140,832	97%
Forecast	$28,308,684		99%

9. Meadow Road

During the third quarter of 2022, $382,461 was spent on the Meadow Road project compared to a forecast of $335,000, which brought the total spend to approximately $2.0 million. The forecasted in-service date for the Meadow Road project as of the end of the third quarter of 2022 slipped six days from the status as of the end of the prior quarter to September 28, 2023.

The primary activities conducted on the Meadow Road project during the third quarter of 2022 included:

- Civil and electrical POs issued;
- Pre-construction licenses and permits compliance meeting held; and
- Commencement of civil construction, beginning with manhole work and the foundations for the switchgear.

The actual spend by period for Meadow Road as compared to the current forecast and URB approved estimate is provided below along with the forecasted spend through the end of the project. During the third quarter of 2022, the Meadow Road project transitioned to the Conceptual level estimate, which resulted in the base estimate increasing from $7.2 million to $8.3 million. This $1.1 million estimate increase was driven by:

- Higher carrying costs based on current staffing plan and surcharge rates ($0.7 million);
- Increased engineering due to revisions associated with the New Jersey Department of Environmental Protection (NJDEP) permit application ($0.6 million);
- Revised estimate for testing and commissioning ($0.3 million); and,
- Lower Division estimate: (-$0.5 million).

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals						*Forecast*	
$63,128	$535,081	$445,234	$288,050	$321,098	$382,461	$1,860,889	$4,510,060

Estimate & Forecast		Actuals to Date	% of Actuals to Estimate & Forecast
Estimate	$8,300,000	$2,035,052	25%
Forecast	$8,406,000		24%

10. Orange Valley

During the third quarter of 2022, $1.0 million was spent on the Orange Valley project compared to a forecast of approximately $787,000, which brought the total spend to approximately $2.2 million. The variance in forecasted to actual spend in the third quarter of 2022 was primarily attributed to manhole installation and related environmental efforts for soil disposal being performed earlier than planned.

The forecasted in-service date for the Orange Valley project as of the end of the third quarter of 2022 slipped 35 days from the status as of the end of the prior quarter to February 2, 2024. This slip in the forecasted in-service date was driven by delays on the expected delivery of the switchgear from Powercon (as shown in **Table 10**).

During the third quarter of 2022, major activities on the Orange Valley project included:

- Civil and electrical construction POs issued;

- Municipal and railroad licenses and permits received; and,
- Commencement of civil construction, beginning with manhole and duct bank work.

The actual spend by period for Orange Valley as compared to the current forecast and URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals						*Forecast*	
$77,029	$362,895	$358,052	$111,565	$276,614	$1,041,753	$627,797	$12,047,584

Estimate & Forecast		Actuals to Date	% of Actuals to Estimate & Forecast
Estimate	$14,700,000	$2,227,908	15%
Forecast	$14,903,289		15%

11. *Ridgefield 13kV*

During the third quarter of 2022, $3,567,625 was spent on the Ridgefield 13kV project compared to a forecast of approximately $3.6 million, which brought the total spend to approximately $25.5 million. The forecasted in-service date for the Ridgefield 13kV project as of the end of the third quarter of 2022 advanced five days from status as of the end of the prior quarter to December 8, 2022.

Notable activities performed on the Ridgefield 13kV project during the third quarter of 2022 included:

- Continued civil construction of the new switchgear #1, including installation of piles, foundations, and duct banks;
- Delivery of the new switchgear #1; and,
- Installation and commencement of commissioning of the new switchgear #1.

The actual spend by period for Ridgefield 13kV as compared to the current forecast and URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals						*Forecast*	
$205,982	$6,232,692	$10,849,681	$2,111,096	$2,557,679	$3,567,625	$1,810,079	$909,998

Estimate & Forecast		Actuals to Date	% of Actuals to Estimate & Forecast
Estimate	$26,100,000	$25,524,756	98%
Forecast	$28,244,833		90%

12. *Ridgefield 4kV*

During the third quarter of 2022, there was no spend the Ridgefield, with the total spend remaining at approximately $20.7 million. The project was placed in-service on May 16, 2021.

The project was closed out during the third quarter of 2022 after the final closeout activities were performed during the first quarter of 2022, which included some trailing costs in the second quarter of 2022.

The actual spend by period for Ridgefield 4kV as compared to the final forecast and URB approved estimate is provided below.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals						***Forecast***	
$143,414	$11,239,534	$9,263,852	$42,604	$14,405	-	-	-

Estimate & Forecast		**Actuals to Date**	**% of Actuals to Estimate & Forecast**
Estimate	$20,700,000	$20,703,808	100%
Forecast	$20,703,808		100%

13. State Street

During the third quarter of 2022, $978,273 was spent on the State Street project compared to a forecast of approximately $815,000, which brought the total spend to approximately $11.6 million. The forecasted in-service date for the State Street project as of the end of the third quarter of 2022 advanced three days from the status of as of the end of the prior quarter to December 16, 2022.

Notable activities performed on the State Street project during the third quarter of 2022 included:

- Setting the new 4kV switchgear;
- Installation of bus supports and busses from the 4kV switchgear to the transformers;
- Installation of the grounding grid and regulators; and,
- Commencement of switchgear commissioning.

The actual spend by period for State Street as compared to the current forecast and URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals						***Forecast***	
$77,590	$662,148	$8,093,227	$751,849	$1,046,814	$978,273	$1,672,283	$6,555,719

Estimate & Forecast		**Actuals to Date**	**% of Actuals to Estimate & Forecast**
Estimate	$19,600,000	$11,609,902	59%
Forecast	$19,837,904		59%

14. Toney's Brook

During the third quarter of 2022, $740,393 was spent on the Toney's Brook project compared to a forecast of approximately $973,000, which brought the total spend to approximately $3.0 million. The variance in forecasted to actual spend during the third quarter of 2022 was primarily attributed to adverse weather in September that impacted the foundation work, which in turn led to delays in the duct bank work that had been planned for the month.

The forecasted in-service date for the Toney's Brook project as of the end of the third quarter of 2022 slipped 39 days from the status as of the end of the prior quarter to May 26, 2023. The slip in the forecasted in-service date was driven by delays on the Powercon switchgear delivery (note the switchgear delivery was originally planned for early November 2022, but as of the first quarter of 2022 that had slipped to late December 2022). Delays on this switchgear were driven by unavailability of the cell kits from Powercon's supplier Eaton. PSE&G worked with its vendors to re-assign the cell kit ready for the Woodlynne switchgear to the Toney's Brook switchgear to partly mitigate this delay.

The notable activities on the Toney's Brook project during the third quarter of 2022 included:

- Pre-construction licenses and permits compliance review meeting held;
- Civil contractor mobilized and commenced work on the equipment foundations; and
- Continued engineering for the outside plant scope of work.

The actual spend by period for Toney's Brook as compared to the current forecast and URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals						*Forecast*	
$211,940	$373,096	$941,519	$138,270	$629,773	$740,393	$4,038,501	$9,177,022

Estimate & Forecast		Actuals to Date	% of Actuals to Estimate & Forecast
Estimate	$16,200,000	$3,034,991	19%
Forecast	$16,250,514		19%

15. Waverly

During the third quarter of 2022, $8,248,435 was spent on the Waverly project compared to a forecast of approximately $8.3 million, which brought the total spend to approximately $17.2 million.

The forecasted in-service date for the Waverly project as of the end of the third quarter of 2022 slipped 63 days from the status as of the end of the prior quarter to April 30, 2024. This slip was due to manhole modifications required before the energization of the 26kV switchgear can occur and the need for Y-buses prior to the 26kV circuit cutovers to support reliability requirements and increasing the overall duration of the cutovers.

The primary activities performed during the third quarter of 2022 included:

- 4kV switchgear building delivered;
- Commissioning of the 26kV switchgear; and,
- Manhole re-design, installation, and repairs.

The actual spend by period for Waverly as compared to the current forecast and URB approved estimate is provided below along with the forecasted spend through the end of the project. During the third quarter of 2022, the Waverly project transitioned to the Conceptual level estimate, which resulted in the Base estimate increasing from $36.2 million to $39.9 million. This $3.7 million increase was driven by:

- Higher than estimated civil construction award ($2.2 million);

- Higher revised estimate for installation of 4kV equipment due to increased market price/labor rates ($0.9 million);
- Change in surcharge methodology ($0.4 million); and,
- Additional storage and handling of the 26kV and 4kV switchgears in warehouse due to site plan revision/delay ($0.2 million).

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals						*Forecast*	
$103,748	$2,460,815	$4,415,223	$432,853	$1,536,375	$8,248,435	$2,930,673	$20,610,443

Estimate & Forecast		Actuals to Date	% of Actuals to Estimate & Forecast
Estimate	$39,900,000	$17,197,448	43%
Forecast	$40,738,565		42%

16. Woodlynne

During the third quarter of 2022, $903,898 was spent on the Woodlynne project compared to a forecast of approximately $826,000, which brought the total spend to approximately $6.0 million. The forecasted in-service date for the Woodlynne project as of the end of the third quarter of 2022 remains unchanged from the status as of the end of the prior quarter at October 10, 2023.

The primary activities performed on the Woodlynne project during the third quarter of 2022 included:

- Continued advancement of the duct bank installations that commenced in the February 2022; and,
- Commencement of manhole installations.

The actual spend by period for Woodlynne as compared to the current forecast and URB approved estimate is provided below along with the forecasted spend through the end of the project. During the third quarter of 2022, the Woodlynne project transitioned to the Definitive level estimate, which resulted in the base estimate increasing from $21.3 million to $24.0 million. This $2.7 million increase was driven by:

- Higher Division estimate ($2.1 million); and,
- Higher revised testing and commissioning estimate ($0.6 million).

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals						*Forecast*	
$110,982	$993,298	$991,630	$1,639,443	$1,347,345	$903,898	$2,159,991	$15,817,908

Estimate & Forecast		Actuals to Date	% of Actuals to Estimate & Forecast
Estimate	$24,000,000	$5,986,597	25%
Forecast	$23,964,496		25%

B. Contingency Reconfiguration

During the third quarter of 2022, the main efforts in the Contingency Reconfiguration subprogram continue to focus on the installation of additional Fuse Savers, following the completion of the recloser scope in the first quarter of 2022. **Table 13 – ES 2 Program Fuse Saver Status as of September 30, 2022** provides a summary of the Fuse Saver scope of the Contingency Reconfiguration subprogram, indicating the number of units completed during the third quarter of 2022 and for the total program, showing the status of engineering, installation, and commissioning out of a total scope of 1,574 units, which represents a reduction of 67 units in the Fuse Savers scope. The target installations are assessed on a quarterly basis by PSE&G based on the actual costs per unit observed to date.

Table 13 – ES 2 Program Fuse Saver Status as of September 30, 2022

Type	Engineering Packages Completed (1 Fuse Saver ea.)	Fuse Savers Installed	Fuse Savers Commissioned
Q3 Qty.	283	286	285
Program Total to Date	700	412	410
Remaining	874	1,162	1,164

The installation of Fuse Savers recommenced in May 2022, following the earlier installations performed as part of the Fuse Saver pilot program in 2020-2021. As shown in **Table 13**, installations in the third quarter of 2022 ramped up significantly from the prior quarter (which was limited to 13 devices installed due to a hold placed on installations during the second quarter). This followed PSE&G's plans to add more installations than initially planned in the second half of 2022, and as previously discussed there is no significant cost impact expected from this shift in installations. PSE&G establishes installation targets on a quarterly basis, which are then split into monthly targets for each Division with the forecasts updated on a bi-weekly basis.

The current forecasted completion date for the primary components that make up the Contingency Reconfiguration subprogram are provided in **Table 14 – ES 2 Contingency Reconfiguration Forecasted Completion Dates as of September 30, 2022**. This table also shows the forecasted final in-service dates as of the end of the second quarter of 2022 to show movement to the forecast as of the end of the third quarter of 2022.

Table 14 – ES 2 Contingency Reconfiguration Forecasted Completion Dates as of September 30, 2022

Scope & Division		Q2 2022 Forecasted Completion Date	Q3 2022 Forecasted Completion Date
Reclosers	Central	1/31/2022 (Actual)	1/31/2022 (Actual)
	Metro	12/31/2021 (Actual)	12/31/2021 (Actual)
	Palisades	1/31/2022 (Actual)	1/31/2022 (Actual)
	Southern	1/31/2022 (Actual)	1/31/2022 (Actual)
Fuse Savers	Central	12/30/2023	12/30/2023
	Metro	12/30/2023	12/30/2023
	Palisades	12/30/2023	12/30/2023
	Southern	12/30/2023	12/30/2023

As shown in **Table 14**, the forecasted in-service dates for the Fuse Saver scope of each Division continues to be the end of 2023.

The Contingency Reconfiguration subprogram costs through the end of the third quarter of 2022 are presented in **Table 15 – ES 2 Contingency Reconfiguration Actual Costs as of September 30, 2022**.

Table 15 – Contingency Reconfiguration Actual Costs as of September 30, 2022

Scope & Division		2019	2020	2021	Q1 2022	Q2 2022	Q3 2022	Total to Date
		Actuals						
Reclosers	Central	$2,737,167	$12,050,820	$9,852,812	$880,537	$45,064	$46,364	$25,612,764
	Metro	$2,231,431	$10,726,610	$11,368,409	$150,325	($31,771)	($8,856)	$24,436,149
	Palisades	$2,515,569	$12,119,436	$8,280,522	($66,771)	$2,816	$500	$22,852,072
	Southern	$2,081,220	$12,405,684	$14,038,043	$530,051	$4,112	$1,476	$29,060,585
Fuse Savers	Central	$9,970	$789,937	$854,118	$249,268	$433,473	$2,097,168	$4,433,935
	Metro	$7,557	$561,915	$507,742	$160,801	$298,329	$1,889,794	$3,426,138
	Palisades	$7,468	$522,454	$577,113	$127,207	$656,533	$2,059,075	$3,949,850
	Southern	$9,792	$859,014	$578,217	$245,990	$714,570	$1,623,412	$4,030,996
Total		**$9,600,174**	**$50,035,871**	**$46,056,977**	**$2,277,408**	**$1,824,151**	**$7,708,933**	**$117,802,488**

Table 16 – Contingency Reconfiguration Forecasted Costs as of September 30, 2022 examines the forecast as of the end of the third quarter of 2022 for each Division's Fuse Saver scope compared to the total actual costs incurred through the end of the third quarter of 2022.

Table 16 – Contingency Reconfiguration Forecasted Costs as of September 30, 2022

Scope & Division		Total to Date	Forecast	Remaining Forecast	% of Actuals to Forecast
Reclosers	Central	$25,612,764	$25,612,764	-	100%
	Metro	$24,436,149	$24,436,149	-	100%
	Palisades	$22,852,072	$22,852,072	-	100%
	Southern	$29,060,585	$29,060,585	-	100%
Fuse Savers	Central	$4,433,935	$11,479,821	$7,045,886	39%
	Metro	$3,426,138	$12,879,102	$9,452,964	27%
	Palisades	$3,949,850	$9,958,265	$6,008,415	40%
	Southern	$4,030,996	$11,337,080	$7,306,084	36%
Total		**$110,093,555**	**$147,615,838**	**$29,813,350**	**80%**

As shown in **Table 15**, the overall Contingency Reconfiguration subprogram has spent 80% of its current forecast. With the total forecast as of the end of the third quarter of 2022 increasing $2.0 million from the status as of the end of the prior quarter, driven by increases to the Central Division Fuse Saver scope (increasing approximately $950,000) and the Metro Division Fuse Saver scope (increasing approximately $1.2 million), slightly offset by a forecast decrease to the Southern Division Fuse Saver scope (decreasing approximately $358,000). These forecast variances reflected the trends observed in the actual cost per unit data, which has seen recent increases in testing and installation labor costs as the work has transitioned from more simple installations to more difficult locations including pole replacements at certain locations.

<u>Findings & Observations</u>:

- Progress on the Fuse Savers scope of the subprogram continued to ramp-up following the with 286 devices installed during the third quarter of 2022. This brough the total number of Fuse Savers installed during the Program to 412 out of a current scope of 1,574 units.

- There was no change to the forecasted completion date of the Fuse Saver scope from the prior quarter, with each Division continuing to forecast the final units being installed in December

2023. Based on the current scope, this averages out to approximately 77 units per month (for comparison in the third quarter of 2022, PSE&G averaged 95 units per month).

- The Contingency Reconfiguration subprogram forecast increased approximately $2.0 million during the third quarter of 2022 to $147.6 million, which reflected higher observed costs per unit on the Fuse Savers testing and installation labor. This is above the Stipulation budget of $145.0 million.

C. Grid Modernization – Communication System

The Stipulation identified the Grid Modernization – Communication System subprogram to include up to $72 million invested in installing a private wireless communications network to eliminate the use of dedicated phone lines for remote communication for both PSE&G and customer equipment. The overall network will provide coverage using both wireless and fiber technologies to all switching devices on the PSE&G system. The primary scopes within the Grid Modernization – Communication System include installation of the wireless network, fiber installations at selected stations, fiber cutovers at selected station with existing fiber to the PSE&G fiber network, and retrofitting existing reclosers and RTUs with updated routers. A summary of the status of these primary scopes of work as of the end of the third quarter of 2022 is as follows:

- Wireless network: placed in-service as of December 16, 2021; remaining work involves providing radios to support the installation of Fuse Savers in the Contingency Reconfiguration subprogram.
- Fiber installations and cutovers: 29 out of 34 fiber installation projects completed and 12 out of 12 fiber cutover projects completed.
- Retrofitting existing reclosers: completed as of the fourth quarter of 2021 with a total of 2,318 retrofit reclosers installed.
- Retrofitting RTUs: 218 substation retrofits completed (48 during the third quarter of 2022) out of a total scope of 218 substations.

As previously reported, the fiber scope includes installing fiber to electric substations and electric operations centers, in addition to cutting over stations with existing fiber service to the PSE&G fiber network. PSE&G preliminarily identified 41 installation projects and 12 cutovers for the subprogram, with three of 41 installation projects were previously removed due to the scheduled elimination of the targeted substations or the intended redundancy benefits not achievable after site review. During the second quarter of 2022, PSE&G assessed the remaining budget for the fiber scope and determined it would remove four additional projects from the planned list due to budgetary constraints (in addition to one of the removed stations, Waverly, having the IP fiber installation included as part of the Electric Station Flood Mitigation project at the substation). The list of currently approved fiber installation and cutover projects is presented in **Table 17 – Fiber Projects by Division as of September 30, 2022**.

Table 17 – Fiber Projects by Division as of September 30, 2022

Division	Fiber Installation*	Fiber Cutover*
Central	Cranford; Elizabeth Sub HQ; Rahway; Hadley Road HQ; Roselle; Central HQ; Carteret; Edison; Keasby; Mechanic Street; First Street	Elizabeth; Henry Street

Metro	East Orange; Metro HQ; Bloomfield; Central Avenue; Haldeon; Irvington; Irvington Sub HQ; Montclair; South Orange; Norfolk Street	-
Palisades	Bergen Point; Hackensack Sub HQ; Fort Lee; Harrison; Ridgewood; West New York; Palisades HQ; Culver Avenue; Morgan Street	Tonnelle Avenue; Spring Valley Road; Union City; Fairview; Polk Street; West Orange
Southern	Southern HQ; Princeton; Chauncey Street; Bordentown	Delair; East Riverton; Riverside; Mount Holly
Total	***34 projects***	***12 projects***
**-Projects underlined have been placed in-service.*		

During the third quarter of 2022 two additional fiber installation projects (Montclair, Palisades HQ) and the final fiber cutover project (West Orange) were placed in-service. Thus, the total fiber projects in-service as of the end of the third quarter of 2022 was 29 for the fiber installation projects and 12 for the fiber cutover projects. **Table 18 – ES 2 Program Fiber Projects Status as of September 30, 2022** provides a summary of the status of the fiber installation and cutover projects within the subprogram as of the end of the third quarter of 2022 with the projects in italics representing those placed in-service.

Table 18 – ES 2 Program Fiber Projects Status as of September 30, 2022

Project Name	Q3 2022 Status
Fiber Installation Projects	
Bergen Point	*In-Service (Q1 2021)*
Bloomfield	Township permit received; OP engineering complete; OP construction complete; IP power installation started
Bordentown	*In-Service (Q3 2021)*
Carteret	Railroad permit secured; Division scheduled overhead work for Q4
Central Ave	*In-Service (Q3 2021)*
Central HQ	*In-Service (Q1 2022)*
Chauncey Street	*In-Service (Q3 2021)*
Cranford	*In-Service (Q4 2020)*
Culver Ave	*In-Service (Q1 2022)*
East Orange	*In-Service (Q1 2021)*
Edison	Conduit work complete; OP run completion dependent on railroad permits
Elizabeth Sub HQ	*In-Service (Q1 2021)*
First Street	*In-Service (Q3 2021)*
Fort Lee	*In-Service (Q1 2022)*
Hackensack Sub HQ	*In-Service (Q4 2020)*
Hadley Rd HQ	*In-Service (Q1 2022)*
Haledon	*In-Service (Q1 2022)*
Harrison	*In-Service (Q3 2021)*
Irvington	*In-Service (Q4 2021)*
Irvington Sub HQ	*In-Service (Q4 2021)*
Keasbey	OP work complete; TFI rack installed
Mechanic Street	OP railroad crossing work complete; TFI rack installed
Metro HQ	*In-Service (Q1 2021)*
Montclair	*In-Service (Q3 2022)*
Morgan Street	*In-Service (Q4 2021)*
Norfolk St	*In-Service (Q3 2021)*
Palisades HQ	*In-Service (Q3 2022)*
Princeton	*In-Service (Q3 2021)*
Rahway	*In-Service (Q1 2021)*

Project Name	Q3 2022 Status
Ridgewood	*In-Service (Q1 2022)*
Roselle	*In-Service (Q2 2021)*
So Orange	*In-Service (Q3 2021)*
Southern HQ	*In-Service (Q4 2020)*
West New York	*In-Service (Q1 2022)*
Fiber Cutover Projects	
Delair	*In-Service (Q4 2020)*
East Riverton	*In-Service (Q4 2020)*
Elizabeth	*In-Service (Q1 2021)*
Fairview	*In-Service (Q1 2022)*
Henry St	*In-Service (Q3 2021)*
Mount Holly	*In-Service (Q4 2020)*
Polk Street	*In-Service (Q1 2022)*
Riverside	*In-Service (Q4 2020)*
Spring Valley Rd	*In-Service (Q1 2021)*
Tonnelle Ave	*In-Service (Q4 2020)*
Union City	*In-Service (Q1 2021)*
West Orange	*In-Service (Q3 2022)*
Substation Remote Terminal Unit (RTU) Cutovers	
Scope: 218 units	218 cutovers completed

The Grid Modernization – Communication System subprogram costs by major period through the end of the third quarter of 2022 are presented in **Table 19 – ES 2 Grid Modernization – Communication System Actual Costs as of September 30, 2022**, while **Table 20 – ES 2 Grid Modernization – Communication System Forecasts as of September 30, 2022** provides the current forecasts as of the end of the second quarter of 2022 compared to the actual costs.

Table 19 – ES 2 Grid Modernization – Communication System Actual Costs as of September 30, 2022

Scope & Division		2019	2020	2021	Q1 2022	Q2 2022	Q3 2022	Total to Date
		Actuals						
Retrofit Reclosers	Central	$0	$884,278	$3,304,797	$215,275	$186,505	$359,309	$4,950,163
	Metro	$0	$818,620	$2,362,797	$135,374	$192,271	$315,543	$3,824,588
	Palisades	$0	$825,174	$3,115,474	$186,059	$184,718	$349,531	$4,660,956
	Southern	$0	$929,058	$3,862,816	$194,826	$193,249	$292,884	$5,472,833
Fiber	Central	$1,691	$2,418,851	$5,973,655	$1,581,263	$681,857	$446,818	$11,104,134
	Metro	$1,457	$1,866,697	$3,086,096	$1,576,328	$347,002	$245,110	$7,122,690
	Palisades	$1,582	$2,046,762	$3,603,134	$656,307	$93,875	$213,474	$6,615,134
	Southern	$4,731	$910,483	$2,466,477	$96,721	$33,229	$24,153	$3,535,794
	Cutovers*	$0	$876,502	$607,056	$851,293	$8,735	$462,707	$2,311,756
Wireless Network		$74,306	$6,035,441	$1,282,986	$61,558	$99,655	$39,482	$7,593,428
Bulk Purchase**		$0	$1,524,874	($520,766)	$641,029	$283,929	$642,690	$2,571,756
Total		**$83,767**	**$19,136,741**	**$29,144,503**	**$6,196,033**	**$3,225,559**	**$3,391,702**	**$61,178,303**

**-Includes fiber communication cutovers and substation RTU cutovers (the latter of which began having spend in Q1 2021).*
***-The Bulk Purchase account is used for the purchase of bulk equipment, which is the then assigned to a specific Division when the equipment is released with a credit back to the Bulk Purchase account. Thus, this account is forecasted to have a $0 balance at the end of the ES 2 Program.*

Table 20 – ES 2 Grid Modernization – Communication System Forecasts as of September 30, 2022

Scope & Division		Total to Date *Actuals*	Total Forecast	% of Actuals to Forecast
Retrofit Reclosers	Central	$4,950,163	$6,684,144	74%
	Metro	$3,824,588	$5,539,747	69%
	Palisades	$4,660,956	$6,373,177	73%
	Southern	$5,472,833	$7,258,179	75%
Fiber	Central	$11,104,134	$11,482,676	97%
	Metro	$7,122,690	$7,397,935	96%
	Palisades	$6,615,134	$6,680,329	99%
	Southern	$3,535,794	$3,458,757	102%
	Cutovers*	$1,415,071	$1,415,071	100%
Wireless Network		$7,593,428	$7,967,538	95%
Bulk Purchase**		$2,571,756	$0	-
Total		**$61,178,303**	**$66,564,461**	**92%**

As shown in **Table 19**, actual costs incurred in the third quarter of 2022 were close to the spend incurred in the second quarter of 2022 and continues to reflect the winding down of the fiber scope and the efforts on the retrofit recloser scope, which was completed during this quarter. The forecasts shown in **Table 20** remained relatively unchanged from the status as of the end of the second quarter of 2022, with an overall forecast increase of approximately $285,000 (or a 0.4% increase).

Findings & Observations:

- The retrofit substation RTU scope completed 48 substations in the third quarter of 2022, bringing the total to 218 substations completed, which also completes this scope of work ahead of forecast.
- The twelfth and final fiber cutover project was completed during the third quarter of 2022 as were two additional fiber projects, bringing the fiber project total to 29 out of 34 currently planned projects. As of the end of the third quarter of 2022, the fiber scope still is expected to be completed by the end of 2022.
- The forecast for the Grid Modernization – Communication system subprogram continued to remain relatively unchanged from the status as of the prior quarter, with an overall forecast increase of approximately $285K (or a 0.4% increase) to $66.6 million.

D. Grid Modernization – ADMS

The Grid Modernization – ADMS scope is split between three primary sections: DMS/DERMS, the OMS, and ADMS platform upgrades. The scope for each primary component of the Grid Modernization – ADMS subprogram and notable activities conducted during the third quarter of 2022 are presented as follows:

DMS/DERMS

- Scope: Provide software and associated services to deploy a Smart Network in order to meet a subset of the ES 2 Program's objectives and use cases.
- Q3 2022 Activities:
    - Completed loading updated model.

- Completed Sprint 21.
- Completed and reviewed Development Testing Plan.
- Completed review of module variance list.

- Forecasted Completion as of the end of the third quarter of 2022: 12/19/2022 (unchanged from the prior quarter).

OMS

- Scope: Provide a single user interface for more efficient management of trouble orders and analysis of outage data through an integrated OMS, system interfaces, and geographic view of all integrated outage data through an integrated OMS, system interfaces, and geographic view of all integrated outage data and damage locations. OMS will include tolls for dynamic visualization supporting incident management, damage location identification, dashboards, and the as-operated real-time view of PSE&G's network model. Field personnel also will have access to many of these tools as it relates to the incident(s) assigned to them via the Compass mobile crew application. 10 years' worth of existing OMS data will be migrated into the new system as well.

- Q3 2022 Activities:
  - Initial scope of conversion data completed, including 10 years of data.
  - Completed team onsite visit at Edison Training Center.
  - Approved interface end-to-end design by SAP and Mulesoft.
  - Completed PowerBI environment test report.
  - Validated and completed firewalls for QAS environments.
  - Completed initial QAS Compass integrations.
  - Completed QAS build/configuration.
  - Prepared for QAS system integration testing, plan/cases, approvals/prep, and staging.

- Forecasted Completion as of the end of the third quarter of 2022: 6/15/2023 (slipped 46 days from the prior quarter, driven by Platform availability to configure the system, which also contributed to the split from one production release to two production releases).

ADMS Platform

- Scope: Replace, enhance, and expand the existing Distribution Supervisory Control and Data acquisition (DSCADA) platform elements inclusive of infrastructure components (servers and workstations) and applications (Monarch, Spectra, and Integra) to create an integrated ADMS platform.

- Q3 2022 Activities:
  - Migrated remaining QAS to Edison Legacy Production.
  - Completed discussions for environment management alignment between OMS and Platform.

- Completed meeting with Geographic Information System (GIS) teams on testing plans for EMap and OSI Maestro.
- Completed decommissioning of legacy ADMS infrastructure at Edison.
- Completed operating system patching and forwarded to Open Systems International Inc. (OSI) for application patching.

- Actual In-Service Date: 1/28/2022.

The Grid Modernization – ADMS subprogram costs through the end of the third quarter of 2022 are presented in **Table 21 – ES 2 Grid Modernization – ADMS Costs as of September 30, 2022**.

Table 21 – ES 2 Grid Modernization – ADMS Costs as of September 30, 2022

Scope	Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
	Actuals						*Forecast*	
OMS	$33,891	$8,375,966	$7,140,445	$2,010,781	$6,360,390	$2,267,867	$5,344,016	$12,541,708
DMS/ DERMS	$1,498	$1,858,969	$1,185,863	$510,094	$676,889	$581,013	$1,145,585	$1,813,572
Platform	$824	$1,998,769	$1,411,403	$646,982	$934,541	$310,094	$208,468	$246,712
ADMS Hardware	-	$4,213,920	$116,732	$30,020	$259,042	$35,462	-	-
Total ADMS	**$36,213**	**$16,447,624**	**$9,854,442**	**$3,197,877**	**$8,230,861**	**$3,194,435**	**$6,698,069**	**$13,247,939**

Scope	Actuals to Date	Forecast	% of Actuals to Forecast
OMS	$26,189,340	$44,075,064	59%
DMS/DERMS	$4,814,325	$6,627,897	73%
Platform	$5,302,613	$5,549,325	96%
ADMS Hardware	$4,655,175	$4,655,175	100%
Total ADMS	**$40,961,453**	**$60,907,462**	**67%**

The cost forecast for the Grid Modernization – ADMS subprogram increased by approximately $7.4 million from the status as of the end of the prior quarter. This increase was driven by the schedule extension on the OMS scope and adjustments to the planned production releases, which changed from one original release planned for April 2023 to two releases planned for May and November 2023. This split was intended to allow all core/mission critical functionalities to be released in May 2023 ahead of the storm season moratorium, with the remaining enhancements included in the November 2023 release after the moratorium period.

Findings & Observations:

- The first of three primary ADMS components (the ADMS Platform) was placed in-service during the first quarter of 2022, with work in the third quarter of 2022 involving decommissioning of legacy ADMS infrastructure and operating system patching. The remaining DMS/DERMS and OMS scopes are currently be forecasted to be placed in-service in December 2022 and June 2023, respectively.

- During the third quarter of 2022, the subprogram forecast increased by approximately $7.4 million to $60.9 million. This increase was driven by an updated OMS schedule and was comprised of approximately $4.1 million related to PSE&G labor and $3.3 million for staff augmentation costs.

- At PSE&G's prompting, its software vendor added additional resources with more technical experience than previous deployments. This is expected to improve the performance of the group, particularly as more testing efforts continue.

E. Electric Stipulated Base

The Stipulation identified that the electric portion of the Stipulated Base include $100 million in investments at PSE&G's discretion towards electric OP-HDS and/or electric stations life cycle subprograms described in the original ES 2 filing.[1] In accordance with what the Stipulation provides, PSE&G plans to fund some of the life cycle station upgrades from the electric program accelerated investment, subject to funds available, after all Electric Station Flood Mitigation projects are funded at their final costs.

PSE&G commenced the OP-HDS in July 2022, but with the current forecasts for the life cycle station upgrade projects consuming the entire Stipulated Base funding ($100.6 million forecast compared to the $100.0 million Electric Stipulated Base budget), this work is presently being executed outside of the ES 2 Program. If the forecasts for the substation projects lower and additional funding becomes available, PSE&G may include some of the OP-HDS through the Program funding. The IM intends to continue to follow the status of this work, but will only report on it should PSE&G include these costs under the ES 2 Program.

As reported in the IM 2020 Second Quarter Report, the initial four stations PSE&G selected for life cycle station upgrades went before the URB in June 2020 for Study level estimate approval and received approval for full funding. In the second quarter of 2021 a fifth station, State Street, was approved by the URB for its outside plant scope to be transferred from the related Electric Station Flood Mitigation project to the life cycle scope. The five life cycle station upgrade projects and their current estimate compared to the actuals to date are provided in **Table 22 – ES 2 Life Cycle Station Upgrade Project Status as of September 30, 2022**.

Table 22 – ES 2 Life Cycle Station Upgrade Project Status as of September 30, 2022

Project	Estimate Level	Base	Risk & Contingency*	Total	Actuals to Date	% of Actuals to Estimate	Forecasted In-Service Date**
1. Hamilton	Definitive	$16,800,000	-	$16,800,000	$12,901,001	77%	10/24/2022 (↓ +19)
2. Paramus	Definitive	$21,400,000	-	$21,400,000	$16,857,336	79%	11/9/2022 (↓ +6)
3. Plainfield	Definitive	$22,600,000	-	$22,600,000	$17,051,905	76%	12/28/2022 (↓ +30)

[1] As noted in the Stipulation, the electric life cycle upgrades are part of the electric Stipulated Base to be recovered in the Company's next base rate case provided the investments are found to be prudent. The Stipulation also notes that should the 16 stations that comprise the Electric Station Flood Mitigation subprogram be completed for under the $389 million allocated for that subprogram, PSE&G may reallocate such unused funds to stations identified in the life cycle station upgrade portion of PSE&G's petition for accelerated recovery.

Project	Estimate Level	Base	Risk & Contingency*	Total	Actuals to Date	% of Actuals to Estimate	Forecasted In-Service Date**
4. Woodbury	Definitive	$18,100,000	-	$18,100,000	$10,570,960	58%	6/27/2023 (↓ +179)
5. State Street (OP)	Study	$19,700,000	-	$19,700,000	$1,691,533	9%	4/21/2023 (↓ +123)
-As discussed in the IM 2022 First Quarter Report, during the first quarter of 2022, PSE&G made the decision to hold risk and contingency at the subprogram level.* *-Reflects the in-service date of the last major asset (e.g. switchgear), certain activities may take place after this date to support the final in-service date (i.e. when all customers are cutover).* (↑)*-Indicates the forecasted in-service date advanced from the prior quarter.* (↓)*-Indicates the forecasted in-service date slipped from the prior quarter.*							

As shown in **Table 22**, all five life cycle station upgrade projects saw the forecasted in-service date slip from the status as of the end of the prior quarter. Overall, these shifts in forecasted in-service dates were relatively minor in two of the five substations, driven by actual project conditions. On Plainfield and Woodbury, the forecasted in-service date slip was the result of updated delivery switchgear delivery timelines provided by the vendor, while on State Street (OP) the in-service date slip was the result of a change in the manhole and conduit design due to an existing obstruction that will result in the manhole and conduit system not being energized until the second circuit is cutover (rather than with the first circuit as had originally been the plan). Additional details on each of these life cycle station upgrade projects is provided in the individual subsections that follow.

Similar to the Electric Station Flood Mitigation subprogram, the life cycle station upgrade projects within the Electric Stipulated Base experienced some delays to the forecasted delivery dates of the major equipment. The status of the major equipment deliveries for the Electric Stipulated Base projects is presented in **Table 23 – Electric Station Flood Mitigation Major Switchgear Deliveries as of September 30, 2022**.

Table 23 – Electric Station Flood Mitigation Switchgear Deliveries as of September 30, 2022

Station	Description	Delivery Status as of Q2 2022	Delivery Status as of Q3 2022
1. Hamilton	4kV switchgear	***4/5/2022***	***4/5/2022***
2. Paramus	4kV switchgear	***5/31/2022***	***5/31/2022***
	4kV cont. switchgear	***7/8/2021***	***7/8/2021***
3. Plainfield	4kV switchgear	8/26/2022	***9/15/2022***
4. Woodbury	4kV switchgear	7/20/2022	***9/21/2022***
Note: bold/italicized dates indicate actual delivery dates.			

As shown in **Table 23**, the major equipment deliveries for Plainfield and Woodbury were both completed in the third quarter of 2022, although both still experienced some slippage from the status at the end of the prior quarter that impacted the forecasted in-service dates for both projects.

<u>Findings & Observations</u>:

- Construction continued on the Hamilton, Paramus, Plainfield, and Woodbury projects, while engineering continued to advance on the State Street OP project (which continues to be expected to commence construction in the fourth quarter of 2022).

- The forecasted in-service dates for the five life cycle station upgrade projects as of the end of the third quarter of 2022 shows three of the five projects expected to go in-service before the end of 2022 (Hamilton, Paramus, and Plainfield). The forecasted in-service date for Woodbury shifted from December 2022 to June 2023 due to switchgear delivery delays (which also impacted the Plainfield project, but to a lesser degree), while the State Street OP forecasted in-service date shifted from December 2022 to April 2023 due to manhole and conduit redesigns, which resulted in the energization of the manhole and conduit system being tied to the second circuit cutover rather than the first circuit cutover (which is planned for December 2022).
- The cost forecasts for the five life cycle upgrade projects collectively increased by approximately $1.5 million (or 1.5%) from the status as of the end of the prior quarter to a total forecast of $100.6 million as of the end of the third quarter of 2022. This increase was largely attributed to minor cost impacts across the projects stemming from actual conditions (e.g. Hamilton and Paramus both had $0.2 million increases attributed to more Relay tech hours than forecasted, Plainfield had a $0.2 increase due to unforeseen underground obstructions, etc.).

1. Hamilton

During the third quarter of 2022, $2,537,609 was spent on the Hamilton project against a forecast of approximately $2.4 million. This brought total spend on the project to approximately $12.9 million through the end of the third quarter of 2022. The forecasted in-service date for the Hamilton project slipped 19 days from the status as of the end of the prior quarter to October 24, 2022.

Notable activities performed on the Hamilton during the third quarter of 2022 included:

- Installation of new OP duct banks and manholes;
- Continued electrical construction, including cable pulls and terminations; and,
- Completion of the Switchgear commissioning.

The actual spend by quarter for Hamilton as compared to the current forecast and URB approved estimate is provided below.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals						*Forecast*	
$0	$362,372	$3,141,022	$3,770,758	$3,089,239	$2,537,609	$1,644,117	$2,930,830

Estimate & Forecast		Actuals to Date	% of Actuals to Estimate & Forecast
Estimate	$16,800,000	$12,901,001	77%
Forecast	$17,475,949		74%

2. Paramus

During the third quarter of 2022, $2,053,294 was spent on the Paramus project against a forecast of approximately $2.1 million. This brought total spend on the project to approximately $16.9 million through the end of the third quarter of 2022. The forecasted in-service date for the Paramus project slipped six days from the status as of the end of the prior quarter to November 9, 2022.

Notable activities conducted during the third quarter of 2022 on the Paramus project included:

- Continued setting up/assembly of the new 4kV switchgear;
- Continued cable pulls to the new 4kV switchgear;
- Assembly of the new 4kV regulators;
- Commencement of switchgear commissioning; and,
- Start of 4kV bus support installation.

The actual spend by quarter for Paramus as compared to the current forecast and URB approved estimate is provided below.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals						*Forecast*	
$0	$840,200	$7,068,765	$952,513	$5,942,564	$2,053,294	$1,332,615	$3,589,704

Estimate & Forecast		Actuals to Date	% of Actuals to Estimate & Forecast
Estimate	$21,400,000	$16,857,336	79%
Forecast	$21,779,654		77%

3. Plainfield

During the third quarter of 2022, $8,420,160 was spent on the Plainfield project against a forecast of approximately $6.9 million. This brought total spend on the project to approximately $17.1 million through the end of the third quarter of 2022. The variance in forecasted to actual spend in the third quarter of 2022 was largely attributed to the invoice for the switchgear being processed earlier than anticipated (last day of the month, which had not been communicated to the cost engineer in advance).

The forecasted in-service date for the Plainfield project as of slipped 30 days from the status as of the prior quarter to December 28, 2022. This slip in the forecasted in-service date was driven by delays associated with the delivery of the switchgear (which slipped from late July 2022 to mid-September 2022).

Notable activities conducted on the Plainfield project during the third quarter of 2022 included:

- Installation of the switchgear platform;
- Commencement of electrical construction, including cable pulls and installing regulators;
- Delivery of the switchgear/setting the switchgear on foundations; and,
- Commencement of switchgear commissioning.

The actual spend by quarter for Plainfield as compared to the current forecast and URB approved estimate is provided below.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals						*Forecast*	
$0	$682,325	$3,584,101	$1,682,480	$2,682,840	$8,420,160	$2,403,443	$3,759,251

Estimate & Forecast		Actuals to Date	% of Actuals to Estimate & Forecast
Estimate	$22,600,000	$17,051,906	76%
Forecast	$23,214,599		73%

4. Woodbury

During the third quarter of 2022, $5,168,609 was spent on the Woodbury project against a forecast of approximately $7.0 million. This brought the total spend on the project to approximately $10.6 million through the end of the third quarter 2022. The variance in forecasted to actual spend in the third quarter of 2022 was largely attributed to the switchgear delivery shifting out to September 2022 (with the delivery shift occurring after the forecast was locked).

The forecasted in-service date for the Woodbury project slipped 179 days from the status as of the end of the prior quarter to June 27, 2023. The in-service date shift was driven by delays to the switchgear and feeder rows deliveries and an expanded duration for commissioning.

Notable activities conducted on the Woodbury project during the third quarter of 2022 included:

- Start of electrical construction; and,
- Switchgear delivered and set on foundation;

The actual spend by quarter for Woodbury as compared to the current forecast and URB approved estimate is provided below.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals						*Forecast*	
$0	$551,165	$1,613,823	$1,460,525	$1,776,838	$5,168,609	$1,875,626	$5,653,414

Estimate & Forecast		Actuals to Date	% of Actuals to Estimate & Forecast
Estimate	$18,100,000	$10,570,960	58%
Forecast	$18,100,000		58%

5. State Street (Outside Plant)

During the third quarter of 2022, $983,856 was spent on the State Street (OP) project against a forecast of approximately $1.7 million. The variance in forecasted to actual spend for the third quarter of 2022 was predominantly the result of overestimated subcontractor services (traffic control and vacuum truck support) and the Division not being able to start overhead work as planned for circuit 4005, which also relates to the shift in forecasted in-service date discussed below.

As of the end of the third quarter of 2022, the forecasted in-service date for the State Street OP project slipped 123 days from the status as of the prior quarter to April 21, 2023. This forecasted in-service date shift was driven by manhole and conduit exits from the substation that required redesigns due to existing underground obstructions. As a result of this redesign, the circuit 4005 (first circuit to be placed in-service) is being placed on its own manhole and conduit system and the energization will follow the second circuit being cutover in 2023.

Notable activities conducted during the third quarter of 2022 included the approval and receipt of the test pits permit and the commencement and completion of the test pits.

The actual spend by quarter for State Street (OP) as compared to the current forecast and URB approved estimate is provided below.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals						*Forecast*	
$0	$0	$211,247	$395,903	$100,527	$983,856	$1,797,246	$16,523,810

Estimate & Forecast		Actuals to Date	% of Actuals to Estimate & Forecast
Estimate	$19,700,000	$1,691,534	9%
Forecast	$20,012,589		8%

F. Gas M&R Station Upgrades

During the third quarter of 2022, PSE&G submitted updated estimates for the Camden and East Rutherford Gas M&R projects, with both advancing to a Definitive level estimate. **Table 24 – ES 2 Gas M&R Summary Status as of September 30, 2022** below provides these newly approved estimates and the other current estimates for each project within the Gas M&R subprogram, along with the actuals to date and forecasted in-service dates.

Table 24 – ES 2 Gas M&R Summary Status as of September 30, 2022

Project	Estimate Level	Base	Risk & Contingency	Total Estimate	Actuals	% of Actuals to Estimate	Forecasted In-Service
1. Camden	Definitive	$21,600,000	$200,000	$21,800,000	$26,707,869	123%	Dec 2022
2. Central*	Conceptual	$31,400,000	$5,500,000	$36,900,000	$23,653,126	64%	Nov 2023
3. East Rutherford	Definitive	$24,100,000	$1,900,000	$26,000,000	$14,604,488	56%	Dec 2022
4. Mount Laurel*	Conceptual	$12,700,000	$3,100,000	$15,800,000	$1,680,782	11%	Nov 2023
5. Paramus*	Study	$11,500,000	$8,400,000	$19,900,000	$1,317,612	7%	Dec 2023
6. Westampton	Definitive	$8,400,000	$-	$8,400,000	$8,413,061	100%	*Oct 2021 (actual)*
Subprogram Total		**$109,700,000**	**$19,100,000**	**$128,800,000**	**$76,376,937**	**59%**	**Dec 2023**

-Included in the Stipulated Base.
(↑)-*Indicates the forecasted in-service date advanced from the prior quarter.*
(↓)-*Indicates the forecasted in-service date slipped from the prior quarter.*

The updated estimates for Camden and East Rutherford collectively resulted in no change to the overall subprogram estimate as the $5.5 million increase to the base estimate was offset by releasing $5.5 million in R&C funds. Note also that while the current actuals for Camden exceed the updated estimate, this is due to the actuals still including costs associated with the liquid propane air (LPA) scope that was removed from the ES 2 project, a cost adjustment is expected to be recorded to account for this in the fourth quarter of 2022. Details of the individual estimate changes are discussed within the individual project discussions that follow.

Relative to the forecasted in-service dates shown in **Table 24**, as of the end of the third quarter of 2022, the forecasted in-service dates for the remaining Gas M&R projects remained essentially unchanged from the status as of the end of the prior quarter (Camden and East Rutherford both saw forecasted in-service date shifts of five days or less, but both remain forecasted to go in-service in December 2022). As previously reported, the Westampton project was placed in-service as of October 22, 2021.

Findings & Observations:

- The six projects that comprise the Gas M&R subprogram continues to advance at various stages of development reflecting the targeted delivery schedule. During the third quarter of 2022, construction continued to advance on the Camden, Central, and East Rutherford projects, while the Mount Laurel and Paramus projects continued pre-construction activities including Mount Laurel preparing the civil construction package and Paramus addressing comments from the zoning board. The Westampton project was previously put in-service in October 2021, while punch list items and site restoration activities continued in the third quarter of 2022.
- There were no significant changes to the forecasted in-service dates of the Gas M&R projects during the third quarter of 2022. The next projects to be completed are the Camden and East Rutherford projects, which are forecasted to be placed in-service in December 2022. The final projects, Central, Mount Laurel, and Paramus each continue to be forecasted for November-December 2023 in-service dates.
- As of the end of the third quarter of 2022, the overall subprogram forecast increased approximately $6.0 million from the status as of the end of the prior quarter. This forecast increase is predominantly within the Camden (forecast increased approximately $3.1 million) and East Rutherford (forecast increased approximately $2.4 million) projects, where the forecast increase aligned with an updated estimate on these projects, which reflected the current status of design, procurement, and construction plans and activities.
- The IM has found nothing to date that would jeopardize the subprogram being completed on time, however, the current forecast of $110.3 million exceeds the Stipulation budget of $101.0 million and with the latest forecast increase is trending upward.

1. Camden

During the third quarter of 2022, $13,240,520 was spent on the Camden project compared to a forecast of approximately $17.3 million, which brought the total spend to approximately $26.7 million. The variance in forecasted to actual spend in the third quarter of 2022 was driven by permit delays that delayed mechanical construction activities and shipping delays for valves and switchgears. Despite these delays, the forecasted in-service date for the Camden project slipped only three days from the status as of the end of the prior quarter to December 19, 2022.

Notable activities on the Camden project during the third quarter of 2022 included:

- Completed excavations and pouring for building footings and foundations;
- Began excavation in street for distribution tie-ins;
- Continued pipe fabrication;
- Began steel erection for the mix and control buildings;
- Began installing outlet piping within the M&R station; and,
- Continued electrical and plumbing rough in.

The actual spend by quarter for Camden as compared to the current forecast and URB approved estimate is provided below. Late in the third quarter of 2022, PSE&G advanced the Camden project estimate to the

Definitive stage, which saw the overall estimate remain at $21.8 million after the allocation of R&C. The specific changes from the prior estimate are as follows:

- Change in pressure control valves ($1.3 million);
- Design refinement – predominantly impacts from unknown underground conditions and electrical requests for information (RFIs) ($0.8 million);
- Escalated material costs and changes between issued for bid (IFB) and IFC drawings, primarily valves, platforms, and electrical materials ($0.7 million);
- Pipeline agreement with Transco required additional modifications to be incorporated ($0.3 million); and,
- Transfer of R&C to base (-$3.1 million).

While the current estimate of $21.8 million and the current forecast of $21.6 million have both been exceeded by the actual costs to date on the Camden project, these actual costs include costs related with the LPA scope of the Camden project that PSE&G is removing from the ES 2 Program and will result in adjusted actual costs for the ES 2 Camden project in the fourth quarter of 2022.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals						*Forecast*	
$13,326	$859,350	$2,147,696	$2,791,701	$7,655,276	$13,240,520	($6,903,540)	$1,795,670

Estimate & Forecast		Actuals to Date	% of Actuals to Estimate & Forecast
Estimate	$21,800,000	$26,707,870*	123%
Forecast	$21,600,000		124%
**-Approximately $9.9 million of actuals will be journaled out in October 2022 to reflect the split of the LPA scope of the Camden project that removes the LPA scope from the ES 2 project.*			

2. Central

During the third quarter of 2022, $4,607,003 was spent on the Central project compared to a forecast of approximately $4.2 million, which brought the total spend to approximately $23.7 million. The forecasted in-service date for the Central project as of the end of the third quarter of 2022 remains at November 30, 2023, unchanged from the status as of the end of the prior quarter.

Notable activities on the Central project during the third quarter of 2022 included:

- Completed erection of the regulator and heater buildings;
- Heat exchangers/flow control building erection complete and fit out initiated;
- Began erecting steel skin for the control building;
- Continued fit out of SCADA building;
- Continued pipe fabrication; and
- Continued electrical and plumbing rough in.

The actual spend by quarter for Central as compared to the current forecast and URB approved estimate is provided below. The forecast of $31.4 million for the Central project remains virtually unchanged from the status as of the end of the prior quarter and excludes costs associated with the LPA scope that was removed from the Program.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals						*Forecast*	
$6,869	$670,582	$4,226,277	$7,112,617	$7,029,778	$4,607,003	$3,740,040	$4,066,834

Estimate & Forecast		Actuals to Date	% of Actuals to Estimate & Forecast
Estimate	$36,900,000	$23,653,126	64%
Forecast	$31,400,000		75%

3. East Rutherford

During the third quarter of 2022, $6,324,865 was spent on the East Rutherford project compared to a forecast of approximately $11.1 million, which brought the total spend to approximately $14.6 million. The variance in forecasted to actual spend during the third quarter of 2022 was driven by supply chain/material delivery delays and a delay in finalizing the Transco pipeline agreement addendum that pushed a forecasted payment. The forecasted in-service date for the East Rutherford project as of the end of the third quarter of 2022 slipped five days from the status as of the end of the prior quarter to December 21, 2022.

Notable activities on the East Rutherford project during the third quarter of 2022 included:

- Drained and removed heaters;
- Completed pile driving;
- Foundation work for regulator and control buildings;
- Continued pipe fabrication;
- Continued electrical rough in;
- Received and set the control SCADA building; and,
- Began excavating for yard piping and piping supports.

The actual spend by quarter for East Rutherford as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project. Late in the third quarter of 2022, PSE&G advanced the East Rutherford project estimate to the Definitive stage, which resulted in no change to the prior estimate of $26.0 million after allocation of R&C. The specific changes from the prior estimate are as follows:

- Design refinement of IFCs through submittals and RFIs derived from unforeseen field conditions, construction sequencing, and design revision including impacts to electrical, mechanical, and civil work ($1.4 million);
- Higher levels of asbestos containing materials and PCB pipe contamination discovered during demolition and change to dewatering strategy ($0.6 million);
- New requirement stemming from a new requirement in the executed pipeline agreement with Transco for daily supervision to oversee activities on Tansco property (East Rutherford site owned by Transco) ($0.4 million);
- Transfer of R&C to base (-$2.4 million).

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals						*Forecast*	
$9,010	$521,865	$1,783,623	$1,551,290	$4,413,835	$6,324,865	$9,010,011	$485,502

Estimate & Forecast		Actuals to Date	% of Actuals to Estimate & Forecast
Estimate	$26,000,000	$14,604,488	64%
Forecast	$24,100,000		61%

4. Mount Laurel

During the third quarter of 2022, $607,409 was spent on the Mount Laurel project compared to a forecast of approximately $760,000, which brought the total spend to approximately $1.7 million. The forecasted in-service date for the Mount Laurel project as of the end of the third quarter of 2022 remained unchanged from the status as of the end of the prior quarter at November 30, 2023.

Notable activities on the Mount Laurel project during the third quarter of 2022 included:

- Prepared and issued the civil construction contract; and,
- Finalized interconnection agreement with Transco.

Construction activities on Mount Laurel are planned to commence in the second quarter of 2023.

The actual spend by quarter for Mount Laurel as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project. The forecast for the Mount Laurel project remained essentially unchanged from the prior quarter at approximately $12.7 million.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals						*Forecast*	
$5,965	$362,167	$527,341	$135,639	$42,260	$607,409	$373,513	$10,645,706

Estimate & Forecast		Actuals to Date	% of Actuals to Estimate & Forecast
Estimate	$15,800,000	$1,680,782	11%
Forecast	$12,700,000		13%

5. Paramus

During the third quarter of 2022, $67,221 was spent on the Paramus project compared to a forecast of approximately $103,000, which brought the total spend to approximately $1.3 million. The forecasted in-service date for the Paramus project as of the end of the third quarter of 2022 remains unchanged from the status as of the end of the prior quarter at December 29, 2023.

Notable activities on the Paramus project during the third quarter of 2022 included:

- Responded to comments from the Paramus Zoning Board; and,
- Received draft IFB drawings and documents, which have resulted in no scope changes.

Construction activities on the Paramus project is planned to commence in the second quarter of 2023.

The actual spend by quarter for Paramus as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project. The forecast for the Paramus project as of the end of the third quarter of 2022 increased approximately $500,000 from the prior quarter, driven by additional A/E support required and offset by R&C funds.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals						***Forecast***	
$8,842	$462,452	$568,344	$94,755	$115,998	$67,221	$1,067,026	$9,615,363

Estimate & Forecast		Actuals to Date	% of Actuals to Estimate & Forecast
Estimate	$19,900,000	$1,317,611	7%
Forecast	$12,00,000		11%

6. *Westampton*

During the third quarter of 2022, $100,140 was spent on the Westampton project compared to a forecast of approximately $242,000, which brought the total spend to approximately $8.4 million. The Westampton was placed in-service as of October 22, 2021, remaining activities include site restoration and final punch list items that continued to be performed in the third quarter of 2022.

During the third quarter of 2022, notable activities on the Westampton project included:

- Continuing to work through punch list items;
- Completed final paving and site restoration.

This effectively concludes the Westampton project, although minor trailing costs are expected in the fourth quarter of 2022.

The actual spend by quarter for Westampton as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals						***Forecast***	
$8,395	$1,032,670	$6,961,216	$178,124	$132,517	$100,140	$59,323	$0

Estimate & Forecast		Actuals to Date	% of Actuals to Estimate & Forecast
Estimate	$8,400,000	$8,413,062	100%
Forecast	$8,472,385		99%

ENERGY STRONG PROGRAM

INDEPENDENT MONITOR

2022 THIRD QUARTER REPORT

APPENDIX A – DRAFT REPORT COMMENTS AND RESPONSES

NOVEMBER 13, 2023

PEGASUS GLOBAL HOLDINGS, INC. ®

Questions & Comments to the IM 2022 Third Quarter Report Formally Submitted to the IM

ID #	Question/Comment	IM Response	Report Changes
S-INF-1	**Reference Q3 2022 Report, Page 2, Table 1 – ES 2 Subprogram & Stipulated Base Status as of September 30, 2022** Please reconcile why the Energy Strong II program is forecasted to be completed in February 2024 despite the Electric Station Flood Mitigation subprogram being forecasted to be completed in April 2024.	The "Total" row on **Table 1** was incorrectly not updated to reflect the latest schedule update to the Waverly Electric Station Flood Mitigation project that shifted from February to April 2024 during the third quarter of 2022 and represents the final forecasted project for the Program.	**Table 1**
S-INF-2	**Reference Q3 2022 Report, Page 16, Table 10 – Electric Station Flood Mitigation Switchgear Deliveries as of September 30, 2022** Please describe the planned timeline for returning the Kingsland 13kV switchgear, which is being used as the Ridgefield 13kV contingency/temporary switchgear, to be installed on the Kingsland project.	The contingency switchgear on Ridgefield 13kV will be disassembled and delivered to the Kingsland site following the commissioning of the permanent switchgear at the Ridgefield 13kV site. This disassembly at Ridgefield 13kV and delivery to Kingsland is expected to take place during the first quarter of 2023.	**Table 11** (was previously Table 10)
S-INF-3	**Reference Q3 2022 Report, Page 24, Meadow Road Substation Project** With respect to the Meadow Road substation project: a. Please discuss if any Energy Strong II work will be combined with proposed transmission work occurring adjacent to the Meadow Road substation (See PJM TEAC Presentation dated September 5, 2023, Slides 5-6) (link:https://www.pjm.com/-/media/committees-groups/committees/teac/2023/20230905/20230905-item-06---pseg-supplemental-projects.ashx). b. The PJM TEAC Presentation notes that PSE&G is proposing to construct a new 230-13kV substation on property adjacent to the existing Meadow Road substation. Please confirm that the scope of the Energy Strong II project still consists of raising and rebuilding the existing Meadow Road substation.	Regarding the Meadow Road project: a. There is no ES 2 project scope combined with the proposed transmission work. b. The ES 2 scope is confirmed as consisting of raising and rebuilding the existing substation.	No changes
S-INF-4	**Reference Q3 2022 Report, Page 31, Contingency Reconfiguration Subprogram** Regarding the Fuse Saver projects within the Contingency Reconfiguration subprogram, please provide additional details about the increases in the actual cost per unit observed since the start of the program.	In the ES 2 filing, PSE&G estimated installation of these devices would range between $11,721 for single-phase devices and $18,262 for two-phase devices. The Black & Veatch "Electric Cost-Benefit Analysis" study attached to PSE&G's ES 2 filing noted that *"PSE&G currently does not have any of these devices installed;*	**Section III.B.**

ID #	Question/Comment	IM Response	Report Changes
		therefore, some work is required to develop a construction standard and training to ensure the workforce is familiar with the construction and operation of the reclosing devices." The construction standard and training were developed through implementation of the Fuse Saver pilot program that commenced in November 2020 and was primarily completed in January 2021 (PSE&G installed 80 devices in this initial period, then opted to install the remaining units in inventory to capture additional cost and performance data, resulting in a total of 113 units installed as of the end of 2021). The actual costs observed through the Fuse Saver pilot program actuals saw single phase devices average \$35,216 and two-phase devices average \$48,031, significantly higher than the estimate at the time of the ES 2 filing. The cost increases were primarily driven by: • The ES 2 filing estimate not including management costs, tree trimming, storage, or traffic control costs; • Higher material costs than estimated, including pole replacements at multiple locations (pole replacement costs not included in the initial estimate assumptions, adds approximately \$10,000 in costs per unit); and, • Average labor hours 4x higher than the ES 2 filing estimate and increased labor rates since filing. PSE&G's approach on forecasting the Fuse Saver scope during its execution is based on a quarterly review of the actual cost data and related installation status information to inform and update the installation plan. PSE&G continues seeking to optimize the number of Fuse Savers installed in alignment with the overall budget for the subprogram. For example, given the added costs of the pole replacements, PSE&G considered attempting to avoid such locations, but in	

ID #	Question/Comment	IM Response	Report Changes
		many cases the existing equipment and height/spacing requirements on the pole required installation of a new pole.	
S-INF-5	**Reference Q3 2022 Report, Page 32, Communication System Subprogram** Regarding the Communication System subprogram projects placed in-service in Q3 2022, please compare the actual costs to the budgeted costs.	For these projects, which consisted of Montclair, Palisades HQ, and West Orange, the budgeted vs. actual costs are presented as follows: • Montclair: budget of $840,000 vs. actual costs of $2,725,350. • Palisades HQ: budget of $255,000 vs. actual costs of $633,296. • West Orange: budget of $50,000 vs. actual costs of approximately $58,000. The cost variances experienced on Montclair and Palisades HQ were largely due to the fact that the estimates were developed at less than 30% confidence via analogous estimates that did not account for differing station field conditions. Originally, PSE&G used a placeholder value for all stations' Inside Plant costs and later refined these values based on the required equipment. The Outside Plant costs were also estimated with lower levels of confidence and were further refined based on the split of Overhead and Underground scope required.	No change
S-INF-6	**Reference Q3 2022 Report, Page 36, Grid Modernization - ADMS Subprogram** Regarding the ADMS project, please provide additional details about the need to incorporate two (2) production releases rather than the originally planned one (1) production release.	The split of OMS implementation into two production releases was intended to go-live with all core/mission critical functionalities in the first release in May 2023 ahead of the start of the "storm season" and remaining enhancements in a second release in fall 2023 after the storm season moratorium. The OMS project ultimately did not meet the May 2023 release date, which resulted in reverting the project to a single production release currently scheduled to go live in December 2023.	**Section III.D.**
S-INF-7	**Reference Q3 2022 Report, Page 44, Camden M&R Station** Regarding the Camden M&R Station project, refer to the statement "Approximately $9.9 million of actuals will be journaled out in October 2022 to reflect the split of	The $18.1 million reduction from the LPA scope removal reflected the entire estimate of the LPA scope while the $9.9 million that will be journaled out of the	No change

ID #	Question/Comment	IM Response	Report Changes
	the LPA scope of the Camden project that removes the LPA scope from the ES 2 project." Please reconcile this with the IM's previous report, which indicated that the removal of the LPA scope would result in a $18.1 million cost reduction to the Camden M&R project (<u>See</u> Q2 2022 Report, Page 48).	ES 2 project actual costs reflects the actual costs incurred on the ES 2 project related to the LPA scope prior to that scope being removed from the Program.	
S-INF-8	**<u>Reference Q3 2022 Report, Page 45, Central M&R Station</u>** Regarding the Central M&R Station project, please clarify if the forecasted cost ($31.4 million) includes the cost of the LPA scope.	The costs associated with the LPA scope were removed from the Central M&R Station project forecast and thus not included in the current $31.4 million forecast.	**Section III.F.2.**
S-INF-9	**<u>Reference Q3 2022 Report, Page 47, Paramus M&R Station</u>** Regarding the Paramus M&R Station project, please provide additional details about the comments received from the Paramus Zoning Board, including any resulting scope changes.	The comments received from the Paramus Zoning Board on the Paramus Gas M&R project have not resulted in any scope changes, but did require among other things: • Improvements are to be completed in accordance with testimony and evidence submitted to the Board. • Building permits are required to be secured, where applicable, prior to conducting any site modifications. • Compliance with the Board Engineer's review memoranda. • Installation of soundproof paneling on the building interior. • Provide the Air Quality Permit from the NJDEP. • Coordinate with Transco for installation of additional security cameras.	**Section III.F.5.**
RCR-IM-1	With reference to page 1 of the Independent Monitor's Draft Third Quarter 2022 Report, please provide an update on the draw down of risk and contingency funds in the Electric Station Flood Mitigation and Gas M&R subprograms.	The changes to R&C on the Electric Station Flood Mitigation and Gas M&R subprograms during the third quarter of 2022 resulted in the R&C balance in the Electric Station Flood Mitigation subprogram decreasing by $12.5 million to $29.3 million (shown as the Placeholder amount in **Table 11)** and in the Gas M&R subprogram by $5.5 million to $19.1 million (shown in **Table 23**). The overall estimates for each of these subprograms remained unchanged as the drawdown in R&C matched an increase in the base estimate for projects that had updated estimates in the quarter (Electric Station Flood Mitigation projects: Clay Street, Meadow Road, Kingsland, Ridgefield 4kV	No change

ID #	Question/Comment	IM Response	Report Changes
		(decreased $100K as part of the project closeout), Waverly, and Woodlynne; and Gas M&R projects: Camden and East Rutherford).	
RCR-IM-2	With reference to page 2 of the Independent Monitor's Draft Third Quarter 2022 Report, Table 1 ES 2 Subprogram & Stipulated Base Status as of September 30, 2022, please identify the additional subprogram costs associated with the delay in the forecasted completion date for the Electric Station Flood Mitigation subprogram from February 2024 reported in the Second Quarter 2022 Report to April 2024.	The Lakeside project within the Electric Station Flood Mitigation subprogram has incurred approximately $500K in additional costs related to the extended duration ($400K in extra carrying costs for the extended schedule, $100K for construction acceleration due to the switchgear delivery over five months after its purchase order delivery date).	No change
RCR-IM-3	With reference to page 2 of the Independent Monitor's Draft Third Quarter 2022 Report, Table 1 ES 2 Subprogram & Stipulated Base Status as of September 30, 2022, please identify the additional subprogram costs associated with the delay in the forecasted completion date for the Grid Modernization - ADMS subprogram from December 2022 reported in the Second Quarter 2022 Report to June 2023.	The delay to the ADMS subprogram has contributed to approximately $7.4 million in additional costs to the subprogram (approximately $4.3 million attributed to PSE&G labor, $3.3 million for staff augmentation costs). See also the response to **RCR-IM-8**.	**Section III.D.**
RCR-IM-4	With reference to page 2 of the Independent Monitor's Draft Third Quarter 2022 Report, Table 1 ES 2 Subprogram & Stipulated Base Status as of September 30, 2022, please identify the source of the $3.6 million increase in the Gas M&R subprogram included in the total subprogram increase of $27.8 million over the stipulation amount of $101 million for this subprogram.	When PSE&G approved this additional funding for the Gas M&R subprogram in the second quarter of 2022, the Base estimate of the six projects within the subprogram totaled $104.2 million, the R&C balances totaled $24.6 million, and the overall subprogram estimate was $128.8 million. This $128.8 million represented a $27.8 million increase over the Stipulation's $101.0 million budget for the subprogram. Of that $27.8 million, $24.6 million was attributed to additional R&C while the remaining $3.2 million was realized in the increased Base estimates of these projects ($104.2 million as of the end of the second quarter of 2022, see Table 25 of the IM's 2022 2nd Quarter Report).	No change
RCR-IM-5	With reference to page 2 of the Independent Monitor's Draft Third Quarter 2022 Report, please indicate whether other supply chain issues in addition to the 4 kV switchgear delivery delays are contributing to the 163 day delay in the forecasted in service date for Lakeside Avenue from September 18, 2023 to February 28, 2024.	There are other supply chain issues from sub-vendors to the switchgear manufacturer that are contributing to this switchgear manufacturing delay, but the current delay to the Lakeside Avenue project is driven by the delay to the switchgear delivery.	No change

ID #	Question/Comment	IM Response	Report Changes
RCR-IM-6	With reference to page 4 of the Independent Monitor's Draft Third Quarter 2022 Report, please confirm for the Contingency Reconfiguration program that only 286 fuse saver units were installed during the 2022 Third Quarter, leaving 1,162 units to be installed by December 31, 2023 as part of the Contingency Reconfiguration subprogram.	The IM confirms 286 Fuse Savers were installed during the third quarter of 2022. This also represented effectively the first full quarter of installations of the Fuse Savers, with nearly 70% of the total devices installed to date installed during this quarter. As noted in the Findings & Observations within **Section III.B.**, based on the current scope, this averages out to approximately 77 units per month (for comparison in the third quarter of 2022, PSE&G averaged 95 units per month).	No change
RCR-IM-7	With reference to page 4 of the Independent Monitor's Draft Third Quarter 2022 Report, please explain the discrepancy between the Contingency Reconfiguration program planned scope of 1,574 units compared to planned scope 1,641 fuse saver units reported in the Second Quarter 2022 Report.	PSE&G assesses the actual cost per unit data and adjusts the Program targets on a quarterly basis based on the current data. As the costs per unit of the Fuse Savers has been higher than initially estimated (see also the response to **S-INF-4**), this has resulted in PSE&G lowering the targeted number of units to be installed in the Program in order to maintain the established budget.	**Section III.B.**
RCR-IM-8	With reference to page 5 of the Independent Monitor's Draft Third Quarter 2022 Report, please elaborate on the $7.4 million increase in the Grid Modernization ADMS subprogram budget, involving changes in the Outage Management System from one to two production releases, at an increased cost of $7.4 million, increasing total ADMS subprogram budget from $53.47 million to $60.90 million.	The delay to the ADMS subprogram has contributed to approximately $7.4 million in additional costs to the subprogram (approximately $4.3 million attributed to PSE&G labor, $3.3 million for staff augmentation costs). There were no additional costs associated with the split to two production releases. See also the response to **RCR-IM-3** and **S-INF-6**.	**Section III.D.**
RCR-IM-9	With reference to page 9, Figure 2 -- ES 2 CWIP Balances by Subprogram as of September 30, 2022, please explain the discrepancy between the $99.39 million Q3 2022 subtotal for the ES 2 Electric Station Flood Mitigation, while the preceding paragraph on page 8 discussing construction work-in-progress highlights CWIP Electric Station Flood Mitigation costs for "Hasbrouck Heights ($14.6 million), State Street ($12.2 million), Clay Street ($13.5 million), and Waverly ($17.9 million)" for $58.2 million in total for the same subprogram. Please identify the CWIP balances by project for ES 2 Electric Station Flood Mitigation subprogram for the remaining 41.19 million.	The paragraph introducing the CWIP discussion highlights the largest components of CWIP by subprogram, in this case the Hasbrouck Heights, State Street, Clay Street, and Waverly projects (note Waverly's balance was incorrectly listed as $17.9 million rather than the correct $18.0 million). **Figure 2** on the other hand depicts the full CWIP balance by subprogram. The CWIP balances by project for each of the Electric Station Flood Mitigation projects is provided below:	**Section II.C.2.**

<table>
<tr><th>ID #</th><th>Question/Comment</th><th>IM Response</th><th>Report Changes</th></tr>
<tr><td></td><td></td><td><table>
<tr><th>Project</th><th>Q3 2022 CWIP Balance</th></tr>
<tr><td>Academy Street</td><td>$0</td></tr>
<tr><td>Clay Street</td><td>$13,472,003</td></tr>
<tr><td>Front Street</td><td>$9,767,419</td></tr>
<tr><td>Hasbrouck Heights</td><td>$14,535,338</td></tr>
<tr><td>Kingsland</td><td>$2,341,261</td></tr>
<tr><td>Lakeside Avenue</td><td>$3,431,600</td></tr>
<tr><td>Leonia</td><td>$5,958,310</td></tr>
<tr><td>Market Street</td><td>$2,230</td></tr>
<tr><td>Meadow Road</td><td>$2,196,464</td></tr>
<tr><td>Orange Valley</td><td>$2,334,015</td></tr>
<tr><td>Ridgefield 13kV</td><td>$5,675,397</td></tr>
<tr><td>Ridgefield 4kV</td><td>$0</td></tr>
<tr><td>State Street</td><td>$12,216,817</td></tr>
<tr><td>Toney's Brook</td><td>$3,235,564</td></tr>
<tr><td>Waverly</td><td>$18,022,455</td></tr>
<tr><td>Woodlynne</td><td>$6,203,817</td></tr>
</table></td><td></td></tr>
<tr><td>RCR-IM-10</td><td>With reference to pages 11 through 12, Table 6 ES 2 Program Overhead Allocations of September 30, 2022, please provide the breakdown of increased labor costs during the Third Quarter 2022 by supervisory, administrative, planning and contract labor categories and subprogram.</td><td>A comparison of the breakdown of overhead costs incurred on the Program during the second and third quarters of 2022 has been added to the report in new Table 7 – Q2 and Q3 2022 Overhead Cost Comparison.</td><td>Table 7</td></tr>
<tr><td>RCR-IM-11</td><td>With reference to page 16 of the Independent Monitor's Draft Third Quarter 2022 Report, concerning communications provided by PSE&G's switchgear vendor, Powercon, please indicate if Powercon has provided the "more detailed and frequent status updates" referred to in the Draft Second and Third Quarter 2022 Reports regarding remaining major equipment deliveries.</td><td>Concerning the additional information from Powercon, PSE&G requested and has received details in Powercon's production schedules and information from the sub-vendors/suppliers.</td><td>No change</td></tr>
<tr><td>RCR-IM-12</td><td>With reference to page 16, Table 10 ES 2 Electric Substation Flood Mitigation Switchgear Deliveries as of September 30, 2022, please explain if the revised delivery dates for 4 kV switchgear for Clay Street, Front Street, Lakeside Avenue, Orange Valley, Waverly and Woodlynne are based on communications from Powercon, or estimates by PSE&G.</td><td>The noted switchgear delivery dates are provided by the vendor.</td><td>No change</td></tr>
<tr><td>RCR-IM-13</td><td>With reference to pages 17 through 18, Table 11 ES 2 Electric Substation Flood Mitigation Project Cost Status as of September 30, 2022, the risk and contingency subprogram total is $29.3 million, a reduction of $12.5 million from the $41.8</td><td>The changes to R&C on the Electric Station Flood Mitigation during the third quarter of 2022 resulted in the R&C balance in the Electric Station Flood</td><td>No change</td></tr>
</table>

ID #	Question/Comment	IM Response	Report Changes
	million risk and contingency subprogram total reported by the IM in the Second Quarter 2022 Report, Table 11 ES 2 Electric Substation Flood Mitigation Project Cost Status as of June 30, 2022, pages 16 through 17. Please specify how the $12.5 million in risk and contingency funds were applied to which Electric Station Flood Mitigation projects.	Mitigation subprogram decreasing by $12.5 million. The overall estimate for the subprograms remained unchanged as the drawdown in R&C matched an increase in the base estimate for projects that had updated estimates in the quarter (Electric Station Flood Mitigation projects: Clay Street, Meadow Road, Kingsland, Ridgefield 4kV (decreased $100K as part of the project closeout), Waverly, and Woodlynne. Details of these estimate changes are provided in the specific subsection for the project.	
RCR-IM-14	With reference to page 19 of the Third Quarter 2022 Report, the IM states that "there is adequate R&C remaining in the subprogram." Please confirm that there is adequate risk and contingency remaining in the subprogram given in-service date slippage driven by switchgear delivery delays.	Based on the current risk profile and work remaining in the subprogram, the total subprogram forecast is approximately $356.9 million, the $29.3 million in R&C represents approximately 8% of that forecast. With three projects currently complete and an additional four projects forecasted to reach in-service by the end of 2022, it appears the contingency is adequate based on the remaining work particularly as the current forecasts are based on the currently forecasted in-service dates. However, R&C is ultimately an estimate based on the information known or expected to be known at the time of the estimate.	No change
RCR-IM-15	With reference to Table 11 ES 2 Electric Substation Flood Mitigation Project Cost Status as of September 30, 2022, on page 17 and the Findings and Observations on pages 17 and 18, for the $1.35 million increased forecast for Front Street from $26.15 million (Second Quarter 2022 Report) to $27.50 million please specify the costs for "bringing six circuits from [outside plant] to [inside plant], additional handling of contingency feeder rows, and additional costs for contingency wire checker and contingency disassembly."	Regarding the details associated with the increased forecast for the Front Street project: • $0.3 million: updated forecast for brining in six circuits from OP to IP and additional handling of contingency feeder rows; • $0.9 million: civil construction additional scope, relay tech direct project charges, added contingency wire checker, and additional contingency switchgear disassembly costs; and, • $0.2 million: late charges for Division material and handling of contingency feeder rows.	No change
RCR-IM-16	With reference to page 19 of the Independent Monitor's Draft Third Quarter 2022 Report, please explain for which projects the primary risk is "resource availability to support schedule requirements."	The resource risk is primarily in the Metro and Southern Division and potentially impacting these projects for the Metro Division: Lakeside, Clay Street, Waverly, Orange Valley, and Toney's Brook; and for	**Section III.A.**

ID #	Question/Comment	IM Response	Report Changes
		the Southern Division: State Street, Woodlynne, and Woodbury.	
RCR-IM-17	With reference to page 19 of the Independent Monitor's Draft Third Quarter 2022 Report, please explain for which projects the primary risk is weather-related impacts.	The weather-related impacts have the potential to impact any of the remaining projects depending on the nature of the impacts, which may involve such specific risks localized flooding or resources being pulled from project work to support recovery efforts.	No change
RCR-IM-18	With reference to page 20 of the Independent Monitor's Draft Third Quarter 2022 Report, please explain the safety incidents and what is the estimated cost of the 52 day slippage in the forecasted in-service date for the Clay Street project.	The forecasted in-service date slipped due to a construction safety incident on the OP Civil work, local flooding that impacted installation of the switchgear building foundation, and additional test pits required to confirm OP MH&C underground design. The safety incident involved an excavator excavating a new duct bank that scraped the top of the concrete and shifted it. The machine was used to lift the concrete with the bucket, which exposed four conduits. The bucket never touched the conduits, however the top of two conduits came off with the concrete. Construction at the site was paused for an incident investigation and to make sure all appropriate safety procedures were reviewed and followed. The costs associated with this delay consist of flood cleanup costs of approximately $56K and schedule acceleration of approximately $100K.	No change
RCR-IM-19	With reference to page 20 of the Independent Monitor's Draft Third Quarter 2022 Report, please explain how the Clay Street "[p]roject schedule recovery" cost of $600,000 was calculated, what exactly does it include, and was this based on the 52 slippage of the in-service date to March 23, 2023 noted at the end of the third quarter of 2022 or other factors? If other factors are involved, please describe how they impact the project schedule recovery cost.	The $600K in costs associated with "project schedule recovery" are comprised of roughly $100K in additional Civil and Electrical supervision and roughly $475K in construction contractor increases. The total delay from the late receipt of construction permits was determined to be approximately six months, with three months recovered through these efforts.	**Section III.A.2.**
RCR-IM-20	With reference to page 22 of the Independent Monitor's Draft Third Quarter 2022 Report, please explain how the Kingsland project cost of $0.4 million for the "[e]xtended project duration: shift from Q2 2023 to Q4 2023 in-service" date was calculated and what components are included in that calculation (labor, borrowing costs, equipment storage, site costs, etc.). Please explain why delay costs have not	The $400K cost increases on Kingsland associated with the extended project duration was based on the in-service date being revised to December 2023 based on the decision to utilize the contingency switchgear on Ridgefield 13kV as the permanent Kingsland	**Section III.A.5.**

ID #	Question/Comment	IM Response	Report Changes
	been calculated and reported for all project delays affecting the ES 2 Electric Station Flood Mitigation Project subprogram and all other programs.	switchgear (representing a cost savings vs. ordering new switchgear). However, this resulted in the carrying costs extended by a full year at a rate of $25K/month for 2023 and an additional five months in 2024 added for post in-service closeout at $20K/month, representing a total of $400K in additional costs. The carrying costs include typical project management activities and resources (e.g. project manager, staff engineer, cost engineer, scheduler, etc.).	
RCR-IM-21	With reference to page 29 of the Independent Monitor's Draft Third Quarter 2022 Report, please explain how "there is no significant cost impact expected from this shift in installations" of the remaining 874 to be installed Fuse Savers from the first half of 2022 to the second half of 2022.	This is a shift in the timing of when the Fuse Saver installations are targeted, but there is no cost impact from installing in the fall of 2022 instead of the spring of 2022.	No change
RCR-IM-22	With reference to page 31 of the Independent Monitor's Draft Third Quarter 2022 Report, please detail the "higher observed costs per unit on the Fuse Savers testing and installation labor," that contributed to the third quarter of 2022 $2.0 million increase above the $145 million stipulated budget for the Contingency Reconfiguration subprogram.	In the ES 2 filing, PSE&G estimated installation of these devices would range between $11,721 for single-phase devices and $18,262 for two-phase devices. The Black & Veatch "Electric Cost-Benefit Analysis" study attached to PSE&G's ES 2 filing noted that *"PSE&G currently does not have any of these devices installed; therefore, some work is required to develop a construction standard and training to ensure the workforce is familiar with the construction and operation of the reclosing devices."* The construction standard and training were developed through implementation of the Fuse Saver pilot program that commenced in November 2020 and was primarily completed in January 2021 (PSE&G installed 80 devices in this initial period, then opted to install the remaining units in inventory to capture additional cost and performance data, resulting in a total of 113 units installed as of the end of 2021). The actual costs observed through the Fuse Saver pilot program actuals saw single phase devices average $35,216 and two-phase devices average $48,031, significantly higher than the estimate at the time of the ES 2 filing. The cost increases were primarily driven by:	**Section III.B.**

ID #	Question/Comment	IM Response	Report Changes
		• The ES 2 filing estimate not including management costs, tree trimming, storage, or traffic control costs; • Higher material costs than estimated, including pole replacements at multiple locations (pole replacement costs not included in the initial estimate assumptions, adds approximately $10,000 in costs per unit); and, • Average labor hours 4x higher than the ES 2 filing estimate and increased labor rates since filing. PSE&G's approach on forecasting the Fuse Saver scope during its execution is based on a quarterly review of the actual cost data and related installation status information to inform and update the installation plan. PSE&G continues seeking to optimize the number of Fuse Savers installed in alignment with the overall budget for the subprogram. For example, given the added costs of the pole replacements, PSE&G considered attempting to avoid such locations, but in many cases the existing equipment and height/spacing requirements on the pole required installation of a new pole.	
RCR-IM-23	With reference the findings and observations on page 31 of the Independent Monitor's Draft Third Quarter 2022 Report, please explain what accounted for the Contingency Reconfiguration subprogram forecast increasing by $2.0 million, to a total of $147.6 million, above the Stipulation budget of $145.0 million.	Higher Fuse Savers cost per unit in installation and testing/commissioning were the primary drivers to the increased forecast.	**Section III.B.**

RCR-IM-24	With reference to page 37 of the Independent Monitor's Draft Third Quarter 2022 Report, please provide costs details on the $7.4 million increase in the Grid Modernization ADMS subprogram budget, involving changes in the Outage Management System from one to two production releases, at an increased cost of $7.4 million, increasing total ADMS subprogram budget from $53.47 million to $60.90 million. Please provide breakdown of increased costs by project category (supervisory, administrative, planning and contract labor, equipment).	Regarding this $7.4 million increase, it was comprised of the following costs:
		• PSE&G Employees: +$4.13 million, comprised of:
		  o Supervisory: $0.8 million;
		  o Labor: $3.2 million; and,
		  o IT resources: $0.14 million.
		• Staff Augmentation: +$3.32 million, comprised of:
		  o Supervisory: $0.14 million;
		  o Testing: $0.74 million;
			Section III.D.

ID #	Question/Comment	IM Response	Report Changes
		- Direct Labor: $2.41 million; and, - Materials: $0.03 million.	
RCR-IM-25	With reference to page 38, Table 21 ES 2 Life Cycle Station Upgrade Project Status as of September 30, 2022, please explain the disposition of the subprogram risk and contingency total of $2.3 million for Hamilton, Paramus, Plainfield, Woodbury and State Street substation projects compared to the risk and contingency total in Table 23 ES 2 Life Cycle Station Upgrade Project Status as of June 30, 2022 in the Independent Monitor's Draft Second Quarter 2022 Report on page 38.	The R&C balance for the Electric Stipulated Base projects is $1.4 million, which is effectively the amount that remains between the Stipulation budget ($100 million) and the current base estimates for the Life Cycle Station Upgrades projects ($98.6 million).	No change
RCR-IM-26	With reference to pages 42 and 43, Table 23 – ES 2 Gas M&R Summary Status as of September 30, 2022, please confirm the remaining risk and contingency allocation of $200,000 is adequate for the Camden project after the transfer to base of $3.1 million given ongoing exceedances affecting the Project.	The $200K remaining R&C balance on Camden reflects the realization of certain risks that resulted in R&C funds being transferred to the Base estimate. The remaining balance is relatively low compared to the overall project costs, however, with this project forecasted to go in-service in December 2022 the work is fairly well advanced and there is less remaining risk. Ultimately the R&C and the overall estimate represent an estimate based on the information known at the time on what the expected risks and overall project costs will be, however, actual conditions can and do change that can increase or decrease the actual costs compared to the estimate.	No change
RCR-IM-27	With reference to page 44, for the Camden Gas M&R Project, please explain how the "$9.9 million of actuals will be journaled out in October 2022 to reflect the split of the LPA scope of the Camden project that removes the LPA scope from the ES 2 project[]" will affect the $26.7 million actuals to date and how will that change affect the Gas M&R subprogram stipulated budget of $101 million and accounting for the $27.8 million increase over the stipulated budget by PSE&G to $128.8 million and how will that be reconciled with $24.6 million for Gas M&R risk and contingency (refer back to page 2, Table 1 – ES 2 Subprograms & Stipulated Base Status as of September 30, 2022).	The removal of the LPA scope from the project costs is expected to reduce the $26.7 million in current actual costs on the Camden project by approximately $9.9 million (though the project will also continue to incur actual costs related to the ES 2 project scope). The $128.8 million current estimate for the Gas M&R subprogram does not include LPA-related costs, however, the R&C balance decreased by $5.5 million reflecting updated estimates in the third quarter of 2022 on the Camden and East Rutherford projects that saw a collective $5.5 million Base estimate increase. This leaves the current R&C balance for the Gas M&R subprogram at $19.1 million.	**Table 1**

ID #	Question/Comment	IM Response	Report Changes
RCR-IM-28	With reference to page 45, for the East Rutherford Gas M&R Project, please provide additional details on how project costs are allocated between PSE&G and Transco and whether that contributed to the "delay in finalizing the Transco pipeline agreement addendum that pushed a forecasted payment." Please provide details on the costs and payment schedule for the pipeline agreement and how these are accounted for in the East Rutherford Gas M&R Project.	During the preliminary design phase, PSE&G Asset Management and the Project Team reviewed the overall general construction scope and duration with Transco. Based on that review, Transco provided an estimate of the scope and costs for its support. The estimated Transco support cost is included in the Interconnection Agreement. Within 6-10 weeks of execution of the Interconnection Agreement, the full amount of estimated support cost is paid by PSE&G to Transco as a deposit to be drawn against periodically as the support scope is executed. Transco periodic updates of scope/estimates, actual and forecast costs are discussed during the project review meetings between PSE&G and Transco. If Transco increases its forecast for its support cost, due to scope changes or other reasons, they notify PSE&G accordingly for discussion, negotiation, and agreement. The Interconnection Agreement is then amended as agreed between Transco and PSE&G. If the total cost incurred by Transco for the complete scope of the support is less than the total amount of deposit paid by PSE&G, Transco is obligated to return the difference. The Transco support costs are captured by PSE&G as an ES 2 capital investment cost on a separate project WBS.	No change

ENERGY STRONG 2 PROGRAM INDEPENDENT MONITOR 2022 FOURTH QUARTER REPORT

PREPARED AND SUBMITTED BY

PEGASUS GLOBAL HOLDINGS, INC. ®

CONFIDENTIAL

JANUARY 2, 2024

Table of Contents

List of Acronyms and Abbreviations

Advanced Distribution Management Systems .... ADMS

Advanced Metering Interface .... AMI

Allowance for Funds Used During Construction .... AFUDC

Architect and Engineer .... A/E

Board of Public Utilities .... BPU

Construction Work In Progress .... CWIP

Costs of Removal .... COR

Distribution Management System .... DMS

Distributed Energy Resource Management System .... DERMS

Distribution Supervisory Control and Data Acquisition .... DSCADA

Energy Strong 2 .... ES 2

Gas Metering & Regulating .... Gas M&R

Independent Monitor .... IM

Inside Plant .... IP

Issued for Bid .... IFB

Issued for Construction .... IFC

Mobile Work Management System .... MWMS

New Jersey Department of Environmental Protection .... NJDEP

New Jersey Sports and Exposition Authority .... NJSEA

Open Systems International Inc. .... OSII

Outage Management System .... OMS

Outside Plant .... OP

Pipeline and Hazardous Materials Safety Administration .... PHMSA

Public Service Electric & Gas .... PSE&G

Purchase Order .... PO

Record of Decision .... ROD

Remote Control Unit .... RCU

Remote Terminal Unit .... RTU

Risk and Contingency .... R&C

Supervisory Control and Data Acquisition.. SCADA

System Average Interruption Duration Index .... SAIDI

Utility Review Board .... URB

I. Executive Summary

Public Service Electric & Gas's (PSE&G's) Energy Strong 2 (ES 2) Program was established from a Stipulation that the involved parties agreed to in August 2019, as approved by a Board of Public Utilities (BPU) Order dated September 11, 2019, with an effective date of September 21, 2019. The Stipulation provided the ES 2 Program would be comprised of five primary subprograms: Electric Station Flood Mitigation; Contingency Reconfiguration; Grid Modernization – Communications; Grid Modernization – Advanced Distribution Management Systems (ADMS); and Gas Metering & Regulating (Gas M&R) Station Upgrades. In addition, a Stipulated Base spend was established that includes both an electric component (higher outside plant design standards and station life cycle upgrades) and a gas component (overlapping with the Gas M&R subprogram). This report contains the Independent Monitor's (IM's) findings and observations on the ES 2 Program elements and other information on the Program's status as of the fourth quarter of 2022.

During the fourth quarter of 2022, the bulk of the spend within the ES 2 Program continued to be within the Electric Station Flood Mitigation, which accounted for over half the Program spend during the quarter and reflective of both the size of this subprogram and having the majority of its projects in construction. Within the Contingency Reconfiguration subprogram, Fuse Saver installations continued with 264 devices installed during the quarter against a target of 252 units, bringing the total number of Fuse Savers installed in the Program to 677 units. In the Grid Modernization – Communication System subprogram, four additional fiber installation projects were completed, bringing the total to 33 out of 34 fiber projects now completed (in addition all 12 fiber cutover projects were previously completed). The Grid Modernization – ADMS subprogram performed additional testing in the Distribution Management System (DMS)/Distributed Energy Resource Management System (DERMS) and Outage Management System (OMS) scopes. Within the Gas M&R subprogram, the Camden and East Rutherford projects were placed in-service during the fourth quarter of 2022 while pre-construction activities continued on the final three projects (Central, Mount Laurel, and Paramus). Under the Electric Stipulated Base scope, four of the five life cycle station upgrade projects (Hamilton, Paramus, Plainfield, and part of State Street Outside Plant (OP)) were placed in-service during the fourth quarter of 2022.

Table 1 – ES 2 Subprogram & Stipulated Base Status as of December 31, 2022 below provides the spend to date on the subprograms within the ES 2 Program and Stipulated Base compared to the total forecast and forecasted completion for each.

Table 1 – ES 2 Subprogram & Stipulated Base Status as of December 31, 2022

Subprogram	2022 Q4 Spend	Total Spend to Date*	Total Forecast*	% of Actuals to Forecast	Forecasted Completion**	Stipulation Funding Amount***
Electric Station Flood Mitigation	$32,035,123	$219,339,351	$362,003,445	61%	May 2024	$389M
Contingency Reconfiguration	$8,085,921	$125,888,410	$147,256,087	85%	Dec 2023	$145M
Grid Modernization – Communications	$2,046,359	$63,224,662	$66,219,762	95%	Dec 2023	$64.3M
Grid Modernization – ADMS	$5,517,418	$46,478,871	$66,344,727	76%	Jun 2023	$42.7M^
Electric Stipulated Base	$8,150,608	$67,223,343	$101,538,769	67%	Dec 2023	$100M

Subprogram	2022 Q4 Spend	Total Spend to Date*	Total Forecast*	% of Actuals to Forecast	Forecasted Completion**	Stipulation Funding Amount***
Gas M&R Station Upgrades^^	**$4,319,510**	**$80,696,447**	**$115,587,414**	**70%**	**Feb 2024**	**$101M^^^**
Total*	**$60,154,938**	**$602,851,083**	**$858,950,204**	**70%**	**May 2024**	**$842M**

-Note: total figures may not fully align due to rounding. Additionally, the total forecast includes only the base cost for the Electric Station Flood Mitigation and Gas M&R subprograms as PSE&G does not include risk and contingency (R&C) in its forecasts for these projects. See **Table 11 and **Table 20** for the Electric Station Flood Mitigation and Gas M&R project estimates, respectively, with base costs and R&C shown.*
***-Final in-service date.*
****-Following the $7.7 million transfer in July 2021 from the Grid Modernization – Communications subprogram to the Grid Modernization – ADMS subprogram.*
^-PSE&G has increased the funding for the Grid Modernization – ADMS subprogram by $13.6 million over the Stipulation amount to a total of $56.3 million (including $2.8 million in R&C).
^^-Includes both the ES 2 projects and the Stipulated Base gas projects.
^^^-PSE&G has increased the funding for the Gas M&R subprogram by $27.8 million over the Stipulation amount to a total of $128.8 million (including $24.6 million in R&C). This R&C balance is currently at $19.1 million as of the end of 2022.

As shown in **Table 1**, the total ES 2 Program forecast as of the end of 2022 is approximately $859 million, representing an increase of approximately $16 million from the prior quarter and also now $16 million over the Stipulation budget. The bulk of the forecast increase was realized in the Electric Station Flood Mitigation (+$5.1 million), Grid Modernization – ADMS (+$5.4 million), and Gas M&R subprograms (+$5.3 million) with details of these forecast increases discussed in the respective subsection for each subprogram.

Given the prominence of the Electric Station Flood Mitigation subprogram, which represents over half of the total ES 2 Program spending, a summary of the projects within this subprogram is provided below in **Table 2 – ES 2 Electric Station Flood Mitigation Status as of December 31, 2022**.

Table 2 – ES 2 Electric Station Flood Mitigation Status as of December 31, 2022

Project	Total Estimate (rounded)	Actuals	% of Actuals to Estimate	Forecasted In-Service Date*
1. Academy Street	$9,300,000	$7,230,725	78%	**10/19/2021**
2. Clay Street	$33,600,000	$21,519,813	64%	4/20/2023 (↓+28)
3. Front Street^	$27,300,000	$11,840,987	43%	1/26/2024 (↓+17)
4. Hasbrouck Heights	$19,300,000	$16,110,052	84%	**11/21/2022**
5. Kingsland	$8,700,000	$4,332,806	50%	10/4/2023 (↑-33)
6. Lakeside Avenue	$33,500,000	$4,587,643	14%	2/28/2024
7. Leonia	$24,900,000	$23,866,055	96%	**11/15/2022**
8. Market Street	$29,100,000	$28,169,888	97%	**6/25/2021**
9. Meadow Road	$8,800,000	$3,676,560	42%	9/28/2023
10. Orange Valley	$15,000,000	$2,536,767	17%	2/16/2024 (↓+14)
11. Ridgefield 13kV	$26,100,000	$27,110,169	104%	**12/12/2022**
12. Ridgefield 4kV	$20,800,000	$20,703,809	100%	**5/16/2021**
13. State Street	$19,600,000	$13,821,016	71%	**12/29/2022**
14. Toney's Brook	$16,000,000	$7,391,999	46%	5/10/2023 (↑-16)
15. Waverly	$39,900,000	$20,074,529	50%	5/7/2024 (↓+7)
16. Woodlynne	$24,000,000	$6,366,604	27%	10/27/2023 (↓+17)

Project	Total Estimate (rounded)	Actuals	% of Actuals to Estimate	Forecasted In-Service Date*
-Reflects the in-service date of the last major asset (e.g. switchgear), certain activities may take place after this date to support the final in-service date (i.e. when all customers are cutover).* ***Bold* *dates indicate the actual in-service date.* (↑)-*Indicates the forecasted in-service date advanced from the prior quarter.* (↓)-*Indicates the forecasted in-service date slipped from the prior quarter.* *^- The Front Street project was proposed by PSE&G during the second quarter of 2021 to replace the cancelled Constable Hook project.*				

As indicated in **Table 2**, four additional projects were placed in-service during the fourth quarter of 2022 (Hasbrouck Heights, Leonia, Ridgefield 13kV, and State Street), bringing the total stations in-service to seven of the 16 projects. Additionally, five of the stations (Front Street, Lakeside Avenue, Meadow Road, Orange Valley, and Toney's Brook) had new estimates approved by the PSE&G's Utility Review Board (URB) during the fourth quarter of 2022. **Table 2** also shows that the majority of the remaining projects had some movement to their respective forecasted in-service dates during the fourth quarter of 2022, ranging from Clay Street being extended 28 days to Kingsland advancing 33 days. The Front Street, Lakeside Avenue, Orange Valley, and Waverly projects continue to be forecasted to be in-service in 2024, primarily the result of the switchgear delivery delays previously discussed.

As per N.JA.C. Section 14:3-2A.5(c)2, the IM reports are to address:

i. *The effectiveness of Infrastructure Investment Program investments in meeting project objectives;*
ii. *The cost-effectiveness and efficiency of investments;*
iii. *The appropriateness of cost assignments; and*
iv. *Any other information required by the Board.*

The IM focuses the majority of the discussion within each report on these primary objectives, after introducing summarized the findings on these areas in the IM 2022 Fourth Quarter Report, the IM will continue to provide a summary on these areas for each report with an emphasis on new information relative to the current reporting period. These summarized findings are as follows:

- **Effectiveness of ES 2 investments in meeting project objectives**: The objectives for each subprogram within the ES 2 were defined within PSE&G's ES 2 filing and confirmed by the Stipulation. The overall objectives focused on improving system resiliency, reliability, and hardening through rebuilding or replacing selected substations, installing smart control and monitoring devices on distribution circuits (reclosers, fuse savers, etc.), installing ADMS and a new communication system, and rebuilding selected Gas M&R stations. Within **Section III** of this report, the IM provides a review of the status of the efforts performed to meet these objectives for each subprogram. During the fourth quarter of 2022, the following projects/scopes were placed in-service and/or completed:
    - Electric Station Flood Mitigation: Academy Street, Market Street, and Ridgefield 4kV were previously placed in-service, during the fourth quarter of 2022, Hasbrouck Heights, Leonia, Ridgefield 13kV, and State Street were also placed in-service, leaving nine projects remaining in the subprogram.

- Contingency Reconfiguration: Following the completion of the recloser scope in early 2022, the Fuse Saver installations continued with 265 units installed during the quarter (677 units installed on the Program in total out of a currently planned scope of 1,574 units).
- Grid Modernization – Communication System: 218 substations previously received RTU retrofits in the Program and 12 out of 12 fiber cutover projects were previously completed. During the fourth quarter of 2022, four additional fiber installation projects were completed, bringing the total number of projects completed to 33 out of a total scope of 34 projects.
- Electric Stipulated Base: Four of the five life cycle station upgrade projects were placed in-service during the fourth quarter of 2022.
- Gas M&R: Westampton previously placed in-service in October 2021, during the fourth quarter of 2022, the Camden and East Rutherford projects were placed in-service.

- **Cost-effectiveness and efficiency of investments**: To assess the cost effectiveness and efficiency of ES 2 investments, the IM began with a review of the initial scope, estimate, and related planning documents for each project to establish a baseline to monitor progress against as the work advances. As the Program execution advances, the IM continues to evaluate actual costs against the initial estimates and current forecasts, including seeking additional information relating to any variances identified. The overall Program's current cost forecast now above the Stipulation amount, reflecting the cost increases that as observed by the IM have largely stemmed from scope evolution and/or more detailed estimates from the time of the ES 2 filing, as well as changes in general market conditions (e.g. Covid-19 impacts, supply chain issues, etc.). The updated subprogram forecasts as of the end of 2022 compared to the end of the third quarter of 2022 were as follows:
    - Electric Station Flood Mitigation: subprogram forecast increased approximately $5.1 million (or 1.4%) to approximately $362.0 million. This increase was predominantly from forecast increases on the Kingsland and Lakeside Avenue projects.
    - Contingency Reconfiguration: subprogram forecast decreased approximately $360K (or -0.2%) to approximately $147.3 million.
    - Grid Modernization – Communication System: subprogram forecast decreased approximately $345K (or -0.5%) to approximately $66.2 million.
    - Grid Modernization – ADMS: subprogram forecast increased approximately $5.4 million (or 8.9%) to approximately $66.3 million. This increase was almost entirely within the OMS scope of the subprogram.
    - Electric Stipulated Base: subprogram forecast increased approximately $1.0 million (or 1.0%) to approximately $101.5 million. This increase was almost entirely from the Hamilton and Plainfield projects.
    - Gas M&R: subprogram forecast increased approximately $5.3 million (or 2.2%) to approximately $115.6 million. This increase was almost entirely from the Camden and East Rutherford projects.

- **Appropriateness of cost assignments**: The IM receives and reviews recurring data concerning the accumulation of costs within the Program. Based on that review, the IM submits follow-up questions to the Company regarding that data for the reporting period. Such follow-up questions generally focus on the following aspects:
  - Review of any unusual changes in cost elements from period-to-period, including but not limited to allowance for funds used during construction (AFUDC), cost of removal (COR), and the allocation of overheads.
  - Review spend on capital accounts, such as Construction Work in Progress (CWIP) as it relates to overall spend, AFUDC, and COR.
  - Verify cost accumulations and classifications appear to be in accordance with Generally Accepted Accounting Principles (GAAP), to the extent the IM has access to such information.
  - Review and investigation of prior period adjustments and/or corrections to capital accounts.
  - Engage the Company's Internal Audit group on specific areas to audit, review, and assess – particularly for areas in which the IM has limited or no visibility (proprietary data, accounting systems, etc.).

Through the above steps, the IM tracks and monitors how the Company is recording costs to support the finding that the cost assignments appear to be appropriately applied. These cost items are discussed further within **Section II.C** of this IM report.

II. Program Status

A. Key Decisions

In order to capture formalized key decisions regarding the ES 2 Program, PSE&G completes a "Record of Decision" (ROD) that includes a description of the decision; alternatives considered; the decision made; and rationale for the decision. The RODs are assessed by the IM as they are completed to review their impact to the Program. In addition, the IM may request PSE&G complete a ROD to formalize a decision if such a decision has not yet been formalized through the ROD process.

The current and pending RODs as of the date of this IM 2022 Fourth Quarter Report are presented below in **Table 3 – ES 2 Records of Decisions**.

Table 3 – ES 2 Records of Decisions

Subprogram	Record of Decision	IM Comments
Electric Station Flood Mitigation	Academy Street & State Street Change in Mitigation Method	Reasonable and appropriate *(See Section B.1. in the IM 2020 First Quarter Report)*
Electric Station Flood Mitigation	Engineering Support for Energy Strong Program Projects	Reasonable and appropriate *(See Section B.2. in the IM 2020 First Quarter Report)*
Grid Modernization – Communication System	Wireless Communication Network	Reasonable and appropriate *(See Section II.A.1. in the IM 2020 Third Quarter Report)*

Subprogram	Record of Decision	IM Comments
Grid Modernization – Communication System	Substation Communication Center	Reasonable and appropriate *(See Section II.A.2. in the IM 2020 Third Quarter Report)*
Grid Modernization – Communication System	Fiber Scope	Reasonable and appropriate *(See Section IV.A. in the IM 2020 Third Quarter Report)*
Electric Station Flood Mitigation	Constable Hook, Lakeside, & Orange Valley Change in Mitigation Method	Reasonable and appropriate *(See Sections II.A.3. and IV.B. in the IM 2020 Third Quarter Report and additional discussion in Section II.A.1. and Section IV.B. of the IM 2020 Fourth Quarter Report)*
Grid Modernization – Communication System	Communication Retrofit of Replacement and non-ES-II Units	Reasonable and appropriate *(See Section II.A.2. in the IM 2020 Fourth Quarter Report)*
Electric Station Flood Mitigation	Market Street Radioactive Soil Testing and Handling	Reasonable and appropriate *(See Section II.A.3. in the IM 2020 Fourth Quarter Report)*
Electric Station Flood Mitigation	Transfer of Clay Street Wastewater Wall Scope from ES2FM to Clay Street 69kV Project	Reasonable and appropriate *(See Section IV.A. in the IM 2020 Fourth Quarter Report)*
Contingency Reconfiguration	Energy Strong II Electric Program – Contingency Reconfiguration Subprogram, 13kV and 4kV Reclosers	Reasonable and appropriate *(See Section IV.A. in the IM 2021 First Quarter Report and Section II.A.1. in the IM 2021 Second Quarter Report)*
Grid Modernization – ADMS	Outage Management System (OMS) Implementation	Reasonable and appropriate *(See Section IV.A. in the IM 2021 First Quarter Report and Section II.A.2. the IM 2021 Second Quarter Report)*

During the fourth quarter of 2022, there were no additional RODs issued.

B. Program Management

Beginning in July 2020, the IM began participating in a bi-weekly call with PSE&G to review its bi-weekly ES 2 Program Dashboard. As with the original Energy Strong Program, the Dashboard provides a mechanism for PSE&G to monitor and control activities to be completed in order to achieve key near-term milestones, including a focus on recently completed activities, any key issues, and other key metrics (e.g. installation targets) as appropriate. These calls have proven to be an effective way for the IM to stay informed on current and upcoming activities and to allow a venue for discussions between the IM and PSE&G on these activities and status updates and continue to be held on a recurring basis.

C. Cost Assignments

1. Costs of Removal (COR)

Costs of Removal (COR) generally include costs for such activities as environmental removal, removal of inside station equipment, structures, foundations, towers and fixtures, conductors and other electrical devices, poles and fixtures, transformers, plant demolition, foundations, and removal of underground conduit and other wiring. Generally, COR are charged to Accumulated Depreciation and are amortized and recovered through a component of depreciation expense. The specific method and amount of recovery is determined in gas and electric rate cases before the BPU.

Table 4 – ES 2 Program Costs of Removal as of December 31, 2022, below itemizes the charges to COR for each quarter of 2022, total COR for the years 2022, 2021, 2020, 2019, and total Energy Strong COR to date. These amounts do not reflect any salvage value reductions, which have been de minimis (about $0.4 million) in the Energy Strong program through December 31, 2022.

Table 4 – ES 2 Program Costs of Removal as of December 31, 2022

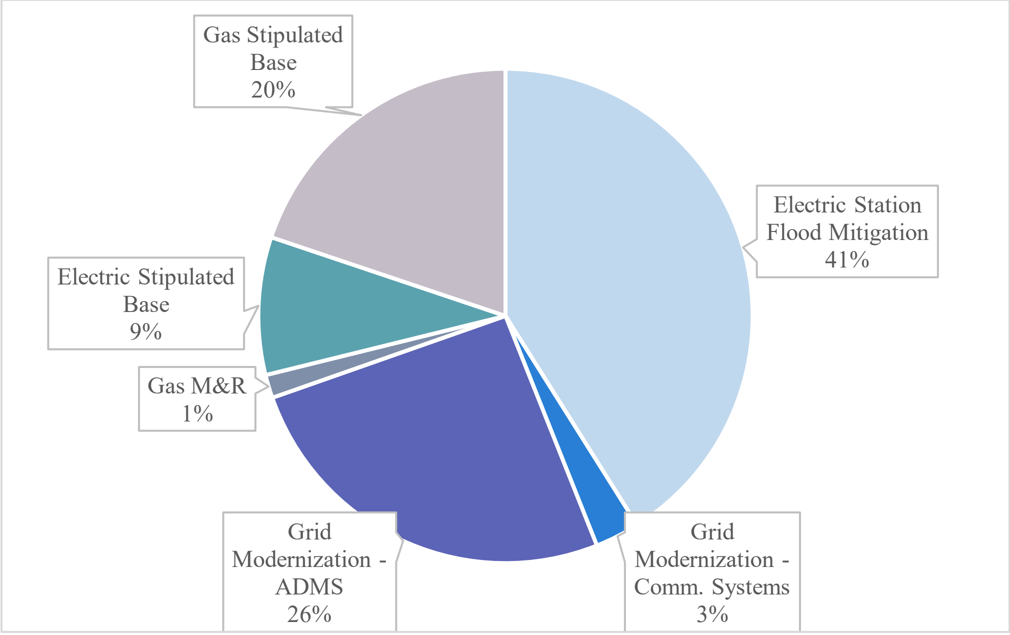
Subprogram	Q4 2022	Q3 2022	Q2 2022	Q1 2022	Total 2022	Total 2021	Total 2020	Total 2019 (Q4)	Total COR
		(in $ thousands)							
Electric Station Flood Mitigation	$1,037.5	$397.2	$595.7	$873.4	$2,903.8	$5,558.7	$1,021.1	$0	**$9,483.6**
Contingency Reconfiguration	$367.1	$213.5	$35.7	$229.3	$845.6	$2,250.2	$2,198.9	$431.0	**$5,725.7**
Grid Modernization – Communications	$0.0	$5.3	$14.0	$11.0	$30.3	$137.8	$24.4	$0	**$192.5**
Grid Modernization – ADMS	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	**$0.0**
Electric Stipulated Base	$467.7	$183.1	$340.5	$370.0	$1,361.3	$150.0	$0.0	$0.0	**$1,511.3**
Gas M&R Station Upgrades	$0.1	$763.0	$0.0	($0.4)	$762.7	$148.9	$0.0	$0.0	**$911.6**
Gas Stipulated Base	($0.1)	$0.0	$0.1	$431.5	$431.5	$0.0	$0.0	$0.0	**$431.5**
Total	**$1,872.3**	**$1,562.1**	**$986.0**	**$1,914.8**	**$6,335.2**	**$8,245.6**	**$3,244.4**	**$431.0**	**$18,256.2**

The COR charges for the fourth quarter of 2022 primarily reflect approximately $0.7 million of demolition activities at the Academy Street substation project, approximately $0.3 million for removal of poles and fixtures in Southern District Fuse Savers scope, and $0.2 million of costs associated with the removal of the old 4kV bus and related equipment at the Paramus Electric Stipulated Base project.

2. Construction Work-in-Progress (CWIP) & In-Service Transfers

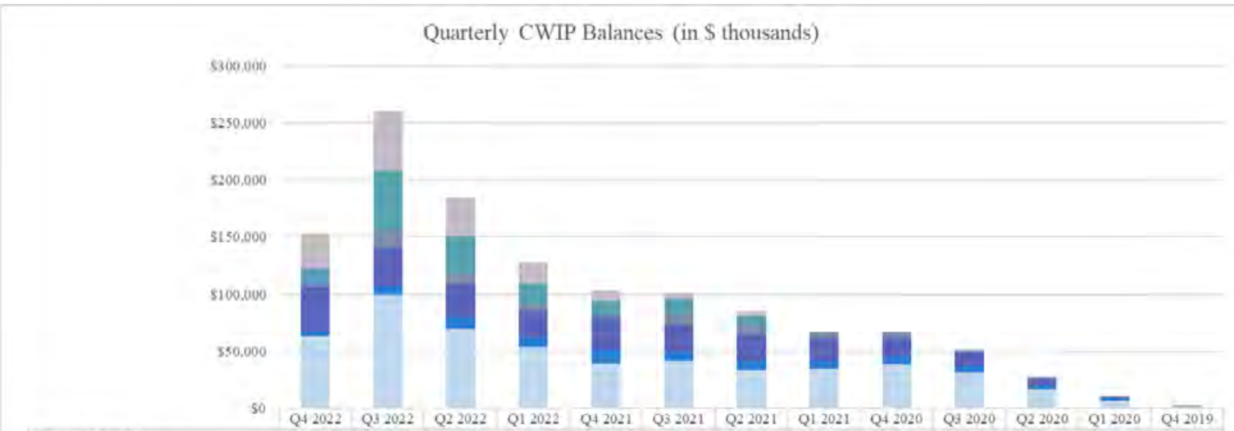
As of December 31, 2022, the Energy Strong CWIP balance was $153.2 million, compared to $260.7 million as of September 30, 2022. The largest components of CWIP as of the end of 2022 were the Clay Street ($22.7 million), Waverly ($8.4 million), and Toney's Brook ($7.7 million) Electric Station Flood Mitigation projects, the Central ($26.3 million) Gas Stipulated Base M&R project, the Woodbury ($12.0 million) Electric Stipulated Base Substation Lifecycle project, and work associated with the ADMS subprogram ($39.3 million). The Electric Station Flood Mitigation subprogram comprises the largest component of total end of period CWIP outstanding, as depicted in **Figure 1 – ES 2 CWIP as of December 31, 2022** below.

Figure 1 – ES 2 CWIP as of December 31, 2022



In addition, **Figure 2 – ES 2 CWIP Balances by Subprogram as of December 31, 2022** below depicts the composition of end-of-quarter CWIP balances by subprogram for each quarter of 2022, 2021 and 2020, and the fourth quarter of 2019.

Figure 2 – ES 2 CWIP Balances by Subprogram as of March 31, 2022



	Q4 2022	Q3 2022	Q2 2022	Q1 2022	Q4 2021	Q3 2021	Q2 2021	Q1 2021	Q4 2020	Q3 2020	Q2 2020	Q1 2020	Q4 2019
Gas Stipulated Base	$30,399	$52,329	$33,854	$18,757	$9,042	$4,691	$3,808	$-	$-	$-	$-	$-	$-
Electric Stipulated Base	$13,804	$51,540	$32,179	$18,841	$11,560	$13,645	$9,280	$-	$-	$-	$-	$-	$-
Gas M&R	$2,336	$15,984	$9,642	$5,086	$3,338	$8,735	$6,574	$6,123	$4,032	$2,149	$951	$291	$53
Grid Modernization - ADMS	$39,310	$33,396	$30,010	$22,534	$28,057	$24,817	$22,085	$19,600	$16,837	$12,502	$5,428	$969	$36
Grid Modernization - Comm. Systems	$4,558	$8,080	$9,872	$8,847	$11,991	$8,077	$9,343	$6,026	$6,760	$4,529	$3,508	$1,908	$75
Electric Station Flood Mitigation	$62,913	$99,393	$69,358	$53,834	$38,947	$41,077	$33,531	$35,299	$38,727	$31,860	$17,149	$7,101	$1,987

Electric Station Flood Mitigation ■ Grid Modernization - Comm. Systems ■ Grid Modernization - ADMS ■ Gas M&R ■ Electric Stipulated Base ■ Gas Stipulated Base

Transfers from CWIP to plant in service were $149.4 million during the fourth quarter of 2022, including the Camden ($19.5 million) and East Rutherford ($21.2 million) Gas M&R projects, the Plainfield ($17.0 million) and Hamilton ($14.6 million) Electric Stipulated Base projects, and the Hasbrouck ($14.3 million) and State Street ($13.2 million) Electric Station Flood Mitigation projects. Total ES 2 transfers from CWIP were $238 million through December 31, 2022. It should be noted that work related to certain assets, such as the reclosers under the Contingency Reconfiguration subprogram, generally can be completed without being recorded through CWIP. As such, no AFUDC is recorded on these expenditures. This accounting treatment is in accord with generally accepted accounting principles and the Company's accounting policies.

3. Allowance for Funds Used During Construction (AFUDC)

The amount of quarterly AFUDC recorded by the Company for each Energy Strong subprogram during each quarter of 2022, and total AFUDC for the years 2022, 2021, 2020 and 2019, and total Energy Strong AFUDC accrued to date, is shown below in **Table 5 – ES 2 Program AFUDC as of December 31, 2022**.

Table 5 – ES 2 Program AFUDC as of December 31, 2022

Subprogram	Q4 2022	Q3 2022	Q2 2022	Q1 2022	Total 2022	Total 2021	Total 2020	Total 2019 (Q4)	Total AFUDC
	(in $ thousands)								
Electric Station Flood Mitigation	$1,365.6	$1,285.1	$944.5	$759.0	$4,354.2	$2,281.2	$936.5	$9.9	**$7,581.8**
Contingency Reconfiguration	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	**$0.0**
Grid Modernization – Communications	$56.6	$98.5	$123.1	$115.6	$393.8	$386.9	$184.3	$0.2	**$965.2**
Grid Modernization – ADMS	$614.8	$536.9	$438.9	$385.7	$1,976.3	$1,365.6	$352.7	$0.1	**$3,694.7**
Electric Stipulated Base	$589.1	$645.0	$383.9	$230.0	$1,848.0	$524.6	$44.0	$0.0	**$798.6**
Gas M&R Station Upgrades (incl. Stip. Base)	$850.9	$733.8	$395.6	$208.3	$2,188.6	$470.0	$70.0	$0.2	**$2,728.8**
Total	**$3,477.0**	**$3,299.3**	**$2,286.0**	**$1,698.6**	**$10,760.9**	**$5,028.3**	**$1,587.5**	**$10.4**	**$17,387.1**

AFUDC accrued for ES 2 projects during the fourth quarter of 2022 increased slightly over AFUDC accrued during the third quarter of 2022 as the result of increases in the average CWIP balances in the early months of the fourth quarter. While the total fourth quarter end-of-period CWIP balances decreased from the previous quarter's end-of-period balances, the higher intra-period balances are reflected in higher total AFUDC accrued during the fourth quarter (the Company uses a mid-month convention for calculating AFUDC).

During the first quarter of each year, the AFUDC rate is reviewed for possible reset as it applies to the current year based on updated capital structure and component cost data. For the year 2022, the new AFUDC rate was calculated to be 6.92%, using the capital structure and component costs as of January 31, 2022. This rate is higher than the 2021 rate of 6.81%, primarily due to a zero balance of short-term in the 2022 calculation (vs. a $44 million balance of short-term debt in 2021), and also to an 8% reduction in the Company's amount of long-term debt outstanding (lowering the debt component of the capital structure from 45.5% to 44.8%), and a reduction in the embedded cost of long-term debt, both as used in the AFUDC calculation. In calculating the 2022 AFUDC rate, the Company used (i) a 3.63% embedded cost of long-term debt (vs. 3.85% in 2021), (ii) no short-term debt, and (iii) a cost of equity of 9.60% (unchanged from 2021).

Subsequent to the annual reset calculation referred to above, and during the course of each year, the AFUDC rate is also recalculated as it applies to each fiscal quarter. If the recalculated rate changes by 25 basis points from the rate then in effect, the rate is reset and retroactively applied to January 1 of that year. For the fourth quarter of 2022, based on data as of December 31, 2022, the recalculated weighted average AFUDC accrual rate (6.92%) did not meet this criterion to warrant changing from the annual rate (6.92%) in effect. Therefore, AFUDC was accrued during the fourth quarter of 2022 at the calculated rate of 6.92%.

The IM observes that the Company's calculation of the AFUDC rate and its application is in accordance with both PSE&G's accounting policy and Plant Instruction 3(17) of the Federal Regulatory Commission's Uniform Systems of Accounts prescribed for public utilities.

The IM also notes that the relevant AFUDC information as it relates to fourth quarter 2022 ES 2 project costs is consistent with the applicable dictates of the Stipulation entered into with respect to these Energy Strong projects. The IM will continue to review future ES 2 AFUDC accruals for consistency with relevant provisions of the Stipulation for accounting and reporting purposes only, and not as a party to, or in expressing an opinion concerning, any rate proceedings.

4. Allocated Overheads

PSE&G follows a philosophy of allocating overhead costs, whether at the Service Company or from utility support organizations, to the operating company or unit receiving the benefit, and ultimately, if appropriate, settling costs to individual assets. Where possible, services are charged directly to the entity receiving the benefit, but where direct charging of costs is not feasible, cost allocations from the Service Company to operating companies are prescribed in a BPU-approved schedule issued pursuant to a BPU order in July 2003. This Order was amended by a BPU Order dated June 8, 2022, allowing the company to transfer certain employees to the PSE&G Service Company in an effort to better support transmission growth opportunities and projects. This action had no impact on existing overhead allocations. The Stipulation requires the Company to follow its current practices with regard to capitalized overheads.

For ES2 electric and gas distribution projects, allocated overhead costs should primarily come from utility-related labor costs associated with administrative and supervisory personnel, labor and other costs associated with bargaining unit personnel, fringe benefits, materials handling costs, payroll taxes and depreciation expense. Shown below in **Table 6 – ES 2 Program Overhead Allocations as of December 31, 2022** are the allocated overhead costs charged to ES 2 projects for each quarter of 2022, total allocated overheads for the years 2022, 2021, 2020, 2019 and total Energy Strong allocated overheads to date.

Table 6 – ES 2 Program Overhead Allocations as of December 31, 2022

Subprogram	Q4 2022	Q3 2022	Q2 2022	Q1 2022	Tota 2022	Total 2021	Total 2020	Total 2019 (Q4)	Total Overhead Allocations
	(in $ thousands)								
Electric Station Flood Mitigation	$5,882	$3,324	$2,208	$2,185	$13,599	$14,368	$14,023	$287	**$42,277**
Contingency Reconfiguration	$3,282	$3,037	$795	$843	$7,957	$14,420	$17,109	$3,415	**$42,901**
Grid Modernization – Communications	$106	$553	$717	$1,802	$3,178	$9,171	$3,625	$12	**$15,986**

Subprogram	Q4 2022	Q3 2022	Q2 2022	Q1 2022	Tota 2022	Total 2021	Total 2020	Total 2019 (Q4)	Total Overhead Allocations
	(in $ thousands)								
Grid Modernization – ADMS	$128	$50	$124	$76	$378	$501	$426	$11	**$1,316**
Electric Stipulated Base	$2,457	$2,751	$1,275	$1,449	$7,932	$2,123	$259	$0	**$10,314**
Gas M&R Station Upgrades (incl. Stip. Base)	$236	$435	$339	$197	$1,207	$735	$291	$15	**$2,248**
Total	**$12,091**	**$10,149**	**$5,458**	**$6,552**	**$34,250**	**$41,318**	**$35,733**	**$3,740**	**$115,041**

The overwhelming majority of overhead costs allocated to ES 2 projects during the fourth quarter of 2022 are costs allocated from areas that support all utility distribution and transmission projects, including ES 2 projects. More specifically, most (approximately 78%) of the fourth quarter allocated costs reflect labor costs of supervisory, administrative and operations planning personnel, labor and other costs from bargaining unit personnel, and fringe benefits associated with these labor costs. The increase in overhead costs for the fourth quarter of 2022 over the third quarter of 2022 primarily reflects an increase in construction activities at a number of Electric Station Flood Mitigation projects, which resulted in increased labor costs and surchargable outside services.

D. System Performance

In the ongoing monitoring of the performance of its completed investments, PSE&G recently assessed the performance of the reclosers installed during the ES 2 Program by measuring the number of customers experiencing an outage for each recloser operation incident that resulted in extended supply interruptions and comparing this data from before (2018-2019) and after the ES 2 investments were made (2022). This analysis concluded that the new reclosers contributed to an approximately 12% improvement in the overall SAIFI compared to the earlier pre-recloser period examined.

1. Current Reporting Quarter Major Events

During the fourth quarter of 2022, there were no Major Events reported in PSE&G's service territory.

III. Project Status

A. Electric Station Flood Mitigation

A summary of the subprogram plan as of the end of 2022 compared to the status as of the end of 2019, end of 2020, and end of 2021 is provided below in **Table 7 – ES 2 Electric Station Flood Mitigation Subprogram Milestone Schedule as of December 31, 2022**. Note that the Academy, Market Street, and Ridgefield 4kV projects were previously placed in-service and closed out, thus there are no further updates to these projects (which have been further called out in italics in **Table 9**).

Table 7 – ES 2 Electric Station Flood Mitigation Milestone Schedule as of December 31, 2022

Project	Plan Status Point	2019		2020				2021				2022				2023				2024
		Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	
1. Academy Street	Dec. 2019		KO					C					IS		CO					
	Dec. 2020		KO		C									CO						
	Dec. 2021		KO		C						IS						CO			
	Dec. 2022		KO		C						IS		CO							
2. Clay Street	Dec. 2019	*Schedule Under Development*																		
	Dec. 2020			KO							C					IS				CO (Q2)
	Dec. 2021			KO							C				IS					CO (Q1)
	Dec. 2022			KO							C						IS			CO (Q2)
3. Front Street^	Dec. 2019	*Not in ES 2 Program*																		
	Dec. 2020	*Not in ES 2 Program*																		
	Dec. 2021								KO				C						IS	CO (Q2)
	Dec. 2022								KO				C							IS (Q1); CO (Q3)
4. Hasbrouck Heights	Dec. 2019		KO						C						IS		CO			
	Dec. 2020		KO									C					IS		CO	
	Dec. 2021		KO									C					IS	CO		
	Dec. 2022		KO									C			IS			CO		
5. Kingsland	Dec. 2019			KO				C			IS		CO							
	Dec. 2020			KO										C					IS	CO (Q2)
	Dec. 2021			KO											C		IS		CO	
	Dec. 2022			KO										C					IS	CO (Q2)
6. Lakeside Avenue	Dec. 2019*				KO				C										IS	CO (Q2)
	Dec. 2020						KO							C					IS	CO (Q2)
	Dec. 2021						KO							C					IS	CO (Q2)
	Dec. 2022						KO							C						IS (Q1); CO (Q3)
7. Leonia	Dec. 2019	*Schedule Under Development*																		
	Dec. 2020			KO		C									IS		CO			
	Dec. 2021			KO		C									IS		CO			
	Dec. 2022			KO		C									IS		CO			
8. Market Street	Dec. 2019			KO				C	OS		CO									
	Dec. 2020			KO					C	OS		CO								
	Dec. 2021			KO						C/OS	CO									
9. Meadow Road	Dec. 2019	*Schedule Under Development*																		
	Dec. 2020			KO											C				IS	CO (Q2)
	Dec. 2021			KO										C				IS		CO (Q1)
	Dec. 2022			KO										C				IS		CO (Q1)
10. Orange Valley	Dec. 2019	*Schedule Under Development*																		
	Dec. 2020					KO										C				IS (Q1); CO (Q3)
	Dec. 2021					KO										C				IS (Q1); CO (Q3)
	Dec. 2022					KO								C						IS (Q1); CO (Q2)
11. Ridgefield 13kV	Dec. 2019			KO	C										IS		CO			
	Dec. 2020			KO	C										IS		CO			
	Dec. 2021			KO	C										IS		CO			
	Dec. 2022			KO	C										IS		CO			

December 31, 2023 - ES 2 Program End Date

Project	Plan Status Point	2019		2020				2021				2022				2023					2024
		Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4		
12. Ridgefield 4kV	Dec. 2019			<u>KO</u>						C	OS			CO						*December 31, 2023 - ES 2 Program End Date*	
	Dec. 2020			<u>KO</u>	<u>C</u>				OS		CO										
	Dec. 2021			<u>KO</u>	<u>C</u>				<u>OS</u>		<u>CO</u>										
13. State Street	Dec. 2019		<u>KO</u>					C								IS					CO (Q1)
	Dec. 2020		<u>KO</u>						C				IS								CO (Q1)
	Dec. 2021		<u>KO</u>						<u>C</u>					IS				CO			
	Dec. 2022		<u>KO</u>						<u>C</u>						<u>IS</u>		CO				
14. Toney's Brook	Dec. 2019			<u>KO</u>						C									IS		CO (Q2)
	Dec. 2020			<u>KO</u>										C			IS				CO (Q2)
	Dec. 2021			<u>KO</u>										C			IS				CO (Q2)
	Dec. 2022			<u>KO</u>										<u>C</u>			IS		CO		
15. Waverly	Dec. 2019	*Schedule Under Development*																			
	Dec. 2020			<u>KO</u>			<u>C</u>												IS		CO (Q2)
	Dec. 2021			<u>KO</u>			<u>C</u>														IS (Q3); CO (Q1 2025)
	Dec. 2022			<u>KO</u>			<u>C</u>														IS (Q2); CO (Q4)
16. Woodlynne	Dec. 2019		<u>KO</u>												C				IS		CO (Q2)
	Dec. 2020		<u>KO</u>												C				IS		CO (Q2)
	Dec. 2021		<u>KO</u>												C				IS		CO (Q2)
	Dec. 2022		<u>KO</u>									<u>C</u>							IS		CO (Q2)

<u>Legend</u>: KO = Kickoff; C = Construction; IS = Fully In-Service (major assets in-service); OS = Out-of-Service (if eliminated); CO = Closeout
-Actuals are indicated with an underline (Note: for the Market Street and Ridgefield 4kV projects, outside plant construction began in the first quarter of 2020, the construction milestone indicated on this chart reflects inside plant construction).
***-The Dec. 2019 Lakeside Avenue project schedule was based on the original raise and rebuild mitigation strategy; the current schedule reflects the proposed mitigation method change that contemplates relocating the substation.**
^-The Front Street project was proposed by PSE&G during the second quarter of 2021 to replace the cancelled Constable Hook project.

A summary of the subprogram status as of the end of 2022 is provided below **Table 8 – ES 2 Electric Station Flood Mitigation Summary Status as of December 31, 2022**.

Table 8 – ES 2 Electric Station Flood Mitigation Summary Status as of December 31, 2022

Activity	Total # of Projects	Specific Projects
Kickoff Meeting	16	Academy Street; Clay Street; Front Street; Hasbrouck Heights; Kingsland; Lakeside Avenue; Leonia; Market Street; Meadow Road; Orange Valley; Ridgefield 13kV; Ridgefield 4kV; State Street; Toney's Brook; Waverly; Woodlynne
Key Drawing Review	16	Academy Street; Clay Street; Front Street; Hasbrouck Heights; Kingsland; Lakeside Avenue; Leonia; Market Street; Meadow Road; Orange Valley; Ridgefield 13kV; Ridgefield 4kV; State Street; Toney's Brook; Waverly; Woodlynne
Scope Locked	16	Academy Street; Clay Street; Front Street; Hasbrouck Heights; Kingsland; Lakeside Avenue; Leonia; Market Street; Meadow Road; Orange Valley; Ridgefield 4kV; Ridgefield 13kV; State Street; Toney's Brook; Waverly; Woodlynne
Major Equipment Purchase Orders (POs)	18*	Academy Street; Clay Street; Front Street*; Hasbrouck Heights; Kingsland; Lakeside; Leonia*; Meadow Road; Orange Valley;

Activity	Total # of Projects	Specific Projects
		Ridgefield 13kV*; State Street; Toney's Brook; Waverly*; Woodlynne
Architect/ Engineer (A/E) Contract Award (or selection of PSE&G internal engineering)	16	Academy Street[1]; Clay Street[1]; Front Street[3]; Hasbrouck Heights[1]; Kingsland[2]; Lakeside Avenue[3]; Leonia[2]; Market Street[2]; Meadow Road[2]; Orange Valley[1]; Ridgefield 13kV[2]; Ridgefield 4kV[2]; State Street[2]; Toney's Brook[3]; Waverly[3]; Woodlynne[1]
Construction Start**	16	Academy Street; Clay Street; Front Street; Hasbrouck Heights; Kingsland; Lakeside Avenue; Leonia; Market Street; Meadow Road; Orange Valley; Ridgefield 4kV; Ridgefield 13kV; State Street; Toney's Brook; Waverly; Woodlynne
In-Service	7	Academy Street; Hasbrouck Heights; Leonia; Market Street; Ridgefield 4kV; Ridgefield 13kV; State Street
Partial In-Service	2	Front Street (contingency); Waverly (26kV switchgear)

**-Three of the listed projects (Front Street, Leonia, Ridgefield 13kV, and Waverly) have two switchgears, thus the current count reflects 18 switchgears at 14 substations.*
[1]-Indicates Burns & McDonnell is serving as the A/E.
[2]-Indicates PSE&G internal resources are serving as the A/E.
[3]-Indicates Black & Veatch is serving as the A/E.
***-Includes projects that have commenced inside plant (IP) and/or outside plant (OP) construction; also maintains identification of projects that have since completed construction (generally those that are shown as in-service).*

Beyond the key activities summarized in **Table 8** above, **Table 9 – ES 2 Electric Station Flood Mitigation Planned Activities for Q1 2023** summarizes the activities planned for each project during the first quarter of 2023, including noted carryover of activities from earlier periods.

Table 9 – ES 2 Electric Station Flood Mitigation Planned Activities for Q1 2023

Station	Planned Activities for Q1 2023	Carryover Activities from Q4 2022
1. Academy Street	• Continued demolition of old station	• Demolition of old station
2. Clay Street	• Start underground Division cold work • Start demolition of existing equipment	• Continue civil and electrical construction
3. Front Street	• Start demolition of existing equipment	• Commission and energize contingency switchgear (completion of circuit cutovers)
4. Hasbrouck Heights	• Start electrical and civil demolition	• Completion of circuit cutovers
5. Kingsland	• Start manhole modifications • Received 13kV switchgear (from Ridgefield 13kV)	• Continued civil and electrical construction
6. Lakeside Avenue	• Install cable trench	• Continued civil construction (elevated switchgear foundation)
7. Leonia	• Start disassembly of contingency switchgear	• Continued electrical construction
8. Market Street	*Project complete*	
9. Meadow Road	• Complete manhole modifications • Start electrical construction	• Continued civil construction
10. Orange Valley	• Install duct banks, platform steel for switchgear	• Continued civil construction (switchgear foundations)
11. Ridgefield 13kV	• Disassembly of contingency switchgear	• Complete circuit cutovers to new switchgear
12. Ridgefield 4kV	*Project complete*	

Station	Planned Activities for Q1 2023	Carryover Activities from Q4 2022
13. State Street	• Demolition of existing equipment	• Complete circuit cutovers to new switchgear
14. Toney's Brook	• Set regulators/reactors • Start switchgear commissioning	• Continued electrical construction
15. Waverly	• Start civil construction phase 3 (new station)	• Continued demolition (existing station)
16. Woodlynne	• Start electrical construction • 26kV circuit reconfiguration (prerequisite work)	• Continued civil construction

As discussed in the IM 2022 First Quarter Report, PSE&G's switchgear vendor, Powercon, informed PSE&G that due to various material and sub-supplier delays, the remaining major equipment deliveries may continue to see impacts. Powercon continues to explore options to improve its production floor efficiencies and ordering supplies earlier to potentially alleviate further impacts. PSE&G has requested more detailed and frequent status updates from Powercon to better inform its project planning. The status of the major equipment deliveries for the Electric Station Flood Mitigation projects is presented in **Table 10 – Electric Station Flood Mitigation Major Switchgear Deliveries as of December 31, 2022**.

Table 10 – Electric Station Flood Mitigation Switchgear Deliveries as of December 31, 2022

Station	Description	Delivery Status as of Q3 2022	Delivery Status as of Q4 2022
1. Academy Street	13kV switchgear	***11/7/2020***	***11/7/2020***
2. Clay Street	4kV switchgear	10/3/2022	***12/5/2022***
3. Front Street	4kV switchgear	8/15/2023	8/14/2023
	4kV cont. switchgear	***8/25/2022***	***8/25/2022***
4. Hasbrouck Heights	4kV switchgear	***11/30/2021***	***11/30/2021***
5. Kingsland	13kV switchgear[1]	***9/30/2020***	***9/30/2020***
6. Lakeside Avenue	4kV switchgear	6/30/2023	6/30/2023
7. Leonia	13kV switchgear #1	***5/24/2021***	***5/24/2021***
	13kV switchgear #2	***6/16/2022***	***6/16/2022***
	13kV cont. switchgear[2]	***10/16/2020***	***10/16/2020***
8. Market Street	Elimination project		
9. Meadow Road	13kV switchgear[2]	2/14/2023	2/14/2023
10. Orange Valley	4kV switchgear	8/15/2023	8/31/2023
11. Ridgefield 13kV	13kV switchgear #1	***8/24/2022***	***8/24/2022***
	13kV switchgear #2	***4/27/2021***	***4/27/2021***
	13kV cont. switchgear[1]	***9/30/2020***	***9/30/2020***
12. Ridgefield 4kV	Elimination project		
13. State Street	4kV switchgear	***12/15/2021***	***12/15/2021***
14. Toney's Brook	4kV switchgear	12/20/2022	1/5/2023
15. Waverly	26kV switchgear	***4/30/2021***	***4/30/2021***
	4kV switchgear	10/31/2022	***11/1/2022***
16. Woodlynne	4kV switchgear	2/6/2023	3/27/2023

Note: bold/italicized dates indicate actual delivery dates.
[1]The Kingsland 13kV switchgear was delivered to the Ridgefield 13kV site where it is being used as the contingency/temporary switchgear for that project before its permanent installation on the Kingsland project. Delivery of the switchgear to the Kingsland site will follow the Ridgefield 13kV project being placed in-service, which was achieved in December 2022 with the disassembly of the contingency/temporary switchgear and delivery to Kingsland expected in the first quarter of 2023.
[2]The Meadow Road project will use the Leonia project's 13kV contingency switchgear as its permanent switchgear.

As indicated in **Table 10**, during the fourth quarter of 2022, there were two additional switchgear deliveries received (4kV switchgears for Clay Street and Waverly), leaving six deliveries remaining for the subprogram. Of the remaining six deliveries, three had the forecasted delivery date unchanged from the prior quarter (or a change of one day for Front Street), while two of the other three each slipped approximately two weeks (Orange Valley and Toney's Brook) and Woodlynne's forecasted delivery slipped approximately seven weeks, continuing to reflect the challenges Powercon is experiencing.

The current project estimates are shown below in **Table 11 – ES 2 Electric Station Flood Mitigation Project Cost Status as of December 31, 2022**. As discussed in the IM 2022 First Quarter Report, PSE&G decided to consolidate the R&C on the individual projects into one R&C balance for the entire subprogram, thus there is no estimated R&C amount at the project level. **Table 11** also shows the current estimate level based on PSE&G's estimating processes and as approved by the URB, the actual spend, and percentage of actuals to estimate as of the end of 2022. In addition, while the current placeholder/R&C balance for the subprogram is $33.2 million, PSE&G has identified the Hamilton lifecycle upgrade project under Electric Stipulated Base as a candidate to receive funding through the Electric Station Flood Mitigation subprogram (and thus via Accelerated Recovery) should funds remain in accordance with the Stipulation.[1]

Table 11 – ES 2 Electric Station Flood Mitigation Project Cost Status as of December 31, 2022

Project	Estimate Level	Base	Risk & Contingency*	Total	Current Forecast	Actuals to Date	% of Actuals to Estimate
1. Academy Street	Definitive	$9,300,000	$-	$9,300,000	$8,231,026	$7,230,725	78%
2. Clay Street	Definitive	$33,600,000	$-	$33,600,000	$33,613,927	$21,519,813	64%
3. Front Street**	Conceptual	$27,300,000	$-	$27,300,000	$27,735,408	$11,840,987	43%
4. Hasbrouck Heights	Definitive	$19,300,000	$-	$19,300,000	$19,094,923	$16,110,052	84%
5. Kingsland	Conceptual	$8,700,000	$-	$8,700,000	$10,578,839	$4,332,806	50%
6. Lakeside Avenue	Conceptual	$33,500,000	$-	$33,500,000	$34,133,083	$4,587,643	14%
7. Leonia	Definitive	$24,900,000	$-	$24,900,000	$25,899,588	$23,866,055	96%
8. Market Street	Definitive	$29,100,000	$-	$29,100,000	$28,272,387	$28,169,888	97%
9. Meadow Road	Definitive	$7,200,000	$-	$8,800,000	$8,897,000	$3,676,560	42%
10. Orange Valley	Conceptual	$15,000,000	$-	$15,000,000	$15,014,505	$2,536,767	17%

[1] Paragraph 25 of the Stipulation indicated *"If the Company determines the work on the 16 aforementioned substations identified in the flood mitigation subprogram can be completed under the $389 million investment ceiling associated with substations, PSE&G may reallocate any funds to those stations identified in the life cycle station upgrade portion of the June 8, 2018 filing for accelerated recovery."*

Project	Estimate Level	Base	Risk & Contingency*	Total	Current Forecast	Actuals to Date	% of Actuals to Estimate
11. Ridgefield 13kV	Conceptual	$26,100,000	$-	$26,100,000	$28,308,468	$27,110,169	104%
12. Ridgefield 4kV	Definitive	$20,700,000	$-	$20,700,000	$20,703,808	$20,703,809	100%
13. State Street	Definitive	$19,600,000	$-	$19,600,000	$20,287,142	$13,821,016	71%
14. Toney's Brook	Definitive	$16,000,000	$-	$16,000,000	$16,228,831	$7,391,999	46%
15. Waverly	Conceptual	$39,900,000	$-	$39,900,000	$40,921,572	$20,074,529	50%
16. Woodlynne	Definitive	$24,000,000	$-	$24,000,000	$24,083,009	$6,366,604	27%
ES 2 Station Placeholder	N/A	$-	$33,200,000	$33,200,000	$-	$-	-
Subprogram Total		**$355,800,000**	**$33,200,000**	**$389,000,000**	**$362,003,445**	**$219,339,352**	**56%**

**-As discussed in Section II.B. of the IM 2022 First Quarter Report, PSE&G made the decision to hold risk and contingency at the subprogram level, which resulted in updated estimates being prepared for each project to reflect this change and other project-specific updates as warranted.*

***-The Front Street project was proposed by PSE&G during the second quarter of 2021 to replace the cancelled Constable Hook project.*

Findings & Observations

- Four projects were placed in-service during the fourth quarter of 2022 (Hasbrouck Heights, Leonia, Ridgefield 13kV, and State Street). As shown in **Table 7**, execution of these projects closely followed the original plans developed earlier in the Program. This brings the total projects placed in-service on the subprogram to seven out of the 16 projects as of the end of 2022. The next projects forecasted to go in-service are Clay Street and Toney's Brook, both forecasted for the second quarter of 2023.

- Of the nine remaining Electric Station Flood Mitigation projects, seven had movement in the forecasted in-service date during the fourth quarter of 2022, with two advancing and five slipping. For most of the projects the shift was roughly two weeks or less with the biggest changes involving the following projects:

    - Kingsland (advancing 33 days to October 4, 2023); and,
    - Clay Street (slipping 28 days to April 20, 2023).

  For Kingsland, the improvement in the forecasted in-service date was driven by the delivery of the 13kV switchgear from the Ridgefield 13kV project advancing from April to March 2023, while on Clay Street the delay was driven by the switchgear controls IFC drawings not being up to date with Powercon's as-builts, which required drawing revisions and resulted in a delay to commissioning activities.

- The overall subprogram forecast as of the end of 2022 increased approximately $5.1 million (or 1.4%) to $362.0 million from the status as of the third quarter of 2022. The forecast continues to remain under the current subprogram estimate and Stipulation amount of $389.0 million (which includes $33.2 million in R&C). The Kingsland and Lakeside Avenue projects accounted for the majority of this forecast increase, as detailed below:
    - Kingsland (increased $1.6 million to $10.6 million): due to required manhole modifications, site investigations, and detailed material take-offs.
    - Lakeside Avenue (increased $1.4 million to $34.1 million): due to the extended project schedule and circuit reconfigurations and re-labeling of circuits.
- With 61% of the subprogram forecast now spent (56% of the Stipulation amount), the IM continues to find that even with some cost pressures on certain projects, there is adequate R&C remaining in the subprogram for it to be completed under budget. However, the schedule status of the later projects in this subprogram, and in particular those with open switchgear deliveries currently forecasted for 2023 will have to continue to be closely followed to monitor if the projects can be completed within the ES 2 Program window. At this time, the primary risk to the project schedule is those major equipment deliveries, followed by resource availability to support schedule requirements and weather-related impacts (e.g. resources diverted to assist with recovery efforts or less activity performed than planned due to inclement weather). Prior delays to switchgear deliveries caused the forecasted in-service dates for Front Street, Lakeside Avenue, Orange Valley, and Waverly to slip into 2024.
- Regarding the projects with remaining switchgear deliveries, PSE&G continues to meet regularly with its vendor to receive updated information as to the status of these deliveries. PSE&G has also worked with the vendor to re-prioritize certain deliveries to optimize the project schedules and advanced the in-service date if possible. During the fourth quarter of 2022 the 4kV switchgears were received at Clay Street and Waverly. Of the remaining five switchgear deliveries, two had their forecasted delivery dates essentially unchanged from the prior quarter, while three slipped from two weeks to five weeks (Orange Valley, Toney's Brook, and Woodlynne). For the Meadow Row project, which is using the contingency switchgear from Leonia as its permanent switchgear, the Leonia project was placed in-service during the fourth quarter of 2022 with disassembly of the contingency switchgear planned for the first quarter of 2023 in line with the current schedule requirements on Meadow Road.

1. Academy Street

During the fourth quarter of 2022, $710,827 was spent on the Academy Street project compared to a forecast of approximately $879,000, which brought the total spend to approximately $7.2 million. The variance in forecasted to actual spend during the quarter was primarily the result of the demolition work starting slower than forecasted.

This project was placed in-service on October 19, 2021, and in the third quarter of 2022 the final circuit was cutover to the switchgear. The demolition of the old substation commenced in October 2022 and is expected to be completed early in 2023.

The actual spend by period for Academy Street as compared to the current forecast and URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals							*Forecast*
$150,398	$4,224,550	$1,754,789	$131,061	$144,172	$114,926	$710,827	$1,000,301

Estimate & Forecast		Actuals to Date	% of Actuals to Estimate & Forecast
Estimate	$9,300,000	$7,230,725	78%
Forecast	$8,231,026		88%

2. *Clay Street*

During the fourth quarter of 2022, $8,497,943 was spent on the Clay Street project compared to a forecast of approximately $8.6 million, which brought the total spend to approximately $21.5 million. The forecasted in-service date for the Clay Street project as of the end of 2022 slipped 28 days from the status as of the end of the prior quarter to April 20, 2023. This shift in the in-service date was driven by the switchgear controls IFC drawings not being up to date with Powercon's as-builts, which required drawing revisions and delayed commissioning activities.

The primary activities on the Clay Street project during the fourth quarter of 2022 included:

- Commencement of electrical construction;
- Completion of structural steel installation;
- Delivery of reactors/regulators;
- Setting the switchgear in place;
- Start of switchgear commissioning; and,
- Completion of the switchgear building roof and panels.

The actual spend by period for Clay Street as compared to the current forecast and URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals							*Forecast*
$116,409	$879,339	$2,806,593	$5,044,642	$1,936,258	$2,238,630	$8,497,943	$12,094,114

Estimate & Forecast		Actuals to Date	% of Actuals to Estimate & Forecast
Estimate	$33,600,000	$21,519,813	64%
Forecast	$33,613,927		64%

3. *Front Street*

During the fourth quarter of 2022, $2,282,477 was spent on the Front Street project compared to a forecast of approximately $2.2 million, which brought total spend to approximately $11.8 million. The forecasted in-service date for the Front Street project as of the end of 2022 slipped 17 days from the status as of the end of the prior quarter to January 26, 2024.

The primary activities on the Front Street project during the fourth quarter of 2022 included:

- Start and completion of commissioning for the contingency switchgear;
- Setting regulators/reactors;
- Civil and electrical work out for bid;

The actual spend by period for Front Street as compared to the current forecast and URB approved estimate is provided below along with the forecasted spend through the end of the project. During the fourth quarter of 2022, the Front Street project transitioned to the Conceptual level estimate, which resulted in the base estimate increasing from $25.9 million to $27.3 million. This $1.4 million estimate increase was driven by:

- Higher than estimated contingency construction costs ($0.7 million);
- Higher than estimated construction costs based on revised IFC drawings and revised wire checker estimate ($0.4 million); and,
- Addition of Human-Machine Interface (HMI) to Switchgear – based on new PSE&G requirement initiated in early 2020 ($0.3 million).

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals							*Forecast*
$-	$-	$2,351,832	$429,607	$889,533	$5,887,539	$2,282,477	$15,894,421

Estimate & Forecast		Actuals to Date	% of Actuals to Estimate & Forecast
Estimate	$27,300,000	$11,840,987	43%
Forecast	$27,500,832		43%

4. *Hasbrouck Heights*

During the fourth quarter of 2022, $2,183,946 was spent on the Hasbrouck Heights project compared to a forecast of approximately $2.1 million, which brought the total spend to approximately $16.1 million. The Hasbrouck Heights project was placed in-service as of November 21, 2022.

Notable activities completed on the Hasbrouck Heights project during the fourth quarter of 2022 included:

- Continued switchgear commissioning;
- Switchgear energization and placed in-service; and,
- Warranty work performed on regulators (no cost/schedule impact to the project).

The actual spend by period for Hasbrouck Heights as compared to the current forecast and URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals							*Forecast*
$149,848	$1,129,934	$4,176,249	$4,323,599	$2,187,907	$1,958,570	$2,183,946	$2,984,870

Estimate & Forecast		Actuals to Date	% of Actuals to Estimate & Forecast
Estimate	$19,300,000	$16,110,169	84%
Forecast	$19,094,923		84%

5. Kingsland

During the fourth quarter of 2022, $2,113,012 was spent on the Kingsland project compared to a forecast of approximately $2.0 million, which brought the total spend to approximately $4.3 million. The forecasted in-service date for the Kingsland project as of the end of 2022 advanced 33 days from the status as of the end of the prior quarter (also reversing the 35-day slip during the third quarter of 2022) to October 4, 2023. This improvement in the forecasted in-service date was driven by the delivery of the 13kV switchgear delivery (from the Ridgefield 13kV project), which advanced from April 2023 to March 2023.

The primary activities on the Kingsland project during the fourth quarter of 2022 included:

- Start of electrical construction, including prepping cables and conducting test pits for underground runs; and,
- Pile driving for new switchgear, duct bank, and other foundations.

The actual spend by period for Kingsland as compared to the current forecast and URB approved estimate is provided below along with the forecasted spend through the end of the project. As of the end of 2022, the forecast for the Kingsland project increased approximately $1.6 million from the forecast at the end of the prior quarter. This increase was the result of required manhole modifications, detailed material takeoffs, and site investigations.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals							*Forecast*
$104,112	$209,667	$510,943	$301,463	$538,906	$554,703	$2,113,012	$6,246,034

Estimate & Forecast		Actuals to Date	% of Actuals to Estimate & Forecast
Estimate	$8,700,000	$4,332,806	50%
Forecast	$10,578,839		41%

6. Lakeside Avenue

During the fourth quarter of 2022, $1,295,033 was spent on the Lakeside Avenue project compared to a forecast of approximately $1.7 million. The variance in forecasted to actual spend during the fourth quarter of 2022 was attributed to delays in manhole work and delays in receiving permits for test pits. However, despite those delays, there was no critical path impact at this time and the forecasted in-service date for the Lakeside Avenue project as of the end of 2022 remain unchanged from the status as of the end of the third quarter of 2022 at February 28, 2024 (which as previously discussed was the result of the switchgear delivery slipping).

Notable activities completed on the Lakeside Avenue project during the fourth quarter of 2022 included:

- Civil/electrical demolition package out for bid (old station);

- Installation of 4kV bus support foundations;
- Continued duct bank installations; and,
- Start of switchgear foundations.

The actual spend by period for Lakeside Avenue as compared to the current forecast and URB approved estimate is provided below along with the forecasted spend through the end of the project. During the fourth quarter of 2022, the Lakeside Avenue project transitioned to the Conceptual level estimate, which resulted in the base estimate decreasing from $39.4 million to $33.5 million. This $5.9 million estimate decrease was driven by:

- T&D surcharge methodology – based on 2022 surcharge methodology ($0.6 million);
- Based on the site assessment, planned dewatering is not required (-$0.4 million);
- Updated material requirements based on detailed design – decrease in linear footage of underground cable (65,300 lf to 55,250 lf) and removal of the contingency that is no longer required (-$0.7 million);
- Lower than estimated costs for soil disposal and abatement based on updated site survey (-$1.0 million); and,
- Final design no longer requires piles and raised foundation for the switchgear, resulting in lower than estimated construction awards (-$4.4 million).

While the estimate was approved at $33.5 million, after the estimate was approved the forecast increased an additional $0.6 million to $34.1 million. This forecast increase was driven by the need to re-label all 4kV circuits with a new station name (North Park Street, where the Lakeside Avenue substation is being relocated to), which requires updates to the associated engineering drawings and underground crews to physically replace the old labels with new labels on all circuits and tie feeders.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2025
Actuals							*Forecast*
$148,943	$453,994	$570,713	$351,720	$230,836	$1,536,403	$1,295,033	$25,545,440

Estimate & Forecast		Actuals to Date	% of Actuals to Estimate & Forecast
Estimate	$33,500,000	$4,587,643	14%
Forecast	$34,133,083		13%

7. Leonia

During the fourth quarter of 2022, $1,561,839 was spent on the Leonia project compared to a forecast of approximately $1.4 million, which brought the total spend to approximately $23.9 million. The Leonia substation was placed in-service as of November 15, 2022.

Notable activities completed on the Leonia project during the fourth quarter of 2022 included:

- Completion of commissioning the new switchgear #2 and cutting over circuits; and,
- Installation of the station's lightning mast.

Remaining activities for Leonia relate to final site restoration and disconnecting/disassembling the contingency switchgear used during construction.

The actual spend by period for Leonia as compared to the current forecast and URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals							*Forecast*
$44,792	$6,033,379	$9,112,257	$1,789,112	$3,968,355	$1,356,322	$1,561,839	$2,033,532

Estimate & Forecast		Actuals to Date	% of Actuals to Estimate & Forecast
Estimate	$24,900,000	$23,866,055	96%
Forecast	$25,899,588		92%

8. Market Street

During the fourth quarter of 2022, $29,055 was spent on the Market Street project compared to a forecast of approximately $86K, which brought the total spend to approximately $28.2 million. The Market Street substation was taken out of service as of June 25, 2021.

The final punch list items and site cleanup activities were completed at the end of the second quarter of 2022, remaining costs including those incurred during the fourth quarter of 2022 relate to final and trailing costs related to this closeout work.

The actual spend by period for Market Street as compared to the current forecast and URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals							*Forecast*
$251,193	$16,079,601	$10,681,487	$808,096	$202,619	$117,836	$29,055	$102,500

Estimate & Forecast		Actuals to Date	% of Actuals to Estimate & Forecast
Estimate	$29,100,000	$28,169,888	97%
Forecast	$28,272,387		100%

9. Meadow Road

During the fourth quarter of 2022, $1,641,509 was spent on the Meadow Road project compared to a forecast of approximately $1.6 million, which brought the total spend to approximately $3.7 million. The forecasted in-service date for the Meadow Road project as of the end of 2022 remained unchanged from the status as of the end of the third quarter of 2022 at September 28, 2023.

The primary activities conducted on the Meadow Road project during the fourth quarter of 2022 included:

- Continued manhole work;
- Installation of station light & power foundations; and,
- Installation of conduit.

The actual spend by period for Meadow Road as compared to the current forecast and URB approved estimate is provided below along with the forecasted spend through the end of the project. During the fourth quarter of 2022, the Meadow Road project transitioned to the Definitive level estimate, which resulted in the base estimate increasing from $8.3 million to $8.8 million. This $0.5 million estimate increase was driven by:

- Revised estimate for construction supervisions and commissioning and additional costs for trailer rentals ($0.3 million);
- Division estimate updated to include required fiber line relocation ($0.1 million); and,
- Higher than estimated cost for structural steel ($0.1 million).

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals							*Forecast*
$63,128	$535,081	$445,234	$288,050	$321,098	$382,461	$1,641,509	$5,220,440

Estimate & Forecast		Actuals to Date	% of Actuals to Estimate & Forecast
Estimate	$8,800,000	$3,676,560	42%
Forecast	$8,897,000		41%

10. Orange Valley

During the fourth quarter of 2022, $308,858 was spent on the Orange Valley project compared to a forecast of approximately $419K, which bought the total spend to approximately $2.5 million. The variance in forecasted to actual spend in the fourth quarter of 2022 was primarily attributed to less environmental work performed than estimated. The forecasted in-service date for the Orange Valley project as of the end of 2022 slipped 14 days from the status as of the end of the third quarter of 2022 to February 16, 2024.

During the fourth quarter of 2022, major activities on the Orange Valley project included:

- Controls drawings IFC;
- Continued duct bank installations; and,
- Commencement of installing switchgear foundations.

The actual spend by period for Orange Valley as compared to the current forecast and URB approved estimate is provided below along with the forecasted spend through the end of the project. During the fourth quarter of 2022, the Orange Valley project transitioned to the Conceptual level estimate, which resulted in the base estimate increasing from $14.7 million to $15.0 million. This $0.3 million estimate increase was driven by:

- Higher than estimated PO awards (labor and equipment prices, NJDEP green infrastructure requirements) ($0.9 million);
- Lower carrying costs based on updated project staffing plan (-$0.2 million); and,
- Reduced 4kV equipment demolition estimate (-$0.4 million).

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals							*Forecast*
$77,029	$362,895	$358,052	$111,565	$276,614	$1,041,753	$308,858	$12,477,738

Estimate & Forecast		Actuals to Date	% of Actuals to Estimate & Forecast
Estimate	$15,000,000	$2,536,767	17%
Forecast	$15,014,505		17%

11. Ridgefield 13kV

During the fourth quarter of 2022, $1,585,414 was spent on the Ridgefield 13kV project compared to a forecast of approximately $1.7 million, which brought the total spend to approximately $27.1 million. The Ridgefield 13kV project was placed in-service as of December 12, 2022.

Notable activities performed on the Ridgefield 13kV project during the fourth quarter of 2022 included:

- Completion of conduit/ducts and cable pulls to station light & power;
- Continued commissioning of the new switchgear #1;
- Switchgear energization and placed in-service;

The actual spend by period for Ridgefield 13kV as compared to the current forecast and URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals							*Forecast*
$205,982	$6,232,692	$10,849,681	$2,111,096	$2,557,679	$3,567,625	$1,585,414	$1,198,298

Estimate & Forecast		Actuals to Date	% of Actuals to Estimate & Forecast
Estimate	$26,100,000	$27,110,169	104%
Forecast	$28,308,468		96%

12. Ridgefield 4kV

During the fourth quarter of 2022, there was no spend the Ridgefield, with the total spend remaining at approximately $20.7 million. The project was placed in-service on May 16, 2021.

The project was closed out during the third quarter of 2022 after the final closeout activities were performed during the first quarter of 2022, which included some trailing costs in the second quarter of 2022.

The actual spend by period for Ridgefield 4kV as compared to the final forecast and URB approved estimate is provided below.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals							*Forecast*
$143,414	$11,239,534	$9,263,852	$42,604	$14,405	-	-	-

Estimate & Forecast		Actuals to Date	% of Actuals to Estimate & Forecast
Estimate	$20,700,000	$20,703,808	100%
Forecast	$20,703,808		100%

13. State Street

During the fourth quarter of 2022, $2,211,115 was spent on the State Street project compared to a forecast of approximately $1.8 million, which brought the total spend to approximately $13.8 million. The State Street project was placed in-service on December 29, 2022.

Notable activities performed on the State Street project during the fourth quarter of 2022 included:

- Continued commissioning of the new switchgear #1; and,
- Switchgear energization and placed in-service.

The actual spend by period for State Street as compared to the current forecast and URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals							*Forecast*
$77,590	$662,148	$8,093,227	$751,849	$1,046,814	$978,273	$2,211,115	$6,466,125

Estimate & Forecast		Actuals to Date	% of Actuals to Estimate & Forecast
Estimate	$19,600,000	$13,821,016	71%
Forecast	$20,287,142		68%

14. Toney's Brook

During the fourth quarter of 2022, $4,357,007 was spent on the Toney's Brook project compared to a forecast of approximately $5.1 million, which brought the total spend to approximately $7.4 million. The variance in forecasted to actual spend during the fourth quarter of 2022 was primarily attributed to less civil progress made than planned in September and a partial delivery of feeder rows not received in December as planned.

The forecasted in-service date for the Toney's Brook project as of the end of 2022 advanced 10 days from the status as of the end of the third quarter of 2022 to May 20, 2023.

The notable activities on the Toney's Brook project during the fourth quarter of 2022 included:

- Commencement of electrical construction;
- Manhole and duct bank installations;
- Grounding grid installation;
- Steel platform installation; and,
- Commencement of switchgear assembly.

The actual spend by period for Toney's Brook as compared to the current forecast and URB approved estimate is provided below along with the forecasted spend through the end of the project. During the fourth quarter of 2022, the Toney's Brook project transitioned to the Definitive level estimate, which resulted in the base estimate decreasing from $16.2 million to $16.0 million. This $0.2 million estimate decrease was driven by:

- Higher than estimated procurement – steel platforms and structural steel ($0.4 million); and,

- Lower than estimated electrical construction award – driven by contingency plan no longer being required (-$0.6 million).

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals							*Forecast*
$211,940	$373,096	$941,519	$138,270	$629,773	$740,393	$4,357,007	$8,836,833

Estimate & Forecast		Actuals to Date	% of Actuals to Estimate & Forecast
Estimate	$16,000,000	$7,391,999	46%
Forecast	$16,228,831		46%

15. Waverly

During the fourth quarter of 2022, $2,877,081 was spent on the Waverly project compared to a forecast of approximately $2.5 million, which brought the total spend to approximately $20.1 million. The variance in forecasted to actual spend during the fourth quarter of 2022 was largely the result additional dewatering required during the manhole rebuild. The forecasted in-service date for the Waverly project as of the end of 2022 slipped seven days from the status as of the end of the third quarter of 2022 to May 7, 2024.

The primary activities performed on the Waverly project during the fourth quarter of 2022 included:

- Cutting over circuits to the new 26kV switchgear; and,
- Completion of manhole rebuild.
- The actual spend by period for Waverly as compared to the current forecast and URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals							*Forecast*
$103,748	$2,460,815	$4,415,223	$432,853	$1,536,375	$8,248,435	$2,877,081	$20,847,043

Estimate & Forecast		Actuals to Date	% of Actuals to Estimate & Forecast
Estimate	$39,900,000	$20,074,529	50%
Forecast	$40,921,572		49%

16. Woodlynne

During the fourth quarter of 2022, $380,008 was spent on the Woodlynne project compared to a forecast of approximately $644K, which brought the total spend to approximately $6.4 million. The variance in forecasted to actual spend during the fourth quarter of 2022 was primarily the result of the December invoice for A/E procured material coming in lower than the November accrual and IP electrical work shifting into 2023 to allow the focus to be on placing the 69kV project in-service. The forecasted in-service date for the Woodlynne project as of the end of 2022 slipped 17 days from the status as of the end of the third quarter of 2022 to October 27, 2023.

The primary activities performed on the Woodlynne project during the fourth quarter of 2022 included the completion of the 4kV duct bank and manhole installations.

The actual spend by period for Woodlynne as compared to the current forecast and URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals							*Forecast*
$110,982	$993,298	$991,630	$1,639,443	$1,347,345	$903,898	$380,008	$17,716,405

Estimate & Forecast		Actuals to Date	% of Actuals to Estimate & Forecast
Estimate	$24,000,000	$6,366,604	27%
Forecast	$24,083,009		26%

B. Contingency Reconfiguration

During the fourth quarter of 2022, the efforts in the Contingency Reconfiguration subprogram continued to focus on the installation of additional Fuse Savers, following the completion of the recloser scope in the first quarter of 2022. **Table 12 – ES 2 Program Fuse Saver Status as of December 31, 2022** provides a summary of the Fuse Saver scope of the Contingency Reconfiguration subprogram, indicating the number of units completed during the fourth quarter of 2022 and for the total program, showing the status of engineering, installation, and commissioning out of a forecasted scope of 1,574 units.[2] The forecasted units is based on the actual cost per unit of installations to date and is updated quarterly based on the current data.

Table 12 – ES 2 Program Fuse Saver Status as of December 31, 2022

Type	Engineering Packages Completed (1 Fuse Saver ea.)	Fuse Savers Installed	Fuse Savers Commissioned
Q4 Qty.	336	265	389
Program Total to Date	1,036	677	674
Remaining	538	897	900

Following the recommencement of the Fuse Saver installations in May 2022, PSE&G has continued to advance the installations towards its forecasted scope of 1,574 Fuse Savers with 265 installed in the fourth quarter of 2022. This followed the 286 units installed during the third quarter of 2022 and leaves 900 units to be installed during 2023. PSE&G continues to establish its installation targets on a quarterly basis, which are then split into monthly targets for each Division with the forecasts updated on a bi-weekly basis.

The current forecasted completion date for the primary components that make up the Contingency Reconfiguration subprogram are provided in **Table 13 – ES 2 Contingency Reconfiguration Forecasted Completion Dates as of December 31, 2022**. This table also shows the forecasted final in-service dates as of the end of the third quarter of 2022 to compare the status to the forecast as of the end of 2022.

[2] Note: this is the forecasted scope as of the end of the fourth quarter of 2022. PSE&G continues to assess the forecasted units in line with the budget for the subprogram and as of the August 2023 this resulted in an updated forecast of 1,344 units.

Table 13 – ES 2 Contingency Reconfiguration Forecasted Completion Dates as of December 31 2022

Scope & Division		Q3 2022 Forecasted Completion Date	Q4 2022 Forecasted Completion Date
Reclosers	Central	1/31/2022 (Actual)	1/31/2022 (Actual)
	Metro	12/31/2021 (Actual)	12/31/2021 (Actual)
	Palisades	1/31/2022 (Actual)	1/31/2022 (Actual)
	Southern	1/31/2022 (Actual)	1/31/2022 (Actual)
Fuse Savers	Central	12/30/2023	11/30/2023
	Metro	12/30/2023	12/30/2023
	Palisades	12/30/2023	11/30/2023
	Southern	12/30/2023	11/30/2023

As shown in **Table 13**, the forecasted in-service dates for the Fuse Saver scope of each Division continues to be the end of 2023, though for each Division, aside from the Metro Division, the forecasted in-service date advanced 30 days to the end of November 2023.

The Contingency Reconfiguration subprogram costs through the end of 2022 are presented in **Table 14 – ES 2 Contingency Reconfiguration Actual Costs as of December 31, 2022**.

Table 14 – Contingency Reconfiguration Actual Costs as of December 31, 2022

Scope & Division		2019	2020	2021	Q1 2022	Q2 2022	Q3 2022	Q4 2022	Total to Date
		Actuals							
Reclosers	Central	$2,737,167	$12,050,820	$9,852,812	$880,537	$45,064	$46,364	$28,410	$25,641,174
	Metro	$2,231,431	$10,726,610	$11,368,409	$150,325	($31,771)	($8,856)	$276	$24,436,424
	Palisades	$2,515,569	$12,119,436	$8,280,522	($66,771)	$2,816	$500	$10,753	$22,862,826
	Southern	$2,081,220	$12,405,684	$14,038,043	$530,051	$4,112	$1,476	$0	$29,060,585
Fuse Savers	Central	$9,970	$789,937	$854,118	$249,268	$433,473	$2,097,168	$1,846,734	$6,280,668
	Metro	$7,557	$561,915	$507,742	$160,801	$298,329	$1,889,794	$2,089,940	$5,516,078
	Palisades	$7,468	$522,454	$577,113	$127,207	$656,533	$2,059,075	$1,646,817	$5,596,667
	Southern	$9,792	$859,014	$578,217	$245,990	$714,570	$1,623,412	$2,462,992	$6,493,988
Total		**$9,600,174**	**$50,035,871**	**$46,056,977**	**$2,277,408**	**$1,824,151**	**$7,708,933**	**$8,085,921**	**$125,888,410**

Table 15 – Contingency Reconfiguration Forecasted Costs as of December 31, 2022 examines the forecast as of the end of 2022 for each Division's Fuse Saver scope compared to the total actual costs incurred through the end of 2022.

Table 15 – Contingency Reconfiguration Forecasted Costs as of December 31, 2022

Scope & Division		Total to Date	Forecast	Remaining Forecast	% of Actuals to Forecast
Reclosers	Central	$25,641,174	$25,641,174	$0	100%
	Metro	$24,436,424	$24,436,424	$0	100%
	Palisades	$22,862,826	$22,862,826	$0	100%
	Southern	$29,060,585	$29,060,585	$0	100%
Fuse Savers	Central	$6,280,668	$10,989,832	$4,709,163	57%
	Metro	$5,516,078	$11,825,778	$6,309,700	47%
	Palisades	$5,596,667	$10,167,971	$4,571,305	55%
	Southern	$6,493,988	$12,271,497	$5,777,509	53%

Scope & Division	Total to Date	Forecast	Remaining Forecast	% of Actuals to Forecast
Total	**$125,888,410**	**$147,256,087**	**$21,367,677**	**85%**

As shown in **Table 15**, the overall Contingency Reconfiguration subprogram has spent 85% of its current forecast. With the total forecast as of the end of 2022 remaining relatively static since the end of the prior quarter, decreasing by approximately $360,000.

Findings & Observations:

- Progress on the Fuse Savers scope of the subprogram continued to advance in the second full quarter of installations (which partially commenced in the second quarter of 2022 ahead of fully commencing in the third quarter of 2022) on the Program with 265 units installed during the fourth quarter of 2022 for a total of 677 installed during the Program. Equipment deliveries have continued to keep pace with Program needs, with inventory averaging around six to eight weeks ahead of installations.
- Based on the progress to date and the current projections, the forecasted final in-service dates for the Fuse Savers scope advanced one month in the Central, Palisades, and Southern Divisions to November 30, 2023, while the Metro Division remained at December 30, 2023.
- The Divisions are conducting inspections of the circuits targeted for the remaining Fuse Savers to confirm viability and inform the planning efforts for 2023.
- The Contingency Reconfiguration subprogram forecast continued to remain relatively static as of the end of 2022, with the total forecast decreasing by approximately $360K (or less than 0.0%) to $147.3 million. This remains slightly above the Stipulation budget of $145.0 million.

C. Grid Modernization – Communication System

The Stipulation identified the Grid Modernization – Communication System subprogram to include up to $72 million invested in installing a private wireless communications network to eliminate the use of dedicated phone lines for remote communication for both PSE&G and customer equipment. The overall network will provide coverage using both wireless and fiber technologies to all switching devices on the PSE&G system. The primary scopes within the Grid Modernization – Communication System include installation of the wireless network, fiber installations at selected stations, fiber cutovers at selected station with existing fiber to the PSE&G fiber network, and retrofitting existing reclosers and RTUs with updated routers. A summary of the status of these primary scopes of work as of the end of 2022 is as follows:

- Wireless network: placed in-service as of December 16, 2021, final coverage testing to be conducted in early 2023; other remaining work involves providing radios to support the installation of Fuse Savers in the Contingency Reconfiguration subprogram.
- Fiber installations and cutovers: 33 out of 34 fiber installation projects completed and 12 out of 12 fiber cutover projects completed.
- Retrofitting existing reclosers: completed as of the fourth quarter of 2021 with a total of 2,318 retrofit reclosers installed.

- Retrofitting RTUs: completed as of the third quarter of 2022 with a total scope of 218 substations.

The list of currently approved fiber installation and cutover projects is presented in **Table 16 – Fiber Projects by Division as of December 31, 2022**.

Table 16 – Fiber Projects by Division as of December 31, 2022

Division	Fiber Installation*	Fiber Cutover*
Central	Cranford; Elizabeth Sub HQ; Rahway; Hadley Road HQ; Roselle; Central HQ; Carteret; Edison; Keasby; Mechanic Street; First Street	Elizabeth; Henry Street
Metro	East Orange; Metro HQ; Bloomfield; Central Avenue; Haldeon; Irvington; Irvington Sub HQ; Montclair; South Orange; Norfolk Street	-
Palisades	Bergen Point; Hackensack Sub HQ; Fort Lee; Harrison; Ridgewood; West New York; Palisades HQ; Culver Avenue; Morgan Street	Tonnelle Avenue; Spring Valley Road; Union City; Fairview; Polk Street; West Orange
Southern	Southern HQ; Princeton; Chauncey Street; Bordentown	Delair; East Riverton; Riverside; Mount Holly
Total	***34 projects***	***12 projects***
**-Projects underlined have been placed in-service.*		

During the fourth quarter of 2022 four additional fiber installation projects (Bloomfield, Carteret, Keasbey, and Mechanic Street) were placed in-service. Thus, the total fiber projects in-service as of the end of 2022 was 33 for the fiber installation projects and 12 for the fiber cutover projects. **Table 17 – ES 2 Program Fiber Projects Status as of December 31, 2022** provides a summary of the status of the fiber installation and cutover projects within the subprogram as of the end of the third quarter of 2022 with the projects in italics representing those placed in-service.

Table 17 – ES 2 Program Fiber Projects Status as of December 31, 2022

Project Name	Q4 2022 Status
Fiber Installation Projects	
Bergen Point	*In-Service (Q1 2021)*
Bloomfield	*In-Service (Q4 2022)*
Bordentown	*In-Service (Q3 2021)*
Carteret	*In-Service (Q4 2022)*
Central Ave	*In-Service (Q3 2021)*
Central HQ	*In-Service (Q1 2022)*
Chauncey Street	*In-Service (Q3 2021)*
Cranford	*In-Service (Q4 2020)*
Culver Ave	*In-Service (Q1 2022)*
East Orange	*In-Service (Q1 2021)*
Edison	In securing railroad permits, it was identified that this particular rail section requires its own outage within Amtrak (powerline for the trains), which will not be available to be scheduled by Amtrak until the spring of 2023.
Elizabeth Sub HQ	*In-Service (Q1 2021)*
First Street	*In-Service (Q3 2021)*
Fort Lee	*In-Service (Q1 2022)*
Hackensack Sub HQ	*In-Service (Q4 2020)*
Hadley Rd HQ	*In-Service (Q1 2022)*
Haledon	*In-Service (Q1 2022)*

Project Name	Q4 2022 Status
Harrison	*In-Service (Q3 2021)*
Irvington	*In-Service (Q4 2021)*
Irvington Sub HQ	*In-Service (Q4 2021)*
Keasbey	*In-Service (Q4 2022)*
Mechanic Street	*In-Service (Q4 2022)*
Metro HQ	*In-Service (Q1 2021)*
Montclair	*In-Service (Q3 2022)*
Morgan Street	*In-Service (Q4 2021)*
Norfolk St	*In-Service (Q3 2021)*
Palisades HQ	*In-Service (Q3 2022)*
Princeton	*In-Service (Q3 2021)*
Rahway	*In-Service (Q1 2021)*
Ridgewood	*In-Service (Q1 2022)*
Roselle	*In-Service (Q2 2021)*
So Orange	*In-Service (Q3 2021)*
Southern HQ	*In-Service (Q4 2020)*
West New York	*In-Service (Q1 2022)*
Fiber Cutover Projects	
Delair	*In-Service (Q4 2020)*
East Riverton	*In-Service (Q4 2020)*
Elizabeth	*In-Service (Q1 2021)*
Fairview	*In-Service (Q1 2022)*
Henry St	*In-Service (Q3 2021)*
Mount Holly	*In-Service (Q4 2020)*
Polk Street	*In-Service (Q1 2022)*
Riverside	*In-Service (Q4 2020)*
Spring Valley Rd	*In-Service (Q1 2021)*
Tonnelle Ave	*In-Service (Q4 2020)*
Union City	*In-Service (Q1 2021)*
West Orange	*In-Service (Q3 2022)*
Substation Remote Terminal Unit (RTU) Cutovers	
Scope: 218 units	218 cutovers completed

During the fourth quarter of 2022, PSE&G's URB approved updated Definitive estimates for the wireless network & retrofit project and the fiber projects, which are presented in **Table 16 – Grid Modernization – Communication System Updated Definitive Estimate** that also shows the progression from the original Office level estimates.

Table 18 – Grid Modernization – Communication System Updated Definitive Estimate

Scope	Item	Description	Cost
Fiber Installations & Cutovers	***Office Estimate***		***$23,400,000***
	New Fiber Scope Refinement	Substation and Operation Center fiber installation scope and estimates modified to align with current communication needs	$7,900,000
	Project Management, Licensing & Permitting, Engineering	Reduction in scope of Distribution Stations with existing fiber that still required communications to be cutover	($3,800,000)
	Study Estimate		***$27,500,000***
	Outside Plant Estimates	Actual costs higher than estimated for contracted work ($1.6 million) and work performed with internal resources ($0.9 million) based on scope and estimate refinement	$2,500,000
	Inside Plant Estimates	Office level estimates further refined	$2,200,000

Scope	Item	Description	Cost
	Changed Routes	Route changed in order to provide simplified design and avoid extensive inspections and permitting associated with original OP routes for Montclair (+$1.3 million) and Bloomfield (-$0.4 million).	$900,000
	Fiber Cutovers	Increase due to scope and estimate refinement	$300,000
	Scope Reduction	32nd Street, Howell Street, Waverly, Haddon Heights, and Lehigh Avenue stations removed from ES 2 Program	($2,900,000)
	Original Definitive Estimate		***$30,500,000***
	OP/IP Construction	Contract awards higher than estimated	$1,000,000
	Substation RTU Overrun	Based on actual costs	$500,000
	Fiber Installation	Additional labor costs incurred	$400,000
	Fiber Installation	Unforeseen field conditions	$300,000
	Updated Definitive Estimate		***$32,700,000***
Wireless Network & Retrofits	***Office Estimate***		***$48,600,000***
	FirstNet Wireless Network Solution	Selection of FirstNet as the wireless network solution in lieu of original plan to build a solely owned and operated private network	($13,500,000)
	Conceptual Estimate		***$35,100,000***
	Radio Reduction	387-unit reduction related to Fuse Savers, Retrofits, and Reclosers – including material and labor	($1,300,000)
	Original Definitive Estimate		***$33,800,000***
	Scope Refinement	Reduction in Program Management and staffing for Fuse Savers	($400,000)
	Scope Refinement	Remove implementation of Network Operations Center (NOC)	($200,000)
	Updated Definitive Estimate		***$33,200,000***
Total Grid Modernization – Communication System Definitive Estimate			**$65,900,000**

Among the items detailed in the Updated Definitive Estimate in **Table 18**, PSE&G removed the Wireless Network Operations Center (NOC) from the subprogram scope. This Wireless NOC was intended to establish a dedicated operating center to monitor the health of the wireless network and operation of devices in the field. After PSE&G assessed the detailed scope and requirements, it identified an the process of combining monitoring and alerting from both the existing D-SCADA and the IT NOC was a viable alternative that allowed the Wireless NOC to be removed from the subprogram while still achieving the desired benefits.

The Grid Modernization – Communication System subprogram actual costs by major period through the end of 2022 are presented in **Table 19 – ES 2 Grid Modernization – Communication System Actual Costs as of December 31, 2022**, while **Table 20 – ES 2 Grid Modernization – Communication System Forecasts as of December 31, 2022** provides the current forecasts as of the end of 2022 compared to the actual costs.

Table 19 – ES 2 Grid Modernization – Communication System Actual Costs as of December 31, 2022

Scope & Division		2019	2020	2021	Q1 2022	Q2 2022	Q3 2022	Q4 2022	Total to Date
		Actuals							
Retrofit Reclosers	Central	$0	$884,278	$3,304,797	$215,275	$186,505	$359,309	$304,632	$5,254,796
	Metro	$0	$818,620	$2,362,797	$135,374	$192,271	$315,543	$308,409	$4,132,996
	Palisades	$0	$825,174	$3,115,474	$186,059	$184,718	$349,531	$306,521	$4,967,477
	Southern	$0	$929,058	$3,862,816	$194,826	$193,249	$292,884	$304,632	$5,777,466

Scope & Division		2019	2020	2021	Q1 2022	Q2 2022	Q3 2022	Q4 2022	Total to Date
		Actuals							
Fiber	Central	$1,691	$2,418,851	$5,973,655	$1,581,263	$681,857	$446,818	$334,822	$11,438,957
	Metro	$1,457	$1,866,697	$3,086,096	$1,576,328	$347,002	$245,110	$160,978	$7,283,668
	Palisades	$1,582	$2,046,762	$3,603,134	$656,307	$93,875	$213,474	$86,148	$6,701,283
	Southern	$4,731	$910,483	$2,466,477	$96,721	$33,229	$24,153	$30,995	$3,566,789
	Cutovers	$0	$876,502	$607,056	$49,907	$8,735	$0	$0	$1,416,980
Wireless Network		$74,306	$6,035,441	$1,282,986	$61,558	$99,655	$39,482	$33,807	$7,627,235
Substation RTU Cutovers		$0	$0	$127,129	$801,385	$920,534	$462,707	($14,739)	$2,297,017
Bulk Purchase*		$0	$1,524,874	($520,766)	$641,029	$283,929	$642,690	$188,244	$2,759,999
Total		**$83,767**	**$19,136,741**	**$29,144,503**	**$6,196,033**	**$3,225,559**	**$3,391,702**	**$2,046,359**	**$63,224,662**
**-The Bulk Purchase account is used for the purchase of bulk equipment, which is the then assigned to a specific Division when the equipment is released with a credit back to the Bulk Purchase account. Thus, this account is forecasted to have a $0 balance at the end of the ES 2 Program.*									

Table 20 – ES 2 Grid Modernization – Communication System Forecasts as of December 31, 2022

Scope & Division		Total to Date *Actuals*	Total Forecast	% of Actuals to Forecast
Retrofit Reclosers	Central	$5,254,796	$11,598,833	79%
	Metro	$4,132,996	$7,301,550	75%
	Palisades	$4,967,477	$6,711,283	78%
	Southern	$5,777,466	$3,456,530	80%
Fiber	Central	$11,438,957	$11,598,833	99%
	Metro	$7,283,668	$7,301,550	100%
	Palisades	$6,701,283	$6,711,283	100%
	Southern	$3,566,789	$3,456,530	103%
	Cutovers*	$1,416,980	$1,416,980	100%
Substation RTU Cutovers		$2,297,017	$2,297,017	100%
Wireless Network		$7,627,235	$7,627,235	100%
Bulk Purchase*		$2,759,999	$0	-
Total		**$63,224,662**	**$66,219,762**	**95%**
**-The Bulk Purchase account is used for the purchase of bulk equipment, which is the then assigned to a specific Division when the equipment is released with a credit back to the Bulk Purchase account. Thus, this account is forecasted to have a $0 balance at the end of the ES 2 Program.*				

As shown in **Table 19**, actual costs incurred in the fourth quarter of 2022 was primarily in the retrofit reclosers scope that relates to the radio kits that are prepared for the Fuse Saver installations. The forecasts shown in **Table 20** remained relatively unchanged from the status as of the end of the second quarter of 2022, with an overall forecast decrease of approximately $345,000 (or a 0.1% decrease) driven by the forecast reflecting a cost transfer of engineering hours spent on the Lehigh Avenue and Haddon Heights fiber projects that were previously removed from the ES 2 Program.

Findings & Observations:

- Four additional fiber installation projects were completed during the fourth quarter of 2022, brining the total number of fiber installation projects in-service to 33. The remaining fiber installation project, Edison, was initially planned to be completed by the end of 2022, but in securing the railroad permit it was identified that the required outage could not be scheduled until the spring of 2023.

- The forecast for the Grid Modernization – Communication system subprogram remained relatively unchanged from the status as of the end of the third quarter of 2022, with an overall forecast decrease of approximately $345K (or a 0.5% decrease) to $66.2 million.
- PSE&G updated its Definitive estimate for the primary scopes generated for the subprogram (fiber installation & cutovers and wireless network & retrofits), which resulted in the overall subprogram estimate increasing by $1.6 million to $65.9 million. The fiber scope estimate increased by $2.2 million from the prior estimate, continuing to be driven primarily by higher than estimated construction costs. While the wireless network & retrofits scope estimate decreased by $0.6 million from the prior estimate due scope refinement. As this represents an expected overrun of the $64.3 million Stipulation budget, PSE&G intends to fund the balance via its distribution base capital.
- While cost pressures have been encountered throughout the execution of the Grid Modernization – Communication system subprogram, PSE&G has continued to balance the delivery of the planned scope of the subprogram with the approved budget. This includes adjustment to the number of fiber projects included in the subprogram and the removal of the Wireless NOC scope from the subprogram via identification of an alternative approach.

D. Grid Modernization – ADMS

The Grid Modernization – ADMS scope is split between three primary sections: DMS/DERMS, the OMS, and ADMS platform upgrades. The scope for each primary component of the Grid Modernization – ADMS subprogram and notable activities conducted during the fourth quarter of 2022 are presented as follows:

DMS/DERMS

- Scope: Provide software and associated services to deploy a Smart Network in order to meet a subset of the ES 2 Program’s objectives and use cases.
- Q4 2022 Activities:
  - Completed technical team training.
  - Completed initial data verification and all uploads.
  - Received test procedure and created test logs.
  - Resolved mismatches in GIS.
  - Started end-to-end testing (six of nine modules completed) and submitted first round of variances to OSI.
- Forecasted Completion as of the end of 2022: 1/29/2023 (slipped 43 days from the status as of the end of the prior quarter). This change in forecasted in-service date reflects the net impact of the delay in achieving stabilization of the system environment, which is required for installation and testing ahead of promotion to production (in-service).

OMS

- Scope: Provide a single user interface for more efficient management of trouble orders and analysis of outage data through an integrated OMS, system interfaces, and geographic view of all integrated outage data and damage locations. OMS will include tools for dynamic visualization supporting incident management, damage location identification, dashboards, and the as-operated real-time view of PSE&G's network model. Field personnel also will have access to many of these tools as it relates to the incident(s) assigned to them via the Compass mobile crew application. 10 years' worth of existing OMS data will be migrated into the new system as well.
- Q4 2022 Activities:
  - Completed Compass setup in the Quality Assurance System (QAS) environments.
  - Established iPad connectivity to Compass.
  - Completed system integration testing (SIT) rounds 1-3; completed remediation for rounds 1-2 and started remediation for round 3.
  - Finalized Kubra interface design.
- Forecasted Completion as of the end of 2022: 6/15/2023 (unchanged from prior quarter)

ADMS Platform

- Scope: Replace, enhance, and expand the existing Distribution Supervisory Control and Data acquisition (DSCADA) platform elements inclusive of infrastructure components (servers and workstations) and applications (Monarch, Spectra, and Integra) to create an integrated ADMS platform.
- Q4 2022 Activities:
  - Installed configuration and patch changes in Platform QAS for testing preparation.
  - Completed production readiness stage gate requirements.
  - Tested patch and configuration changes.
- Actual In-Service Date: 1/28/2022.

The Grid Modernization – ADMS subprogram costs through the end of 2022 are presented in **Table 21 – ES 2 Grid Modernization – ADMS Costs as of December 31, 2022**. The OMS scope forecast increased from $44.1 million as of the prior quarter to $49.4 million as of the end of 2022, which was driven by additional schedule durations and additional resources required.

Table 21 – ES 2 Grid Modernization – ADMS Costs as of December 31, 2022

Scope	Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
	Actuals							*Forecast*
OMS	$33,891	$8,375,966	$7,140,445	$2,010,781	$6,360,390	$2,267,867	$4,336,646	$18,865,044
DMS/ DERMS	$1,498	$1,858,969	$1,185,863	$510,094	$676,889	$581,013	$962,859	$850,713
Platform	$824	$1,998,769	$1,411,403	$646,982	$934,541	$310,094	$214,084	$150,099

Scope	Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
	Actuals							*Forecast*
ADMS Hardware	-	$4,213,920	$116,732	$30,020	$259,042	$35,462	$3,829	$0
Total ADMS	**$36,213**	**$16,447,624**	**$9,854,442**	**$3,197,877**	**$8,230,861**	**$3,194,435**	**$5,517,418**	**$19,865,856**

Scope	Actuals to Date	Forecast	% of Actuals to Forecast
OMS	$30,525,986	$49,391,030	62%
DMS/DERMS	$5,777,184	$6,627,897	87%
Platform	$5,516,697	$5,666,796	97%
ADMS Hardware	$4,659,004	$4,659,004	100%
Total ADMS	**$46,478,871**	**$66,344,727**	**70%**

Findings & Observations:

- The forecast for the Grid Modernization – ADMS subprogram increased by approximately $5.4 million from the status as of the end of the prior quarter, with a total current forecast of $66.3 million. This increase was almost entirely with the OMS scope of the subprogram and was driven by an extended execution schedule and additional resources required, reflecting the challenges encountered with the development of the OMS.
- Following the transition of the subprogram estimate to the Definitive stage at $56.3 million in the second quarter of 2022, there have been no further updates to the subprogram estimate. PSE&G's URB approved $13.6 million in additional funding for the subprogram to be covered by distribution base capital.
- The first of three primary ADMS components (the ADMS Platform) was placed in-service during the first quarter of 2022. The remaining DMS/DERMS and OMS scopes are forecasted to be placed in-service in January 2023 and June 2023, respectively. OSI (vendor) and PSE&G resources continue to collaboratively continue the ADMS development and are addressing issues as they are identified.

E. Electric Stipulated Base

The Stipulation identified that the electric portion of the Stipulated Base include $100 million in investments at PSE&G's discretion towards electric Outside Plant-Higher Design Standards (OP-HDS) and/or electric stations life cycle subprograms described in the original ES 2 filing.[3] As mentioned in the IM's 2022 Third Quarter Report, PSE&G commenced the OP-HDS in July 2022, but with the current forecasts for the life cycle station upgrade projects consuming the entire Stipulated Base funding ($101.5 million forecast compared to the $100.0 million Electric Stipulated Base budget), this work is presently being executed outside of the ES 2 Program. If the forecasts for the substation projects lower and additional funding becomes available, PSE&G may include some of the OP-HDS through the Program

[3] As noted in the Stipulation, the electric life cycle upgrades are part of the electric Stipulated Base to be recovered in the Company's next base rate case provided the investments are found to be prudent. The Stipulation also notes that should the 16 stations that comprise the Electric Station Flood Mitigation subprogram be completed for under the $389 million allocated for that subprogram, PSE&G may reallocate such unused funds to stations identified in the life cycle station upgrade portion of PSE&G's petition for accelerated recovery.

funding. The IM intends to continue to follow the status of this work, but will only report on it should PSE&G include these costs under the ES 2 Program.

In accordance with what the Stipulation provides, PSE&G plans to fund some of the life cycle station upgrades from the electric program accelerated investment, subject to funds available, after all Electric Station Flood Mitigation projects are funded at their final costs. While this shift in funding from stipulated base to accelerated recovery will not be determined until closer to the Program completion, PSE&G identified the Hamilton project as a candidate to be funded through the accelerated recovery mechanism.

As reported in the IM 2020 Second Quarter Report, the initial four stations PSE&G selected for life cycle station upgrades went before the URB in June 2020 for Study level estimate approval and received approval for full funding. In the second quarter of 2021 a fifth station, State Street, was approved by the URB for its outside plant scope to be transferred from the related Electric Station Flood Mitigation project to the life cycle scope. The five life cycle station upgrade projects and their current estimate compared to the actuals to date are provided in **Table 22 – ES 2 Life Cycle Station Upgrade Project Status as of December 31, 2022**.

Table 22 – ES 2 Life Cycle Station Upgrade Project Status as of December 31, 2022

Project	Estimate Level	Base	Risk & Contingency*	Total	Actuals to Date	% of Actuals to Estimate	Forecasted In-Service Date**
1. Hamilton	Definitive	$17,500,000	-	$17,500,000	$14,656,732	84%	10/22/2022 (actual)
2. Paramus	Definitive	$21,400,000	-	$21,400,000	$18,158,600	85%	11/9/2022 (actual)
3. Plainfield	Definitive	$22,600,000	-	$22,600,000	$19,749,610	87%	12/14/2022 (actual)
4. Woodbury	Definitive	$18,100,000	-	$18,100,000	$11,595,702	64%	10/17/2023 (↓ +112)
5. State Street (OP)	Study	$19,700,000	-	$19,700,000	$3,062,699	16%	12/29/2022 (actual)
Total Elec. Stip. Base	**-**	**$99,300,000**	**$700,000**	**$100,000,000**	**$67,223,343**	**67%**	**-**

**-As discussed in the IM 2022 First Quarter Report, during the first quarter of 2022, PSE&G made the decision to hold risk and contingency at the subprogram level.*
***-Reflects the in-service date of the last major asset (e.g. switchgear), certain activities may take place after this date to support the final in-service date (i.e. when all customers are cutover).*
(↑)*-Indicates the forecasted in-service date advanced from the prior quarter.*
(↓)*-Indicates the forecasted in-service date slipped from the prior quarter.*

As shown in **Table 22**, four of the five life cycle station upgrade projects were placed in-service during the fourth quarter of 2022. This included the State Street (OP) project that had been forecasted to go in-service in April 2023 as of the end of the third quarter of 2022, with the advancement of the in-service date driven by first circuit energization moved into December 2022 to support the State Street project within the Electric Station Flood Mitigation subprogram (essentially the IP scope), with remaining cutovers still planned for 2023. The Woodbury forecasted in-service date slipped 112 days from the status of the prior quarter, driven by a switchgear foundation installation error that requires rework and results in pushing the initial circuit cutover past the summer outage period. Additional details on each of these life cycle station upgrade projects are provided in the individual subsections that follow.

Findings & Observations:

- Four of the five Life Cycle Station Upgrade projects were placed in-service during the fourth quarter of 2022 (all but Woodbury). Construction continued on the Hamilton, Paramus, Plainfield, and Woodbury projects, while construction started on the State Street OP project with the first circuit placed in-service.
- The cost forecasts for the five life cycle upgrade projects collectively increased by approximately \$1.0 million (or 1.0%) from the status as of the end of the third quarter of 2022 to a total forecast of \$101.5 million at the end of 2022. This increase was predominantly accounted for within the Hamilton and Plainfield projects, while the Woodbury project had a very minor forecast increase (approximately \$3K) and Paramus and State Street OP both had slight decreases to their respective forecasts (collectively an approximately \$123K decrease). For Hamilton and Plainfield, the forecast increases related to higher than estimated Division and commissioning costs for completing the cutovers.
- Updated estimates were approved during the second quarter of 2022 on the Hamilton, Plainfield, and Woodbury projects, each of which advanced to the Definitive estimate stage and each saw the base estimate increase by \$100K to \$600K, with the primary drivers relating to higher than estimated construction costs.

1. Hamilton

During the fourth quarter of 2022, \$1,755,731 was spent on the Hamilton project against a forecast of approximately \$1.2 million, which brough total spend on the project to approximately \$14.7 million. The variance in forecasted to actual spend during the fourth quarter of 2022 was primarily attributed to higher than forecasted costs for underground cable installation, additional civil contractor work, and additional traffic control hours to support circuit cutovers. The Hamilton project was placed in-service on October 22, 2022.

Notable activities performed on the Hamilton during the fourth quarter of 2022 included energizing the switchgear, placing it in-service, and cutting over all circuits.

The actual spend by quarter for Hamilton as compared to the current forecast and URB approved estimate is provided below. During the fourth quarter of 2022, the Hamilton project submitted a revised Definitive level estimate for URB approval, which resulted in the base estimate increasing from \$16.8 million to \$17.5 million. This \$0.7 million estimate increase was driven by:

- IP electrical subcontract labor and material higher than estimated (\$0.4 million);
- Additional Relay hours (\$0.2 million); and,
- Higher switchgear procurement costs (\$0.1 million).

Following development and approval of the updated estimate, PSE&G increased the forecast for the Hamilton project by approximately \$500K, which was driven by higher than estimated Division and commissioning costs for completing the cutovers.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals							***Forecast***
$0	$362,372	$3,141,022	$3,770,758	$3,089,239	$2,537,609	$1,755,731	$3,317,944

Estimate & Forecast		**Actuals to Date**	**% of Actuals to Estimate & Forecast**
Estimate	$17,500,000	$14,656,732	84%
Forecast	$17,974,676		82%

2. Paramus

During the fourth quarter of 2022, $1,301,265 was spent on the Paramus project against a forecast of approximately $1.4 million. This brought total spend on the project to approximately $18.2 million through the end of 2022. The Paramus project was placed in-service on November 9, 2022.

Notable activities conducted during the fourth quarter of 2022 on the Paramus project included the completion of switchgear commissioning and placing it in-service.

The actual spend by quarter for Paramus as compared to the current forecast and URB approved estimate is provided below.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals							***Forecast***
$0	$840,200	$7,068,765	$952,513	$5,942,564	$2,053,294	$1,301,265	$3,531,644

Estimate & Forecast		**Actuals to Date**	**% of Actuals to Estimate & Forecast**
Estimate	$21,400,000	$18,158,600	85%
Forecast	$21,690,245		84%

3. Plainfield

During the fourth quarter of 2022, $2,697,705 was spent on the Plainfield project against a forecast of approximately $2.3 million. The variance in forecasted to actual spend during the fourth quarter of 2022 was driven by a combination of higher than estimated traffic control and material costs, additional engineering hours, and higher actual hours for cutovers. This brought total spend on the project to approximately $19.7 million through the end of 2022. The Plainfield project was placed in-service as of December 14, 2022.

Notable activities conducted on the Plainfield project during the fourth quarter of 2022 included:

- Completion of switchgear commissioning; and,
- 1st circuit cutover and station placed in-service.

The actual spend by quarter for Plainfield as compared to the current forecast and URB approved estimate is provided below. The forecast for the Plainfield project increased by approximately $578K from the prior quarter, which was driven by higher than estimated Division and commissioning costs for completing the cutovers.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals							***Forecast***
$0	$682,325	$3,584,101	$1,682,480	$2,682,840	$8,420,160	$2,697,705	$4,042,689

Estimate & Forecast		Actuals to Date	% of Actuals to Estimate & Forecast
Estimate	$22,600,000	$17,051,906	87%
Forecast	$23,792,299		83%

4. *Woodbury*

During the fourth quarter of 2022, $1,024,742 was spent on the Woodbury project against a forecast of approximately $1.1 million. This brought the total spend on the project to approximately $11.6 million through the end of 2022.

The forecasted in-service date for the Woodbury project slipped 112 days from the status as of the end of the prior quarter to October 17, 2023. This slip was due to an error in the switchgear foundation that required rework to correct and resulted in the initial circuit cutover being pushed into the summer outage period. The corrective work on the switchgear foundation was completed later in the fourth quarter of 2022, with the direct construction and additional rigging costs paid for by the contractor. Costs for the foundation redesign were charged back to the contractor and internal PSE&G costs related to this issue are being assessed and will also be back charged.

Notable activities conducted on the Woodbury project during the fourth quarter of 2022 included:

- Start of electrical construction;
- Switchgear delivered; and,
- Switchgear foundation repaired and switchgear set on foundation.

The actual spend by quarter for Woodbury as compared to the current forecast and URB approved estimate is provided below.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals							***Forecast***
$0	$551,165	$1,613,823	$1,460,525	$1,776,838	$5,168,609	$1,024,742	$6,506,929

Estimate & Forecast		Actuals to Date	% of Actuals to Estimate & Forecast
Estimate	$18,100,000	$11,622,472	64%
Forecast	$18,102,631		64%

5. *State Street (Outside Plant)*

During the fourth quarter of 2022, $1,371,165 was spent on the State Street (OP) project against a forecast of approximately $1.3 million, which brough total spend on the project to approximately $3.1 million. As of the prior quarter, the forecasted in-service date for the State Street OP project was April 21, 2023, which was driven a redesign of the manhole and conduit exits from the substation. During the fourth quarter of 2022, PSE&G was able to move the first circuit energization back into 2022, with the first circuit in-service as of December 29, 2022. This aligned with the State Street IP energization for the companion project within the Electric Station Flood Mitigation subprogram.

Notable activities conducted during the fourth quarter of 2022 included the start of civil and electrical construction and the energization of circuit 4005.

The actual spend by quarter for State Street (OP) as compared to the current forecast and URB approved estimate is provided below.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals							*Forecast*
$0	$0	$211,247	$395,903	$100,527	$983,856	$1,371,165	$16,916,220

Estimate & Forecast		Actuals to Date	% of Actuals to Estimate & Forecast
Estimate	$19,700,000	$3,062,699	16%
Forecast	$19,978,918		15%

F. Gas M&R Station Upgrades

During the fourth quarter of 2022, the Camden and East Rutherford projects were placed in-service, while construction continued to advance on Paramus and the Central and Mount Laurel projects continued pre-construction activities. **Table 23 – ES 2 Gas M&R Summary Status as of December 31, 2022** below provides these newly approved estimates for each project within the Gas M&R subprogram, along with the actuals to date and forecasted in-service dates.

Table 23 – ES 2 Gas M&R Summary Status as of December 31, 2022

Project	Estimate Level	Base	Risk & Contingency	Total Estimate	Actuals	% of Actuals to Estimate	Forecasted In-Service
1. Camden*	Definitive	$21,600,000	$1,200,000	$22,800,000	$19,773,551	87%	*Dec 2022 (actual)*
2. Central*	Conceptual	$31,400,000	$5,500,000	$36,900,000	$25,817,651	70%	Nov 2023
3. East Rutherford	Definitive	$24,100,000	$1,900,000	$26,000,000	$22,817,102	88%	*Dec 2022 (actual)*
4. Mount Laurel	Conceptual	$12,700,000	$3,100,000	$15,800,000	$2,085,475	13%	Nov 2023
5. Paramus*	Study	$11,500,000	$7,400,000	$18,900,000	$1,725,954	9%	Feb 2024 (↓)
6. Westampton	Definitive	$8,400,000	$-	$8,400,000	$8,476,715	101%	*Oct 2021 (actual)*
Subprogram Total		**$109,700,000**	**$19,100,000**	**$128,800,000**	**$80,696,447**	**63%**	**Dec 2023**

**-Included in the Stipulated Base.*
(↑)-Indicates the forecasted in-service date advanced from the prior quarter.
(↓)-Indicates the forecasted in-service date slipped from the prior quarter.

During the fourth quarter of 2022, there were no updated estimates approved for any of the Gas M&R projects. The cost forecasts were also unchanged for three of the projects (Central, Mount Laurel, and Paramus), while the Camden and East Rutherford projects saw forecast increases of approximately $2.9

million and $2.4 million, respectively, and the Westampton project forecast increased approximately $31K. Collectively, the subprogram forecast increased from approximately $110.3 million as of the end of the third quarter of 2022 to approximately $115.6 million as of the end of 2022. Details of the individual forecast changes are discussed within the individual project discussions that follow.

Relative to the forecasted in-service dates shown in **Table 23**, as of the end of 2022, the forecasted in-service dates for the three remaining Gas M&R projects was unchanged from the prior quarter for Mount Laurel and Central (both remaining at November 2023), while the Paramus project's forecasted in-service date slipped from December 2023 to February 2024 later than planned deliver of the heater building, which pushes out other construction activities.

Findings & Observations:

- During the fourth quarter of 2022, the Camden and East Rutherford projects were placed in-service, joining the previously completed Westampton project and leaving three projects remaining in the Gas M&R subprogram (Central, Mount Laurel, and Paramus).
- The three remaining projects continued to advance at various stages of development, with Central actively in construction and Mount Laurel and Paramus continuing pre-construction activities with construction planned to commence in the second quarter of 2023 for both projects.
- The only change to the forecasted in-service dates from the status as of the end of the prior quarter was to the Paramus project, which encountered a forecasted delay to the delivery of the heater building, resulting in a shift of all related construction activities. PSE&G and its contractor are evaluating opportunities to re-sequence work to mitigate the impacts and are continuing discussions with the heater building vendor to expedite delivery if possible.
- With the Paramus project encountering a forecasted equipment delay, this project is currently forecasted to be completed in February 2024, after the December 2023 Program end date. The status of PSE&G efforts to regain the schedule will be monitored and reported on in future reports.
- The overall Gas M&R subprogram forecast increased by approximately $5.3 million from the end of the prior quarter, which was virtually entirely driven by forecast increases for the Camden and East Rutherford projects. In both projects the forecast increase was largely driven by additional construction work and support, including higher than estimated water disposal costs. The overall Gas M&R subprogram forecast is now at approximately $115.6 million, above the Stipulation amount of $101.0 million, but under PSE&G's current $128.8 million funding for the subprogram.

1. Camden

During the fourth quarter of 2022, the recorded spend on the Camden project was -$6,934,318 compared to a forecast of approximately -$6.8 million, which reflected the LPA-associated costs being removed from the ES 2 project costs and as a result reduced the total spend to approximately $19.8 million. The Camden project was placed in-service as of December 30, 2022.

Notable activities on the Camden project during the fourth quarter of 2022 included:

- Received and set in place the regulating control skids;
- Completed Transco tie-in;

- Completed temporary power connections and energized;
- Completed hydrotest of station inlet piping and made final connections;
- Completed distribution system tie-ins;
- Continued control building fit out; and,
- Gassed in all piping and placed pressure regulating system in-service.

Remaining work on Camden includes the completion of storm sewer tie-ins, final fit out of the control room, delivery, installation and startup of the electrical switchgear, switchover to site permanent power, demolition of existing buildings, security improvements, and final grading and paving of the site.

The actual spend by quarter for Camden as compared to the current forecast and URB approved estimate is provided below. The forecast for the Camden project increased by approximately $2.9 million from the status as of the end of the third quarter of 2022 to a current forecast of approximately $24.5 million as of the end of 2022. This increase was driven by construction change orders and additional environmental costs for water and soil disposal.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals							***Forecast***
$13,326	$859,350	$2,147,696	$2,791,701	$7,655,276	$13,240,520	($6,822,220)	$4,710,072

Estimate & Forecast		Actuals to Date	% of Actuals to Estimate & Forecast
Estimate	$22,800,000	$19,773,551	87%
Forecast	$24,483,623		81%

2. Central

During the fourth quarter of 2022, $2,164,525 was spent on the Central project compared to a forecast of slightly under $1.0 million, which brought the total spend to approximately $25.8 million. The variance in forecasted to actual spend during the fourth quarter of 2022 was attributed to material invoices coming in higher than what was accrued, more piping being installed than forecasted, and additional environmental costs incurred. The forecasted in-service date for the Central project as of the end of 2022 remains at November 30, 2023, unchanged from the status as of the end of the prior quarter.

Notable activities on the Central project during the fourth quarter of 2022 included:

- Completed foundations for piers and pipe supports;
- Completed erection of regulator and heater buildings;
- Received large control valves;
- Began pipe rack installation;
- Completed partial hydro testing of piping sections;
- Set heaters and circulating pumps; and,
- Continued electrical and plumbing rough in.

The actual spend by quarter for Central as compared to the current forecast and URB approved estimate is provided below. The forecast of $31.4 million for the Central project remains unchanged from the status as of the end of the prior quarter.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals							*Forecast*
$6,869	$670,582	$4,226,277	$7,112,617	$7,029,778	$4,607,003	$2,164,525	$5,582,350

Estimate & Forecast		Actuals to Date	% of Actuals to Estimate & Forecast
Estimate	$36,900,000	$25,817,650	70%
Forecast	$31,400,000		82%

3. East Rutherford

During the fourth quarter of 2022, $8,212,614 was spent on the East Rutherford project compared to a forecast of approximately $9.9 million, which brought the total spend to approximately $22.8 million. The variance in forecasted to actual spend during the fourth quarter of 2022 was driven by delays in completion of the building flooring that impacted construction sequencing and resulted in delaying receipt of material due to limited space in the laydown area and electrical work and site restoration activities forecasted for December that were pushed into 2023 to maintain the in-service date. The East Rutherford project was placed in-service as of December 23, 2022.

Notable activities on the East Rutherford project during the fourth quarter of 2022 included:

- Installed 20” inlet header, 24” and 30” outlet headers;
- Completing pressure testing of piping;
- Made final tie-ins of inlet piping and header;
- Placed regulator runs in-service (two in November, the remaining five in December);
- Placed new heaters in-service; and,
- Continued wire pulling and terminations.

Remaining work on East Rutherford involves completion of the regulator building walls and lighting, refurbishment of the scrubber pads, final fit out of the control room, installation and commissioning of the MEG unit, fencing and security, and final grading and site paving.

The actual spend by quarter for East Rutherford as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project. The forecast for the East Rutherford project increased by $2.4 million from the status as of the end of the third quarter of 2022 to a current forecast of $26.5 million as of the end of 2022. This increase was driven by a combination of construction change orders, additional M&R support for commissioning activities, additional Transco fees, additional water disposal following significant rain events, and additional construction support.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals						*Forecast*	
$9,010	$521,865	$1,783,623	$1,551,290	$4,413,835	$6,324,865	$9,010,011	$485,502

Estimate & Forecast		Actuals to Date	% of Actuals to Estimate & Forecast
Estimate	$26,000,000	$22,817,102	88%
Forecast	$26,500,000		86%

4. Mount Laurel

During the fourth quarter of 2022, $404,693 was spent on the Mount Laurel project compared to a forecast of approximately $526K, which brought the total spend to approximately $2.1 million. The forecasted in-service date for the Mount Laurel project as of the end of 2022 remained unchanged from the status as of the end of the prior quarter at November 30, 2023.

Notable activities on the Mount Laurel project during the fourth quarter of 2022 included:

- Completed final reviews and issued IFC drawings;
- Submitted site plan application to the Mount Laurel planning board and received approval;
- Finalized lease agreement for laydown area; and,
- Continued discussions with Transco for coordination with their project.

Construction activities on Mount Laurel remain planned to commence in the second quarter of 2023.

The actual spend by quarter for Mount Laurel as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project. The forecast for the Mount Laurel project remained unchanged from the status as of the prior quarter at $12.7 million.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals							*Forecast*
$5,965	$362,167	$527,341	$135,639	$42,260	$607,409	$404,693	$10,614,525

Estimate & Forecast		Actuals to Date	% of Actuals to Estimate & Forecast
Estimate	$15,800,000	$2,085,475	13%
Forecast	$12,700,000		16%

5. Paramus

During the fourth quarter of 2022, $408,342 was spent on the Paramus project compared to a forecast of approximately $453K, which brought the total spend to approximately $1.7 million. The forecasted in-service date for the Paramus project as of the end of 2022 slipped 55 days from the status as of the end of the prior quarter to February 22, 2024 a forecasted delay to the delivery of the heater building, which shifts out other construction activities. PSE&G and its contractor are evaluating opportunities to re-sequence work to improve the in-service date and are continuing discussion with the heater building vendor to expedite delivery if possible.

Notable activities on the Paramus project during the fourth quarter of 2022 included:

- Received construction bids and commenced evaluation; and,
- Received interconnection agreement from Transco for review.

Construction activities on the Paramus project remain planned to commence in the second quarter of 2023.

The actual spend by quarter for Paramus as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project. The forecast for the Paramus project as of the end of 2022 remained unchanged from the prior quarter at $12.0 million.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals							*Forecast*
$8,842	$462,452	$568,344	$94,755	$115,998	$67,221	$408,342	$10,274,047

Estimate & Forecast		Actuals to Date	% of Actuals to Estimate & Forecast
Estimate	$18,900,000	$1,725,953	9%
Forecast	$12,000,000		14%

6. Westampton

During the fourth quarter of 2022, $63,654 was spent on the Westampton project compared to a forecast of approximately $56K, which brought the total spend to approximately $8.5 million. The Westampton was placed in-service as of October 22, 2021, final punch list items were worked down and completed during the fourth quarter of 2022 and a final inspection was scheduled with the township. This effectively concludes the Westampton project.

The actual spend by quarter for Westampton as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals							*Forecast*
$8,395	$1,032,670	$6,961,216	$178,124	$132,517	$100,140	$56,123	$27,075

Estimate & Forecast		Actuals to Date	% of Actuals to Estimate & Forecast
Estimate	$8,400,000	$8,476,715	101%
Forecast	$8,503,790		100%

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PSEG Services Corporation

November 30, 2023

VIA ELECTRONIC MAIL ONLY
Sherri Golden, Board Secretary
Board of Public Utilities
44 South Clinton Avenue, 1st Floor
P.O. Box 350
Trenton, New Jersey 08625-0350

**Re: Energy Strong II Program Quarterly Report
Q3 - 2023**

Dear Secretary Golden:

Enclosed for filing is the report on the second quarter of the Energy Strong II program for July to September, 2023.

The Energy Strong II program was addressed by a Board Order dated September 11, 2019 September 11 Order) in Docket Nos. EO18060629 & GO18060630. That order adopted a Stipulation pursuant to which PSE&G is operating the program known as Energy Strong II.

Paragraph 45 of that Stipulation requires reports on:

- the estimated quantity of work and the quantity completed to date or, if the project cannot be quantified with numbers, the major tasks completed, e.g. design phase, material procurement, permit gathering, phases of construction;
- the forecasted and actual Energy Strong II costs-to-date for the quarterly reporting period and for the program-to-date; where projects are identified by major category (with actual variances from forecasted amounts expressed in dollar and percentage terms);
- the estimated Energy Strong II project completion date, and estimated completion dates for each Energy Strong II sub-program and the Program as a whole;
- Anticipated changes to ES II projects, if any;
- Actual capital expenditures made in the normal course of business on similar projects, identified by comparable Energy Strong II sub-program; and
- Any other performance metrics concerning the IIP required by the Board.

The reporting requirements listed in paragraph 45 of the Stipulation are addressed by the enclosed materials.

Paragraphs 46, 47, and 49 of that Stipulation provide that PSE&G shall report quarterly on the performance of Electric Stations and gas M&R Stations; Contingency Reconfiguration Strategies and Grid Modernization ADMS in a manner that compares the performance of the upgraded or new plant to pre-Energy Strong II Plant.

Please contact the undersigned with any questions or concerns.

Very truly yours,

Danielle Lopez

cc: ***Via Email only***
Brian Lipman
David Wand
Maura Caroselli
Karen Forbes
Stacy Peterson
Malike Cummings
Matko Illic
Caroline Vachier

ES II Program Quarterly Report to the Board of Public Utilities

Q3-2023 – July, August, September 2023

Table of Contents

Metric 1 – Estimated Quantity of Work

For each Energy Strong II Subprogram:

A. Estimated quantity of work

i. **For the subprogram**

ii. **Planned to date (based on forecasted estimates at the beginning of the reporting period)**

B. Quantity completed to date or, if the project cannot be quantified with numbers, the major tasks completed, e.g., design phase, material procurement, permit gathering, phases of construction.

NOTE: This quarterly report covers Program to date performance up to the Q3-2023 period – July 1, 2023, through September 30, 2023. At the end of the period, all subprograms/projects have advanced through varying stages of planning, authorization and execution and completion. Where applicable, forecasted, and actual units of work and/or major tasks completed are provided.

Energy Strong II Electric Program

Electric Station Flood Mitigation

A. Estimated Quantity of Work:

i. **Project:** The estimated quantity of work for this Subprogram includes implementation of flood mitigation (FM) measures at 16 Substations. The Stipulation also allows for inclusion of substation switchgear Life Cycle (LC) replacement, subject to funding available within the Flood Mitigation budget cap.

In 2021, the Front St substation was initially included in the program as a Lifecycle (LC) station, as identified in the list of LC stations identified in the stipulation. This station was added into the subprogram as a Lifecycle replacement project for potential funding however, during the project initiation, the project team discovered that in addition to life cycle improvements, Front St. station also requires flood mitigation as it is located within an identified FEMA mapping zone and below the NJ DEP flood Hazard area level.

One (1) project (Constable Hook) will be included in the execution of another transmission project and will not be executed under the ESII program. Subsequently, the Energy Strong II stipulation was amended by removing the Constable Hook substation project from the Program and replacing it with flood mitigation work on the Company’s Front Street substation.

Constable Hook is not included in the updates below.

ii. **Planned to Date:** Major work planned to the end of September 2023 (Front St included):

a. Completion of Key Drawing Review (KDR) for 16 FM stations, cost estimate update to Study Level (50% confidence level) transition approval for 16 flood stations, estimate update to Conceptual (70% CL) level estimate transition for 16 projects and estimate update to Definitive (90% CL) level estimate for 15 stations.
b. Issue Switchgear purchase orders for 14 flood stations.
c. Detailed Engineering on 16 flood stations.
d. Site plan approvals for 10 flood stations
e. 12 ESFM projects in active construction.
f. Switchgear installation at 13 flood stations.
g. Elimination of Ridgefield and Market St 4 kV stations and full completion of 13kv conversion work.
h. In-service of 10 flood stations.
i. Close out completed for Ridgefield 4kV Elimination and Market Street Elimination

B. Quantity of Work Completed to Date:

As of the end of September 2023 most projects in the ESFM program progressed on schedule. Orange Valley and Front St received delivery of their Powercon equipment. Lakeside now is the only project awaiting delivery and with its forecasted in-service date beyond the end of the Program Period. All projects issued their major equipment purchase orders. Ten projects requiring site plan have received approval. In Q3 2023, twelve projects were in construction. To date the Ridgefield 4kV and Market St Elimination projects completed their 4kV to 13kV conversions, and transfer of customers from Ridgefield and Market St 4kV Substations. Eleven projects (Academy, Leonia, Ridgefield 13kV, Hasbrouck Heights, Kingsland, State St, Waverly 4kV, Toney's Brook, Clay St, Meadow Rd and Front St (contingency)) have placed switchgears into service.

- 15 projects of the 16 flood mitigation projects have transitioned to Definitive (90%) level estimate, 1 project (Lakeside) is at Conceptual (70%) level estimate.
- Purchase Orders have been awarded for major equipment (switchgear) on all 14 projects requiring switchgear.
- 16 projects have substantially completed detailed engineering design.
- 9 projects have awarded POs for A/E design. PSE&G is the engineer for the other 7 projects.

- 16 projects have completed scope lockdown.
- 16 projects have awarded purchase orders for civil construction phase commencement.
- 15 projects have awarded a purchase order for electrical construction commencement.
- 10 projects requiring site plan approval have submitted applications, 10 have been approved.
- 12 projects (Leonia, State St, Clay St, Waverly, Front St, Meadow Road, Kingsland, Lakeside, Toney's Brook, Orange Valley, Woodlynne and Hasbrouck Heights) are in construction. Four projects are completed with construction (Market St, Academy, Ridgefield 4kV and Ridgefield 13kV). Two projects are complete with closeout (Market St. and Ridgefield 4kV).
- Leonia has successfully energized new 13kV switchgear #2 and placed it into service. All circuits on both switchgears have been cutover to the new switchgears.
- Ridgefield has successfully energized new 13kV switchgear #2 and placed it into service. All circuits on both switchgears have been cutover to the new switchgears.
- Waverly has successfully energized the 26kV switchgear and placed it into service. All 26kV circuits have been cutover to the new switchgear.
- Hasbrouck Heights has successfully energized new 4kV switchgear and placed it into service. All circuits have been cutover to the new switchgear.
- Academy has successfully energized the new 13kV switchgear and placed it into service at the new Fairmont station. All circuits from the Academy station have been upgraded from 4kV to 13kV and transferred to the new station.
- Front St has successfully energized the contingency 4kV equipment and placed it into service.
- State St has successfully energized the new 4kV switchgear and placed it into service.
- Toney's Brook has successfully energized the new 4kV switchgear and placed it into service.
- Clay St has successfully energized the new 4kV switchgear and placed it into service.
- Contingency switchgear from Leonia was disassembled and delivered and set at Meadow Road. Meadow Road has successfully energized the new 13kV switchgear and placed it into service. All circuits have been cutover to the new switchgear.
- Contingency switchgear from Ridgefield was disassembled and delivered and set at Kingsland. Kingsland has successfully energized the new 13kV switchgear and placed it into service.
- The Ridgefield 4kV and Market St Elimination projects completed their 4kV to 13kV conversions, eliminated the flood risk to customers supplied from Ridgefield and Market St 4kV Substations. Both station elimination projects went in-service.
- Market St has completed inside plant (substation) civil demolition and ISRA related activities.

- Project closeout completed for Ridgefield 4kV Elimination and Market St Elimination.

Electric Contingency Reconfiguration

A. Estimated Quantity of Work:

i. **Project:** CR Subprogram estimated 1,467 Reclosers and 1,344 Fuse Savers to be installed over the life of the program.

ii. **Planned to Date:** Major work planned to the end of September 2023 included the following.

a. Install 1,467 Reclosers program to date (PTD) by end of Q3-2022
b. Commission 1,467 Reclosers PTD by the end of Q3-2023
c. Install and commission 1,348 Fuse Saver program to date (PTD) by end of Q3-2023

B. Quantity of Work Completed to Date:

Reclosers

All Reclosers planned for the program have been completed

- All 1,467 Reclosers planned for the Program have been engineered, installed and commissioned into service.

Fuse Savers

- 1,326 Fuse Savers have been installed program to date to the end of Q3 2023.
- 1,325 of the 1,326 installed Fuse Savers were commissioned into service.
- 1,393 Fuse Savers have been engineered for installation.

Electric Grid Modernization - Communication System

A. Estimated Quantity of Work:

i. **Project:** The Company will install a communication system upgrade, comprised of a new Wireless Radio Network and fiber technology (approximately 134.5 miles of new fiber), and 218 Retrofit Substation RTU’s. SCADA system communications at designated substations will be cutover to the fiber network. The system will provide coverage for all switching devices on the system to facilitate both system and customer equipment communication moving forward. The

Company will install 1,176 Remote Device Management (RDM) on the reclosers on system using Blueframe Software.

ii. **Planned to Date:** Major work planned to the end of September 2023 included the following:

a. Complete In-Service on thirty-four (34) Fiber Install Projects
b. Build and Install Blueframe Software for RDM
c. Develop Process to Prepare for RDM Cutover

B. Quantity of Work Completed to Date:

- One (Edison) project in progress, pending railroad crossing outage to be scheduled for 1st Quarter 2024)
- Completed Cutover Process for RDM for 2 Reclosers/Division with final release and validated functionality.

Electric Grid Modernization - ADMS

A. Estimated Quantity of Work:

i. **Project:** The Advanced Distribution Management System (ADMS) subprogram is made up of Supervisory Control and Data Acquisition (SCADA) Platform Upgrade; new Outage Management System (OMS); deployment of additional modules of Distribution Management System (DMS) and Distributed Energy Resources Management System (DERMS) Applications. This remains unchanged from the beginning of the Energy Strong II Program.

ii. **Planned to Date:** Major work planned to the end of September 2023 included the following:

a. Close Out DMS/DERMS Project Financially.
b. Complete SIT Round 5
c. Begin SIT Planning 6 and 7.

B. Quantity of Work Completed to Date:

- Completed Close Out DMS/DERMS Project Financially.
- Completed SIT 5

- Completed SIT 6

Electric Stipulated Base Subprogram

A. Estimated Quantity of Work:

i. **Project:** The Electric Stipulated Base provides for investment of up to $100 million to be spent at the Company's discretion toward electric outside plant higher design and construction standards ("Outside Plant" or OP-HDS) and/or electric 4kV substations life cycle subprograms identified in the Energy Strong II petition. Based on agreement, new underground distribution circuits (State St. OP project), which is part of the State St. Flood Mitigation project scope, is also included in Stipulated Base.

ii. **Planned to Date:** Major work planned to the end of September 2023 included:

a. Completion of Key Drawing Review (KDR) for all stations, cost estimate update to Study Level (50% confidence level) transition approval for 5 Stations, estimate update to Conceptual (70% CL) level estimate transition for 4 projects and estimate update to Definitive (90% CL) level estimate for 4 stations.
b. Issuance of Switchgear purchase orders for the 4 IP Lifecycle stations.
c. A/E contract awards for all Lifecycle stations.
d. Detailed design for all 4 IP Lifecycle stations and the State St OP Project.
e. Approval of Site Plan applications for all four (4) IP Lifecycle stations.
f. Start civil construction at all Lifecycle stations.
g. Start electrical construction at all Lifecycle stations.
h. In-service of the contingency switchgear at Paramus LC.
i. Installation of 4kv switchgear, commencement of electrical construction and commissioning at four (4) IP lifecycle stations.
j. Energization and in service of Hamilton. All circuits cutovers.
k. Energization and in-service of Paramus and Plainfield 4kv switchgears.
l. Energization and in-service of first circuit at New State St OP.
m. Demolition of existing feeder rows complete at Plainfield and Hamilton.

B. Quantity of work Completed to Date:

- As of the end of June 2023, Key Drawing Review (KDR), estimate update to Definitive 90% level and URB estimate transition have been completed for all Lifecycle stations.
- Four electric 4kV life cycle substation projects (Plainfield, Paramus, Hamilton, & Woodbury) have awarded major equipment PO's.
- Four electric 4kV life cycle substation projects (Plainfield, Paramus, Hamilton, & Woodbury) and the State St OP project have substantially completed detailed engineering design and locked their scopes.
- Site plan applications have been approved on all four IP electric 4kV life cycle substation projects.
- All life cycle substation projects are in civil construction.
- All life cycle substation projects are in electrical construction.
- Paramus 4kV substations life cycle project contingency switchgear is in-service.
- Hamilton, Paramus and Plainfield have set and energized their new 4kV switchgears and placed them into service.
- State St OP has placed the first OP circuit into service from the New State St substation.
- Hamilton completed all circuit cutovers.

Energy Strong II Gas M&R

A. Estimated Quantity of work:

i. **Project:** The estimated quantity of work for this subprogram includes implementation of flood mitigation measures at 2 of the 6 Gas M&R Substations (Camden and East Rutherford) listed in the Program Stipulation and life cycle upgrades at all 6 M&R Substations (Camden, Central, East Rutherford, Mt. Laurel, Paramus, and Westampton). This remains unchanged from the beginning of the Energy Strong II Program.

ii. **Planned to Date:** Major work planned to the end of September 2023 included:

A. Camden

a. Complete fit out of control / SCADA building.

b. Complete electrical installation and terminations.

   c. Complete installation of gas chromatograph and odor analyzer.
   d. Complete wiring and commission new electrical switchgear.
   e. Switch over to permanent power.
   f. Begin demolition of decommissioned piping and structures

B. East Rutherford
   a. Complete electrical installation and terminations.
   b. Complete erection of regulator building.
   c. Completed control building fit out.
   d. Demobilize contractor.
   e. Restore laydown area.

C. Central
   a. Complete Control / SCADA building fit out.
   b. Complete tie in for 60 psi distribution system.
   c. Completed installation of piping, conduits in pipe rack.
   d. Complete inlet tie-ins from Transco and Texas Eastern.
   e. Begin Commissioning of regulation runs and ancillary equipment.

D. Mount Laurel
   a. Complete foundations for regulation and SCADA buildings, MEG Unit.
   b. Fabrication of piping run segments.
   c. Begin installation of electrical conduits.
   d. Begin installation of below grade piping runs, inlet and outlet piping regulating runs.
   e. Receive and set SCADA building.
   f. Receive and begin erection of regulation building.
   g. Receive, connect and commission full flow bypass skid.

E. Paramus
   a. Continue to receive materials and equipment.
   b. Complete electrical power upgrade.
   c. Begin fabrication of contingency bypass skids.
   d. Begin distribution tie-ins for contingency skids.
   e. Set up secure front yard to receive contingency skids.

F. Westampton

   a. Install screening on fence.

   b. Close out all building permits.

B. Quantity of Work Completed to Date:

Major work completed as to the end of June 2023 includes the following:

Camden

- Commissioned electrical switchgear and metering sections.
- Completed switchover to permanent power.
- Commissioned gas chromatograph and odor analyzer.
- Commissioned heaters.
- Relocated propane vaporizers.
- Completed fit out of Control / SCADA building.
- Completed electrical wire pulls and terminations.
- Completed removal of hazardous materials in building slated for demolition.
- Began removal of decommissioned piping.

East Rutherford

- Completed erection of control building.
- Completed control building fit out.
- Demobilized contractor.
- Restored laydown area.
- Completion of punch list items and final site grading remain.

Central

- Completed tie-in of Transco supply.
- Completed tie-in to 60 psi distribution systems.
- Completed installation of pipe rack foundations and supports.
- Completed commissioning of regulator runs.
- Completed fit out of control/SCADA building.
- Completed installation of electrical conduit, pulling wire and terminations.
- Put Central M&R station in-service.

Mt. Laurel

- Completed foundations for regulation and SCADA buildings, MEG Unit.
- Continued fabrication of piping run segments.
- Began installation of electrical conduits.
- Began installation of below grade piping runs, inlet and outlet piping regulating runs.

- Received and set SCADA building.
- Received and began erection of regulation building.
- Received, connected and commissioned full flow bypass skid.

Paramus
- Continued to receive materials and equipment.
- Completed electrical power upgrade.
- Began fabrication of contingency bypass skids.
- Began distribution tie-ins for contingency skids.
- Set up and secured front yard to receive contingency skids.

Westampton
- Completed requirements needed to satisfy township engineer in order to close out permits. These included replacement of one light, cleaning of storm sewer and change fabric on perimeter fence.
- Installed fence screening.
- Closed out building permits.

Metric 2 – Estimated Program and Subprogram Completion Dates

The estimated ES II project completion date, and estimated completion dates for each ESII sub-program and the Program as a whole.

Note - Project completion date is defined by the date project closeout report is completed.

Energy Strong II Program

Program	Forecast In-Service (Last major equipment)	Timeline for Completion
Electric Energy Strong II Program	Mar-24	Nov-24
Gas Energy Strong II Program	Oct-24	Apr-25

Energy Strong II Accelerated Recovery Programs

Program	Subprogram	Forecast In-Service	Timeline for Completion
Electric Energy Strong II Program	Electric Flood Mitigation	Mar-24	Nov-24
	Contingency Reconfiguration	Sep-23	Jun-24
	Grid Modernization - Communication	Dec-23	Dec-23
	Grid Modernization - ADMS	Dec-23	Jun-24
Gas Energy Strong II Program	M&R Stations Upgrade	Oct-24	Apr-25

Electric Station Flood Mitigation

Project	Forecast In-Service	Timeline for Completion[1]	Updates	Expected Changes
Market Street Substation Elimination	Jun-21A	Dec-21A		
Meadow Road Substation	May-23	Nov-23		
Academy Street Substation	Oct-21A	Jun-22A		
Ridgefield 4kv Substation Elimination	May-21A	Dec-21A		
Ridgefield 13kv Substation	Dec-22A	Jun-23A		
Hasbrouck Substation	Nov-22A	Jul-23A		
Kingsland Substation	Jul-23A	Jun-24		
Lakeside Avenue Substation	Mar-24	Nov-24		
Leonia Substation	Nov-22A	May-23A		
Clay Street Substation	Apr-23	Apr-24		
State Street Substation	Dec-22A	Feb-24		
Toney's Brook Substation	May-23A	Apr-24		
Waverly Substation*	Dec-23	Nov-24		
Woodlynne Substation	Dec-23	Aug-24		
Orange Valley Substation	Dec-23	Jul-24		
Front Street Substation	Dec-23	Jul-24		

*** Based on updated schedule resulting from Waverly Site Plan application denial by City of Newark**

[1] Project completion date is defined by the date project closeout report is completed.

Contingency Reconfiguration

Project	Forecast In-Service	Timeline for Completion[1]	Updates	Expected Changes
Reclosers	Jan-22A	Jul-22A		
Fuse Savers	Sep-23	Jun-24		

Grid Modernization - Communication

Project	Forecast In-Service	Timeline for Completion[1]	Updates	Expected Changes
Wireless Network	Dec-21A	Dec-21A		
Fiber	Dec-23	Dec-23		
Retrofits Reclosers	Dec-21A	Jun-22A		
Radio Commissioning	Dec-23	Jun-24		
RDM Recloser	Jun-23	Dec-23		

Grid Modernization - ADMS

Project	Forecast In-Service	Timeline for Completion[1]	Updates	Expected Changes
Platform/SCADA Upgrade	Jun-22A	Jun-22A		
DMS/DERMS	Jan-23A	Jun-23		
OMS	Oct-23	Apri-24		In-service date may shift to March 2024

[1] Project completion date is defined by the date project closeout report is completed.

Gas Metering & Regulation (M&R)

Project	Forecast In-Service	Timeline for Completion[1]	Updates	Expected Changes
Camden (M&R)	Dec-22A	Oct-23		
East Rutherford (M&R)	Dec-22A	Jul-23A		
Westampton (M&R)	Oct-21A	May-22A		

[1] Project completion date is defined by the date project closeout report is completed.

ENERGY STRONG II STIUPLATED BASE PROGRAM

Program	Forecast In-Service (Last major equipment)	Timeline for Completion
Electric Stipulated Base	Dec-23	Jun-24
Gas Stipulated Base	Oct-24	Apr-25

Electric Stipulated Base

Project	Forecast In-Service	Timeline for Completion[1]	Updates	Expected Changes
Paramus Substation	Nov-22A	Nov-23		
Hamilton Substation	Oct-22A	May-23A		
Woodbury Substation	Oct-23	May-24		
Plainfield	Dec-22A	Jun-23A		
State Street Outside Plant	Dec-22A	Jun-24		
Outside Plant – Higher design Standard (OP-HDS)	Dec-23	Jun-24		

[1] Project completion date is defined by the date project closeout report is completed.

Gas Metering & Regulation (M&R) Stipulated Base

Project	Forecast In-Service	Timeline for Completion[1]	Updates	Expected Changes
Mt. Laurel (M&R)	Nov-23	May-24		
Central (M&R)	Oct-23	May-24		
Paramus (M&R)	Oct-24	Apr-25		

[1] Project completion date is defined by the date project closeout report is completed.

Metric 3 – SAIFI/MAIFI

A. This metric includes data for circuits involved in the Major and Non-Major events in **Q3-2023.**

- There were No Major Events in Q3-2023, therefore only the Non-major Event Report is included for this period.

Detailed tables for this metric (Non-major Events) are included at the end of this report.

Metric 3 Reports Included for Q3-2023

- Table M3.1 – Quarterly Report Non-Major Event Performance. (Clause #47)

Metric 4 – Quarterly and Program To-Date Forecast and Actual Costs

Flood Mitigation

Quarter Performance (Q3-2023, July to September)

Cost Type	Actuals	Forecast*	Variance ($)	Variance (%)
Material	$21,823,572	$23,911,726	($2,088,155)	-9%
Other Costs	$17,264,124	$23,437,904	($6,173,780)	-26%
Total	$39,087,696	$47,349,631	($8,261,934)	-17%

Program to Date (September 2023)

Cost Type	Actuals	Forecast	Variance ($)	Variance (%)
Material	$98,412,431	$127,696,768	($29,284,337)	-23%
Other Costs	$211,004,606	$189,982,203	$21,022,402	11%
Total	$309,417,037	$317,678,971	($8,261,934)	-3%

Contingency Reconfiguration

Quarter Performance (Q3-2023, July to September)

Cost Type	Actuals	Forecast*	Variance ($)	Variance (%)
Material	$1,154,631	$1,104,426	$50,205	5%
Other Costs	$2,923,136	$2,574,976	$348,160	14%
Total	$4,077,768	$3,679,402	$398,365	11%

Program to Date (September 2023)

Cost Type	Actuals	Forecast	Variance ($)	Variance (%)
Material	$58,770,602	$52,105,393	$6,665,209	13%
Other Costs	$86,356,023	$92,622,867	($6,266,844)	-7%
Total	$145,126,625	$144,728,260	$398,365	0%

Grid Modernization - Communication

Quarter Performance (Q3-2023, July to September)

Cost Type	Actuals	Forecast*	Variance ($)	Variance (%)
Material	($14,870)	($1,333,340)	$1,318,470	-99%
Other Costs	$587,044	$1,761,987	($1,174,943)	-67%
Total	$572,174	$428,647	$143,527	33%

Program to Date (September 2023)

Cost Type	Actuals	Forecast	Variance ($)	Variance (%)
Material	$2,467,700	$13,011,072	($10,543,372)	-81%
Other Costs	$62,531,136	$51,844,237	$10,686,900	21%
Total	$64,998,836	$64,855,308	$143,527	0%

Grid Modernization – ADMS

Quarter Performance (Q3-2023, July to September)

Cost Type	Actuals	Forecast*	Variance ($)	Variance (%)
Material	$36,023	$629,007	($592,984)	-94%
Other Costs	$3,857,829	$4,111,640	($253,811)	-6%
Total	$3,893,852	$4,740,647	($846,795)	-18%

Program to Date (September 2023)

Cost Type	Actuals	Forecast	Variance ($)	Variance (%)
Material	$4,239,317	$11,764,068	($7,524,751)	-64%
Other Costs	$55,631,457	$48,953,500	$6,677,956	14%
Total	$59,870,774	$60,717,568	($846,795)	-1%

Electric Stipulated Base

Quarter Performance (Q3-2023, July to September)

Cost Type	Actuals	Forecast*	Variance ($)	Variance (%)
Material	$898,928	$202,665	$696,263	344%
Other Costs	$5,320,350	$7,381,646	($2,061,296)	-28%
Total	$6,219,279	$7,584,311	($1,365,032)	-18%

Program to Date (September 2023)

Cost Type	Actuals	Forecast	Variance ($)	Variance (%)
Material	$28,475,630	$33,640,422	($5,164,792)	-15%
Other Costs	$62,369,572	$58,569,813	$3,799,760	6%
Total	$90,845,203	$92,210,235	($1,365,032)	-1%

Gas M&R

Quarter Performance (Q3-2023, July to September)

Cost Type	Actuals	Forecast*	Variance ($)	Variance (%)
Material	$3,319,342	$4,910,520	($1,591,178)	-32%
Other Costs	$8,280,762	$9,636,908	($1,356,146)	-14%
Total	$11,600,104	$14,547,428	($2,947,324)	-20%

Program to Date (September 2023)

Cost Type	Actuals	Forecast	Variance ($)	Variance (%)
Material	$25,840,602	$39,452,423	($13,611,821)	-35%
Other Costs	$85,983,318	$75,318,821	$10,664,497	14%
Total	$111,823,920	$114,771,244	($2,947,324)	-3%

* Quarterly forecast is as of September 1, 2023

Similar Projects Comparable to ES II Subprograms

Actual capital expenditures made in the normal course of business on similar projects, identified by comparable ESII sub-program:

ES II Investment Category	Description	Applicable ES II Subprograms	Capital Spend on Comparable Non-ES II Programs
Hardening & Resilience	Harden infrastructure, thereby making it less susceptible to damage from wind, flying debris, and water damage in anticipation of future Major Storm Events; Strengthen the resiliency of the Company's delivery system	* Electric Stations Flood Mitigation * OP-HDS * Gas M&R Flood Mitigation * Electric Contingency Reconfiguration * Electric Grid Modernization	$ 45,195,720
Life Cycle	Reliability - LC replacements	* Electric Stations LC (4kV) Replacement * Gas M&R	$ 94,316,405
Total	**Capital Spend from September 2019 to September 2023**		**$ 139,512,125**

Detailed Tables for Metric 3 for Q3-2023 – SAIFI/MAIFI

Table M3.1 - Quarterly Report Non-Major Event Performance during the quarter. (#47)

This report includes quarterly non-major event performance combining all events

Blank cell indicates no outage for the circuit.
Note: The 0.00000 signifies there was an outage but the value is beyond 5 decimal place

	5 Year Benchmark				Report Quarter Performance (Q1-2023)			
Circuit	MAIFI	SAIFI	CAIDI	SAIDI	MAIFI	SAIFI	CAIDI	SAIDI
ADA 8011	0.00130	0.00140	106.59	0.07590	0.00011	0.00025	190.55	0.04808
ADA 8012	0.00140	0.00068	105.00	0.05254	0.00160	0.00064	80.90	0.05210
ADA 8015	0.00076	0.00009	125.36	0.00268	0.00139	0.00021	36.67	0.00775
ADA 8021	0.00060	0.00034	39.84	0.00508		0.00008	195.64	0.01511
ADA 8022	0.00360	0.00141	45.85	0.08044	0.00324			
ADA 8023	0.00159	0.00043	176.88	0.05644	0.00147	0.00064	66.03	0.04221
ADA 8024	0.00063	0.00030	49.87	0.00811		0.00012	73.70	0.00912
ADA 8025	0.00059	0.00023	34.75	0.00679	0.00041	0.00002	27.47	0.00042
ADA 8026	0.00020	0.00014	144.32	0.01479	0.00001			
ALD 8012	0.00246	0.00090	88.82	0.09278		0.00002	161.00	0.00384
ALD 8013	0.00300	0.00065	70.14	0.05012	0.00026	0.00028	71.58	0.01977
ALD 8015	0.00357	0.00148	51.50	0.07728		0.00088	38.36	0.03362
ALD 8016	0.00215	0.00121	87.13	0.08348	0.00129	0.00006	103.75	0.00661
ALD 8022	0.00224	0.00070	77.05	0.04252	0.00054	0.00001	76.00	0.00085
ALD 8023	0.00206	0.00094	67.11	0.05120	0.00200	0.00048	64.54	0.03067
ALD 8024	0.00002	0.00001	51.61	0.00251				
ALD 8025	0.00225	0.00140	42.76	0.06011	0.00175	0.00077	51.13	0.03913
ALD 8026	0.00110	0.00040	189.11	0.03887	0.00114	0.00051	46.73	0.02395
ARC 4001		0.00042	15.00	0.00624				
ARC 4003	0.00023	0.00023	99.00	0.02270				
AUD 4003	0.00082	0.00020	122.50	0.02365		0.00118	75.67	0.08926
BAO 8003	0.00229	0.00116	31.48	0.03098	0.00148	0.00007	145.22	0.00977
BAO 8006	0.00076	0.00058	132.41	0.10855	0.00036	0.00002	81.00	0.00155
BAO 8008	0.00006	0.00001	81.75	0.00130				
BAO 8013	0.00288	0.00095	91.93	0.07640		0.00003	47.00	0.00142
BAO 8014	0.00138	0.00084	80.66	0.04137	0.00105	0.00007	78.33	0.00533
BAO 8015	0.00060	0.00051	87.02	0.04290	0.00044			
BAO 8023	0.00305	0.00042	69.51	0.02819		0.00003	475.00	0.01531
BAO 8033	0.00204	0.00045	87.78	0.04117	0.00101			
BAO 8043	0.00330	0.00182	47.53	0.07989		0.00018	73.55	0.01294
BAO 8044	0.00224	0.00050	74.75	0.02936	0.00597	0.00115	29.00	0.03340
BEA 8001	0.00157	0.00027	61.80	0.01563	0.00144	0.00003	62.62	0.00162
BEA 8003	0.00017	0.00004	46.44	0.00195	0.00033	0.00002	7.00	0.00014
BEA 8004	0.00010	0.00017	60.51	0.01157	0.00018			
BEA 8010	0.00138	0.00052	110.52	0.05293	0.00095	0.00125	36.91	0.04610

	5 Year Benchmark				Report Quarter Performance (Q1-2023)			
Circuit	**MAIFI**	**SAIFI**	**CAIDI**	**SAIDI**	**MAIFI**	**SAIFI**	**CAIDI**	**SAIDI**
BEF 8012	0.00115	0.00035	116.11	0.03754		0.00004	178.44	0.00710
BEF 8013	0.00063	0.00038	76.27	0.02442	0.00171	0.00039	48.45	0.01899
BEF 8014	0.00108	0.00044	62.23	0.02632	0.00186	0.00005	91.04	0.00475
BEF 8015	0.00116	0.00068	63.06	0.03652	0.00013	0.00004	89.71	0.00364
BEF 8016	0.00080	0.00054	154.86	0.09106	0.00187	0.00043	61.09	0.02597
BEF 8021	0.00047	0.00032	112.37	0.04112	0.00019	0.00009	69.07	0.00618
BEF 8023	0.00134	0.00082	116.88	0.09529	0.00020	0.00022	22.36	0.00488
BEM 8001	0.00716	0.00120	131.49	0.07051	0.00795	0.00261	30.81	0.08041
BEN 8011	0.00052	0.00032	111.70	0.02616		0.00008	120.55	0.00960
BEN 8012	0.00302	0.00096	111.90	0.04210	0.00075	0.00116	90.11	0.10468
BEN 8014	0.00068	0.00020	117.06	0.00939	0.00048	0.00004	136.22	0.00548
BEN 8015	0.00012	0.00015	115.11	0.01703				
BEN 8016	0.00128	0.00039	74.94	0.02376	0.00080	0.00003	69.91	0.00186
BEN 8021	0.00060	0.00055	74.47	0.03094	0.00037	0.00032	61.11	0.01980
BEN 8022	0.00277	0.00132	117.27	0.07413	0.00043	0.00170	8.22	0.01401
BEN 8023	0.00056	0.00060	82.91	0.04347		0.00075	14.98	0.01123
BEN 8025	0.00041	0.00072	72.26	0.03071	0.00193	0.00027	9.00	0.00243
BEN 8026	0.00257	0.00091	33.10	0.02869	0.00078	0.00094	18.85	0.01772
BLO 4002		0.00023	213.03	0.03279				
BLO 4004		0.00004	138.42	0.00518				
BLO 4006		0.00019	184.17	0.02210		0.00068	68.82	0.04675
BLO 4007		0.00034	108.50	0.03146				
BLO 4009	0.00022	0.00039	52.09	0.02121				
BLO 4012					0.00039	0.00032	6.00	0.00193
BLO 4014		0.00053	150.36	0.07724		0.00018	6.00	0.00107
BLO 4015	0.00072	0.00070	88.88	0.06310		0.00023	8.00	0.00183
BLO 4016		0.00086	62.95	0.04790		0.00112	66.82	0.07494
BLO 4017		0.00032	64.00	0.01859				
BLO 4018	0.00065	0.00044	88.89	0.04532		0.00035	51.00	0.01776
BOR 4001	0.00013	0.00024	144.38	0.02264	0.00042	0.00028	47.75	0.01353
BOR 4002	0.00018	0.00028	60.23	0.01562	0.00042	0.00021	30.00	0.00626
BRU 8011	0.00048	0.00010	95.60	0.00890		0.00008	124.48	0.00996
BRU 8012	0.00140	0.00104	38.76	0.03879	0.00215	0.00041	90.42	0.03718
BRU 8013	0.00173	0.00025	110.80	0.02238		0.00004	168.80	0.00712
BRU 8021	0.00134	0.00042	51.04	0.01104	0.00106	0.00005	70.24	0.00319
BRU 8022	0.00060	0.00050	115.02	0.01495	0.00003	0.00004	109.49	0.00431
BRU 8023	0.00117	0.00049	43.18	0.01041	0.00049			
BUS 8011	0.00060	0.00044	73.82	0.02945		0.00004	127.00	0.00566
BUS 8012	0.00233	0.00029	127.52	0.03119	0.00079	0.00019	88.05	0.01637
BUS 8013	0.00039	0.00039	130.96	0.03495	0.00104	0.00022	98.00	0.02126
BUS 8015	0.00024	0.00017	129.92	0.02429	0.00024	0.00001	149.38	0.00095
BUS 8023	0.00188	0.00104	44.44	0.04111	0.00208	0.00036	26.50	0.00941
CAR 8002	0.00018	0.00010	103.07	0.01138	0.00008	0.00009	79.00	0.00692
CAR 8003	0.00008	0.00004	80.62	0.00304	0.00006			
CAR 8004	0.00022	0.00011	135.12	0.00540	0.00034	0.00033	21.54	0.00719
CAR 8006	0.00008	0.00006	39.01	0.00105				

	5 Year Benchmark				Report Quarter Performance (Q1-2023)			
Circuit	MAIFI	SAIFI	CAIDI	SAIDI	MAIFI	SAIFI	CAIDI	SAIDI
CAS 8001	0.00142	0.00101	76.82	0.07861		0.00059	13.04	0.00775
CAS 8002	0.00017	0.00016	107.18	0.01737	0.00040	0.00003	36.00	0.00099
CAT 4003	0.00025	0.00025	6.00	0.00149				
CAT 4005	0.00017	0.00001	597.00	0.00597				
CAT 4006		0.00024	72.00	0.01742				
CAT 4009	0.00024	0.00039	80.63	0.02959				
CED 8011	0.00204	0.00138	69.28	0.07747	0.00083	0.00006	157.79	0.00892
CED 8013	0.00067	0.00016	163.02	0.03975		0.00004	104.06	0.00468
CED 8016	0.00097	0.00070	139.05	0.10119	0.00013	0.00029	77.49	0.02224
CED 8021	0.00263	0.00117	42.47	0.04564	0.00018	0.00004	76.00	0.00309
CED 8022	0.00226	0.00094	64.01	0.07450	0.00358	0.00021	54.29	0.01117
CED 8025	0.00054	0.00030	99.48	0.01486		0.00025	44.27	0.01096
CED 8026	0.00098	0.00018	96.89	0.02075	0.00102	0.00036	49.37	0.01765
CET 4012	0.00114	0.00141	79.17	0.10537		0.00156	53.51	0.08356
CET 4019	0.00070	0.00070	37.67	0.02629		0.00007	547.24	0.04073
CHA 4001		0.00013	73.06	0.00332	0.00022	0.00012	21.00	0.00255
CHA 4002		0.00017	229.00	0.03992				
CHA 4004	0.00033	0.00086	41.55	0.03577				
CHA 4005		0.00030	69.40	0.02097		0.00047	54.00	0.02540
CHA 4008		0.00026	149.00	0.03858				
CHA 4012	0.00068	0.00099	103.71	0.05275		0.00052	31.23	0.01620
CHA 4013		0.00022	71.83	0.01581	0.00026	0.00028	138.00	0.03834
CHA 4014		0.00064	292.01	0.03046	0.00020			
CHA 4015		0.00022	153.76	0.03138	0.00028	0.00028	20.00	0.00566
CHE 4008		0.00027	92.63	0.02678				
CHS 4001		0.00031	153.98	0.05336		0.00006	222.00	0.01387
CHS 4003		0.00012	19.00	0.00224				
CHS 4006		0.00017	457.50	0.09976				
CHS 4007		0.00002	56.00	0.00126				
CHS 4008	0.00023	0.00039	73.12	0.03517				
CIN 8001	0.00111	0.00055	122.00	0.06213	0.00010	0.00057	210.47	0.11912
CIN 8002	0.00049	0.00043	89.93	0.03238	0.00015	0.00067	185.95	0.12382
CIN 8004	0.00007	0.00003	67.92	0.00241		0.00063	123.51	0.07762
CIN 8005	0.00028	0.00039	54.53	0.02113	0.00014	0.00009	57.00	0.00501
CIN 8009	0.00050	0.00025	141.25	0.03254	0.00079	0.00002	149.95	0.00245
CIN 8031	0.00088	0.00032	143.47	0.01574		0.00004	100.45	0.00364
CIN 8032	0.00157	0.00068	81.13	0.03143		0.00007	57.08	0.00411
CIN 8033	0.00054	0.00060	79.69	0.04570	0.00053	0.00048	58.03	0.02765
CIN 8043	0.00243	0.00219	101.28	0.14568	0.00095	0.00093	91.15	0.08438
CLA 4005		0.00006	76.00	0.00448				
CLA 4006		0.00024	63.64	0.01801		0.00028	164.33	0.04552
CLA 4008		0.00016	102.50	0.01095		0.00020	14.00	0.00275
CLE 4001		0.00067	52.25	0.03690	0.00012	0.00012	28.00	0.00347
CLE 4011		0.00085	41.75	0.04072				
CLE 4016	0.00050	0.00139	63.61	0.08871				
CLF 8012	0.00119	0.00027	70.16	0.01637	0.00079	0.00002	66.00	0.00118

	5 Year Benchmark				Report Quarter Performance (Q1-2023)			
Circuit	**MAIFI**	**SAIFI**	**CAIDI**	**SAIDI**	**MAIFI**	**SAIFI**	**CAIDI**	**SAIDI**
CLF 8013	0.00066	0.00023	64.92	0.01612	0.00128	0.00002	126.47	0.00302
CLF 8014	0.00095	0.00021	122.15	0.01542	0.00049	0.00014	24.00	0.00336
CLF 8015	0.00686	0.00173	45.79	0.07563	0.00966	0.00231	48.96	0.11309
CLF 8023	0.00156	0.00068	78.80	0.04824	0.00210	0.00088	17.19	0.01520
CLF 8024	0.00111	0.00103	56.61	0.04757	0.00254	0.00029	40.79	0.01184
CLF 8025	0.00092	0.00021	99.43	0.01390	0.00134			
CLK 8012	0.00027	0.00015	26.26	0.00563	0.00008	0.00003	17.00	0.00057
CLK 8013	0.00011	0.00011	67.58	0.01366		0.00027	99.53	0.02674
CLK 8014	0.00070	0.00051	90.27	0.02349	0.00043	0.00073	13.50	0.00979
CLK 8015	0.00175	0.00140	53.99	0.07709	0.00210	0.00099	35.20	0.03498
CLK 8016	0.00106	0.00097	17.75	0.02150	0.00007	0.00000	369.00	0.00029
CLK 8022	0.00099	0.00096	36.09	0.01337		0.00026	39.37	0.01042
CLK 8023	0.00002	0.00002	31.25	0.00034	0.00008	0.00002	63.00	0.00100
CLK 8024	0.00037	0.00014	49.06	0.00330				
CLK 8031		0.00016	56.68	0.01082		0.00016	42.00	0.00664
CLK 8032	0.00171	0.00306	86.10	0.16706	0.00054	0.00095	51.21	0.04888
CLK 8033	0.00057	0.00159	39.30	0.08732	0.00055	0.00027	41.08	0.01099
CLK 8034	0.00052	0.00019	138.37	0.00798	0.00012			
CLK 8041		0.00021	128.67	0.01218	0.00061	0.00038	172.00	0.06592
CLK 8042	0.00070	0.00057	10.13	0.00554	0.00037	0.00000	151.00	0.00006
CON 8001	0.00123	0.00074	49.22	0.03802	0.00079			
COR 8013	0.00237	0.00026	119.36	0.01207	0.00050	0.00224	45.97	0.10294
COR 8015	0.00214	0.00044	83.94	0.02335		0.00001	305.83	0.00426
COR 8025	0.00065	0.00024	43.92	0.01036	0.00062	0.00044	30.28	0.01322
COR 8033	0.00397	0.00068	68.12	0.03302		0.00004	122.69	0.00435
COR 8034	0.00217	0.00067	88.36	0.04539	0.00329	0.00072	122.20	0.08779
COR 8035	0.00099	0.00016	542.55	0.08476				
COR 8041	0.00238	0.00087	68.13	0.04026	0.00153	0.00054	9.73	0.00523
COR 8042	0.00158	0.00063	76.44	0.02864	0.00047	0.00054	23.74	0.01280
CRA 4001		0.00026	62.48	0.01619		0.00026	91.00	0.02383
CRA 4003		0.00058	50.63	0.02649	0.00017	0.00060	79.85	0.04783
CRA 4004	0.00016	0.00047	59.24	0.02491				
CRA 4009		0.00036	68.33	0.02487				
CRA 4010		0.00073	84.60	0.06377				
CRA 4011		0.00027	66.00	0.02016	0.00014	0.00018	117.00	0.02063
CRA 4012		0.00037	143.13	0.03455	0.00018	0.00012	115.00	0.01387
CRA 4016	0.00029	0.00038	102.93	0.03404				
CRX 8001	0.00100	0.00049	83.67	0.04344	0.00066	0.00125	189.64	0.23768
CRX 8003	0.00040	0.00041	100.73	0.03758	0.00051	0.00047	41.20	0.01924
CRX 8004	0.00128	0.00063	112.33	0.04511	0.00170	0.00050	145.25	0.07192
CRX 8005	0.00080	0.00050	102.20	0.05726	0.00017	0.00004	18.57	0.00076
CRX 8007	0.00198	0.00112	88.75	0.11410	0.00003	0.00215	99.95	0.21522
CRX 8008	0.00112	0.00052	86.38	0.04260	0.00081	0.00018	61.52	0.01134
CRX 8009	0.00081	0.00064	87.92	0.05623	0.00170	0.00065	30.64	0.01999
CUL 4001	0.00098	0.00094	152.00	0.14126				
CUL 4012		0.00069	113.49	0.08070		0.00065	32.24	0.02101

	5 Year Benchmark				Report Quarter Performance (Q1-2023)			
Circuit	MAIFI	SAIFI	CAIDI	SAIDI	MAIFI	SAIFI	CAIDI	SAIDI
CUT 8001	0.00107	0.00042	39.89	0.01972		0.00007	61.64	0.00432
CUT 8002	0.00012	0.00007	163.83	0.00685	0.00011	0.00006	118.91	0.00700
CUT 8003	0.00289	0.00124	80.43	0.08582	0.00152	0.00083	27.31	0.02267
CUT 8004	0.00288	0.00205	112.13	0.21608	0.00082	0.00022	762.78	0.16515
CUT 8005	0.00067	0.00048	76.28	0.04550		0.00006	6.00	0.00037
CUT 8006	0.00037	0.00060	93.32	0.05233	0.00068	0.00058	13.09	0.00757
CUT 8007	0.00261	0.00117	66.91	0.06548	0.00457	0.00251	138.56	0.34749
CUT 8008	0.00125	0.00063	118.71	0.05503	0.00077	0.00066	22.15	0.01455
CUT 8010	0.00144	0.00060	223.33	0.08988	0.00088	0.00097	13.74	0.01337
CUT 8031	0.00042	0.00014	182.26	0.01471	0.00015	0.00008	19.18	0.00153
CUT 8033	0.00067	0.00075	68.42	0.04152	0.00191	0.00082	97.49	0.07950
CUT 8034	0.00380	0.00128	81.19	0.09521	0.00511	0.00047	82.34	0.03867
CUT 8041	0.00047	0.00049	102.94	0.05030	0.00033	0.00009	34.01	0.00317
CUT 8042	0.00076	0.00052	142.57	0.08197	0.00113	0.00077	53.23	0.04106
CUT 8043	0.00255	0.00244	76.63	0.18682	0.00095	0.00354	79.53	0.28133
CUT 8044	0.00012	0.00033	67.78	0.02200	0.00031	0.00055	190.90	0.10531
CXC 8012	0.00106	0.00035	73.14	0.01629		0.00000	713.00	0.00085
DAY 8001	0.00222	0.00069	65.27	0.02911	0.00040	0.00005	73.13	0.00352
DAY 8002	0.00019	0.00005	191.44	0.00719		0.00003	6.00	0.00015
DEA 4001	0.00024	0.00017	75.85	0.01215		0.00023	107.76	0.02526
DEA 4009		0.00016	78.67	0.00863				
DFD 8007	0.00445	0.00216	74.57	0.16276	0.00270	0.00186	45.43	0.08440
DFD 8008	0.00063	0.00067	86.37	0.06272	0.00134	0.00035	84.86	0.02959
DFD 8009	0.00098	0.00038	80.46	0.02557	0.00080	0.00014	86.11	0.01182
DFD 8031	0.00256	0.00134	48.77	0.05390	0.00004	0.00011	244.70	0.02698
DFD 8041	0.00140	0.00065	134.57	0.06599	0.00129	0.00004	136.54	0.00522
DOR 8012	0.00213	0.00039	50.16	0.01495				
DOR 8013	0.00022	0.00043	60.84	0.02166		0.00003	118.00	0.00399
DOR 8015	0.00286	0.00172	44.31	0.06885	0.00126	0.00055	40.17	0.02225
DOR 8024	0.00126	0.00048	43.08	0.02067	0.00046	0.00002	58.00	0.00111
DOR 8025	0.00175	0.00066	59.02	0.03816	0.00187	0.00127	159.11	0.20201
DOR 8035	0.00311	0.00236	127.15	0.12402	0.00213	0.00286	18.26	0.05220
DOR 8036	0.00408	0.00064	103.08	0.06537	0.00981	0.00197	50.33	0.09927
DOR 8044	0.00253	0.00164	48.73	0.04869	0.00230	0.00134	29.87	0.03991
DOR 8045	0.00199	0.00054	79.38	0.04002	0.00592	0.00205	156.95	0.32169
DUM 4001	0.00026	0.00043	88.58	0.03366				
DUM 4002		0.00024	97.00	0.02371		0.00010	74.27	0.00715
DUM 4004	0.00025	0.00011	64.08	0.00953		0.00021	44.67	0.00928
DUM 4007	0.00047	0.00026	202.50	0.02180				
DVB 8011	0.00069	0.00028	21.56	0.00435		0.00002	132.00	0.00263
DVB 8012	0.00014	0.00022	57.83	0.01133	0.00023	0.00007	37.87	0.00249
DVB 8013	0.00062	0.00027	67.81	0.00996	0.00147	0.00000	52.00	0.00019
DVB 8014	0.00002	0.00002	12.37	0.00027	0.00007			
DVB 8015	0.00025	0.00026	183.71	0.00572		0.00001	351.00	0.00279
DVB 8021	0.00002	0.00001	260.00	0.00114	0.00002			
DVB 8022	0.00016	0.00003	48.87	0.00071		0.00000	323.00	0.00116

	5 Year Benchmark				Report Quarter Performance (Q1-2023)			
Circuit	MAIFI	SAIFI	CAIDI	SAIDI	MAIFI	SAIFI	CAIDI	SAIDI
DVB 8023	0.00062	0.00032	99.31	0.02731	0.00016	0.00042	109.94	0.04568
DVB 8025	0.00013	0.00006	119.16	0.00130		0.00001	148.00	0.00094
EAO 4006		0.00075	40.06	0.02721				
EAO 4008		0.00085	76.30	0.03925				
EAO 4013		0.00096	43.37	0.04116				
EAO 4019		0.00046	132.22	0.04778				
EAO 4023	0.00091	0.00075	205.38	0.12784		0.00010	160.44	0.01667
EAO 4024		0.00051	94.98	0.02018				
EAT 8011	0.00156	0.00130	89.85	0.07833	0.00144	0.00141	59.30	0.08357
EAT 8012	0.00057	0.00061	75.64	0.05846		0.00027	12.00	0.00323
EAT 8013	0.00138	0.00111	37.80	0.03944	0.00038	0.00017	21.14	0.00360
EAT 8014	0.00012	0.00011	70.17	0.00976	0.00008	0.00001	15.00	0.00014
EAT 8021	0.00089	0.00072	57.80	0.03280	0.00052	0.00043	17.00	0.00723
EAT 8022	0.00143	0.00043	88.83	0.02605	0.00196	0.00005	90.72	0.00451
EAT 8023	0.00114	0.00076	63.41	0.05969	0.00280	0.00227	32.37	0.07358
EAT 8025	0.00038	0.00009	101.54	0.00298	0.00031	0.00057	27.30	0.01561
EDI 4003		0.00030	61.67	0.01924		0.00026	6.14	0.00161
EDI 4006		0.00032	38.00	0.01080		0.00047	6.00	0.00282
EDI 4007		0.00039	40.00	0.01474	0.00019	0.00057	25.25	0.01427
EDI 4008	0.00056	0.00039	17.67	0.00385		0.00057	14.37	0.00820
EDI 4009		0.00035	24.63	0.00567		0.00034	6.00	0.00202
ENG 4004								
ENG 4005								
ENG 4006		0.00008	346.00	0.02638		0.00005	86.56	0.00403
ENG 4007		0.00010	139.00	0.01429				
ENG 4012		0.00025	65.12	0.01633				
ENG 4016								
ENG 4017	0.00021	0.00020	74.50	0.00426				
EWI 4001		0.00008	90.02	0.00694				
EWI 4002	0.00051	0.00102	64.69	0.05538				
EWI 4003		0.00007	81.63	0.00520				
EWI 4004		0.00025	242.90	0.03756		0.00036	83.60	0.03008
EWI 4006		0.00036	160.28	0.02690		0.00040	8.00	0.00323
EWI 4007	0.00031	0.00052	48.96	0.02178		0.00031	15.00	0.00468
EWI 4008		0.00026	191.49	0.05015				
FAR 4002		0.00058	42.19	0.02164				
FAR 4005		0.00022	119.40	0.01626		0.00031	73.12	0.02276
FAR 4006	0.00026	0.00051	141.87	0.05931	0.00021			
FAW 8011	0.00071	0.00054	107.77	0.05763	0.00066	0.00081	121.62	0.09855
FAW 8012	0.00107	0.00075	72.13	0.05940	0.00030	0.00004	120.08	0.00492
FAW 8013	0.00122	0.00033	116.15	0.01661		0.00122	23.76	0.02892
FAW 8014	0.00131	0.00060	102.51	0.03419		0.00014	87.95	0.01225
FAW 8015	0.00028	0.00027	26.89	0.00365	0.00025			
FAW 8016	0.00164	0.00044	90.99	0.03383	0.00097	0.00076	47.28	0.03579
FAW 8022	0.00089	0.00054	105.00	0.02390				
FAW 8023	0.00113	0.00031	94.96	0.00684	0.00059	0.00117	22.54	0.02644

	5 Year Benchmark				Report Quarter Performance (Q1-2023)			
Circuit	MAIFI	SAIFI	CAIDI	SAIDI	MAIFI	SAIFI	CAIDI	SAIDI
FAW 8026	0.00098	0.00084	34.57	0.02676	0.00004	0.00001	453.12	0.00307
FED 4004	0.00072	0.00022	290.00	0.06452	0.00038			
FED 4010								
FED 4013								
FED 4018		0.00054	88.11	0.04389				
FED 4021	0.00075	0.00037	54.50	0.02034				
FED 4022	0.00068	0.00003	159.00	0.00469				
FED 4030		0.00044	110.34	0.02282	0.00029			
FEN 8041	0.00082	0.00034	46.06	0.01647	0.00063	0.00053	31.10	0.01657
FIT 8003	0.00126	0.00078	118.83	0.10582				
FOH 4002	0.00072	0.00073	111.00	0.08086				
FOH 4003	0.00051	0.00050	94.50	0.04809				
FOH 4004	0.00013	0.00048	23.26	0.01130				
FOH 4006		0.00038	55.18	0.01065				
FOH 4007		0.00187	13.34	0.02490				
FOH 4008		0.00042	71.00	0.02330		0.00031	109.13	0.03414
FOR 4009	0.00000	0.00027	87.50	0.02246				
FOT 8004	0.00065	0.00089	62.31	0.07043		0.00003	94.00	0.00296
FOU 8012	0.00343	0.00174	61.43	0.08986		0.00063	128.43	0.08086
FOU 8014	0.00031	0.00010	96.45	0.00825	0.00027	0.00009	307.99	0.02746
FOU 8022	0.00011	0.00010	54.86	0.00529				
FOU 8024	0.00024	0.00015	57.84	0.01108	0.00020	0.00004	83.88	0.00367
FRA 8011	0.00003	0.00001	140.00	0.00147				
FRA 8012	0.00007	0.00003	8.00	0.00035	0.00025	0.00010	49.52	0.00493
FRA 8013	0.00022	0.00015	56.38	0.01018	0.00014	0.00000	36.00	0.00001
FRA 8021	0.00023	0.00012	7.30	0.00165		0.00018	12.00	0.00221
FRA 8023	0.00021	0.00011	48.59	0.00571				
FRO 4006	0.00026	0.00026	56.00	0.01480				
FRO 4007	0.00070	0.00090	45.28	0.03543		0.00004	18.00	0.00066
FRO 4008	0.00054							
FRO 4009	0.00031	0.00032	293.94	0.09962		0.00030	108.00	0.03245
GBK 8011	0.00133	0.00048	85.46	0.03307	0.00116	0.00053	21.01	0.01124
GBK 8013	0.00136	0.00065	49.00	0.01892	0.00281	0.00002	124.56	0.00193
GBK 8014	0.00168	0.00060	72.12	0.02965	0.00135	0.00078	82.18	0.06446
GBK 8021	0.00126	0.00072	38.29	0.03490	0.00018	0.00026	94.07	0.02400
GBK 8022	0.00218	0.00084	54.31	0.03369	0.00123	0.00005	120.74	0.00610
GBK 8023	0.00136	0.00081	59.15	0.04199	0.00079	0.00039	82.44	0.03255
GBK 8024	0.00102	0.00091	111.54	0.12556	0.00076	0.00005	212.60	0.00973
GBK 8025	0.00214	0.00120	44.72	0.04564	0.00203	0.00048	163.90	0.07899
GET 4003	0.00112	0.00091	61.49	0.05942	0.00172			
GET 4004	0.00018				0.00052			
GET 4007	0.00078	0.00105	50.70	0.05340	0.00036			
GET 4008	0.00126	0.00087	9.80	0.00850	0.00106	0.00078	50.91	0.03979
GET 4009	0.00087	0.00056	123.04	0.01714	0.00046			
GRE 4002		0.00012	108.24	0.00875		0.00031	68.13	0.02099
GRE 4003	0.00039	0.00040	39.94	0.01622		0.00032	92.00	0.02948

Circuit	5 Year Benchmark				Report Quarter Performance (Q1-2023)			
	MAIFI	SAIFI	CAIDI	SAIDI	MAIFI	SAIFI	CAIDI	SAIDI
GRE 4004	0.00019	0.00020	69.00	0.01333		0.00002	173.00	0.00420
GRE 4005		0.00015	76.76	0.01184				
GRE 4006		0.00008	64.50	0.00492				
GRE 4007	0.00047	0.00052	124.33	0.03894				
GRN 4001		0.00104	81.24	0.08215	0.00098	0.00036	132.26	0.04796
GRN 4003		0.00021	107.00	0.02288		0.00020	87.00	0.01776
GRN 4008	0.00042	0.00027	82.60	0.02212	0.00064	0.00039	53.67	0.02072
GRN 4009		0.00068	81.23	0.05522		0.00065	23.00	0.01484
GRN 4011	0.00082	0.00057	120.67	0.04630		0.00080	73.00	0.05852
HAC 4005	0.00024	0.00024	75.12	0.01906	0.00015			
HAC 4006	0.00019	0.00056	152.04	0.08589				
HAC 4007	0.00018	0.00016	80.50	0.01046				
HAC 4009	0.00020	0.00016	43.79	0.00911				
HAC 4010	0.00007	0.00010	39.77	0.00416				
HAC 4011	0.00081	0.00034	93.00	0.03208				
HAC 4012	0.00021	0.00010	33.33	0.00163				
HAC 4013	0.00023	0.00028	67.60	0.01750				
HAC 4016	0.00020	0.00027	94.32	0.02057	0.00027	0.00027	8.00	0.00214
HAC 4018	0.00013	0.00018	89.68	0.01470				
HAD 4002		0.00080	137.26	0.10512		0.00001	122.00	0.00180
HAD 4003		0.00001	369.00	0.00371		0.00001	21.00	0.00018
HAD 4005		0.00024	86.46	0.02060		0.00005	48.31	0.00219
HAD 4008		0.00013	82.33	0.00941				
HAD 4009		0.00019	146.61	0.01842				
HAD 4010		0.00049	154.44	0.06024				
HAL 4001		0.00002	112.50	0.00156				
HAL 4002		0.00030	78.67	0.02580				
HAL 4004		0.00004	116.14	0.00408				
HAL 4005	0.00074	0.00020	198.50	0.02322		0.00069	68.06	0.04686
HAL 4007						0.00044	6.00	0.00265
HAL 4008	0.00054	0.00039	90.96	0.01765	0.00018			
HAM 4007		0.00010	46.38	0.00328				
HAM 4008		0.00032	54.47	0.01966		0.00020	39.00	0.00793
HAM 4009		0.00028	50.58	0.01556	0.00019			
HAR 4001		0.00040	113.50	0.04585				
HAR 4006		0.00039	124.00	0.06396	0.00110	0.00044	77.60	0.03397
HAR 4014		0.00059	165.81	0.09629		0.00117	22.23	0.02597
HAR 4015		0.00046	171.00	0.07807				
HAR 4018	0.00043	0.00043	171.00	0.07348				
HAR 4021		0.00040	139.42	0.05593	0.00011	0.00004	74.00	0.00303
HAT 8011	0.00015	0.00028	130.70	0.03922				
HAT 8012	0.00117	0.00077	54.21	0.03898	0.00010	0.00003	124.84	0.00373
HAT 8015	0.00019	0.00013	67.77	0.00895	0.00008			
HAT 8021	0.00041	0.00013	31.09	0.00358	0.00031	0.00050	48.77	0.02426
HAT 8022	0.00068	0.00091	67.06	0.03857	0.00039	0.00008	92.73	0.00779
HAT 8023	0.00020	0.00013	128.46	0.01949				

Circuit	5 Year Benchmark				Report Quarter Performance (Q1-2023)			
	MAIFI	SAIFI	CAIDI	SAIDI	MAIFI	SAIFI	CAIDI	SAIDI
HAT 8027	0.00085	0.00014	125.04	0.00827	0.00193	0.00025	50.86	0.01289
HAT 8034	0.00004	0.00000			0.00005			
HAT 8035	0.00080	0.00060	53.20	0.03130	0.00020	0.00003	87.80	0.00287
HAT 8037	0.00125	0.00058	111.56	0.04832		0.00011	198.05	0.02183
HAW 8032	0.00188	0.00112	80.62	0.05650	0.00264			
HAW 8041	0.00123	0.00014	116.25	0.01631	0.00005	0.00013	33.74	0.00434
HBG 4007		0.00034	11.00	0.00378				
HBG 4008		0.00000						
HID 8011	0.00099	0.00045	61.43	0.02045		0.00001	143.75	0.00137
HID 8013	0.00028	0.00023	125.15	0.02879	0.00058	0.00010	48.44	0.00503
HID 8034	0.00030	0.00026	52.93	0.01680	0.00061	0.00008	33.00	0.00263
HID 8035	0.00098	0.00056	76.29	0.04630	0.00153	0.00060	54.42	0.03249
HID 8042	0.00078	0.00021	115.61	0.02107		0.00013	60.56	0.00791
HID 8043	0.00028	0.00018	125.59	0.01925	0.00035	0.00009	198.91	0.01853
HID 8044	0.00190	0.00092	96.68	0.06810	0.00051	0.00078	208.98	0.16286
HID 8045	0.00174	0.00032	115.22	0.03682	0.00163	0.00031	26.00	0.00803
HNC 8015	0.00062	0.00033	91.75	0.02052	0.00066	0.00028	23.61	0.00662
HNC 8021	0.00165	0.00060	71.31	0.02175	0.00154	0.00143	55.68	0.07986
HNC 8022	0.00094	0.00026	105.33	0.02054	0.00032			
HNC 8024	0.00143	0.00040	80.29	0.03343	0.00080	0.00016	62.22	0.00978
HNC 8025	0.00029	0.00020	126.26	0.02124	0.00029	0.00013	109.53	0.01447
HOE 8037	0.00590	0.00166	50.55	0.06688	0.00205			
HOE 8038	0.00300	0.00122	30.33	0.04414	0.00168			
HOE 8044	0.01231	0.00256	44.61	0.10503	0.00578	0.00066	166.09	0.10881
HOE 8047	0.00203	0.00075	38.06	0.01764	0.00256	0.00059	12.30	0.00730
HOE 8048	0.00079	0.00036	134.01	0.02391	0.00047			
HOM 8001	0.00372	0.00077	54.11	0.03386	0.00107	0.00136	90.33	0.12317
HOM 8002	0.00013	0.00001	86.00	0.00072				
HOM 8003	0.00085	0.00022	70.52	0.01459	0.00023	0.00075	70.94	0.05336
HOM 8012	0.00213	0.00148	29.67	0.05052	0.00317	0.00034	26.00	0.00879
HOM 8014	0.00337	0.00137	34.61	0.05173	0.00236	0.00003	78.00	0.00217
HOM 8025	0.00073	0.00040	43.01	0.02199	0.00015	0.00017	117.07	0.02004
HOM 8032	0.00577	0.00208	59.95	0.10408		0.00010	110.00	0.01108
HOM 8033	0.00268	0.00127	109.08	0.09908	0.00254	0.00175	35.81	0.06268
HOM 8034	0.00482	0.00105	63.51	0.07339	0.00126	0.00085	129.00	0.10931
HOM 8041	0.00603	0.00104	32.94	0.02027		0.00000	394.00	0.00031
HOM 8042	0.00022	0.00009	37.73	0.00398				
HOM 8044	0.00049	0.00012	87.51	0.00608				
HOM 8046	0.00263	0.00116	45.18	0.05232	0.00140	0.00059	15.00	0.00880
IRO 4002								
IRO 4003		0.00000				0.00022	43.00	0.00955
IRO 4005	0.00052	0.00074	86.51	0.06203				
IRO 4009	0.00028	0.00028	21.00	0.00595		0.00028	61.00	0.01714
IRO 4011	0.00063	0.00060	19.86	0.01192	0.00054			
IRO 4012		0.00023	61.00	0.01417				
IRO 4013	0.00025	0.00024	255.00	0.06211		0.00011	169.00	0.01789

	5 Year Benchmark				Report Quarter Performance (Q1-2023)			
Circuit	MAIFI	SAIFI	CAIDI	SAIDI	MAIFI	SAIFI	CAIDI	SAIDI
IRO 4014		0.00075	82.00	0.06111		0.00046	272.00	0.12450
IRV 4002	0.00050	0.00124	77.76	0.10014		0.00058	57.67	0.03362
IRV 4004	0.00077	0.00141	113.88	0.15724				
IRV 4006	0.00042	0.00120	67.94	0.07233	0.00043	0.00084	18.00	0.01503
IRV 4011	0.00062	0.00033	323.50	0.02804				
IRV 4013		0.00042	112.00	0.04694		0.00044	69.00	0.03010
IRV 4017	0.00036	0.00051	44.36	0.02946	0.00025	0.00003	159.00	0.00449
IRV 4019		0.00034	102.62	0.03536		0.00050	64.96	0.03271
IRV 4021	0.00040	0.00032	116.33	0.02566				
IRV 4022		0.00025	112.00	0.01388		0.00002	162.00	0.00400
JAC 8011	0.00021	0.00020	55.83	0.01278				
JAC 8012	0.00039	0.00017	73.60	0.01336	0.00027	0.00005	23.28	0.00112
JAC 8021	0.00022	0.00004	23.37	0.00088				
JAC 8022	0.00041	0.00012	105.12	0.01287	0.00006			
JAC 8023	0.00059	0.00058	37.66	0.02336	0.00069	0.00033	111.69	0.03725
JAC 8024	0.00031	0.00026	105.08	0.01982	0.00024	0.00028	86.23	0.02454
JAC 8025	0.00081	0.00029	65.83	0.01021	0.00041			
JAC 8033	0.00109	0.00064	92.21	0.04911	0.00050	0.00056	37.88	0.02135
JAC 8043	0.00033	0.00004	101.82	0.00356	0.00061	0.00001	68.00	0.00049
KEN 4002		0.00036	35.26	0.01262				
KEN 4003	0.00035	0.00090	84.38	0.07144		0.00077	90.67	0.06986
KEN 4004		0.00023	100.17	0.01869		0.00001	364.00	0.00377
KEN 4005	0.00039	0.00046	51.22	0.02836	0.00019	0.00036	50.90	0.01829
KEN 4006		0.00068	32.12	0.03350		0.00027	110.00	0.02920
KIL 8012	0.00077	0.00077	101.12	0.07694	0.00025	0.00055	46.81	0.02558
KIL 8013	0.00021	0.00023	53.59	0.01746	0.00002			
KIL 8014	0.00121	0.00040	97.94	0.02004		0.00012	112.45	0.01387
KIL 8015	0.00041	0.00013	79.07	0.01046		0.00000	38.00	0.00018
KIL 8016	0.00140	0.00043	92.27	0.02587	0.00053	0.00025	85.38	0.02100
KIL 8022	0.00176	0.00077	68.09	0.04316	0.00090	0.00010	50.81	0.00516
KIL 8023	0.00044	0.00050	63.39	0.04287	0.00007	0.00008	68.63	0.00552
KIL 8024	0.00068	0.00045	87.97	0.03239	0.00079	0.00011	72.94	0.00833
KIL 8025	0.00207	0.00074	74.72	0.05098	0.00026	0.00027	40.34	0.01072
KIL 8031	0.00013	0.00009	53.52	0.00394	0.00004			
KIL 8033	0.00027	0.00022	36.13	0.00759	0.00001			
KIL 8034	0.00130	0.00028	106.57	0.01816	0.00143	0.00103	26.45	0.02737
KIL 8041	0.00077	0.00032	43.44	0.00777	0.00087	0.00073	52.65	0.03866
KIL 8042	0.00104	0.00042	83.94	0.01920	0.00001	0.00004	114.96	0.00512
KIL 8043	0.00039	0.00019	80.20	0.01345	0.00009	0.00001	192.77	0.00100
KIL 8044	0.00247	0.00058	125.14	0.03845	0.00232	0.00029	15.75	0.00453
KIN 8011	0.00047	0.00017	49.73	0.00862	0.00061			
KIN 8012	0.00043	0.00008	103.93	0.00388	0.00031	0.00005	8.00	0.00041
KIN 8013	0.00016	0.00002	233.46	0.00536				
KIN 8014	0.00048	0.00007	44.67	0.00254		0.00009	53.00	0.00464
KIN 8015	0.00245	0.00112	108.97	0.11851	0.00293			
KIN 8022	0.00244	0.00051	80.38	0.04365	0.00161	0.00074	28.44	0.02114

	5 Year Benchmark				Report Quarter Performance (Q1-2023)			
Circuit	MAIFI	SAIFI	CAIDI	SAIDI	MAIFI	SAIFI	CAIDI	SAIDI
KIN 8023	0.00185	0.00051	83.37	0.02411	0.00157			
KIN 8024	0.00154	0.00080	80.49	0.05082	0.00018			
KIN 8025	0.00405	0.00167	40.85	0.08721	0.00043	0.00055	35.61	0.01966
KIN 8041		0.00117	18.86	0.02200				
KIN 8042		0.00022	41.53	0.01867	0.00013			
KNY 8011	0.00022	0.00017	140.29	0.01794		0.00010	14.00	0.00134
KUL 8012	0.00201	0.00104	81.71	0.05391	0.00142	0.00039	41.68	0.01621
KUL 8013	0.00200	0.00210	52.48	0.08807	0.00152	0.00156	42.98	0.06687
KUL 8021	0.00438	0.00162	27.28	0.04564	0.00079	0.00044	7.00	0.00309
KUL 8022	0.00214	0.00107	73.15	0.05578	0.00037	0.00089	19.91	0.01775
KUL 8023	0.00118	0.00032	74.48	0.01063	0.00061	0.00030	15.00	0.00447
KUS 8002	0.00141	0.00114	94.26	0.12250				
KUS 8003	0.00274	0.00092	61.29	0.05550		0.00003	68.00	0.00227
KUS 8004	0.00107	0.00073	42.43	0.02543	0.00055	0.00072	23.36	0.01676
KUS 8006	0.00170	0.00057	69.08	0.01082	0.00139	0.00118	31.18	0.03684
KUS 8008	0.00052	0.00032	31.48	0.00460		0.00017	6.00	0.00104
KUS 8009	0.00146	0.00151	37.24	0.04252	0.00202	0.00090	28.97	0.02597
KUS 8010	0.00084	0.00050	96.51	0.03228	0.00004			
KUS 8034	0.00056	0.00019	74.95	0.01103		0.00004	87.08	0.00364
KUS 8042	0.00104	0.00077	56.65	0.04017				
KUS 8043	0.00105	0.00030	75.39	0.02037		0.00020	25.21	0.00512
KUS 8044	0.00111	0.00047	90.14	0.03620		0.00007	103.58	0.00730
KUS 8045	0.00168	0.00074	87.68	0.03942	0.00084	0.00040	272.46	0.10942
LAF 8013	0.00029	0.00031	58.35	0.01580		0.00002	49.00	0.00094
LAF 8014	0.00019	0.00017	176.81	0.02337		0.00002	81.00	0.00164
LAF 8015	0.00216	0.00046	37.21	0.01240	0.00206	0.00002	75.23	0.00159
LAF 8021	0.00002	0.00001	8.00	0.00008				
LAF 8022	0.00232	0.00064	59.13	0.03580	0.00115	0.00205	23.45	0.04816
LAF 8023	0.00036	0.00039	68.49	0.02989				
LAF 8025	0.00013	0.00007	17.67	0.00128				
LAF 8026	0.00187	0.00074	81.20	0.04624	0.00169	0.00072	33.69	0.02415
LAK 8011	0.00019	0.00003	32.00	0.00181	0.00016	0.00006	19.00	0.00107
LAK 8012	0.00005	0.00006	60.88	0.00309				
LAK 8013	0.00011	0.00021	135.87	0.02658	0.00016	0.00000	85.00	0.00037
LAK 8015	0.00003	0.00001	27.96	0.00035				
LAK 8021	0.00019	0.00006	60.15	0.00442	0.00010			
LAK 8022	0.00004	0.00002	60.68	0.00118				
LAK 8023	0.00009	0.00003	57.65	0.00190		0.00000		
LAK 8024	0.00143	0.00059	62.23	0.03255	0.00110	0.00008	107.10	0.00848
LAK 8025	0.00001	0.00000	136.00	0.00047				
LAU 8011	0.00144	0.00127	78.85	0.08953	0.00081	0.00027	27.49	0.00740
LAU 8012	0.00083	0.00035	75.20	0.01523	0.00094	0.00024	78.54	0.01872
LAU 8014	0.00104	0.00025	53.95	0.01189	0.00037	0.00035	16.72	0.00577
LAU 8021	0.00171	0.00078	91.07	0.05505	0.00075	0.00064	79.46	0.05076
LAU 8023	0.00079	0.00073	64.66	0.04997	0.00110	0.00087	74.78	0.06539
LAU 8024	0.00009	0.00012	114.45	0.01480	0.00015			

	5 Year Benchmark				Report Quarter Performance (Q1-2023)			
Circuit	MAIFI	SAIFI	CAIDI	SAIDI	MAIFI	SAIFI	CAIDI	SAIDI
LAU 8025	0.00071	0.00084	92.91	0.06272	0.00105	0.00056	80.83	0.04520
LAU 8034	0.00159	0.00116	72.04	0.09416	0.00142	0.00004	91.43	0.00375
LAU 8035	0.00144	0.00109	123.00	0.08036	0.00166	0.00128	16.69	0.02128
LAU 8044	0.00009	0.00006	145.96	0.00604				
LAW 8014	0.00106	0.00036	133.79	0.04047	0.00049	0.00003	116.40	0.00371
LAW 8015	0.00023	0.00024	44.87	0.00890		0.00000	51.00	0.00018
LAW 8016	0.00079	0.00093	55.22	0.05573	0.00054	0.00016	33.95	0.00534
LAW 8023	0.00074	0.00094	72.98	0.06122	0.00080	0.00051	102.73	0.05270
LAW 8024	0.00122	0.00075	107.43	0.05493	0.00042	0.00044	60.66	0.02668
LAW 8025	0.00082	0.00110	81.77	0.08155	0.00026	0.00087	84.05	0.07346
LAW 8033	0.00088	0.00029	101.37	0.02923	0.00171	0.00134	83.36	0.11144
LAW 8039	0.00030	0.00016	95.04	0.01316		0.00003	98.00	0.00261
LCE 8003	0.00060	0.00074	39.41	0.02090	0.00047	0.00027	18.34	0.00488
LCE 8005	0.00047	0.00023	57.44	0.01243	0.00044	0.00006	556.13	0.03497
LCE 8010	0.00059	0.00047	91.97	0.03263	0.00106	0.00038	138.14	0.05278
LCE 8012	0.00029	0.00061	64.74	0.03965	0.00171	0.00024	20.94	0.00502
LCE 8032	0.00211	0.00129	38.72	0.05027		0.00006	102.62	0.00600
LCE 8033	0.00177	0.00049	44.64	0.02295		0.00077	85.79	0.06631
LCE 8034	0.00155	0.00053	159.52	0.02644	0.00260	0.00099	38.49	0.03798
LCE 8035	0.00039	0.00006	112.56	0.00281		0.00004	27.00	0.00113
LCE 8042	0.00064	0.00106	95.56	0.14059	0.00056	0.00087	131.04	0.11401
LCE 8043	0.00108	0.00078	21.34	0.02096	0.00033	0.00009	91.86	0.00863
LCE 8044	0.00111	0.00074	72.40	0.04405		0.00029	150.90	0.04450
LCE 8045	0.00088	0.00069	52.68	0.02312	0.00051	0.00019	14.82	0.00280
LCE 8046	0.00106	0.00081	51.10	0.04191	0.00010	0.00096	27.69	0.02646
LCU 8051	0.00281	0.00108	59.61	0.05653	0.00219			
LEH 4002		0.00049	95.34	0.03054				
LEH 4003		0.00008	145.00	0.00782				
LEH 4004	0.00042	0.00054	77.54	0.04146				
LEH 4006		0.00027	89.33	0.01551		0.00003	104.00	0.00319
LEH 4007		0.00017	83.00	0.01371				
LEO 8003	0.00209	0.00158	114.76	0.12987		0.00042	60.36	0.02546
LEO 8004	0.00159	0.00219	74.42	0.16494	0.00049	0.00010	65.85	0.00640
LEO 8005	0.00134	0.00155	63.60	0.08730	0.00150	0.00072	30.31	0.02195
LEO 8006	0.00075	0.00029	76.99	0.01843	0.00018	0.00005	123.50	0.00590
LEO 8008	0.00064	0.00034	93.58	0.02146				
LEO 8009	0.00003	0.00007	194.81	0.00615	0.00002	0.00005	69.11	0.00377
LEO 8032	0.00060	0.00021	83.53	0.01064	0.00064	0.00054	71.17	0.03841
LEO 8033	0.00034	0.00040	53.09	0.02325		0.00014	122.18	0.01726
LEO 8034	0.00080	0.00091	59.06	0.05782		0.00125	27.96	0.03493
LEO 8041	0.00228	0.00228	62.33	0.14603	0.00081	0.00010	62.67	0.00641
LEO 8042	0.00040	0.00033	44.53	0.01746	0.00091	0.00038	62.36	0.02348
LEO 8043	0.00123	0.00028	137.06	0.01765	0.00044	0.00018	58.00	0.01053
LEO 8044	0.00097	0.00015	239.89	0.02436	0.00061	0.00023	160.52	0.03712
LEO 8045	0.00068	0.00040	76.73	0.03070	0.00047			
LEV 8002	0.00267	0.00110	81.12	0.07731	0.00100	0.00136	52.46	0.07151

	5 Year Benchmark				Report Quarter Performance (Q1-2023)			
Circuit	MAIFI	SAIFI	CAIDI	SAIDI	MAIFI	SAIFI	CAIDI	SAIDI
LEV 8006	0.00126	0.00069	80.48	0.04455	0.00124	0.00048	32.58	0.01576
LEV 8008	0.00178	0.00115	96.01	0.07985	0.00220	0.00017	82.75	0.01446
LEV 8011	0.00058	0.00029	77.11	0.02693	0.00052	0.00013	43.00	0.00578
LEV 8012	0.00141	0.00091	90.30	0.07877		0.00010	277.00	0.02778
LEV 8013	0.00040	0.00029	98.25	0.02433	0.00082	0.00021	109.39	0.02251
LEV 8016	0.00126	0.00057	150.99	0.02231	0.00100	0.00046	36.00	0.01658
LIB 4003	0.00085	0.00134	67.88	0.08977				
LIB 4004	0.00033	0.00034	58.00	0.01948				
LIB 4005	0.00047	0.00024	6.00	0.00291		0.00102	41.17	0.04211
LIB 4007	0.00060	0.00119	148.00	0.17622	0.00084	0.00058	38.26	0.02211
LIB 4009	0.00055	0.00030	23.00	0.00302		0.00028	270.00	0.07436
LIT 8001	0.00127	0.00033	156.52	0.03515	0.00098			
LIT 8004	0.00141	0.00016	124.80	0.02508	0.00060	0.00002	88.00	0.00196
LOC 8012	0.00209	0.00064	64.17	0.01576	0.00006			
LOC 8014	0.00086	0.00030	36.82	0.01096	0.00069	0.00001	858.00	0.00478
LOC 8033	0.00026	0.00010	21.00	0.00215	0.00026	0.00002	54.00	0.00101
LOI 8001	0.00292	0.00037	80.51	0.02505	0.00169	0.00052	161.24	0.08432
LUM 8014	0.00078	0.00037	107.18	0.04317	0.00097	0.00000	355.00	0.00057
LUM 8021	0.00114	0.00146	62.23	0.09114		0.00075	101.93	0.07623
LUM 8022	0.00099	0.00025	66.68	0.02118	0.00097	0.00028	69.38	0.01922
LUM 8024	0.00116	0.00047	128.91	0.03928	0.00011	0.00053	88.47	0.04708
MAD 8014	0.00014	0.00005	84.76	0.00388	0.00013	0.00002	115.87	0.00254
MAD 8015	0.00132	0.00031	105.30	0.02911	0.00011	0.00042	33.72	0.01424
MAD 8016	0.00018	0.00007	68.39	0.00368		0.00003	26.00	0.00078
MAD 8018	0.00241	0.00110	68.80	0.07374	0.00108	0.00002	70.50	0.00174
MAD 8021	0.00046	0.00039	223.14	0.02598	0.00046	0.00006	142.48	0.00856
MAD 8022	0.00050	0.00054	131.92	0.04273		0.00043	68.02	0.02908
MAD 8024	0.00009	0.00003	68.97	0.00222	0.00009	0.00001	131.44	0.00141
MAD 8026	0.00012	0.00010	148.76	0.01702	0.00003	0.00018	71.37	0.01295
MAD 8031	0.00168	0.00066	133.86	0.05565	0.00068	0.00026	101.25	0.02603
MAD 8032	0.00101	0.00066	142.57	0.11149	0.00067	0.00019	139.97	0.02668
MAD 8037	0.00132	0.00056	74.62	0.03142		0.00016	57.55	0.00930
MAI 8013	0.00066	0.00030	81.52	0.01958	0.00026	0.00051	78.08	0.03968
MAR 8001	0.00013	0.00003	104.00	0.00370	0.00010	0.00011	117.46	0.01272
MAR 8002	0.00118	0.00030	80.07	0.01904	0.00128	0.00117	85.77	0.10047
MAR 8004	0.00014	0.00008	69.17	0.00472		0.00012	14.50	0.00172
MAR 8005	0.00008	0.00007	104.03	0.00404	0.00000	0.00022	56.38	0.01245
MAR 8006	0.00016	0.00009	89.16	0.00775				
MAR 8008	0.00042	0.00020	99.04	0.01672	0.00023	0.00004	114.83	0.00494
MAR 8009	0.00114	0.00028	89.61	0.02115		0.00041	35.01	0.01444
MAR 8010	0.00036	0.00038	52.75	0.02191	0.00029	0.00002	171.00	0.00388
MAR 8011	0.00082	0.00008	149.50	0.00488				
MAR 8012	0.00031	0.00005	100.86	0.00605	0.00031	0.00002	126.50	0.00312
MAR 8013	0.00113	0.00032	123.72	0.04409	0.00021			
MAR 8016	0.00057	0.00034	144.66	0.01881	0.00045			
MAR 8017	0.00042	0.00041	133.97	0.04925	0.00088	0.00009	88.00	0.00823

	5 Year Benchmark				Report Quarter Performance (Q1-2023)			
Circuit	MAIFI	SAIFI	CAIDI	SAIDI	MAIFI	SAIFI	CAIDI	SAIDI
MAR 8018	0.00124	0.00042	88.03	0.02276	0.00124	0.00013	126.66	0.01659
MAS 4006	0.00022	0.00004	102.00	0.00433				
MAY 8013	0.00053	0.00038	60.85	0.02041	0.00083			
MAY 8014	0.00059	0.00045	64.93	0.01770	0.00073	0.00023	61.90	0.01434
MAY 8015	0.00437	0.00209	50.25	0.09899	0.00699	0.00165	25.54	0.04213
MAY 8022	0.00152	0.00100	39.21	0.04314		0.00046	135.64	0.06219
MAY 8023	0.00093	0.00085	64.62	0.05909	0.00055	0.00005	84.50	0.00444
MAY 8024	0.00052	0.00030	72.16	0.01418	0.00188	0.00006	72.77	0.00405
MAY 8034	0.00376	0.00110	68.16	0.06274	0.00468	0.00065	33.18	0.02141
MAY 8036	0.00113	0.00108	15.50	0.01638	0.00096	0.00051	16.08	0.00817
MAY 8043	0.00085	0.00039	130.04	0.03176	0.00204	0.00047	50.02	0.02345
MAY 8044	0.00079	0.00048	127.56	0.06925	0.00044	0.00021	90.63	0.01886
MAY 8045	0.00012	0.00020	97.12	0.00624				
MCL 4001		0.00017	56.39	0.00786		0.00000	96.00	0.00004
MCL 4002	0.00057	0.00131	28.26	0.03677		0.00037	21.35	0.00800
MCL 4003		0.00010	145.30	0.00892		0.00061	9.82	0.00601
MCL 4004	0.00027	0.00026	18.50	0.00498				
MCL 4006		0.00060	18.00	0.01085		0.00000	180.00	0.00072
MCL 4007		0.00148	184.80	0.33918				
MCL 4008		0.00055	77.78	0.03748				
MCL 4010		0.00038	36.82	0.01399	0.00032	0.00010	10.00	0.00102
MDF 8012	0.00128	0.00058	108.15	0.05896	0.00048	0.00025	22.30	0.00549
MDF 8014	0.00104	0.00030	146.07	0.02124		0.00016	154.42	0.02501
MDF 8021	0.00242	0.00087	120.05	0.06121	0.00024	0.00005	120.13	0.00645
MDF 8023	0.00073	0.00057	99.69	0.04389	0.00161	0.00207	94.45	0.19536
MDF 8024	0.00101	0.00095	100.56	0.05945		0.00038	74.05	0.02797
MDS 4003		0.00063	82.50	0.05215				
MDS 4012		0.00042	87.50	0.03622				
MEA 8011	0.00011	0.00017	68.51	0.01019	0.00027	0.00011	233.19	0.02543
MEA 8012	0.00026	0.00006	83.22	0.00510	0.00033			
MEA 8013	0.00150	0.00060	77.46	0.03420	0.00171	0.00078	23.44	0.01826
MEA 8015	0.00008	0.00005	142.27	0.00312	0.00006			
MEA 8016	0.00042	0.00019	98.63	0.01100	0.00027	0.00007	78.99	0.00569
MEA 8021	0.00117	0.00030	66.01	0.01068	0.00065	0.00055	22.14	0.01223
MEA 8024	0.00178	0.00188	54.15	0.09269	0.00199	0.00010	501.02	0.05165
MEA 8025	0.00049	0.00014	54.51	0.00677	0.00177	0.00040	90.31	0.03602
MEC 8004	0.00092	0.00033	93.50	0.02350		0.00048	63.34	0.03061
MIN 8011	0.00048	0.00023	115.79	0.03279		0.00002	43.00	0.00079
MIN 8012	0.00032	0.00021	172.77	0.01324	0.00004	0.00005	47.75	0.00224
MIN 8013	0.00325	0.00128	43.64	0.02221	0.00117	0.00004	86.84	0.00311
MIN 8015	0.00190	0.00025	164.98	0.01536	0.00226	0.00043	63.28	0.02735
MIN 8021	0.00004	0.00001	13.00	0.00024				
MIN 8022	0.00146	0.00025	44.44	0.01073	0.00289	0.00047	18.00	0.00837
MIN 8023	0.00023	0.00013	125.74	0.01755		0.00006	143.53	0.00880
MIN 8024	0.00065	0.00017	177.97	0.02511	0.00005	0.00028	7.75	0.00220
MIN 8025	0.00159	0.00048	52.34	0.02802	0.00073	0.00132	19.50	0.02571

	5 Year Benchmark				Report Quarter Performance (Q1-2023)			
Circuit	MAIFI	SAIFI	CAIDI	SAIDI	MAIFI	SAIFI	CAIDI	SAIDI
MIN 8026	0.00182	0.00016	87.04	0.01271				
MNT 4004		0.00035	142.94	0.01842		0.00018	155.90	0.02860
MNT 4005		0.00056	134.55	0.05502		0.00029	91.55	0.02696
MNT 4006	0.00038	0.00034	314.46	0.03677		0.00021	506.00	0.10452
MNT 4009		0.00023	131.40	0.01339		0.00001	245.33	0.00264
MNT 4010	0.00037	0.00042	79.77	0.02655				
MNT 4012		0.00053	233.16	0.04186		0.00011	176.67	0.01856
MNT 4015		0.00064	34.86	0.02994		0.00020	8.00	0.00161
MOG 4001		0.00073	45.50	0.03292		0.00027	161.00	0.04357
MOG 4002		0.00100	53.03	0.05648		0.00053	48.08	0.02558
MOG 4006	0.00083	0.00026	46.70	0.01190		0.00025	5.00	0.00123
MOG 4011		0.00051	45.50	0.02331				
MON 8002	0.00105	0.00135	79.93	0.10034	0.00096	0.00033	120.68	0.03991
MON 8003	0.00130	0.00066	77.61	0.02157		0.00009	150.30	0.01304
MON 8004	0.00104	0.00052	91.74	0.03113		0.00004	41.55	0.00150
MOT 8001	0.00061	0.00049	85.94	0.03831	0.00024	0.00024	94.70	0.02310
MOT 8002	0.00042	0.00018	183.37	0.01148		0.00012	148.41	0.01831
MOT 8003	0.00065	0.00043	69.29	0.02392	0.00008	0.00021	87.79	0.01852
MOY 4002	0.00045	0.00063	59.84	0.04838				
MOY 4003	0.00019	0.00028	55.00	0.01802		0.00014	40.00	0.00568
MOY 4005	0.00030	0.00001	361.52	0.00264				
MOY 4009	0.00052	0.00054	71.15	0.03871				
MRO 8012	0.00167	0.00084	97.12	0.07311	0.00118	0.00057	113.33	0.06500
MRO 8013	0.00115	0.00030	84.95	0.02439	0.00118	0.00016	38.69	0.00621
MRO 8022	0.00111	0.00128	62.81	0.06208	0.00082	0.00075	85.92	0.06483
MRO 8023	0.00127	0.00072	145.59	0.10133	0.00063	0.00131	94.34	0.12342
MRO 8024	0.00184	0.00048	74.27	0.03475	0.00213	0.00101	64.75	0.06520
MSD 8001	0.00111	0.00082	76.56	0.05759	0.00091	0.00002	63.00	0.00110
MTL 8013	0.00234	0.00078	97.41	0.03105		0.00004	109.79	0.00476
MTL 8014	0.00017	0.00012	104.43	0.01028		0.00005	83.26	0.00451
MTL 8015	0.00098	0.00051	114.82	0.04669	0.00057	0.00025	162.93	0.04105
MTL 8022	0.00070	0.00024	109.43	0.01181	0.00081			
MTL 8024	0.00012	0.00008	99.59	0.00580	0.00028	0.00010	62.97	0.00619
NBS 8011	0.00070	0.00051	68.66	0.02203	0.00266	0.00004	51.43	0.00229
NBS 8012	0.00052	0.00025	112.89	0.02898	0.00002	0.00011	232.80	0.02492
NBS 8013	0.00215	0.00048	39.48	0.01477				
NBS 8021	0.00034	0.00002	95.00	0.00379	0.00008	0.00001	67.00	0.00072
NBS 8023	0.00021	0.00001	109.34	0.00393	0.00016	0.00023	87.21	0.02027
NED 8013	0.00060	0.00029	52.15	0.01435	0.00102	0.00013	69.85	0.00931
NED 8014	0.00026	0.00033	79.22	0.01981	0.00015	0.00014	91.12	0.01280
NED 8015	0.00148	0.00089	83.19	0.06818	0.00142	0.00029	85.60	0.02501
NED 8016	0.00125	0.00059	147.80	0.06662	0.00116	0.00043	77.65	0.03338
NED 8022	0.00110	0.00084	26.80	0.02081		0.00000	231.00	0.00092
NED 8024	0.00057	0.00033	51.39	0.01363	0.00077	0.00004	67.89	0.00238
NED 8025	0.00277	0.00065	107.68	0.06845	0.00101	0.00012	102.18	0.01175
NEV 8001	0.00182	0.00047	81.59	0.03734		0.00005	93.79	0.00433

	5 Year Benchmark				Report Quarter Performance (Q1-2023)			
Circuit	MAIFI	SAIFI	CAIDI	SAIDI	MAIFI	SAIFI	CAIDI	SAIDI
NEW 8011	0.00044	0.00018	135.78	0.01834		0.00005	41.00	0.00186
NEW 8013	0.00207	0.00045	99.55	0.03237				
NEW 8014	0.00100	0.00062	92.00	0.04881		0.00005	35.92	0.00174
NEW 8023	0.00061	0.00032	92.23	0.02734		0.00031	43.08	0.01336
NEW 8025	0.00066	0.00031	159.08	0.04196		0.00018	35.57	0.00623
NEW 8032	0.00015	0.00024	81.70	0.01998				
NEW 8033	0.00078	0.00061	81.15	0.03393	0.00065			
NEW 8034	0.00130	0.00121	57.43	0.06839	0.00086	0.00004	88.53	0.00331
NEW 8041	0.00212	0.00062	76.35	0.02987	0.00190	0.00086	76.29	0.06531
NEW 8042	0.00108	0.00056	98.59	0.05165	0.00068	0.00049	40.11	0.01968
NEW 8044	0.00098	0.00048	107.66	0.03597	0.00055	0.00141	11.10	0.01566
NIN 4001		0.00042	231.06	0.03644				
NIN 4002		0.00156	31.12	0.04910	0.00111	0.00073	32.00	0.02349
NIN 4003	0.00134	0.00157	60.38	0.05305	0.00066			
NIN 4004		0.00042	173.70	0.03815				
NIN 4005	0.00080	0.00109	73.64	0.06603				
NIN 4006	0.00295	0.00002	192.58	0.00471	0.00127	0.00250	17.33	0.04327
NIT 8007	0.00233	0.00065	90.21	0.07520	0.00134	0.00012	149.13	0.01864
NOF 4003	0.00056	0.00026	87.33	0.01972	0.00035	0.00002	187.98	0.00419
NOF 4004		0.00111	76.92	0.11608		0.00057	50.00	0.02856
NOF 4010	0.00045	0.00071	71.59	0.05470				
NOT 8011	0.00004	0.00002	245.25	0.00130	0.00003	0.00001	73.00	0.00049
NOT 8013	0.00109	0.00049	34.95	0.01806	0.00003	0.00003	178.00	0.00489
NOT 8014	0.00123	0.00046	152.51	0.03799		0.00037	9.00	0.00330
NOT 8016	0.00041	0.00042	61.02	0.02571				
NOT 8021	0.00110	0.00063	102.78	0.04143				
NOT 8022	0.00059	0.00049	56.75	0.01040	0.00080	0.00000		
NOT 8023	0.00004	0.00003	61.39	0.00210				
NOT 8024	0.00178	0.00105	119.79	0.09724	0.00113	0.00041	112.08	0.04613
NRB 8012	0.00039	0.00025	72.76	0.02435	0.00081	0.00000	68.00	0.00003
NRB 8013	0.00288	0.00030	70.30	0.01483	0.00178	0.00048	5.00	0.00241
NRB 8014	0.00219	0.00068	112.39	0.05665	0.00297	0.00153	33.53	0.05145
NRB 8015	0.00117	0.00061	88.15	0.03949	0.00261			
NRB 8022	0.00258	0.00119	89.43	0.06005	0.00064	0.00005	206.00	0.00992
NRP 4001	0.00029	0.00029	41.00	0.01204				
NRP 4002	0.00047	0.00035	137.00	0.04846				
NRP 4003	0.00104	0.00172	45.89	0.08996		0.00003	125.00	0.00378
NRP 4004	0.00040							
NRP 4007	0.00068	0.00051	43.64	0.01042		0.00131	109.83	0.14381
NRP 4009		0.00025	43.02	0.01111		0.00001	237.00	0.00255
NRP 4010	0.00085	0.00147	38.83	0.04329	0.00060	0.00421	37.26	0.15705
NRP 4012	0.00019	0.00015	61.90	0.00922				
NRP 4014	0.00046	0.00043	92.82	0.02491	0.00095			
NRP 4015	0.00040	0.00039	30.22	0.01171				
NUT 4001		0.00008	191.31	0.00723				
NUT 4002		0.00006	257.29	0.01192	0.00015	0.00041	72.38	0.02947

	5 Year Benchmark				Report Quarter Performance (Q1-2023)			
Circuit	MAIFI	SAIFI	CAIDI	SAIDI	MAIFI	SAIFI	CAIDI	SAIDI
OAK 4004	0.00179	0.00061	150.90	0.04071	0.00293	0.00118	43.68	0.05162
OAK 4008	0.00222	0.00216	68.59	0.10917	0.00146	0.00148	23.81	0.03519
ORA 4001		0.00084	100.34	0.03252				
ORA 4002		0.00034	137.44	0.02313		0.00024	118.43	0.02847
ORA 4003		0.00071	7.00	0.00500				
ORA 4006		0.00091	74.37	0.06782				
PAR 4002	0.00018							
PAR 4003		0.00010	216.88	0.01240				
PAR 4006		0.00015	78.27	0.01318	0.00015	0.00040	84.75	0.03414
PAS 4003	0.00070	0.00070	73.70	0.03265				
PAS 4007		0.00070	54.83	0.03844				
PAS 4008	0.00017	0.00021	35.12	0.00829		0.00008	6.00	0.00051
PAS 4011		0.00035	83.88	0.02030		0.00087	59.72	0.05222
PAS 4016	0.00048	0.00115	59.01	0.06618		0.00046	9.00	0.00416
PAS 4020	0.00066	0.00096	74.00	0.06564				
PAT 4003	0.00041	0.00054	89.80	0.04903		0.00091	80.70	0.07320
PAT 4008		0.00042	113.50	0.02505		0.00108	27.90	0.03018
PAT 4010		0.00007	391.13	0.02599	0.00008			
PAT 4011	0.00043	0.00043	9.50	0.00818				
PAT 4012	0.00046	0.00052	29.38	0.01746	0.00040			
PAT 4016						0.00019	40.29	0.00766
PEH 8001	0.00028	0.00014	43.31	0.00607		0.00014	33.39	0.00468
PEH 8004	0.00006	0.00004	66.19	0.00282		0.00001	60.00	0.00060
PEH 8013	0.00164	0.00070	49.64	0.02179	0.00084			
PEH 8015	0.00396	0.00082	52.00	0.03991		0.00008	94.20	0.00799
PEH 8022	0.00012	0.00005	32.21	0.00188				
PEH 8025	0.00007	0.00002	11.00	0.00018		0.00001	37.00	0.00031
PEK 8018	0.00043	0.00027	148.79	0.03679	0.00026	0.00053	50.20	0.02642
PEK 8021	0.00055	0.00007	88.96	0.00360	0.00041	0.00002	168.00	0.00374
PEK 8022	0.00134	0.00047	59.28	0.02088				
PEK 8023	0.00103	0.00105	89.28	0.07620		0.00069	36.87	0.02554
PEK 8026	0.00121	0.00040	148.11	0.03507				
PEK 8034		0.00000	107.56	0.00029	0.00012			
PEK 8035	0.00090	0.00089	113.77	0.05819	0.00104	0.00039	109.35	0.04234
PEK 8036	0.00030	0.00021	184.43	0.03676	0.00012	0.00008	98.22	0.00786
PIE 8011	0.00006	0.00009	82.40	0.00784	0.00004	0.00001	206.00	0.00213
PIE 8013	0.00104	0.00036	49.80	0.01542	0.00010	0.00019	33.32	0.00618
PIE 8014	0.00225	0.00072	69.75	0.05139	0.00063	0.00009	100.61	0.00937
PIE 8015	0.00083	0.00029	109.64	0.01346	0.00030	0.00004	127.80	0.00463
PIE 8022	0.00059	0.00018	72.64	0.01529	0.00012	0.00009	38.37	0.00330
PIE 8023	0.00164	0.00061	65.59	0.02577		0.00002	171.29	0.00382
PIN 4001		0.00069	416.48	0.07134		0.00002	72.00	0.00166
PIN 4002		0.00060	109.00	0.06557	0.00008			
PLA 4004		0.00008	81.00	0.00068				
PLA 4007	0.00055							
PLA 4008	0.00034	0.00052	23.00	0.01187				

	5 Year Benchmark				Report Quarter Performance (Q1-2023)			
Circuit	MAIFI	SAIFI	CAIDI	SAIDI	MAIFI	SAIFI	CAIDI	SAIDI
PLA 4010		0.00063	77.25	0.04234		0.00065	62.02	0.04021
PLA 4012	0.00015	0.00052	207.93	0.01965				
PLA 4013	0.00185	0.00032	84.62	0.01420		0.00025	5.00	0.00124
PLI 8003	0.00159	0.00057	116.08	0.03994	0.00102	0.00021	74.14	0.01582
PLI 8004	0.00117	0.00121	95.10	0.07267		0.00029	216.65	0.06269
PLI 8005	0.00114	0.00023	56.42	0.00614		0.00010	155.73	0.01512
PLI 8007	0.00089	0.00069	100.60	0.05460		0.00006	139.89	0.00807
PLI 8008	0.00110	0.00051	86.91	0.04167	0.00005	0.00035	71.56	0.02501
PLI 8010	0.00042	0.00030	49.80	0.01154				
PLI 8011	0.00011	0.00008	49.32	0.00342		0.00012	82.72	0.01014
PLI 8012	0.00032	0.00010	45.60	0.00300	0.00025			
POH 8012	0.00006	0.00001	80.77	0.00172				
POH 8013	0.00056	0.00027	60.80	0.01980	0.00054	0.00003	147.02	0.00480
POH 8015	0.00064	0.00024	34.86	0.00972				
POH 8021	0.00027	0.00004	96.75	0.00147		0.00008	26.00	0.00199
POH 8022	0.00109	0.00037	88.63	0.02245	0.00001	0.00017	104.11	0.01724
POH 8023	0.00234	0.00058	158.46	0.03658				
POH 8024	0.00058	0.00059	40.08	0.01575	0.00006	0.00009	68.05	0.00623
POH 8026	0.00036	0.00026	77.88	0.00839				
POL 4001					0.00142	0.00216	78.33	0.16929
POL 4003		0.00148	98.45	0.14543		0.00047	180.00	0.08411
POL 4004		0.00020	68.00	0.02754		0.00041	174.00	0.07085
POL 4005		0.00058	28.50	0.01668	0.00055	0.00055	191.00	0.10483
POL 4006		0.00081	13.84	0.01119		0.00041	201.00	0.08184
POL 4010		0.00056	40.13	0.02237		0.00064	201.00	0.12928
POL 4012		0.00026	46.00	0.00841	0.00024	0.00084	174.71	0.14679
POR 8021	0.00032	0.00008	31.98	0.00251	0.00017	0.00019	62.59	0.01216
PRI 4001		0.00008	226.67	0.00314				
RAV 8003	0.00086	0.00058	43.10	0.02941		0.00003	431.70	0.01134
RFL 8011	0.00111	0.00018	100.96	0.01326	0.00171	0.00009	68.84	0.00633
RFL 8012	0.00332	0.00051	51.71	0.02604	0.00210	0.00103	17.05	0.01762
RFL 8014	0.00097	0.00053	67.65	0.02622	0.00054	0.00002	466.09	0.00835
RFL 8021	0.00013	0.00011	83.14	0.00689				
RFL 8022	0.00003	0.00001	94.50	0.00104				
RFL 8023	0.00047	0.00013	137.93	0.00550	0.00031	0.00003	17.20	0.00044
RFL 8025	0.00018	0.00010	65.64	0.00359	0.00016	0.00001	18.00	0.00024
RFL 8032	0.00152	0.00072	72.01	0.03340	0.00014			
RFL 8034	0.00198	0.00149	46.29	0.06455	0.00102	0.00046	22.36	0.01036
RFL 8035	0.00200	0.00137	42.69	0.06029	0.00023			
RFL 8042	0.00022	0.00007	15.00	0.00146				
RFL 8044	0.00010	0.00001	54.00	0.00041				
RGW 4004		0.00006	107.00	0.00134				
RGW 4005	0.00019	0.00000	280.50	0.00219				
RGW 4006	0.00029	0.00015	88.83	0.00727				
RGW 4007		0.00036	95.00	0.03427		0.00088	105.68	0.09300
RGW 4009		0.00022	84.72	0.01877				

	5 Year Benchmark				Report Quarter Performance (Q1-2023)			
Circuit	MAIFI	SAIFI	CAIDI	SAIDI	MAIFI	SAIFI	CAIDI	SAIDI
RGW 4012		0.00028	119.88	0.01813				
RGW 4013		0.00016	46.26	0.00602		0.00030	31.45	0.00936
RGW 4014		0.00010	102.50	0.00831		0.00032	104.31	0.03288
RGW 4015						0.00004	125.00	0.00537
RIS 4004	0.00041					0.00017	32.00	0.00553
RIS 4005		0.00027	11.00	0.00294		0.00031	33.00	0.01036
RIV 8006	0.00326	0.00086	70.60	0.05850	0.00071	0.00088	30.83	0.02724
RSL 4003	0.00079	0.00043	78.67	0.03386		0.00074	219.46	0.16325
RSL 4006		0.00157	103.11	0.16146		0.00055	171.00	0.09344
RSL 4007		0.00057	371.62	0.12168		0.00047	230.26	0.10823
RSL 4008	0.00072	0.00090	85.96	0.07398		0.00068	184.00	0.12589
RUN 8001	0.00090	0.00034	106.78	0.01449	0.00027	0.00006	116.15	0.00721
RUN 8003	0.00059	0.00041	104.43	0.03428		0.00015	154.84	0.02280
RUN 8004	0.00096	0.00018	91.18	0.01730		0.00003	80.91	0.00222
RUN 8005	0.00072	0.00041	142.43	0.02914	0.00127	0.00006	125.25	0.00813
RVR 8011	0.00200	0.00107	56.19	0.05534		0.00110	75.20	0.08237
RVR 8022	0.00114	0.00164	62.87	0.10572	0.00023	0.00062	48.98	0.03021
RVR 8031	0.00090	0.00078	93.07	0.08001	0.00138	0.00049	118.23	0.05783
SAD 8002	0.00253	0.00144	54.18	0.04421	0.00119	0.00062	58.75	0.03664
SAD 8003	0.00073	0.00045	116.37	0.03871	0.00195	0.00008	126.00	0.00968
SAD 8004	0.00030	0.00009	163.18	0.00324		0.00002	169.00	0.00283
SAD 8006	0.00026	0.00022	60.71	0.01385				
SAD 8008	0.00157	0.00065	59.79	0.03864	0.00093	0.00095	106.42	0.10059
SAD 8032	0.00135	0.00062	56.12	0.03453	0.00005	0.00000	110.00	0.00018
SAD 8033	0.00018	0.00007	74.39	0.00644		0.00005	106.00	0.00481
SAD 8043	0.00156	0.00053	55.42	0.02807	0.00095	0.00051	19.68	0.01012
SAD 8044	0.00193	0.00102	113.24	0.08095	0.00202	0.00132	12.00	0.01590
SAD 8045	0.00148	0.00066	37.98	0.01923	0.00085	0.00058	269.74	0.15695
SDH 8021	0.00090	0.00064	60.73	0.03318	0.00095	0.00001	218.00	0.00217
SDH 8023	0.00137	0.00084	55.16	0.02451	0.00070	0.00020	43.02	0.00860
SDH 8024	0.00125	0.00083	63.93	0.03290	0.00067	0.00080	35.26	0.02826
SDH 8025	0.00112	0.00097	103.28	0.09314	0.00120	0.00092	112.64	0.10410
SDH 8026	0.00208	0.00087	67.62	0.04871	0.00059	0.00061	83.33	0.05098
SDH 8031	0.00199	0.00057	138.44	0.04389	0.00328	0.00119	58.63	0.06977
SDH 8033	0.00056	0.00019	97.72	0.01603	0.00056			
SDH 8034	0.00048	0.00060	68.68	0.02592	0.00072	0.00038	34.34	0.01315
SDH 8035	0.00036	0.00047	112.19	0.04545		0.00001	88.00	0.00105
SMV 8011	0.00033	0.00019	125.85	0.00790	0.00032	0.00000		
SMV 8012	0.00078	0.00028	64.07	0.00648	0.00067			
SMV 8013	0.00092	0.00102	50.71	0.04201	0.00100	0.00024	46.79	0.01140
SMV 8014	0.00070	0.00046	59.04	0.03868	0.00051			
SMV 8021	0.00138	0.00035	50.01	0.01030		0.00012	97.26	0.01161
SMV 8022	0.00143	0.00066	25.70	0.01733		0.00001	323.00	0.00334
SMV 8023	0.00054	0.00058	48.42	0.01499	0.00008	0.00010	24.88	0.00260
SMV 8024	0.00087	0.00033	37.48	0.01267	0.00109	0.00046	22.48	0.01028
SMV 8025	0.00054	0.00044	47.51	0.01467		0.00012	60.03	0.00693

	5 Year Benchmark				Report Quarter Performance (Q1-2023)			
Circuit	MAIFI	SAIFI	CAIDI	SAIDI	MAIFI	SAIFI	CAIDI	SAIDI
SOH 8022	0.00150	0.00056	100.93	0.04714	0.00071	0.00002	166.17	0.00351
SOO 4004	0.00048	0.00057	74.10	0.05188		0.00053	76.71	0.04033
SOO 4011		0.00013	251.89	0.03476		0.00001	280.38	0.00324
SOO 4012	0.00032	0.00035	71.33	0.02655		0.00049	85.95	0.04198
SOP 4007		0.00044	42.88	0.02005	0.00028			
SOP 4008		0.00049	143.00	0.06984				
SOP 4010								
SOS 8015	0.00200	0.00065	64.61	0.03737	0.00063	0.00064	54.48	0.03495
SOS 8016	0.00547	0.00197	60.38	0.12723	0.00155	0.00009	209.39	0.01850
SOS 8025	0.00206	0.00113	76.54	0.08468		0.00010	236.85	0.02310
SPF 8012	0.00495	0.00183	96.55	0.08153	0.00139	0.00155	42.81	0.06620
SPF 8014	0.00013	0.00029	40.92	0.01176	0.00003	0.00010	174.30	0.01679
SPF 8015	0.00017	0.00010	74.71	0.00910	0.00007	0.00001	230.44	0.00293
SPF 8016	0.00018	0.00002	97.00	0.00536		0.00009	224.31	0.01991
SPF 8023	0.00025	0.00028	55.61	0.01552	0.00003	0.00026	98.14	0.02586
SPF 8024	0.00051	0.00018	192.74	0.00883		0.00005	141.00	0.00758
SPF 8025	0.00162	0.00073	58.72	0.02639	0.00253	0.00023	78.34	0.01833
STL 8011	0.00670	0.00456	21.12	0.10480	0.00279	0.00003	234.46	0.00653
STP 8001	0.00170	0.00087	53.11	0.02855	0.00276	0.00136	66.39	0.09055
STP 8002	0.00228	0.00071	95.01	0.02554	0.00245	0.00007	325.87	0.02231
STS 4003	0.00038	0.00032	194.00	0.06165				
STS 4005		0.00039	98.97	0.03381				
STS 4010	0.00087	0.00062	124.98	0.07707				
SUN 8011	0.00115	0.00024	83.20	0.00695	0.00023	0.00075	80.73	0.06076
SUN 8013	0.00033	0.00013	241.51	0.00757		0.00007	215.85	0.01615
SUN 8021	0.00254	0.00051	55.14	0.01733	0.00118	0.00005	97.71	0.00471
SUN 8022	0.00215	0.00058	39.97	0.01920	0.00074	0.00003	95.10	0.00307
SUN 8024	0.00189	0.00054	89.19	0.03067	0.00096	0.00081	59.97	0.04842
SUN 8033	0.00063	0.00027	75.43	0.01624		0.00004	171.73	0.00642
SUN 8034		0.00018	137.95	0.01246	0.00045			
SUN 8035	0.00057	0.00037	39.61	0.01089		0.00003	92.37	0.00305
SUN 8043	0.00040	0.00030	148.42	0.02731	0.00120	0.00130	57.99	0.07543
SUN 8044	0.00102	0.00026	84.32	0.01284	0.00114	0.00056	19.54	0.01086
SUN 8045	0.00023	0.00015	110.80	0.01465	0.00229	0.00081	89.87	0.07264
SWT 8001	0.00183	0.00095	46.04	0.03740				
SWT 8002	0.00193	0.00219	34.63	0.07177				
TEA 4002	0.00109	0.00074	36.60	0.03528				
TEA 4004		0.00011	38.92	0.00422				
TEA 4007		0.00024	15.00	0.00367				
THO 8012	0.00157	0.00026	134.53	0.01768	0.00055	0.00004	139.07	0.00509
THO 8013	0.00103	0.00017	158.51	0.02317		0.00002	73.00	0.00137
THO 8014		0.00000	142.43	0.00031				
THO 8022	0.00022	0.00010	51.16	0.00496	0.00010			
THO 8024	0.00012	0.00002	175.42	0.00270				
THY 4003	0.00039	0.00064	101.17	0.08718		0.00051	31.06	0.01580
THY 4004	0.00045	0.00045	143.49	0.09226	0.00089	0.00007	115.00	0.00774

	5 Year Benchmark				Report Quarter Performance (Q1-2023)			
Circuit	MAIFI	SAIFI	CAIDI	SAIDI	MAIFI	SAIFI	CAIDI	SAIDI
THY 4005		0.00055	36.51	0.01943				
THY 4006		0.00037	87.00	0.03237				
THY 4007		0.00071	82.87	0.05104		0.00001	172.00	0.00199
THY 4008	0.00037	0.00030	71.99	0.02124	0.00025			
THY 4009	0.00054	0.00029	177.49	0.04075	0.00053			
THY 4010	0.00029	0.00038	69.42	0.03030		0.00021	159.49	0.03313
THY 4011	0.00020	0.00040	25.00	0.01151				
THY 4012		0.00046	125.00	0.05790				
THY 4013		0.00070	100.68	0.07037		0.00048	41.02	0.01971
THY 4014	0.00033	0.00025	85.24	0.02894				
TNY 4001	0.00051	0.00046	205.55	0.08804		0.00023	85.47	0.01987
TNY 4002		0.00113	141.68	0.11170		0.00102	70.68	0.07177
TNY 4003		0.00058	126.49	0.05371				
TNY 4008		0.00037	154.08	0.03331		0.00061	74.10	0.04527
TNY 4010	0.00146	0.00086	165.05	0.09743		0.00009	251.76	0.02365
TON 4003		0.00060	47.13	0.02846				
TON 4006	0.00056	0.00039	305.00	0.01609				
TON 4007	0.00043	0.00029	113.88	0.02519	0.00043			
TOT 4001	0.00012	0.00004	167.00	0.00605				
TOT 4002		0.00026	31.00	0.00772				
TOT 4007	0.00006	0.00004	92.32	0.00490				
TUR 8001	0.00016	0.00013	70.57	0.00731	0.00032	0.00003	62.69	0.00212
TUR 8003	0.00013	0.00006	265.74	0.01014		0.00002	166.37	0.00324
TUR 8004	0.00173	0.00062	77.79	0.03887				
TUR 8015	0.00217	0.00043	86.32	0.03157	0.00201	0.00075	17.16	0.01283
TUR 8025	0.00220	0.00132	62.24	0.05542	0.00111	0.00041	94.26	0.03849
UN 4004								
UN 4006								
UN 4010								
UN 4011								
UNC 4001		0.00054	31.50	0.02586				
UNC 4006		0.00148	49.54	0.07565				
UNC 4007		0.00029	31.50	0.00912				
UNC 4009		0.00085	39.26	0.02840				
UNC 4010		0.00049	46.69	0.01912	0.00032	0.00032	10.00	0.00319
UNC 4012		0.00058	31.50	0.01840	0.00027			
VIL 8001	0.00144	0.00017	104.25	0.01185	0.00122	0.00060	152.23	0.09143
VNH 4002		0.00006	166.00	0.00969				
VNH 4003	0.00045	0.00000	180.00	0.00008		0.00043	23.53	0.01012
VNK 4006								
VNK 4010	0.00086	0.00043	27.98	0.01197				
VNK 4012		0.00007	30.00	0.00639				
VNK 4013	0.00036	0.00036	53.50	0.01982		0.00035	16.11	0.00557
VNK 4015								
WAD 8011	0.00036	0.00031	126.21	0.03185	0.00049	0.00024	80.12	0.01955
WAD 8013	0.00078	0.00050	68.28	0.02292	0.00121	0.00169	59.51	0.10036

	5 Year Benchmark				Report Quarter Performance (Q1-2023)			
Circuit	MAIFI	SAIFI	CAIDI	SAIDI	MAIFI	SAIFI	CAIDI	SAIDI
WAD 8022	0.00148	0.00048	104.40	0.02581	0.00059	0.00062	24.98	0.01548
WAD 8025	0.00180	0.00078	84.43	0.04230		0.00014	128.01	0.01809
WAD 8041	0.00050	0.00072	69.26	0.02930	0.00034	0.00088	72.88	0.06448
WAN 8014	0.00083	0.00023	69.94	0.01007	0.00064	0.00004	124.42	0.00500
WAN 8015		0.00008	71.82	0.00558	0.00024	0.00000	121.00	0.00005
WAN 8022	0.00192	0.00027	90.57	0.01467	0.00077	0.00023	18.04	0.00412
WAN 8025	0.00132	0.00002	50.00	0.00275	0.00101	0.00005	90.00	0.00487
WAR 4001	0.00056	0.00067	82.16	0.04252		0.00060	95.25	0.05687
WAR 4002		0.00022	87.22	0.01686				
WAR 4003		0.00016	70.47	0.01096				
WAR 4004	0.00019	0.00020	162.75	0.01790		0.00018	183.59	0.03346
WAR 4005		0.00017	62.36	0.00972				
WAR 4006	0.00029	0.00030	42.38	0.01257		0.00002	166.00	0.00277
WAR 4007		0.00030	67.57	0.02050				
WAR 4008		0.00017	112.05	0.01953				
WAR 4009	0.00028	0.00037	51.79	0.01630				
WAV 4001		0.00024	31.00	0.00737		0.00013	68.00	0.00917
WAV 4004		0.00026	116.33	0.02406	0.00025			
WAV 4015	0.00072	0.00079	94.90	0.07106				
WAV 4016	0.00016	0.00004	61.00	0.00125	0.00004	0.00008	15.53	0.00117
WAV 4018		0.00075	112.68	0.07451		0.00053	51.00	0.02681
WEW 8011	0.00113	0.00068	80.42	0.05172	0.00137	0.00045	90.78	0.04101
WEW 8014	0.00015	0.00008	105.50	0.00714	0.00024			
WEW 8015	0.00015	0.00006	42.73	0.00252				
WEW 8021	0.00243	0.00140	76.89	0.11332	0.00144	0.00029	39.49	0.01152
WEW 8023	0.00033	0.00036	41.22	0.01499	0.00046	0.00028	20.41	0.00567
WEW 8025	0.00036	0.00016	68.31	0.00630	0.00034	0.00033	35.71	0.01184
WEW 8031	0.00013	0.00003	505.67	0.00932	0.00015			
WEW 8032	0.00001	0.00001	30.58	0.00025				
WEW 8033	0.00256	0.00084	106.17	0.04947	0.00397	0.00230	91.18	0.20936
WEW 8034	0.00015	0.00014	121.88	0.01301				
WEW 8041	0.00025	0.00012	58.80	0.00446		0.00001	99.14	0.00110
WEW 8042	0.00093	0.00096	57.30	0.05564	0.00173	0.00029	116.58	0.03336
WEW 8044	0.00118	0.00086	37.91	0.03418	0.00063	0.00126	12.31	0.01547
WFL 8011	0.00118	0.00049	117.68	0.04186		0.00011	87.53	0.00951
WFL 8012	0.00138	0.00059	41.97	0.02723	0.00047	0.00013	133.74	0.01693
WFL 8021	0.00079	0.00017	32.00	0.00531	0.00027	0.00021	89.53	0.01906
WFL 8032	0.00215	0.00155	54.39	0.07771	0.00055	0.00041	90.07	0.03710
WFL 8034	0.00141	0.00061	161.91	0.09736		0.00004	105.07	0.00439
WFL 8041	0.00119	0.00079	105.88	0.08710	0.00135			
WMT 4002	0.00045	0.00016	98.05	0.01250				
WMT 4004	0.00045	0.00009	153.91	0.00429	0.00006	0.00010	269.43	0.02799
WMT 4005	0.00056	0.00019	175.50	0.04236	0.00077	0.00022	93.73	0.02082
WMT 4006	0.00072	0.00025	94.41	0.02600		0.00053	33.53	0.01767
WMT 4007	0.00072	0.00039	152.14	0.10679	0.00079	0.00011	119.23	0.01295
WOA 4003		0.00054	122.98	0.01890		0.00000	916.89	0.00328

	5 Year Benchmark				Report Quarter Performance (Q1-2023)			
Circuit	MAIFI	SAIFI	CAIDI	SAIDI	MAIFI	SAIFI	CAIDI	SAIDI
WOD 4001	0.00020	0.00009	72.00	0.00915				
WOD 4004	0.00020	0.00008	102.90	0.00837				
WOD 4006	0.00025	0.00024	44.72	0.01106		0.00000	347.00	0.00138
WOD 4007	0.00017							
WOD 4008	0.00016	0.00010	50.52	0.00304		0.00017	15.00	0.00250
WOD 4009	0.00009	0.00009	36.56	0.00343				
WOD 4010	0.00026	0.00013	56.55	0.01473				
WOR 8011	0.00180	0.00039	121.88	0.04242	0.00051	0.00006	6.00	0.00036
WOR 8013	0.00247	0.00053	81.09	0.04137	0.00005	0.00002	60.00	0.00148
WOR 8017	0.00182	0.00163	65.21	0.09589		0.00002	63.35	0.00116
WOR 8018	0.00042	0.00019	120.65	0.02589	0.00253	0.00171	33.56	0.05726
WOR 8019	0.00123	0.00044	71.42	0.01697	0.00060	0.00018	6.00	0.00108
WOR 8021	0.00066	0.00023	213.28	0.02546		0.00004	205.86	0.00770
WOR 8022	0.00172	0.00039	99.97	0.03769		0.00027	39.79	0.01083
WOR 8024	0.00021	0.00004	320.00	0.01985	0.00043	0.00000	119.00	0.00009
WOR 8025	0.00220	0.00131	117.25	0.21998	0.00018	0.00034	46.94	0.01607
WOR 8034	0.00013	0.00004	84.33	0.00344	0.00037	0.00006	91.06	0.00591
WOR 8035	0.00103	0.00014	74.28	0.00648	0.00036	0.00005	63.62	0.00337
WOR 8037	0.00023	0.00005	205.68	0.01092	0.00022	0.00013	83.55	0.01124
WOR 8039	0.00284	0.00050	78.02	0.02839		0.00007	84.58	0.00613
WRY 4001		0.00018	124.36	0.02382		0.00003	253.00	0.00705
WRY 4005		0.00019	208.72	0.04428				
WRY 4006		0.00014	169.00	0.02343				
WRY 4010		0.00029	90.96	0.03278				
WRY 4011		0.00020	265.33	0.03944		0.00063	49.11	0.03096
WYN 4001	0.00033	0.00017	235.50	0.00272	0.00021	0.00010	118.00	0.01146
WYN 4002	0.00089	0.00086	54.65	0.05393	0.00044			
WYN 4003	0.00086	0.00029	94.90	0.02237		0.00003	176.00	0.00448
WYN 4004	0.00056	0.00084	11.01	0.00973				
WYN 4005	0.00043	0.00034	100.00	0.02802	0.00076			
WYN 4006	0.00056					0.00001	62.00	0.00044
WYN 4007		0.00013	297.67	0.01586	0.00018			
WYN 4008	0.00017	0.00042	22.80	0.01149				
WYN 4009	0.00028	0.00030	68.92	0.02062		0.00002	174.00	0.00284
WYN 4010		0.00041	238.50	0.04976		0.00037	111.31	0.04111
YRD 8011	0.00017	0.00006	65.98	0.00208	0.00022	0.00004	133.00	0.00551
YRD 8012	0.00057	0.00030	98.22	0.03054	0.00003	0.00017	89.53	0.01479
YRD 8014	0.00076	0.00011	6.00	0.00068	0.00031	0.00006	41.59	0.00262
YRD 8021	0.00025	0.00027	62.77	0.01610	0.00103	0.00014	27.75	0.00382
YRD 8023	0.00072	0.00020	141.65	0.00763		0.00020	13.66	0.00268
YRD 8024	0.00045	0.00057	44.61	0.02372	0.00033	0.00048	69.20	0.03333

Danielle Lopez
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PSEG Services Corporation

March 4, 2024

VIA ELECTRONIC MAIL ONLY
Sherri Golden, Board Secretary
Board of Public Utilities
44 South Clinton Avenue, 1st Floor
P.O. Box 350
Trenton, New Jersey 08625-0350

Re: Energy Strong II Program Quarterly Report Q4 - 2023

Dear Secretary Golden:

Enclosed for filing is the report on the second quarter of the Energy Strong II program for October to December, 2023.

The Energy Strong II program was addressed by a Board Order dated September 11, 2019 September 11 Order) in Docket Nos. EO18060629 & GO18060630. That order adopted a Stipulation pursuant to which PSE&G is operating the program known as Energy Strong II.

Paragraph 45 of that Stipulation requires reports on:

- the estimated quantity of work and the quantity completed to date or, if the project cannot be quantified with numbers, the major tasks completed, e.g. design phase, material procurement, permit gathering, phases of construction;
- the forecasted and actual Energy Strong II costs-to-date for the quarterly reporting period and for the program-to-date; where projects are identified by major category (with actual variances from forecasted amounts expressed in dollar and percentage terms);
- the estimated Energy Strong II project completion date, and estimated completion dates for each Energy Strong II sub-program and the Program as a whole;
- Anticipated changes to ES II projects, if any;
- Actual capital expenditures made in the normal course of business on similar projects, identified by comparable Energy Strong II sub-program; and
- Any other performance metrics concerning the IIP required by the Board.

The reporting requirements listed in paragraph 45 of the Stipulation are addressed by the enclosed materials.

Paragraphs 46, 47, and 49 of that Stipulation provide that PSE&G shall report quarterly on the performance of Electric Stations and gas M&R Stations; Contingency Reconfiguration Strategies and Grid Modernization ADMS in a manner that compares the performance of the upgraded or new plant to pre-Energy Strong II Plant.

Please contact the undersigned with any questions or concerns.

Very truly yours,

Danielle Lopez

cc: ***Via Email only***
Brian Lipman
David Wand
Maura Caroselli
Karen Forbes
Stacy Peterson
Matko Illic
Caroline Vachier

ES II Program Quarterly Report to the Board of Public Utilities

Q4-2023: October - December 2023

Table of Contents

Metric 1 – Estimated Quantity of Work

For each Energy Strong II Subprogram:

A. Estimated quantity of work

i. **For the subprogram**

ii. **Planned to date (based on forecasted estimates at the beginning of the reporting period)**

B. Quantity completed to date or, if the project cannot be quantified with numbers, the major tasks completed, e.g., design phase, material procurement, permit gathering, phases of construction.

NOTE: This quarterly report covers Program to date performance up to the Q4-2023 period – October 1, 2023, through December 31, 2023. Where applicable, forecasted, and actual units of work and/or major tasks completed are provided.

At the end of Q4-2023, which coincides with the end of the ES II Program Period, the work under all subprograms/projects have progressed through planning, authorization and execution and are mostly in the final stages of completion. The Program work is over ninety percent complete. Of the five subprograms in the Electric Program, three have substantially achieved their planned scope, two have less than ten percent of work remaining. For the Gas M&R Program, five of the six stations are substantially complete, and one is in advanced stage of construction.

Energy Strong II Electric Program

Electric Station Flood Mitigation

A. Estimated Quantity of Work:

i. **Subprogram Scope:** The estimated quantity of work for this Subprogram includes implementation of flood mitigation (FM) measures at 16 Substations. The Stipulation also allows for inclusion of substation switchgear Life Cycle (LC) replacement, subject to funding available within the Flood Mitigation budget cap.

In 2021, the Front St substation was initially included in the program as a Lifecycle (LC) station, as identified in the list of LC stations identified in the stipulation. This station was added into the subprogram as a Lifecycle replacement project for potential funding however, during the project initiation, it was determined that in addition to life cycle improvements, Front St. station also required flood mitigation as it is located within a current FEMA mapping flood zone and below the NJ DEP flood Hazard area elevation.

One (1) project (Constable Hook) will be included in the execution of another transmission project and has been removed from the ESII Program. The Energy Strong II Electric Stations Flood Mitigation subprogram scope was amended in Company's November 2021 accelerated recovery filing to reflect the exclusion of Constable Hook and inclusion of Front St. as replacement.

Constable Hook is not included in the updates below.

ii. **Planned to Date:** Major work planned to the end of December 2023 (Front St included):

a. Completion of Key Drawing Review (KDR) for all 16 FM stations,
b. Transitioned from Study (50% CL) to Conceptual (70% CL) to Definitive (90% CL) level estimates for all 16 stations.
c. Issue Switchgear purchase orders for 14 flood stations (raise & rebuild stations).
d. Detailed Engineering on 16 flood stations.
e. Obtain Site Plan approvals required for 10 flood stations.
f. 12 ESFM projects in active construction.
g. Switchgear installation at 14 flood stations (raise & rebuild stations).
h. Elimination of Ridgefield and Market St 4kV stations and completion of associated circuit conversion from 4kV to 13kv.
i. Commissioning and In-service of new raised switchgear at 14 flood stations (raise & rebuild stations).
j. Close out Ridgefield 4kV and Market Street Elimination projects

B. Quantity of Work Completed to Date:

As of the end of December 2023 most projects in the ESFM program progressed on schedule. During Q4-2023, five stations - Lakeside, Orange Valley, Woodlynne, Waverly 4kV, and Front St all placed their switchgear in service. Program to date, 14 projects (Academy, Leonia, Ridgefield 13kV, Hasbrouck Heights, Kingsland, State St, Waverly, Toney's Brook, Clay St, Meadow Rd, Lakeside, Woodlynne, Orange Valley and Front St.) have placed switchgears into service. To date the Ridgefield 4kV and Market St Elimination projects completed their 4kV to 13kV conversions, and transfer of customers from Ridgefield and Market St 4kV Substations.

- All 16 projects in the Flood Mitigation subprogram have transitioned from Study (50% CL) to Conceptual (70% CL) to Definitive (90% CL) level estimates.

- Purchase Orders have been awarded for major equipment (switchgear) on all 14 projects requiring switchgear.
- 16 projects have completed detailed engineering design.
- 9 projects have awarded POs for A/E design. (PSE&G is the engineer for the other 7 projects.)
- 16 projects have completed scope lockdown.
- 16 projects have awarded purchase orders for civil construction.
- 15 projects have awarded a purchase order for electrical construction.
- Required Site Plan approval received for 10 projects.
- 12 projects (Leonia, State St, Clay St, Waverly, Front St, Meadow Road, Kingsland, Lakeside, Toney's Brook, Orange Valley, Woodlynne and Hasbrouck Heights) continue in construction. Four projects are completed with construction (Market St, Academy, Ridgefield 4kV and Ridgefield 13kV). Two projects are complete with closeout (Market St. and Ridgefield 4kV).
- Leonia has successfully energized new 13kV switchgear #1 and #2 and placed it into service. All circuits on both switchgears have been cutover to the new switchgears.
- Ridgefield has successfully energized new 13kV switchgear #1 and #2 and placed it into service. All circuits on both switchgears have been cutover to the new switchgears.
- Waverly has successfully energized the 26kV and 4kV switchgears and placed them into service. All 26kV circuits have been cutover to the new switchgear.
- Hasbrouck Heights has successfully energized new 4kV switchgear and placed it into service. All circuits have been cutover to the new switchgear.
- Academy has successfully energized the new 13kV switchgear and placed it into service at the new Fairmont station. All circuits from the Academy station have been upgraded from 4kV to 13kV and transferred to the new Fairmont station.
- Toney's Brook has successfully energized the new 4kV switchgear and placed it into service. All Circuits have been cutover to the new switchgear.
- The 13kV Contingency switchgear from Leonia was disassembled and delivered and installed and placed in-service as permanent raised 13kV switchgear at Meadow Road. All circuits have been cutover to the new switchgear.
- The 4kV switchgear at Front St. has been energized and placed in-service.
- State St. energized the new 4kV switchgear and placed it in-service.
- Clay St. energized the new 4kV switchgear and placed it in-service.

- The 13kV Contingency switchgear from Ridgefield was disassembled and delivered, installed, and placed in-service as permanent raised 13kV switchgear at Kingsland.
- The Ridgefield 4kV and Market St Elimination projects completed the 4kV to 13kV conversions, thereby mitigating the flood risk to customers previously supplied from Ridgefield and Market St 4kV Substations. Both station elimination projects are complete.
- Market St has completed inside plant (substation) civil demolition and ISRA related activities.
- Project closeout completed for Ridgefield 4kV Elimination and Market St Elimination.

Electric Contingency Reconfiguration (CR)

A. Estimated Quantity of Work:

i. **Subprogram Scope:** Install 1,467 new reclosers to increase the number of sections in the present loop designs, adding redundancy within each loop scheme. The work includes installing additional feeder reclosers to traditional 13kV loops; install new reclosers on 4kV circuits and install new branch reclosers. By having more sections in loop schemes and/or more circuit ties, fewer customers should be interrupted when damage occurs in a specific section of the loop. The scope also includes installation of 1,348 single phase reclosing devices (Fuse Savers) at fuse locations on single phase branch circuits.

ii. **Planned to Date:** Major work planned for the CR subprogram to the end of December 2023 included the following.

a. Install 1,467 Reclosers program to date (PTD) by end of Q3-2022
b. Commission 1,467 Reclosers PTD by the end of Q3-2023
c. Install and commission 1,348 Fuse Saver program to date (PTD) by end of Q3-2023

B. Quantity of Work Completed to Date:

Reclosers

- All 1,467 Reclosers planned for the Program have been engineered, installed, and commissioned into service as of Q3-2022.

Fuse Savers

- All 1,348 Fuse Savers planned for the Program have been installed as of as of Q3-2023.
- 1,347 of the 1,348 installed Fuse Savers were commissioned into service by end of Q3-2023.

Electric Grid Modernization - Communication System

A. Estimated Quantity of Work:

i. **Subprogram Scope:** Install a communication system upgrade, comprised of a new Wireless Radio Network and New fiber installations. The wireless communication component includes a new Wireless Radio Network service (FirstNet), installation of approximately 5,000 new radios covering all existing reclosers, new reclosers and fuses savers installed under the ES II program, as well as 218 substation RTU's. Also included is a Remote Device Management System (RDM) installed on all reclosers on the system using Blueframe Software. The New Fiber Installation scope provides new fiber connection to 26 electric substations and 8 operations locations, and cutover SCADA system communications at 12 substations to the existing fiber network.

ii. Work Planned to Date: Major work planned to the end of December 2023 included the following:

a. Establish new Wireless Network.
b. Retrofit 2,318 existing reclosers with wireless on the new wireless network.
c. Install wireless radios in 1,467 new Reclosers.
d. Install wireless radios in 1,348 new Fuse Savers
e. Develop Cutover Process and completed cutover 3,896 Reclosers on distribution circuits across all four operating divisions to the Blue Frame RDM system.
f. Build and Install Blueframe Software for RDM.
g. Develop Process to Prepare for RDM Cutover.
h. Complete installation and place in-service new fiber connection installations at 26 substations and 8 Company operations locations.
i. Complete cutover of SCADA communication to existing fiber connection at 12 substations.

B. Quantity of Work Completed to Date:

- Established new Wireless Network.
- Retrofitted 2,318 existing reclosers with radios on the new wireless network (completed December 2021).
- Installed wireless radios in 1,467 new reclosers (completed January 2022).
- Installed wireless radios in 1,347 new Fuse Savers (as of December 2023).

- Built and Installed Blueframe Software to provide remote device monitoring (RDM) of Reclosers.
- Develop Cutover Process and completed cutover 3,683 reclosers on distribution circuits across all four operating divisions to the Blueframe RDM system.
- Complete installation and place in-service new fiber connection installations at 26 substations and 8 Company operations locations.
- Completed cutover of SCADA communication to existing fiber connection at 12 substations.

Electric Grid Modernization - ADMS

A. Estimated Quantity of Work:

i. **Project:** The Advanced Distribution Management System (ADMS) subprogram is made up of Supervisory Control and Data Acquisition (SCADA) Platform Upgrade; new Outage Management System (OMS); deployment of additional modules of Distribution Management System (DMS) and Distributed Energy Resources Management System (DERMS) Applications. This remains unchanged from the beginning of the Energy Strong II Program.

ii. **Planned to Date:** Major work planned to the end of December 2023 included the following:

a. SCADA Platform Upgrade – Complete requirements definition; design; procurement; testing and defects/variances correction, and "go-live" to production of SCADA Platform Upgrade (to facilitate completion of DMS/DERMS and OMS)

b. DMS/DERMS - Complete requirements definition; design; procurement; testing and defects/variances correction, user training, and "go-live" to production.

c. Outage Management System (OMS):

- Complete requirements definition; design (architecture and interfaces); procurement.
- Complete Site Acceptance Testing (SAT), Site Integration Testing (SIT) and User Acceptance Testing (UAT)
- Defects/variances correction and remediation.
- Organizational Change Management and user training
- Place new OMS system (QAS/Production/Disaster Recovery) in production ("go-live").

d. Complete SIT Round 5

e. Begin SIT Planning 6 and 7.

B. Quantity of Work Completed to Date:

a. SCADA Platform Upgrade:

- Completed requirements definition; design; procurement; installation; testing and defects/variances correction, and placed SCADA Platform Upgrade in-service (“go-live”) - Achieved Jun’2022.
- Completed user training.
- Completed retirement and removal of existing Platform Quality Assurance and Production systems.
- Completed post go-live hyper-care and project close.

b. DMS/DERMS:

- Completed requirements definition; design; procurement; installation; testing and defects/variances correction, and “go-live” to production. (Achieved January 2023).
- Completed user training.
- Completed post go-live hyper care and project financial close.

c. Outage Management System (OMS):

- Complete requirements definition; design (architecture and interfaces); procurement, and installation
- Complete Site Acceptance Testing (SAT), Site Integration Testing (SIT) and User Acceptance Testing (UAT)
- Continued correction and remediation of variances.
- Organizational Change Management and user training
- Place new OMS system (QAS/Production/Disaster Recovery) in production (“go-live”).
- Completed SIT 5, 6 & 7
- Installed 10 Compass mobile application software upgrades (2.0.10 to 2.0.19)
- Continued organizational change management, product demonstrations, and training material development.

Electric Stipulated Base Subprogram

A. Estimated Quantity of Work:

i. **Subprogram scope:** The scope of Electric Stipulated Base includes upgrading selected distribution circuits by replacing existing open wire with spacer cable conductors utilizing outside plant higher design and construction standards ("Outside Plant" or OP-HDS) and electric 4kV substations switchgear life cycle replacement at 4 stations. Also included are the installation new underground distribution circuits (State St. OP project), which is part of the State St. Flood Mitigation project scope, as noted in Company's Accelerated Recovery filings.

ii. **Planned to Date:** Major work planned to the end of December 2023 included:

a. Completion of IP Key Drawing Review (KDR) for the four LC stations; cost estimate update to Study Level (50% confidence level) transition approval for 5 station projects (including State St. OP), estimate update to Conceptual (70% CL) level estimate transition for 4 projects and estimate update to Definitive (90% CL) level estimate for 4 stations.
b. Issuance of Switchgear purchase orders for the 4 IP Lifecycle stations.
c. A/E contract awards for all Lifecycle stations.
d. Detailed design for all 4 IP Lifecycle stations and the State St OP Project.
e. Approval of Site Plan applications for all four (4) IP Lifecycle stations.
f. Complete civil construction at all Lifecycle stations.
g. Complete electrical construction at all Lifecycle stations.
h. Installation of contingency switchgear and phased temporary transfer of distribution circuits, removal of contingency switchgear after connection of all existing circuits to new switchgear with all existing.
i. Removal of existing feeder rows (switchgear) and demolition of foundations
j. Installation, commissioning, and in-service of new raised 4kv switchgear at all four (4) Lifecycle stations.
k. Complete cutover of new and existing circuits to the new switchgear at Plainfield, Paramus, and Hamilton. Cutover first circuit at Woodbury.
l. Removal of existing feeder rows (old switchgear) at Plainfield, Paramus, and Hamilton.

B. Quantity of work Completed to Date:

- As of the end of December 2023, Key Drawing Review (KDR), estimate update to Definitive 90% level and URB estimate transition have been completed for all Lifecycle stations.
- Four electric 4kV life cycle substation projects (Plainfield, Paramus, Hamilton, & Woodbury) have awarded major equipment PO's.
- Four electric 4kV life cycle substation projects (Plainfield, Paramus, Hamilton, & Woodbury) and the State St OP project have substantially completed detailed engineering design and locked their scopes.
- Site plan applications have been approved on all four IP electric 4kV life cycle substation projects.
- All life cycle substation projects are in civil construction.
- All life cycle substation projects are in electrical construction.
- Paramus 4kV substations life cycle project contingency switchgear is in-service.
- Hamilton, Paramus, and Plainfield have set and energized their new 4kV switchgears and placed them into service.
- Hamilton, Paramus, and Plainfield completed all circuit cutovers.
- State St OP has placed the first OP circuit into service from the New State St substation.

Energy Strong II Gas M&R

A. Estimated Quantity of work:

i. **Subprogram Scope:** The estimated quantity of work for this subprogram includes implementation of flood mitigation measures at 2 of the 6 Gas M&R Substations (Camden and East Rutherford) listed in the Program Stipulation and life cycle upgrades at all 6 M&R Substations (Camden, Central, East Rutherford, Mt. Laurel, Paramus, and Westampton). This remains unchanged from the beginning of the Energy Strong II Program.

ii. **Planned to Date:** Major work planned to the end of December 2023 included:

A. <u>Camden</u>

a. Complete project estimate updates and URB approvals from Study (50% CL) to Conceptual (70% CL) to Definitive (90% CL) level estimates.

b. Bid and award contracts for engineering and procurement services.
c. Prepare all necessary permit packages for dewatering, soil conservation, Site Plan County approvals, submit applications and obtain all required permits.
d. Through AE procurement, bid and award contracts, and receive delivery for supply of major materials and equipment – (Heater, buildings, piping, Skids, and other materials).
e. Negotiate and finalize Interconnection Agreement with Transco for Camden.
f. Bid and award construction contracts.
g. Construct/install and fit out equipment buildings (control/heater/chromatography, Regulator Building, equipment platforms, pipe racks).
h. Install piping and instrumentation.
i. Commission M&R regulating equipment and place in service. Commission LPA vaporizers LPA system and place LPA system in-service.
j. Complete asbestos remediation and demolition of replaced buildings and removal of abandoned piping.
k. Demobilize from the site.
l. Preparation of as-built drawings and turnover package.

B. <u>East Rutherford</u>

a. Complete project estimate updates and URB approvals from Study (50% CL) to Conceptual (70% CL) to Definitive (90% CL) level estimates.
b. Bid and award contracts for engineering and procurement services.
c. Prepare all necessary permit packages for waterfront development, Meadowlands Commission, dewatering, soil conservation, Site Plan, county approvals, submit applications and obtain all required permits.
d. Through AE procurement, bid and award contracts, and receive delivery for supply of major materials and equipment – (Heater, buildings, piping, Skids, and other materials
e. Negotiate and finalize Interconnection Agreements with Transco at East Rutherford.
f. Acquire land rights (for laydown area lease for material storage yards)
g. Bid and award construction contracts.

h. Install bypass skids.
i. Complete asbestos remediation and demolition of existing buildings and removal of abandoned piping.
j. Drive piles and Construct/install and fit out equipment buildings (control/heater/chromatography, Regulator Building, equipment platforms, heaters, scrubbers)
k. Install piping and instrumentation.
l. Commission M&R regulating equipment and place in service.
m. Demobilize from the site.
n. Restore laydown area.
o. Continue resolution of punch list items.
p. Continue updating “As-Built” drawings and preparation of turnover package.

C. <u>Central</u>

a. Complete project estimate updates and URB approvals from Study (50% CL) to Conceptual (70% CL) to Definitive (90% CL) level estimates.
b. Bid and award contracts for engineering procurement.
c. Prepare all necessary permit packages for dewatering, soil conservation, Title-V air permit, Site Plan County approvals; submit applications and obtain all required permits.
d. Through AE procurement services, bid and award contracts, and receive delivery for supply of major materials and equipment – (Heater, buildings, piping, Skids, and other materials)
e. Negotiate and finalize Interconnection Agreements with Transco and Enbridge at Central.
f. Bid and award construction contracts.
g. Construct/install and fit out equipment buildings (control/heater/chromatography, Regulator Building, flow control building, equipment platforms, pipe racks)
h. Install piping and instrumentation.

i. Commission M&R regulating equipment and place in service. Commission LPA vaporizers LPA system and place LPA system in-service.
j. Complete asbestos remediation and demolition of replaced buildings and removal of abandoned piping.
k. Complete site restoration.
l. Demobilize contractors from the site.
m. Develop punch list.
n. Begin preparing as-built drawings and turnover package.

D. Mount Laurel

a. Complete project estimate updates and URB approvals from Study (50% CL) to Conceptual (70% CL) to Definitive (90% CL) level estimates.
b. Bid and award contracts for engineering and procurement services.
c. Prepare all necessary permit packages for dewatering, soil conservation, Site Plan, county approvals. Submit applications and obtain all required permits.
d. Through AE procurement, bid and award contracts, and receive delivery of major materials and equipment – (Heater, buildings, piping, Skids, other materials)
e. Negotiate and finalize Interconnection Agreements with Transco at Mt. Laurel.
f. Acquire required land rights.
g. Bid and award construction contracts.
h. Complete asbestos remediation and demolition of existing buildings and removal of abandoned piping.
i. Construct/install and fit out equipment buildings (control/heater/chromatography, Regulator Building, scrubbers).
j. Install bypass skids.
k. Install piping and instrumentation.
l. Complete all mechanical, civil, electrical, and instrumentation work.
m. Commission all systems.
n. Place station in service.
o. Begin demobilization.

p. Develop punch list.

q. Begin preparing “as-built” drawings and turnover packages.

E. <u>Paramus</u>

a. Complete project estimate updates and URB approvals from Study (50% CL) to Conceptual (70% CL) to level estimates.

b. Bid and award contracts for engineering and procurement services.

c. Prepare all necessary permit packages for dewatering, soil conservation, Site Plan, county approvals, submit applications and obtain all required permits.

d. Through AE procurement, bid and award contracts, and receive delivery for supply of major materials and equipment – (Heater, buildings, piping, Skids, other materials).

e. Negotiate and finalize Interconnection Agreements with Transco at Paramus.

f. Bid and award construction contracts.

g. Install bypass skids.

h. Complete asbestos remediation and demolition of existing buildings and removal of abandoned piping.

i. Construct/install and fit out equipment buildings (control/heater/chromatography, Regulator Building, scrubbers).

j. Install piping and instrumentation.

k. Continue to receive materials and equipment.

l. Complete fabrication of contingency bypass skids.

m. Tie in, commission and place in service contingency bypass skids.

n. Take Paramus station out of service.

o. Continue fabrication of piping segments.

F. <u>Westampton</u>

a. Complete project estimate updates and URB approvals from Study (50% CL) to Conceptual (70% CL) to level estimates.

b. Bid and award contracts for engineering services (AEs) and procurement.

c. Prepare all necessary permit packages for dewatering, soil conservation, Site Plan, county approvals, submit applications and obtain all required permits.
d. Through AE procurement, bid and award contracts, and receive delivery for supply of major materials and equipment – (buildings, piping, scrubber, other materials)
e. Negotiate and finalize Interconnection Agreements with Transco.
f. Acquire lease for material storage yards and other required land rights for
g. Bid and award construction contracts.
h. Complete asbestos remediation and demolition of existing buildings and removal of abandoned piping.
i. Construct/install and fit out equipment buildings (control/heater/chromatography, Regulator Building, equipment platforms, scrubbers)
j. Install piping and instrumentation.
k. Commission M&R regulating equipment and place in service.
l. Demobilize from the site.
m. Restore laydown area.
n. Working down punch-list items.
o. Work on As-Builts and turnover package.

B. Quantity of Work Completed to Date:

Major work completed as to the end of December 2023 includes the following:

<u>Camden</u>

- Completed project estimate updates and URB approvals from Study (50% CL) to Conceptual (70% CL) to Definitive (90% CL) level estimates.
- Awarded contracts for engineering and procurement services (AE) to Burns & McDonnell
- Prepared all required permit packages, submitted applications, and obtained all required permits.
- awarded contracts, and received delivery of major materials and equipment – (Heater, buildings, piping, Skids, other materials)
- Finalized Interconnection Agreements with Transco.
- Awarded construction contract to Henkels and McCoy.
- Constructed/installed and fit out equipment buildings pipe racks and equipment platforms.
- Installed all piping and instrumentation.
- Commissioned LPA vaporizers and LPA system.

- Completed all remaining hazardous materials abatement and demolition of buildings and piping.
- Began demobilization from the site.
- Commenced compiling all data for turnover package.
- Started preparation of "as-built" drawings.

East Rutherford

- Completed project estimate updates and URB approvals from Study (50% CL) to Conceptual (70% CL) to Definitive (90% CL) level estimates.
- Awarded contracts for engineering and procurement services (AE) to Entrust Engineering.
- Prepared all required permit packages. Submitted applications and obtained all required permits.
- awarded contracts, and received delivery of major materials and equipment – (Heater, buildings, piping, Skids, and other material)
- Finalized Interconnection Agreements with Transco.
- Awarded construction contract to J Fletcher Creamer.
- Installed contingency bypass skids.
- Abated and demolished buildings and yard piping.
- Constructed/installed and fitted out equipment building, control building, and equipment platforms.
- Installed all piping and instrumentation.
- Commissioned system.
- Demobilization from the site.
- Completed final site restoration.
- Continued resolution of open punch list items.
- Continued working on completion of "as-built" drawings.

Central

- Completed project estimate updates and URB approvals from Study (50% CL) to Conceptual (70% CL) to Definitive (90% CL) level estimates.
- Awarded contracts for engineering services (AE) to Odin Engineering and to Burns & McDonnell for procurement.
- Prepared all required permit packages, submitted applications, and obtained all required permits.
- awarded contracts, and received delivery of major materials and equipment – (Heater, buildings, piping, Skids, other materials)
- Finalized Interconnection Agreements with Transco and Enbridge.
- Awarded construction contract to Henkels & McCoy.
- Constructed/installed and fitted out equipment building, control building, pipe racks, and equipment platforms.
- Installed all piping and instrumentation.
- Commissioned system.
- Completed demolition of buildings and abandoned piping.

- Completed site restoration.
- Completed demobilization of the site.
- Began compiling all data for turnover package.
- Started preparation of “as-built” drawings.
- Developed project punch list.

Mt. Laurel

- Completed project estimate updates and URB approvals from Study (50% CL) to Conceptual (70% CL) to Definitive (90% CL) level estimates.
- Awarded contracts for engineering and procurement services (AE) to Kiely Engineering.
- Prepared all required permit packages, submitted applications, and obtained all required permits.
- Awarded contracts, and received delivery of major materials and equipment – (Heater, buildings, piping, Skids, other materials)
- Finalized Interconnection Agreement with Transco.
- Awarded construction contract to Henkels & McCoy.
- Installed contingency bypass skids.
- Abated and demolished buildings and yard piping.
- Constructed/installed and fit out equipment building, control building, and equipment platforms.
- Installed all piping and instrumentation.
- Completed installation of electrical conduits.
- Completed installation of below grade piping runs, inlet and outlet piping regulating runs.
- Completed wiring of SCADA building.
- Completed erection of regulation building.
- Commissioned all systems.
- Put Mt. Laurel station in service.
- Began decommissioning temporary bypass skid.

Paramus

- Completed project estimate updates and URB approvals from Study (50% CL) to Conceptual (70% CL) level estimates.
- Awarded contracts for engineering and procurement services (AE) to Entrust Engineering.
- Prepared all required permit packages. Submitted applications and obtained all required permits.
- awarded contracts and received delivery of major materials and equipment – (Heater, buildings, piping, Skids, other materials).
- Finalized Interconnection Agreement with Transco.
- Awarded construction contract to Furino and Sons.
- Continued to receive materials and equipment.
- Completed fabrication of contingency bypass skids and shipped to site.

- Completed inlet and outlet tie-ins for contingency skids.
- Continued to fabricate piping segments for project upgrades.

Westampton

- Completed project estimate updates and URB approvals from Study (50% CL) to Conceptual (70% CL) to Definitive (90% CL) level estimates.
- Awarded contracts for engineering and procurement services (AEs) to NV-5 Engineering.
- Prepared all required permit packages, submitted applications, and obtained all required permits.
- awarded contracts and received delivery of major materials and equipment – (buildings, piping, Skids, other materials).
- Finalized Interconnection Agreements with Transco.
- Awarded construction contract to Henkels & McCoy.
- Abated and demolished buildings and yard piping.
- Constructed/installed and fitted out equipment building, control building, and equipment platforms.
- Installed all piping and instrumentation.
- Commissioned system.
- Demobilized from the site.
- Completed final site restoration.
- Completed punch list items.
- Completed as-built drawings.

Metric 2 – Estimated Program and Subprogram Completion Dates

The estimated ES II project completion date, and estimated completion dates for each ESII sub-program and the Program as a whole.

Note - Project completion date is defined by the date project closeout report is completed.

Energy Strong II Program

Program	Actual/Forecast In-Service (Last major equipment)	Timeline for Completion
Electric Energy Strong II Program	Mar-24	Mar-25
Gas Energy Strong II Program	Nov-24	May-25

Energy Strong II Accelerated Recovery Programs

Program	Subprogram	Actual/Forecast In-Service	Timeline for Completion
Electric Energy Strong II Program	Electric Flood Mitigation	Mar-24	Nov-24
	Contingency Reconfiguration	Sep-23A	Jun-24
	Grid Modernization - Communication	Dec-23A	Jun-24
	Grid Modernization - ADMS	Mar-24	Jun-24
Gas Energy Strong II Program	M&R Stations Upgrade	Nov-24	May-25

Electric Station Flood Mitigation

Project	Actual/Forecast In-Service	Timeline for Completion[1]	Updates	Expected Changes
Market Street Substation Elimination	Jun-21A	Dec-21A		
Meadow Road Substation	May-23A	Nov-23A		
Academy Street Substation	Oct-21A	Jun-22A		
Ridgefield 4kv Substation Elimination	May-21A	Dec-21A		
Ridgefield 13kv Substation	Dec-22A	Jun-23A		
Hasbrouck Substation	Nov-22A	Jul-23A		
Kingsland Substation	Jul-23A	Jun-24		
Lakeside Avenue Substation	Dec-23A	Oct-24		
Leonia Substation	Nov-22A	May-23A		
Clay Street Substation	Apr-23A	Apr-24		
State Street Substation	Dec-22A	Feb-24		
Toney's Brook Substation	May-23A	Apr-24		
Waverly Substation*	Dec-23A	Mar-25		
Woodlynne Substation	Dec-23A	Jul-24		
Orange Valley Substation	Dec-23A	Dec-24		
Front Street Substation	Dec-23A	Jul-24		

*** Based on updated schedule resulting from Waverly Site Plan application denial by City of Newark**

[1] Project completion date is defined by the date project closeout report is completed.

Contingency Reconfiguration

Project	Actual/Forecast In-Service	Timeline for Completion[1]	Updates	Expected Changes
Reclosers	Jan-22A	Jul-22A		
Fuse Savers	Jan-24	Jun-24		

Grid Modernization - Communication

Project	Actual/Forecast In-Service	Timeline for Completion[1]	Updates	Expected Changes
Wireless Network	Dec-21A	Dec-21A		
Fiber	Feb-24	Aug-24		
Retrofits Reclosers	Dec-21A	Jun-22A		
Radio Commissioning – Reclosers and Fuse Savers	Jan-24	Jun-24		
RDM Recloser	Dec-23	March-24		

Grid Modernization - ADMS

Project	Actual/Forecast In-Service	Timeline for Completion[1]	Updates	Expected Changes
Platform/SCADA Upgrade	Jan-22A	Jun-22A		
DMS/DERMS	Jan-23A	Jun-23A		
OMS	Mar-24	Jun-24		

[1] Project completion date is defined by the date project closeout report is completed.

Gas Metering & Regulation (M&R)

Project	Actual/Forecast In-Service	Timeline for Completion[1]	Updates	Expected Changes
Camden (M&R)	Dec-22A	Oct-23A		
East Rutherford (M&R)	Dec-22A	Jul-23A		
Westampton (M&R)	Oct-21A	May-22A		

[1] Project completion date is defined by the date project closeout report is completed.

ENERGY STRONG II STIUPLATED BASE PROGRAM

Program	Actual/Forecast In-Service (Last major equipment)	Timeline for Completion
Electric Stipulated Base	Mar-24	Jul-24
Gas Stipulated Base	Nov-24	May-25

Electric Stipulated Base

Project	Actual/Forecast In-Service	Timeline for Completion[1]	Updates	Expected Changes
Paramus Substation	Nov-22A	May-24		
Hamilton Substation	Oct-22A	May-23A		
Woodbury Substation	Mar-24	Sep-24		
Plainfield	Dec-22A	Jun-23A		
State Street Outside Plant	Dec-22A	Jul-24		
Outside Plant – Higher design Standard (OP-HDS)	Dec-23A	Jun-24		

[1] Project completion date is defined by the date project closeout report is completed.

Gas Metering & Regulation (M&R) Stipulated Base

Project	Actual/Forecast In-Service	Timeline for Completion[1]	Updates	Expected Changes
Mt. Laurel (M&R)	Dec-23A	May-24		
Central (M&R)	Sep-23A	May-24		
Paramus (M&R)	Nov-24	May-25		

[1] Project completion date is defined by the date project closeout report is completed.

Metric 3 – SAIFI/MAIFI

A. This metric includes data for circuits involved in the Major and Non-Major events in **Q4-2023.**

- There were No Major Events in Q4-2023, therefore only the Non-major Event Report is included for this period.

Detailed tables for this metric (Non-major Events) are included at the end of this report.

Metric 3 Reports Included for Q4-2023

- Table M3.1 – Quarterly Report Non-Major Event Performance. (Clause #47)

Metric 4 – Quarterly and Program To-Date Forecast and Actual Costs

Flood Mitigation

Quarter Performance (Q4-2023, October to December)

Cost Type	Actuals	Forecast*	Variance ($)	Variance (%)
Material	$4,831,274	$3,569,495	$1,261,779	35%
Other Costs	$21,190,126	$26,798,147	($5,608,021)	-21%
Total	$26,021,400	$30,367,642	($4,346,242)	-14%

Program to Date (Q4-2023, October to December)

Cost Type	Actuals	Forecast	Variance ($)	Variance (%)
Material	$103,243,706	$131,266,263	($28,022,558)	-21%
Other Costs	$232,194,732	$208,518,416	$23,676,316	11%
Total	$335,438,437	$339,784,679	($4,346,241)	-1%

Contingency Reconfiguration

Quarter Performance (Q4-2023, October to December)

Cost Type	Actuals	Forecast*	Variance ($)	Variance (%)
Material	$157,323	$221,256	($63,933)	-29%
Other Costs	$465,636	$167,987	$297,649	177%
Total	$622,959	$389,243	$233,716	60%

Program to Date (Q4-2023, October to December)

Cost Type	Actuals	Forecast	Variance ($)	Variance (%)
Material	$58,927,925	$52,426,177	$6,501,748	12%
Other Costs	$86,821,659	$93,089,691	($6,268,032)	-7%
Total	$145,749,584	$145,515,868	$233,716	0%

Grid Modernization - Communication

Quarter Performance (Q4-2023, October to December)

Cost Type	Actuals	Forecast*	Variance ($)	Variance (%)
Material	($388,732)	($712,060)	$323,328	-45%
Other Costs	$1,047,838	$1,061,900	($14,062)	-1%
Total	$659,105	$349,840	$309,266	88%

Program to Date (Q4-2023, October to December)

Cost Type	Actuals	Forecast	Variance ($)	Variance (%)
Material	$2,467,700	$13,011,072	($10,543,372)	-81%
Other Costs	$62,531,136	$51,844,237	$10,686,900	21%
Total	$64,998,836	$64,855,308	$143,527	0%

Grid Modernization – ADMS

Quarter Performance (Q4-2023, October to December)

Cost Type	Actuals	Forecast*	Variance ($)	Variance (%)
Material	$0	$564,542	($564,542)	-100%
Other Costs	$4,098,499	$4,795,773	($697,274)	-15%
Total	$4,098,499	$5,360,315	($1,261,816)	-24%

Program to Date (Q4-2023, October to December)

Cost Type	Actuals	Forecast	Variance ($)	Variance (%)
Material	$4,239,317	$11,710,128	($7,470,811)	-64%
Other Costs	$59,729,956	$53,520,961	$6,208,995	12%
Total	$63,969,273	$65,231,089	($1,261,816)	-2%

Electric Stipulated Base

Quarter Performance (Q4-2023, October to December)

Cost Type	Actuals	Forecast*	Variance ($)	Variance (%)
Material	$1,134,704	$122,024	$1,012,680	830%
Other Costs	$11,770,872	$13,854,277	($2,083,405)	-15%
Total	$12,905,576	$13,976,301	($1,070,725)	-8%

Program to Date (Q4-2023, October to December)

Cost Type	Actuals	Forecast	Variance ($)	Variance (%)
Material	$29,610,334	$33,762,446	($4,152,112)	-12%
Other Costs	$77,839,892	$74,758,505	$3,081,387	4%
Total	$107,450,226	$108,520,951	($1,070,725)	-1%

Gas M&R

ES II Gas M&R Program Q4-2023 Performance

Quarter Performance (Q4-2023, October to December)

Cost Type	Actuals	Forecast*	Variance ($)	Variance (%)
Material	$269,307	$1,472,163	($1,202,856)	-82%
Other Costs	$7,908,411	$14,956,172	($7,047,761)	-47%
Total	$8,177,718	$16,428,336	($8,250,618)	-50%

Program to Date (Q4-2023, October to December)

Cost Type	Actuals	Forecast	Variance ($)	Variance (%)
Material	$26,109,909	$40,924,586	($14,814,678)	-36%
Other Costs	$93,891,729	$87,327,669	$6,564,060	8%
Total	$120,001,638	$128,252,255	($8,250,618)	-6%

* Quarterly forecast is as of October 1, 2023

Similar Projects Comparable to ES II Subprograms

Actual capital expenditures made in the normal course of business on similar projects, identified by comparable ESII sub-program:

ES II Investment Category	Description	Applicable ES II Subprograms	Capital Spend on Comparable Non-ES II Programs
Hardening & Resilience	Harden infrastructure, thereby making it less susceptible to damage from wind, flying debris, and water damage in anticipation of future Major Storm Events; Strengthen the resiliency of the Company's delivery system	* Electric Stations Flood Mitigation * OP-HDS * Gas M&R Flood Mitigation * Electric Contingency Reconfiguration * Electric Grid Modernization	$ 47,090,628
Life Cycle	Reliability - LC replacements	* Electric Stations LC (4kV) Replacement * Gas M&R	$ 94,212,896
Total	**Capital Spend from September 2019 to December 2023**		**$ 141,303,524**

Detailed Tables for Metric 3 for Q3-2023 – SAIFI/MAIFI

Table M3.1 - Quarterly Report Non-Major Event Performance during the quarter. (#47)

This report includes quarterly non-major event performance combining all events

Blank cell indicates no outage for the circuit.
Note: The 0.00000 signifies there was an outage but the value is beyond 5 decimal place

	5 Year Benchmark				Report Quarter Performance (Q1-2023)			
Circuit	MAIFI	SAIFI	CAIDI	SAIDI	MAIFI	SAIFI	CAIDI	SAIDI
ADA 8011	0.00130	0.00140	106.59	0.07590	0.00011	0.00028	193.93	0.05364
ADA 8012	0.00140	0.00068	105.00	0.05254	0.00177	0.00134	45.60	0.06127
ADA 8015	0.00076	0.00009	125.36	0.00268	0.00139	0.00021	36.67	0.00775
ADA 8021	0.00060	0.00034	39.84	0.00508		0.00012	167.31	0.01978
ADA 8022	0.00360	0.00141	45.85	0.08044	0.00324			
ADA 8023	0.00159	0.00043	176.88	0.05644	0.00147	0.00064	66.03	0.04221
ADA 8024	0.00063	0.00030	49.87	0.00811	0.00028	0.00012	73.70	0.00912
ADA 8025	0.00059	0.00023	34.75	0.00679	0.00041	0.00002	43.09	0.00081
ADA 8026	0.00020	0.00014	144.32	0.01479	0.00001			
ALD 8012	0.00246	0.00090	88.82	0.09278		0.00002	161.00	0.00384
ALD 8013	0.00300	0.00065	70.14	0.05012	0.00026	0.00066	40.39	0.02667
ALD 8015	0.00357	0.00148	51.50	0.07728		0.00092	39.90	0.03656
ALD 8016	0.00215	0.00121	87.13	0.08348	0.00129	0.00007	98.14	0.00687
ALD 8022	0.00224	0.00070	77.05	0.04252	0.00307	0.00005	97.47	0.00466
ALD 8023	0.00206	0.00094	67.11	0.05120	0.00404	0.00053	66.55	0.03533
ALD 8024	0.00002	0.00001	51.61	0.00251				
ALD 8025	0.00225	0.00140	42.76	0.06011	0.00175	0.00077	51.13	0.03913
ALD 8026	0.00110	0.00040	189.11	0.03887	0.00114	0.00051	46.73	0.02395
ARC 4001		0.00042	15.00	0.00624				
ARC 4003	0.00023	0.00023	99.00	0.02270				
AUD 4003	0.00082	0.00020	122.50	0.02365	0.00039	0.00119	75.73	0.09012
BAO 8003	0.00229	0.00116	31.48	0.03098	0.00196	0.00011	124.72	0.01320
BAO 8006	0.00076	0.00058	132.41	0.10855	0.00054	0.00002	81.00	0.00155
BAO 8008	0.00006	0.00001	81.75	0.00130	0.00003	0.00002	91.00	0.00174
BAO 8013	0.00288	0.00095	91.93	0.07640		0.00010	74.44	0.00717
BAO 8014	0.00138	0.00084	80.66	0.04137	0.00105	0.00007	78.33	0.00533
BAO 8015	0.00060	0.00051	87.02	0.04290	0.00044			
BAO 8023	0.00305	0.00042	69.51	0.02819	0.00099	0.00095	45.31	0.04294
BAO 8033	0.00204	0.00045	87.78	0.04117	0.00101			
BAO 8043	0.00330	0.00182	47.53	0.07989		0.00023	66.05	0.01525
BAO 8044	0.00224	0.00050	74.75	0.02936	0.00597	0.00121	31.11	0.03778
BEA 8001	0.00157	0.00027	61.80	0.01563	0.00216	0.00003	62.62	0.00162
BEA 8003	0.00017	0.00004	46.44	0.00195	0.00044	0.00007	25.67	0.00182
BEA 8004	0.00010	0.00017	60.51	0.01157	0.00018			
BEA 8010	0.00138	0.00052	110.52	0.05293	0.00159	0.00127	37.48	0.04775

	5 Year Benchmark				Report Quarter Performance (Q1-2023)			
Circuit	MAIFI	SAIFI	CAIDI	SAIDI	MAIFI	SAIFI	CAIDI	SAIDI
BEF 8012	0.00115	0.00035	116.11	0.03754		0.00004	178.44	0.00710
BEF 8013	0.00063	0.00038	76.27	0.02442	0.00171	0.00041	52.96	0.02169
BEF 8014	0.00108	0.00044	62.23	0.02632	0.00310	0.00005	91.04	0.00475
BEF 8015	0.00116	0.00068	63.06	0.03652	0.00068	0.00024	26.07	0.00615
BEF 8016	0.00080	0.00054	154.86	0.09106	0.00192	0.00052	82.19	0.04236
BEF 8021	0.00047	0.00032	112.37	0.04112	0.00073	0.00020	106.97	0.02167
BEF 8023	0.00134	0.00082	116.88	0.09529	0.00020	0.00026	54.44	0.01434
BEM 8001	0.00716	0.00120	131.49	0.07051	0.00795	0.00262	31.05	0.08151
BEN 8011	0.00052	0.00032	111.70	0.02616		0.00008	120.55	0.00960
BEN 8012	0.00302	0.00096	111.90	0.04210	0.00075	0.00120	87.89	0.10533
BEN 8014	0.00068	0.00020	117.06	0.00939	0.00095	0.00007	132.51	0.00970
BEN 8015	0.00012	0.00015	115.11	0.01703	0.00008	0.00004	78.00	0.00286
BEN 8016	0.00128	0.00039	74.94	0.02376	0.00080	0.00003	69.91	0.00186
BEN 8021	0.00060	0.00055	74.47	0.03094	0.00100	0.00032	61.11	0.01980
BEN 8022	0.00277	0.00132	117.27	0.07413	0.00043	0.00170	8.22	0.01401
BEN 8023	0.00056	0.00060	82.91	0.04347		0.00076	15.42	0.01170
BEN 8025	0.00041	0.00072	72.26	0.03071	0.00193	0.00027	9.00	0.00243
BEN 8026	0.00257	0.00091	33.10	0.02869	0.00153	0.00098	23.93	0.02341
BLO 4002		0.00023	213.03	0.03279		0.00002	305.00	0.00522
BLO 4004		0.00004	138.42	0.00518				
BLO 4006		0.00019	184.17	0.02210		0.00068	68.82	0.04675
BLO 4007		0.00034	108.50	0.03146				
BLO 4009	0.00022	0.00039	52.09	0.02121				
BLO 4012					0.00039	0.00034	6.17	0.00207
BLO 4014		0.00053	150.36	0.07724		0.00018	6.00	0.00107
BLO 4015	0.00072	0.00070	88.88	0.06310		0.00023	8.00	0.00183
BLO 4016		0.00086	62.95	0.04790	0.00071	0.00112	66.82	0.07494
BLO 4017		0.00032	64.00	0.01859		0.00056	11.00	0.00611
BLO 4018	0.00065	0.00044	88.89	0.04532		0.00035	51.00	0.01776
BOR 4001	0.00013	0.00024	144.38	0.02264	0.00064	0.00059	147.83	0.08690
BOR 4002	0.00018	0.00028	60.23	0.01562	0.00042	0.00021	30.00	0.00626
BRU 8011	0.00048	0.00010	95.60	0.00890		0.00008	124.48	0.00996
BRU 8012	0.00140	0.00104	38.76	0.03879	0.00215	0.00042	90.30	0.03763
BRU 8013	0.00173	0.00025	110.80	0.02238		0.00004	168.80	0.00712
BRU 8021	0.00134	0.00042	51.04	0.01104	0.00106	0.00005	70.24	0.00319
BRU 8022	0.00060	0.00050	115.02	0.01495	0.00003	0.00004	109.49	0.00431
BRU 8023	0.00117	0.00049	43.18	0.01041	0.00049			
BUS 8011	0.00060	0.00044	73.82	0.02945	0.00060	0.00004	127.00	0.00566
BUS 8012	0.00233	0.00029	127.52	0.03119	0.00079	0.00019	88.05	0.01637
BUS 8013	0.00039	0.00039	130.96	0.03495	0.00145	0.00087	29.22	0.02532
BUS 8015	0.00024	0.00017	129.92	0.02429	0.00028	0.00001	149.38	0.00095
BUS 8023	0.00188	0.00104	44.44	0.04111	0.00208	0.00036	26.50	0.00941
CAR 8002	0.00018	0.00010	103.07	0.01138	0.00008	0.00009	79.00	0.00692
CAR 8003	0.00008	0.00004	80.62	0.00304	0.00011			
CAR 8004	0.00022	0.00011	135.12	0.00540	0.00034	0.00033	21.54	0.00719
CAR 8006	0.00008	0.00006	39.01	0.00105				

	5 Year Benchmark				Report Quarter Performance (Q1-2023)			
Circuit	**MAIFI**	**SAIFI**	**CAIDI**	**SAIDI**	**MAIFI**	**SAIFI**	**CAIDI**	**SAIDI**
CAS 8001	0.00142	0.00101	76.82	0.07861		0.00166	10.55	0.01748
CAS 8002	0.00017	0.00016	107.18	0.01737	0.00040	0.00003	36.00	0.00099
CAT 4003	0.00025	0.00025	6.00	0.00149				
CAT 4005	0.00017	0.00001	597.00	0.00597				
CAT 4006		0.00024	72.00	0.01742				
CAT 4009	0.00024	0.00039	80.63	0.02959				
CED 8011	0.00204	0.00138	69.28	0.07747	0.00139	0.00014	117.35	0.01644
CED 8013	0.00067	0.00016	163.02	0.03975		0.00004	104.06	0.00468
CED 8016	0.00097	0.00070	139.05	0.10119	0.00096	0.00033	77.56	0.02574
CED 8021	0.00263	0.00117	42.47	0.04564	0.00018	0.00021	198.37	0.04248
CED 8022	0.00226	0.00094	64.01	0.07450	0.00358	0.00021	54.29	0.01117
CED 8025	0.00054	0.00030	99.48	0.01486		0.00025	44.27	0.01096
CED 8026	0.00098	0.00018	96.89	0.02075	0.00102	0.00036	49.37	0.01765
CET 4012	0.00114	0.00141	79.17	0.10537		0.00158	55.61	0.08799
CET 4019	0.00070	0.00070	37.67	0.02629		0.00007	547.24	0.04073
CHA 4001		0.00013	73.06	0.00332	0.00022	0.00012	21.00	0.00255
CHA 4002		0.00017	229.00	0.03992				
CHA 4004	0.00033	0.00086	41.55	0.03577				
CHA 4005		0.00030	69.40	0.02097		0.00047	54.00	0.02540
CHA 4008		0.00026	149.00	0.03858				
CHA 4012	0.00068	0.00099	103.71	0.05275		0.00052	31.23	0.01620
CHA 4013		0.00022	71.83	0.01581	0.00026	0.00028	138.00	0.03834
CHA 4014		0.00064	292.01	0.03046	0.00020			
CHA 4015		0.00022	153.76	0.03138	0.00028	0.00028	20.00	0.00566
CHE 4008		0.00027	92.63	0.02678		0.00025	6.00	0.00150
CHS 4001		0.00031	153.98	0.05336		0.00006	222.00	0.01387
CHS 4003		0.00012	19.00	0.00224				
CHS 4006		0.00017	457.50	0.09976				
CHS 4007		0.00002	56.00	0.00126				
CHS 4008	0.00023	0.00039	73.12	0.03517		0.00000	138.00	0.00066
CIN 8001	0.00111	0.00055	122.00	0.06213	0.00010	0.00071	223.86	0.15850
CIN 8002	0.00049	0.00043	89.93	0.03238	0.00015	0.00067	184.32	0.12405
CIN 8004	0.00007	0.00003	67.92	0.00241		0.00063	123.51	0.07762
CIN 8005	0.00028	0.00039	54.53	0.02113	0.00014	0.00009	57.00	0.00501
CIN 8009	0.00050	0.00025	141.25	0.03254	0.00079	0.00024	73.50	0.01790
CIN 8031	0.00088	0.00032	143.47	0.01574		0.00005	122.63	0.00591
CIN 8032	0.00157	0.00068	81.13	0.03143		0.00007	57.08	0.00411
CIN 8033	0.00054	0.00060	79.69	0.04570	0.00053	0.00048	58.47	0.02825
CIN 8043	0.00243	0.00219	101.28	0.14568	0.00095	0.00098	89.61	0.08785
CLA 4005		0.00006	76.00	0.00448				
CLA 4006		0.00024	63.64	0.01801		0.00028	164.33	0.04552
CLA 4008		0.00016	102.50	0.01095		0.00020	14.00	0.00275
CLE 4001		0.00067	52.25	0.03690	0.00012	0.00012	28.00	0.00347
CLE 4011		0.00085	41.75	0.04072				
CLE 4016	0.00050	0.00139	63.61	0.08871				
CLF 8012	0.00119	0.00027	70.16	0.01637	0.00091	0.00004	52.38	0.00217

	5 Year Benchmark				Report Quarter Performance (Q1-2023)			
Circuit	MAIFI	SAIFI	CAIDI	SAIDI	MAIFI	SAIFI	CAIDI	SAIDI
CLF 8013	0.00066	0.00023	64.92	0.01612	0.00128	0.00004	102.67	0.00392
CLF 8014	0.00095	0.00021	122.15	0.01542	0.00063	0.00014	24.00	0.00336
CLF 8015	0.00686	0.00173	45.79	0.07563	0.00966	0.00232	48.99	0.11384
CLF 8023	0.00156	0.00068	78.80	0.04824	0.00374	0.00148	20.74	0.03070
CLF 8024	0.00111	0.00103	56.61	0.04757	0.00326	0.00123	61.36	0.07522
CLF 8025	0.00092	0.00021	99.43	0.01390	0.00134			
CLK 8012	0.00027	0.00015	26.26	0.00563	0.00020	0.00007	13.93	0.00095
CLK 8013	0.00011	0.00011	67.58	0.01366	0.00013	0.00027	99.53	0.02674
CLK 8014	0.00070	0.00051	90.27	0.02349	0.00090	0.00073	13.50	0.00979
CLK 8015	0.00175	0.00140	53.99	0.07709	0.00330	0.00106	43.21	0.04559
CLK 8016	0.00106	0.00097	17.75	0.02150	0.00007	0.00004	37.04	0.00165
CLK 8022	0.00099	0.00096	36.09	0.01337		0.00026	39.37	0.01042
CLK 8023	0.00002	0.00002	31.25	0.00034	0.00008	0.00002	63.00	0.00100
CLK 8024	0.00037	0.00014	49.06	0.00330				
CLK 8031		0.00016	56.68	0.01082		0.00016	42.00	0.00664
CLK 8032	0.00171	0.00306	86.10	0.16706	0.00054	0.00111	48.12	0.05334
CLK 8033	0.00057	0.00159	39.30	0.08732	0.00055	0.00027	41.08	0.01099
CLK 8034	0.00052	0.00019	138.37	0.00798	0.00012			
CLK 8041		0.00021	128.67	0.01218	0.00061	0.00038	172.00	0.06592
CLK 8042	0.00070	0.00057	10.13	0.00554	0.00079	0.00019	51.85	0.00986
CON 8001	0.00123	0.00074	49.22	0.03802	0.00162			
COR 8013	0.00237	0.00026	119.36	0.01207	0.00050	0.00226	52.90	0.11957
COR 8015	0.00214	0.00044	83.94	0.02335	0.00036	0.00001	305.83	0.00426
COR 8025	0.00065	0.00024	43.92	0.01036	0.00062	0.00044	30.28	0.01322
COR 8033	0.00397	0.00068	68.12	0.03302	0.00303	0.00065	75.87	0.04961
COR 8034	0.00217	0.00067	88.36	0.04539	0.00329	0.00079	116.33	0.09181
COR 8035	0.00099	0.00016	542.55	0.08476		0.00002	91.00	0.00138
COR 8041	0.00238	0.00087	68.13	0.04026	0.00466	0.00054	9.73	0.00523
COR 8042	0.00158	0.00063	76.44	0.02864	0.00452	0.00061	27.05	0.01645
CRA 4001		0.00026	62.48	0.01619		0.00026	91.00	0.02383
CRA 4003		0.00058	50.63	0.02649	0.00017	0.00060	86.55	0.05219
CRA 4004	0.00016	0.00047	59.24	0.02491				
CRA 4009		0.00036	68.33	0.02487				
CRA 4010		0.00073	84.60	0.06377				
CRA 4011		0.00027	66.00	0.02016	0.00014	0.00018	117.00	0.02063
CRA 4012		0.00037	143.13	0.03455	0.00018	0.00012	115.00	0.01387
CRA 4016	0.00029	0.00038	102.93	0.03404				
CRX 8001	0.00100	0.00049	83.67	0.04344	0.00066	0.00125	189.62	0.23788
CRX 8003	0.00040	0.00041	100.73	0.03758	0.00051	0.00047	41.20	0.01924
CRX 8004	0.00128	0.00063	112.33	0.04511	0.00170	0.00086	90.62	0.07834
CRX 8005	0.00080	0.00050	102.20	0.05726	0.00017	0.00004	18.57	0.00076
CRX 8007	0.00198	0.00112	88.75	0.11410	0.00105	0.00349	79.64	0.27789
CRX 8008	0.00112	0.00052	86.38	0.04260	0.00081	0.00020	60.18	0.01176
CRX 8009	0.00081	0.00064	87.92	0.05623	0.00170	0.00065	30.64	0.01999
CUL 4001	0.00098	0.00094	152.00	0.14126				
CUL 4012		0.00069	113.49	0.08070		0.00065	32.24	0.02101

	5 Year Benchmark				Report Quarter Performance (Q1-2023)			
Circuit	MAIFI	SAIFI	CAIDI	SAIDI	MAIFI	SAIFI	CAIDI	SAIDI
CUT 8001	0.00107	0.00042	39.89	0.01972		0.00059	38.06	0.02241
CUT 8002	0.00012	0.00007	163.83	0.00685	0.00021	0.00016	49.56	0.00771
CUT 8003	0.00289	0.00124	80.43	0.08582	0.00152	0.00084	27.68	0.02330
CUT 8004	0.00288	0.00205	112.13	0.21608	0.00085	0.00022	752.40	0.16680
CUT 8005	0.00067	0.00048	76.28	0.04550		0.00041	45.07	0.01830
CUT 8006	0.00037	0.00060	93.32	0.05233	0.00068	0.00058	13.09	0.00757
CUT 8007	0.00261	0.00117	66.91	0.06548	0.00476	0.00256	136.94	0.34991
CUT 8008	0.00125	0.00063	118.71	0.05503	0.00077	0.00066	22.15	0.01455
CUT 8010	0.00144	0.00060	223.33	0.08988	0.00180	0.00075	41.80	0.03138
CUT 8031	0.00042	0.00014	182.26	0.01471	0.00015	0.00008	19.18	0.00153
CUT 8033	0.00067	0.00075	68.42	0.04152	0.00245	0.00082	97.27	0.07994
CUT 8034	0.00380	0.00128	81.19	0.09521	0.00549	0.00085	56.95	0.04869
CUT 8041	0.00047	0.00049	102.94	0.05030	0.00033	0.00011	31.17	0.00344
CUT 8042	0.00076	0.00052	142.57	0.08197	0.00147	0.00159	46.92	0.07440
CUT 8043	0.00255	0.00244	76.63	0.18682	0.00249	0.00359	80.13	0.28762
CUT 8044	0.00012	0.00033	67.78	0.02200	0.00031	0.00055	190.90	0.10531
CXC 8012	0.00106	0.00035	73.14	0.01629	0.00018	0.00002	165.62	0.00257
DAY 8001	0.00222	0.00069	65.27	0.02911	0.00042	0.00007	96.96	0.00726
DAY 8002	0.00019	0.00005	191.44	0.00719		0.00003	6.00	0.00015
DEA 4001	0.00024	0.00017	75.85	0.01215		0.00023	107.76	0.02526
DEA 4009		0.00016	78.67	0.00863				
DFD 8007	0.00445	0.00216	74.57	0.16276	0.00385	0.00224	41.88	0.09381
DFD 8008	0.00063	0.00067	86.37	0.06272	0.00137	0.00039	130.03	0.05097
DFD 8009	0.00098	0.00038	80.46	0.02557	0.00080	0.00014	85.93	0.01235
DFD 8031	0.00256	0.00134	48.77	0.05390	0.00004	0.00087	38.92	0.03380
DFD 8041	0.00140	0.00065	134.57	0.06599	0.00129	0.00007	349.40	0.02531
DOR 8012	0.00213	0.00039	50.16	0.01495				
DOR 8013	0.00022	0.00043	60.84	0.02166		0.00003	118.00	0.00399
DOR 8015	0.00286	0.00172	44.31	0.06885	0.00126	0.00062	44.11	0.02730
DOR 8024	0.00126	0.00048	43.08	0.02067	0.00092	0.00002	58.00	0.00111
DOR 8025	0.00175	0.00066	59.02	0.03816	0.00187	0.00127	159.11	0.20201
DOR 8035	0.00311	0.00236	127.15	0.12402	0.00749	0.00320	32.85	0.10522
DOR 8036	0.00408	0.00064	103.08	0.06537	0.00981	0.00197	50.33	0.09927
DOR 8044	0.00253	0.00164	48.73	0.04869	0.00282	0.00136	30.34	0.04130
DOR 8045	0.00199	0.00054	79.38	0.04002	0.00721	0.00205	156.95	0.32169
DUM 4001	0.00026	0.00043	88.58	0.03366				
DUM 4002		0.00024	97.00	0.02371		0.00010	74.27	0.00715
DUM 4004	0.00025	0.00011	64.08	0.00953		0.00021	44.67	0.00928
DUM 4007	0.00047	0.00026	202.50	0.02180				
DVB 8011	0.00069	0.00028	21.56	0.00435		0.00002	132.00	0.00263
DVB 8012	0.00014	0.00022	57.83	0.01133	0.00023	0.00007	37.87	0.00249
DVB 8013	0.00062	0.00027	67.81	0.00996	0.00147	0.00000	52.00	0.00019
DVB 8014	0.00002	0.00002	12.37	0.00027	0.00007			
DVB 8015	0.00025	0.00026	183.71	0.00572		0.00001	351.00	0.00279
DVB 8021	0.00002	0.00001	260.00	0.00114	0.00002			
DVB 8022	0.00016	0.00003	48.87	0.00071		0.00000	323.00	0.00116

	5 Year Benchmark				Report Quarter Performance (Q1-2023)			
Circuit	MAIFI	SAIFI	CAIDI	SAIDI	MAIFI	SAIFI	CAIDI	SAIDI
DVB 8023	0.00062	0.00032	99.31	0.02731	0.00016	0.00042	109.94	0.04568
DVB 8025	0.00013	0.00006	119.16	0.00130		0.00001	159.47	0.00108
EAO 4006		0.00075	40.06	0.02721	0.00092	0.00056	46.58	0.02623
EAO 4008		0.00085	76.30	0.03925				
EAO 4013		0.00096	43.37	0.04116				
EAO 4019		0.00046	132.22	0.04778				
EAO 4023	0.00091	0.00075	205.38	0.12784		0.00010	160.44	0.01667
EAO 4024		0.00051	94.98	0.02018				
EAT 8011	0.00156	0.00130	89.85	0.07833	0.00209	0.00175	57.02	0.09982
EAT 8012	0.00057	0.00061	75.64	0.05846		0.00027	12.00	0.00323
EAT 8013	0.00138	0.00111	37.80	0.03944	0.00038	0.00017	21.14	0.00360
EAT 8014	0.00012	0.00011	70.17	0.00976	0.00008	0.00001	15.00	0.00014
EAT 8021	0.00089	0.00072	57.80	0.03280	0.00052	0.00046	32.93	0.01514
EAT 8022	0.00143	0.00043	88.83	0.02605	0.00196	0.00005	90.72	0.00451
EAT 8023	0.00114	0.00076	63.41	0.05969	0.00280	0.00228	32.41	0.07385
EAT 8025	0.00038	0.00009	101.54	0.00298	0.00031	0.00057	27.30	0.01561
EDI 4003		0.00030	61.67	0.01924		0.00026	6.14	0.00161
EDI 4006		0.00032	38.00	0.01080		0.00047	6.00	0.00282
EDI 4007		0.00039	40.00	0.01474	0.00019	0.00057	25.25	0.01427
EDI 4008	0.00056	0.00039	17.67	0.00385		0.00057	14.37	0.00820
EDI 4009		0.00035	24.63	0.00567		0.00035	8.62	0.00297
ENG 4004								
ENG 4005								
ENG 4006		0.00008	346.00	0.02638		0.00005	86.56	0.00403
ENG 4007		0.00010	139.00	0.01429				
ENG 4012		0.00025	65.12	0.01633				
ENG 4016								
ENG 4017	0.00021	0.00020	74.50	0.00426				
EWI 4001		0.00008	90.02	0.00694				
EWI 4002	0.00051	0.00102	64.69	0.05538		0.00027	38.90	0.01051
EWI 4003		0.00007	81.63	0.00520				
EWI 4004		0.00025	242.90	0.03756		0.00036	83.60	0.03008
EWI 4006		0.00036	160.28	0.02690		0.00040	8.00	0.00323
EWI 4007	0.00031	0.00052	48.96	0.02178		0.00031	15.00	0.00468
EWI 4008		0.00026	191.49	0.05015				
FAR 4002		0.00058	42.19	0.02164				
FAR 4005		0.00022	119.40	0.01626		0.00031	73.12	0.02276
FAR 4006	0.00026	0.00051	141.87	0.05931	0.00021	0.00043	103.00	0.04452
FAW 8011	0.00071	0.00054	107.77	0.05763	0.00100	0.00081	121.62	0.09855
FAW 8012	0.00107	0.00075	72.13	0.05940	0.00032	0.00005	137.96	0.00741
FAW 8013	0.00122	0.00033	116.15	0.01661		0.00124	24.82	0.03073
FAW 8014	0.00131	0.00060	102.51	0.03419		0.00016	83.98	0.01340
FAW 8015	0.00028	0.00027	26.89	0.00365	0.00051			
FAW 8016	0.00164	0.00044	90.99	0.03383	0.00097	0.00077	47.81	0.03690
FAW 8022	0.00089	0.00054	105.00	0.02390				
FAW 8023	0.00113	0.00031	94.96	0.00684	0.00059	0.00174	43.24	0.07528

	5 Year Benchmark				Report Quarter Performance (Q1-2023)			
Circuit	MAIFI	SAIFI	CAIDI	SAIDI	MAIFI	SAIFI	CAIDI	SAIDI
FAW 8026	0.00098	0.00084	34.57	0.02676	0.00004	0.00001	302.70	0.00325
FED 4004	0.00072	0.00022	290.00	0.06452	0.00038			
FED 4010								
FED 4013								
FED 4018		0.00054	88.11	0.04389				
FED 4021	0.00075	0.00037	54.50	0.02034		0.00014	51.00	0.00692
FED 4022	0.00068	0.00003	159.00	0.00469				
FED 4030		0.00044	110.34	0.02282	0.00029			
FEN 8041	0.00082	0.00034	46.06	0.01647	0.00063	0.00053	31.10	0.01657
FIT 8003	0.00126	0.00078	118.83	0.10582	0.00019	0.00120	10.32	0.01241
FOH 4002	0.00072	0.00073	111.00	0.08086				
FOH 4003	0.00051	0.00050	94.50	0.04809				
FOH 4004	0.00013	0.00048	23.26	0.01130				
FOH 4006		0.00038	55.18	0.01065				
FOH 4007		0.00187	13.34	0.02490				
FOH 4008		0.00042	71.00	0.02330		0.00031	109.13	0.03414
FOR 4009	0.00000	0.00027	87.50	0.02246				
FOT 8004	0.00065	0.00089	62.31	0.07043	0.00067	0.00003	94.00	0.00296
FOU 8012	0.00343	0.00174	61.43	0.08986		0.00063	128.43	0.08086
FOU 8014	0.00031	0.00010	96.45	0.00825	0.00046	0.00009	307.99	0.02746
FOU 8022	0.00011	0.00010	54.86	0.00529				
FOU 8024	0.00024	0.00015	57.84	0.01108	0.00029	0.00009	113.01	0.00990
FRA 8011	0.00003	0.00001	140.00	0.00147				
FRA 8012	0.00007	0.00003	8.00	0.00035	0.00029	0.00010	49.52	0.00493
FRA 8013	0.00022	0.00015	56.38	0.01018	0.00014	0.00000	36.00	0.00001
FRA 8021	0.00023	0.00012	7.30	0.00165		0.00020	19.27	0.00380
FRA 8023	0.00021	0.00011	48.59	0.00571				
FRO 4006	0.00026	0.00026	56.00	0.01480				
FRO 4007	0.00070	0.00090	45.28	0.03543		0.00004	18.00	0.00066
FRO 4008	0.00054							
FRO 4009	0.00031	0.00032	293.94	0.09962		0.00030	108.00	0.03245
GBK 8011	0.00133	0.00048	85.46	0.03307	0.00116	0.00057	25.26	0.01436
GBK 8013	0.00136	0.00065	49.00	0.01892	0.00281	0.00032	24.28	0.00775
GBK 8014	0.00168	0.00060	72.12	0.02965	0.00219	0.00106	72.52	0.07654
GBK 8021	0.00126	0.00072	38.29	0.03490	0.00107	0.00079	67.00	0.05326
GBK 8022	0.00218	0.00084	54.31	0.03369	0.00123	0.00005	120.74	0.00610
GBK 8023	0.00136	0.00081	59.15	0.04199	0.00079	0.00040	82.28	0.03271
GBK 8024	0.00102	0.00091	111.54	0.12556	0.00076	0.00020	54.86	0.01079
GBK 8025	0.00214	0.00120	44.72	0.04564	0.00203	0.00048	163.90	0.07899
GET 4003	0.00112	0.00091	61.49	0.05942	0.00215			
GET 4004	0.00018				0.00064			
GET 4007	0.00078	0.00105	50.70	0.05340	0.00072			
GET 4008	0.00126	0.00087	9.80	0.00850	0.00160	0.00078	50.91	0.03979
GET 4009	0.00087	0.00056	123.04	0.01714	0.00092			
GRE 4002		0.00012	108.24	0.00875		0.00031	68.13	0.02099
GRE 4003	0.00039	0.00040	39.94	0.01622		0.00032	92.00	0.02948

	5 Year Benchmark				Report Quarter Performance (Q1-2023)			
Circuit	MAIFI	SAIFI	CAIDI	SAIDI	MAIFI	SAIFI	CAIDI	SAIDI
GRE 4004	0.00019	0.00020	69.00	0.01333	0.00019	0.00002	173.00	0.00420
GRE 4005		0.00015	76.76	0.01184				
GRE 4006		0.00008	64.50	0.00492				
GRE 4007	0.00047	0.00052	124.33	0.03894				
GRN 4001		0.00104	81.24	0.08215	0.00098	0.00036	132.26	0.04796
GRN 4003		0.00021	107.00	0.02288		0.00020	87.00	0.01776
GRN 4008	0.00042	0.00027	82.60	0.02212	0.00064	0.00039	53.67	0.02072
GRN 4009		0.00068	81.23	0.05522		0.00129	36.00	0.04647
GRN 4011	0.00082	0.00057	120.67	0.04630		0.00080	73.00	0.05852
HAC 4005	0.00024	0.00024	75.12	0.01906	0.00015	0.00020	6.00	0.00117
HAC 4006	0.00019	0.00056	152.04	0.08589		0.00018	6.00	0.00109
HAC 4007	0.00018	0.00016	80.50	0.01046				
HAC 4009	0.00020	0.00016	43.79	0.00911		0.00020	6.00	0.00122
HAC 4010	0.00007	0.00010	39.77	0.00416		0.00007	6.00	0.00041
HAC 4011	0.00081	0.00034	93.00	0.03208		0.00033	6.00	0.00200
HAC 4012	0.00021	0.00010	33.33	0.00163		0.00014	6.00	0.00087
HAC 4013	0.00023	0.00028	67.60	0.01750		0.00022	6.00	0.00132
HAC 4016	0.00020	0.00027	94.32	0.02057	0.00027	0.00054	7.00	0.00375
HAC 4018	0.00013	0.00018	89.68	0.01470				
HAD 4002		0.00080	137.26	0.10512		0.00001	122.00	0.00180
HAD 4003		0.00001	369.00	0.00371		0.00001	21.00	0.00018
HAD 4005		0.00024	86.46	0.02060		0.00005	48.31	0.00219
HAD 4008		0.00013	82.33	0.00941				
HAD 4009		0.00019	146.61	0.01842				
HAD 4010		0.00049	154.44	0.06024				
HAL 4001		0.00002	112.50	0.00156		0.00000	470.00	0.00187
HAL 4002		0.00030	78.67	0.02580				
HAL 4004		0.00004	116.14	0.00408				
HAL 4005	0.00074	0.00020	198.50	0.02322		0.00069	68.06	0.04686
HAL 4007						0.00044	6.00	0.00265
HAL 4008	0.00054	0.00039	90.96	0.01765	0.00018			
HAM 4007		0.00010	46.38	0.00328				
HAM 4008		0.00032	54.47	0.01966		0.00020	39.00	0.00793
HAM 4009		0.00028	50.58	0.01556	0.00019			
HAR 4001		0.00040	113.50	0.04585				
HAR 4006		0.00039	124.00	0.06396	0.00110	0.00044	77.60	0.03397
HAR 4014		0.00059	165.81	0.09629		0.00117	22.23	0.02597
HAR 4015		0.00046	171.00	0.07807				
HAR 4018	0.00043	0.00043	171.00	0.07348				
HAR 4021		0.00040	139.42	0.05593	0.00011	0.00004	74.00	0.00303
HAT 8011	0.00015	0.00028	130.70	0.03922	0.00007	0.00001	64.00	0.00064
HAT 8012	0.00117	0.00077	54.21	0.03898	0.00027	0.00007	104.28	0.00760
HAT 8015	0.00019	0.00013	67.77	0.00895	0.00008			
HAT 8021	0.00041	0.00013	31.09	0.00358	0.00041	0.00071	47.43	0.03366
HAT 8022	0.00068	0.00091	67.06	0.03857	0.00061	0.00009	98.54	0.00878
HAT 8023	0.00020	0.00013	128.46	0.01949	0.00019	0.00013	12.69	0.00164

	5 Year Benchmark				Report Quarter Performance (Q1-2023)			
Circuit	MAIFI	SAIFI	CAIDI	SAIDI	MAIFI	SAIFI	CAIDI	SAIDI
HAT 8027	0.00085	0.00014	125.04	0.00827	0.00193	0.00025	50.86	0.01289
HAT 8034	0.00004	0.00000			0.00007			
HAT 8035	0.00080	0.00060	53.20	0.03130	0.00064	0.00004	92.72	0.00339
HAT 8037	0.00125	0.00058	111.56	0.04832		0.00014	169.75	0.02344
HAW 8032	0.00188	0.00112	80.62	0.05650	0.00264			
HAW 8041	0.00123	0.00014	116.25	0.01631	0.00076	0.00015	48.27	0.00701
HBG 4007		0.00034	11.00	0.00378				
HBG 4008		0.00000						
HID 8011	0.00099	0.00045	61.43	0.02045		0.00023	19.35	0.00448
HID 8013	0.00028	0.00023	125.15	0.02879	0.00160	0.00010	48.44	0.00503
HID 8034	0.00030	0.00026	52.93	0.01680	0.00061	0.00008	33.00	0.00263
HID 8035	0.00098	0.00056	76.29	0.04630	0.00164	0.00060	60.44	0.03642
HID 8042	0.00078	0.00021	115.61	0.02107		0.00013	61.36	0.00828
HID 8043	0.00028	0.00018	125.59	0.01925	0.00035	0.00009	198.91	0.01853
HID 8044	0.00190	0.00092	96.68	0.06810	0.00051	0.00082	215.07	0.17702
HID 8045	0.00174	0.00032	115.22	0.03682	0.00163	0.00032	34.69	0.01123
HNC 8015	0.00062	0.00033	91.75	0.02052	0.00066	0.00028	24.19	0.00686
HNC 8021	0.00165	0.00060	71.31	0.02175	0.00252	0.00143	55.68	0.07986
HNC 8022	0.00094	0.00026	105.33	0.02054	0.00032			
HNC 8024	0.00143	0.00040	80.29	0.03343	0.00135	0.00044	29.22	0.01289
HNC 8025	0.00029	0.00020	126.26	0.02124	0.00065	0.00035	234.10	0.08302
HOE 8037	0.00590	0.00166	50.55	0.06688	0.00205			
HOE 8038	0.00300	0.00122	30.33	0.04414	0.00168			
HOE 8044	0.01231	0.00256	44.61	0.10503	0.00578	0.00122	120.54	0.14656
HOE 8047	0.00203	0.00075	38.06	0.01764	0.00453	0.00059	12.30	0.00730
HOE 8048	0.00079	0.00036	134.01	0.02391	0.00047	0.00019	20.00	0.00374
HOM 8001	0.00372	0.00077	54.11	0.03386	0.00216	0.00197	67.10	0.13209
HOM 8002	0.00013	0.00001	86.00	0.00072	0.00004			
HOM 8003	0.00085	0.00022	70.52	0.01459	0.00025	0.00097	68.26	0.06623
HOM 8012	0.00213	0.00148	29.67	0.05052	0.00317	0.00034	26.00	0.00879
HOM 8014	0.00337	0.00137	34.61	0.05173	0.00236	0.00003	78.00	0.00217
HOM 8025	0.00073	0.00040	43.01	0.02199	0.00084	0.00017	117.07	0.02004
HOM 8032	0.00577	0.00208	59.95	0.10408	0.00280	0.00010	110.00	0.01108
HOM 8033	0.00268	0.00127	109.08	0.09908	0.00260	0.00178	36.59	0.06508
HOM 8034	0.00482	0.00105	63.51	0.07339	0.00126	0.00085	129.00	0.10931
HOM 8041	0.00603	0.00104	32.94	0.02027	0.00007	0.00000	394.00	0.00031
HOM 8042	0.00022	0.00009	37.73	0.00398	0.00027			
HOM 8044	0.00049	0.00012	87.51	0.00608	0.00067	0.00011	17.00	0.00194
HOM 8046	0.00263	0.00116	45.18	0.05232	0.00278	0.00059	15.00	0.00880
IRO 4002								
IRO 4003		0.00000				0.00022	43.00	0.00955
IRO 4005	0.00052	0.00074	86.51	0.06203				
IRO 4009	0.00028	0.00028	21.00	0.00595		0.00028	61.00	0.01714
IRO 4011	0.00063	0.00060	19.86	0.01192	0.00054			
IRO 4012		0.00023	61.00	0.01417				
IRO 4013	0.00025	0.00024	255.00	0.06211		0.00011	169.00	0.01789

	5 Year Benchmark				Report Quarter Performance (Q1-2023)			
Circuit	MAIFI	SAIFI	CAIDI	SAIDI	MAIFI	SAIFI	CAIDI	SAIDI
IRO 4014		0.00075	82.00	0.06111		0.00128	100.27	0.12862
IRV 4002	0.00050	0.00124	77.76	0.10014		0.00058	57.67	0.03362
IRV 4004	0.00077	0.00141	113.88	0.15724				
IRV 4006	0.00042	0.00120	67.94	0.07233	0.00043	0.00084	18.00	0.01503
IRV 4011	0.00062	0.00033	323.50	0.02804				
IRV 4013		0.00042	112.00	0.04694		0.00044	69.00	0.03010
IRV 4017	0.00036	0.00051	44.36	0.02946	0.00025	0.00003	159.00	0.00449
IRV 4019		0.00034	102.62	0.03536		0.00050	64.96	0.03271
IRV 4021	0.00040	0.00032	116.33	0.02566				
IRV 4022		0.00025	112.00	0.01388		0.00002	162.00	0.00400
JAC 8011	0.00021	0.00020	55.83	0.01278	0.00016	0.00002	5,177.00	0.12775
JAC 8012	0.00039	0.00017	73.60	0.01336	0.00027	0.00005	23.28	0.00112
JAC 8021	0.00022	0.00004	23.37	0.00088				
JAC 8022	0.00041	0.00012	105.12	0.01287	0.00006			
JAC 8023	0.00059	0.00058	37.66	0.02336	0.00102	0.00046	98.92	0.04579
JAC 8024	0.00031	0.00026	105.08	0.01982	0.00049	0.00028	86.23	0.02454
JAC 8025	0.00081	0.00029	65.83	0.01021	0.00041			
JAC 8033	0.00109	0.00064	92.21	0.04911	0.00050	0.00056	37.88	0.02135
JAC 8043	0.00033	0.00004	101.82	0.00356	0.00061	0.00001	68.00	0.00049
KEN 4002		0.00036	35.26	0.01262				
KEN 4003	0.00035	0.00090	84.38	0.07144		0.00077	90.67	0.06986
KEN 4004		0.00023	100.17	0.01869		0.00001	364.00	0.00377
KEN 4005	0.00039	0.00046	51.22	0.02836	0.00019	0.00036	50.90	0.01829
KEN 4006		0.00068	32.12	0.03350		0.00027	110.00	0.02920
KIL 8012	0.00077	0.00077	101.12	0.07694	0.00073	0.00111	75.61	0.08414
KIL 8013	0.00021	0.00023	53.59	0.01746	0.00002			
KIL 8014	0.00121	0.00040	97.94	0.02004		0.00012	112.45	0.01387
KIL 8015	0.00041	0.00013	79.07	0.01046	0.00017	0.00001	50.00	0.00048
KIL 8016	0.00140	0.00043	92.27	0.02587	0.00123	0.00025	85.38	0.02100
KIL 8022	0.00176	0.00077	68.09	0.04316	0.00090	0.00011	53.40	0.00602
KIL 8023	0.00044	0.00050	63.39	0.04287	0.00010	0.00008	68.63	0.00552
KIL 8024	0.00068	0.00045	87.97	0.03239	0.00118	0.00016	88.77	0.01389
KIL 8025	0.00207	0.00074	74.72	0.05098	0.00030	0.00027	40.34	0.01072
KIL 8031	0.00013	0.00009	53.52	0.00394	0.00004	0.00001	149.00	0.00202
KIL 8033	0.00027	0.00022	36.13	0.00759	0.00001			
KIL 8034	0.00130	0.00028	106.57	0.01816	0.00143	0.00154	21.44	0.03295
KIL 8041	0.00077	0.00032	43.44	0.00777	0.00087	0.00073	52.65	0.03866
KIL 8042	0.00104	0.00042	83.94	0.01920	0.00108	0.00007	112.26	0.00818
KIL 8043	0.00039	0.00019	80.20	0.01345	0.00009	0.00001	184.38	0.00191
KIL 8044	0.00247	0.00058	125.14	0.03845	0.00232	0.00029	15.75	0.00453
KIN 8011	0.00047	0.00017	49.73	0.00862	0.00061	0.00012	30.33	0.00368
KIN 8012	0.00043	0.00008	103.93	0.00388	0.00031	0.00005	8.00	0.00041
KIN 8013	0.00016	0.00002	233.46	0.00536				
KIN 8014	0.00048	0.00007	44.67	0.00254	0.00011	0.00039	27.69	0.01070
KIN 8015	0.00245	0.00112	108.97	0.11851	0.00296	0.00002	116.00	0.00249
KIN 8022	0.00244	0.00051	80.38	0.04365	0.00161	0.00074	28.44	0.02114

	5 Year Benchmark				Report Quarter Performance (Q1-2023)			
Circuit	MAIFI	SAIFI	CAIDI	SAIDI	MAIFI	SAIFI	CAIDI	SAIDI
KIN 8023	0.00185	0.00051	83.37	0.02411	0.00157			
KIN 8024	0.00154	0.00080	80.49	0.05082	0.00018			
KIN 8025	0.00405	0.00167	40.85	0.08721	0.00043	0.00055	35.61	0.01966
KIN 8041		0.00117	18.86	0.02200				
KIN 8042		0.00022	41.53	0.01867	0.00019			
KNY 8011	0.00022	0.00017	140.29	0.01794		0.00010	14.00	0.00134
KUL 8012	0.00201	0.00104	81.71	0.05391	0.00142	0.00039	41.68	0.01621
KUL 8013	0.00200	0.00210	52.48	0.08807	0.00152	0.00156	42.98	0.06687
KUL 8021	0.00438	0.00162	27.28	0.04564	0.00079	0.00044	7.00	0.00309
KUL 8022	0.00214	0.00107	73.15	0.05578	0.00142	0.00138	27.25	0.03770
KUL 8023	0.00118	0.00032	74.48	0.01063	0.00061	0.00052	18.61	0.00962
KUS 8002	0.00141	0.00114	94.26	0.12250				
KUS 8003	0.00274	0.00092	61.29	0.05550		0.00005	113.38	0.00569
KUS 8004	0.00107	0.00073	42.43	0.02543	0.00147	0.00145	33.96	0.04914
KUS 8006	0.00170	0.00057	69.08	0.01082	0.00139	0.00118	31.18	0.03684
KUS 8008	0.00052	0.00032	31.48	0.00460		0.00017	6.00	0.00104
KUS 8009	0.00146	0.00151	37.24	0.04252	0.00202	0.00090	28.97	0.02597
KUS 8010	0.00084	0.00050	96.51	0.03228	0.00043			
KUS 8034	0.00056	0.00019	74.95	0.01103	0.00016	0.00013	128.52	0.01683
KUS 8042	0.00104	0.00077	56.65	0.04017				
KUS 8043	0.00105	0.00030	75.39	0.02037		0.00020	25.21	0.00512
KUS 8044	0.00111	0.00047	90.14	0.03620		0.00010	95.54	0.00924
KUS 8045	0.00168	0.00074	87.68	0.03942	0.00204	0.00040	272.46	0.10942
LAF 8013	0.00029	0.00031	58.35	0.01580		0.00002	49.00	0.00094
LAF 8014	0.00019	0.00017	176.81	0.02337		0.00002	81.00	0.00164
LAF 8015	0.00216	0.00046	37.21	0.01240	0.00206	0.00002	75.23	0.00159
LAF 8021	0.00002	0.00001	8.00	0.00008				
LAF 8022	0.00232	0.00064	59.13	0.03580	0.00115	0.00208	24.48	0.05100
LAF 8023	0.00036	0.00039	68.49	0.02989		0.00005	41.00	0.00196
LAF 8025	0.00013	0.00007	17.67	0.00128				
LAF 8026	0.00187	0.00074	81.20	0.04624	0.00326	0.00072	33.69	0.02415
LAK 8011	0.00019	0.00003	32.00	0.00181	0.00033	0.00006	19.00	0.00107
LAK 8012	0.00005	0.00006	60.88	0.00309				
LAK 8013	0.00011	0.00021	135.87	0.02658	0.00016	0.00000	85.00	0.00037
LAK 8015	0.00003	0.00001	27.96	0.00035				
LAK 8021	0.00019	0.00006	60.15	0.00442	0.00021			
LAK 8022	0.00004	0.00002	60.68	0.00118	0.00002			
LAK 8023	0.00009	0.00003	57.65	0.00190		0.00000		
LAK 8024	0.00143	0.00059	62.23	0.03255	0.00110	0.00008	107.10	0.00848
LAK 8025	0.00001	0.00000	136.00	0.00047				
LAU 8011	0.00144	0.00127	78.85	0.08953	0.00081	0.00032	34.65	0.01117
LAU 8012	0.00083	0.00035	75.20	0.01523	0.00146	0.00047	91.22	0.04277
LAU 8014	0.00104	0.00025	53.95	0.01189	0.00037	0.00035	16.72	0.00577
LAU 8021	0.00171	0.00078	91.07	0.05505	0.00075	0.00073	79.79	0.05827
LAU 8023	0.00079	0.00073	64.66	0.04997	0.00110	0.00088	76.22	0.06713
LAU 8024	0.00009	0.00012	114.45	0.01480	0.00019			

	5 Year Benchmark				Report Quarter Performance (Q1-2023)			
Circuit	MAIFI	SAIFI	CAIDI	SAIDI	MAIFI	SAIFI	CAIDI	SAIDI
LAU 8025	0.00071	0.00084	92.91	0.06272	0.00105	0.00058	82.99	0.04829
LAU 8034	0.00159	0.00116	72.04	0.09416	0.00142	0.00010	126.75	0.01271
LAU 8035	0.00144	0.00109	123.00	0.08036	0.00168	0.00128	17.57	0.02246
LAU 8044	0.00009	0.00006	145.96	0.00604				
LAW 8014	0.00106	0.00036	133.79	0.04047	0.00077	0.00027	83.14	0.02253
LAW 8015	0.00023	0.00024	44.87	0.00890	0.00026	0.00027	126.76	0.03400
LAW 8016	0.00079	0.00093	55.22	0.05573	0.00054	0.00033	36.28	0.01210
LAW 8023	0.00074	0.00094	72.98	0.06122	0.00080	0.00063	96.69	0.06099
LAW 8024	0.00122	0.00075	107.43	0.05493	0.00042	0.00047	58.79	0.02768
LAW 8025	0.00082	0.00110	81.77	0.08155	0.00026	0.00140	75.53	0.10605
LAW 8033	0.00088	0.00029	101.37	0.02923	0.00171	0.00134	83.36	0.11144
LAW 8039	0.00030	0.00016	95.04	0.01316	0.00023	0.00003	98.00	0.00261
LCE 8003	0.00060	0.00074	39.41	0.02090	0.00047	0.00027	18.34	0.00488
LCE 8005	0.00047	0.00023	57.44	0.01243	0.00044	0.00006	556.13	0.03497
LCE 8010	0.00059	0.00047	91.97	0.03263	0.00143	0.00046	146.96	0.06785
LCE 8012	0.00029	0.00061	64.74	0.03965	0.00243	0.00028	24.89	0.00696
LCE 8032	0.00211	0.00129	38.72	0.05027		0.00007	113.20	0.00770
LCE 8033	0.00177	0.00049	44.64	0.02295	0.00055	0.00132	58.83	0.07787
LCE 8034	0.00155	0.00053	159.52	0.02644	0.00260	0.00103	40.33	0.04141
LCE 8035	0.00039	0.00006	112.56	0.00281		0.00004	27.00	0.00113
LCE 8042	0.00064	0.00106	95.56	0.14059	0.00112	0.00170	105.23	0.17908
LCE 8043	0.00108	0.00078	21.34	0.02096	0.00045	0.00009	91.86	0.00863
LCE 8044	0.00111	0.00074	72.40	0.04405		0.00036	132.44	0.04739
LCE 8045	0.00088	0.00069	52.68	0.02312	0.00051	0.00019	14.82	0.00280
LCE 8046	0.00106	0.00081	51.10	0.04191	0.00054	0.00096	28.04	0.02704
LCU 8051	0.00281	0.00108	59.61	0.05653	0.00219			
LEH 4002		0.00049	95.34	0.03054				
LEH 4003		0.00008	145.00	0.00782				
LEH 4004	0.00042	0.00054	77.54	0.04146				
LEH 4006		0.00027	89.33	0.01551		0.00003	104.00	0.00319
LEH 4007		0.00017	83.00	0.01371				
LEO 8003	0.00209	0.00158	114.76	0.12987		0.00045	60.74	0.02746
LEO 8004	0.00159	0.00219	74.42	0.16494	0.00049	0.00010	65.85	0.00640
LEO 8005	0.00134	0.00155	63.60	0.08730	0.00182	0.00072	30.31	0.02195
LEO 8006	0.00075	0.00029	76.99	0.01843	0.00062	0.00005	123.50	0.00590
LEO 8008	0.00064	0.00034	93.58	0.02146				
LEO 8009	0.00003	0.00007	194.81	0.00615	0.00002	0.00008	52.56	0.00416
LEO 8032	0.00060	0.00021	83.53	0.01064	0.00064	0.00054	71.17	0.03841
LEO 8033	0.00034	0.00040	53.09	0.02325	0.00026	0.00014	122.18	0.01726
LEO 8034	0.00080	0.00091	59.06	0.05782	0.00001	0.00125	27.96	0.03493
LEO 8041	0.00228	0.00228	62.33	0.14603	0.00081	0.00015	59.67	0.00876
LEO 8042	0.00040	0.00033	44.53	0.01746	0.00091	0.00038	62.36	0.02348
LEO 8043	0.00123	0.00028	137.06	0.01765	0.00044	0.00018	58.00	0.01053
LEO 8044	0.00097	0.00015	239.89	0.02436	0.00068	0.00044	179.62	0.07950
LEO 8045	0.00068	0.00040	76.73	0.03070	0.00047			
LEV 8002	0.00267	0.00110	81.12	0.07731	0.00100	0.00141	53.99	0.07622

	5 Year Benchmark				Report Quarter Performance (Q1-2023)			
Circuit	MAIFI	SAIFI	CAIDI	SAIDI	MAIFI	SAIFI	CAIDI	SAIDI
LEV 8006	0.00126	0.00069	80.48	0.04455	0.00145	0.00048	32.58	0.01576
LEV 8008	0.00178	0.00115	96.01	0.07985	0.00223	0.00017	82.75	0.01446
LEV 8011	0.00058	0.00029	77.11	0.02693	0.00076	0.00015	58.43	0.00865
LEV 8012	0.00141	0.00091	90.30	0.07877	0.00002	0.00019	218.84	0.04207
LEV 8013	0.00040	0.00029	98.25	0.02433	0.00082	0.00021	109.39	0.02251
LEV 8016	0.00126	0.00057	150.99	0.02231	0.00100	0.00046	36.00	0.01658
LIB 4003	0.00085	0.00134	67.88	0.08977		0.00047	68.00	0.03229
LIB 4004	0.00033	0.00034	58.00	0.01948		0.00016	11.00	0.00180
LIB 4005	0.00047	0.00024	6.00	0.00291		0.00102	41.17	0.04211
LIB 4007	0.00060	0.00119	148.00	0.17622	0.00084	0.00058	38.26	0.02211
LIB 4009	0.00055	0.00030	23.00	0.00302		0.00028	270.00	0.07436
LIT 8001	0.00127	0.00033	156.52	0.03515	0.00158			
LIT 8004	0.00141	0.00016	124.80	0.02508	0.00146	0.00053	70.18	0.03723
LOC 8012	0.00209	0.00064	64.17	0.01576	0.00006			
LOC 8014	0.00086	0.00030	36.82	0.01096	0.00111	0.00001	858.00	0.00478
LOC 8033	0.00026	0.00010	21.00	0.00215	0.00026	0.00002	54.00	0.00101
LOI 8001	0.00292	0.00037	80.51	0.02505	0.00169	0.00052	161.24	0.08432
LUM 8014	0.00078	0.00037	107.18	0.04317	0.00097	0.00000	355.00	0.00057
LUM 8021	0.00114	0.00146	62.23	0.09114	0.00179	0.00076	104.29	0.07974
LUM 8022	0.00099	0.00025	66.68	0.02118	0.00158	0.00037	55.33	0.02042
LUM 8024	0.00116	0.00047	128.91	0.03928	0.00068	0.00053	88.47	0.04708
MAD 8014	0.00014	0.00005	84.76	0.00388	0.00022	0.00006	83.19	0.00477
MAD 8015	0.00132	0.00031	105.30	0.02911	0.00011	0.00042	33.72	0.01424
MAD 8016	0.00018	0.00007	68.39	0.00368	0.00016	0.00003	26.00	0.00078
MAD 8018	0.00241	0.00110	68.80	0.07374	0.00108	0.00004	81.76	0.00342
MAD 8021	0.00046	0.00039	223.14	0.02598	0.00097	0.00006	142.48	0.00856
MAD 8022	0.00050	0.00054	131.92	0.04273		0.00045	69.61	0.03106
MAD 8024	0.00009	0.00003	68.97	0.00222	0.00024	0.00007	25.69	0.00176
MAD 8026	0.00012	0.00010	148.76	0.01702	0.00003	0.00018	71.37	0.01295
MAD 8031	0.00168	0.00066	133.86	0.05565	0.00071	0.00026	101.47	0.02613
MAD 8032	0.00101	0.00066	142.57	0.11149	0.00071	0.00019	139.97	0.02668
MAD 8037	0.00132	0.00056	74.62	0.03142		0.00017	59.70	0.01041
MAI 8013	0.00066	0.00030	81.52	0.01958	0.00100	0.00128	54.34	0.06982
MAR 8001	0.00013	0.00003	104.00	0.00370	0.00010	0.00011	117.46	0.01272
MAR 8002	0.00118	0.00030	80.07	0.01904	0.00335	0.00117	85.77	0.10047
MAR 8004	0.00014	0.00008	69.17	0.00472		0.00012	14.50	0.00172
MAR 8005	0.00008	0.00007	104.03	0.00404	0.00000	0.00022	56.38	0.01245
MAR 8006	0.00016	0.00009	89.16	0.00775	0.00007			
MAR 8008	0.00042	0.00020	99.04	0.01672	0.00070	0.00004	114.83	0.00494
MAR 8009	0.00114	0.00028	89.61	0.02115	0.00060	0.00057	30.89	0.01762
MAR 8010	0.00036	0.00038	52.75	0.02191	0.00029	0.00054	28.85	0.01551
MAR 8011	0.00082	0.00008	149.50	0.00488				
MAR 8012	0.00031	0.00005	100.86	0.00605	0.00061	0.00002	126.50	0.00312
MAR 8013	0.00113	0.00032	123.72	0.04409	0.00021	0.00021	40.00	0.00845
MAR 8016	0.00057	0.00034	144.66	0.01881	0.00091	0.00003	260.00	0.00652
MAR 8017	0.00042	0.00041	133.97	0.04925	0.00088	0.00009	88.00	0.00823

	5 Year Benchmark				Report Quarter Performance (Q1-2023)			
Circuit	MAIFI	SAIFI	CAIDI	SAIDI	MAIFI	SAIFI	CAIDI	SAIDI
MAR 8018	0.00124	0.00042	88.03	0.02276	0.00237	0.00053	65.90	0.03494
MAS 4006	0.00022	0.00004	102.00	0.00433				
MAY 8013	0.00053	0.00038	60.85	0.02041	0.00102	0.00012	185.06	0.02313
MAY 8014	0.00059	0.00045	64.93	0.01770	0.00073	0.00023	61.90	0.01434
MAY 8015	0.00437	0.00209	50.25	0.09899	0.00744	0.00165	25.54	0.04213
MAY 8022	0.00152	0.00100	39.21	0.04314		0.00046	135.64	0.06219
MAY 8023	0.00093	0.00085	64.62	0.05909	0.00093	0.00006	79.57	0.00488
MAY 8024	0.00052	0.00030	72.16	0.01418	0.00188	0.00006	72.77	0.00405
MAY 8034	0.00376	0.00110	68.16	0.06274	0.00585	0.00065	33.18	0.02141
MAY 8036	0.00113	0.00108	15.50	0.01638	0.00096	0.00051	16.08	0.00817
MAY 8043	0.00085	0.00039	130.04	0.03176	0.00245	0.00047	57.69	0.02735
MAY 8044	0.00079	0.00048	127.56	0.06925	0.00075	0.00058	58.86	0.03404
MAY 8045	0.00012	0.00020	97.12	0.00624				
MCL 4001		0.00017	56.39	0.00786		0.00000	96.00	0.00004
MCL 4002	0.00057	0.00131	28.26	0.03677		0.00037	21.35	0.00800
MCL 4003		0.00010	145.30	0.00892	0.00019	0.00098	29.31	0.02877
MCL 4004	0.00027	0.00026	18.50	0.00498				
MCL 4006		0.00060	18.00	0.01085		0.00000	180.00	0.00072
MCL 4007		0.00148	184.80	0.33918				
MCL 4008		0.00055	77.78	0.03748				
MCL 4010		0.00038	36.82	0.01399	0.00032	0.00010	10.00	0.00102
MDF 8012	0.00128	0.00058	108.15	0.05896	0.00059	0.00073	45.58	0.03321
MDF 8014	0.00104	0.00030	146.07	0.02124		0.00016	154.42	0.02501
MDF 8021	0.00242	0.00087	120.05	0.06121	0.00024	0.00005	120.13	0.00645
MDF 8023	0.00073	0.00057	99.69	0.04389	0.00161	0.00207	94.53	0.19556
MDF 8024	0.00101	0.00095	100.56	0.05945		0.00039	73.78	0.02875
MDS 4003		0.00063	82.50	0.05215				
MDS 4012		0.00042	87.50	0.03622				
MEA 8011	0.00011	0.00017	68.51	0.01019	0.00027	0.00011	233.19	0.02543
MEA 8012	0.00026	0.00006	83.22	0.00510	0.00033			
MEA 8013	0.00150	0.00060	77.46	0.03420	0.00171	0.00079	24.24	0.01907
MEA 8015	0.00008	0.00005	142.27	0.00312	0.00006			
MEA 8016	0.00042	0.00019	98.63	0.01100	0.00039	0.00007	78.99	0.00569
MEA 8021	0.00117	0.00030	66.01	0.01068	0.00065	0.00058	24.36	0.01418
MEA 8024	0.00178	0.00188	54.15	0.09269	0.00211	0.00012	480.02	0.05559
MEA 8025	0.00049	0.00014	54.51	0.00677	0.00177	0.00040	90.31	0.03602
MEC 8004	0.00092	0.00033	93.50	0.02350		0.00068	95.73	0.06515
MIN 8011	0.00048	0.00023	115.79	0.03279	0.00042	0.00017	90.45	0.01580
MIN 8012	0.00032	0.00021	172.77	0.01324	0.00137	0.00010	73.19	0.00728
MIN 8013	0.00325	0.00128	43.64	0.02221	0.00315	0.00087	44.29	0.03868
MIN 8015	0.00190	0.00025	164.98	0.01536	0.00300	0.00043	63.28	0.02735
MIN 8021	0.00004	0.00001	13.00	0.00024				
MIN 8022	0.00146	0.00025	44.44	0.01073	0.00289	0.00047	18.00	0.00837
MIN 8023	0.00023	0.00013	125.74	0.01755		0.00006	143.53	0.00880
MIN 8024	0.00065	0.00017	177.97	0.02511	0.00005	0.00028	7.75	0.00220
MIN 8025	0.00159	0.00048	52.34	0.02802	0.00307	0.00179	18.95	0.03393

	5 Year Benchmark				Report Quarter Performance (Q1-2023)			
Circuit	MAIFI	SAIFI	CAIDI	SAIDI	MAIFI	SAIFI	CAIDI	SAIDI
MIN 8026	0.00182	0.00016	87.04	0.01271				
MNT 4004		0.00035	142.94	0.01842		0.00018	155.90	0.02860
MNT 4005		0.00056	134.55	0.05502		0.00036	83.79	0.03035
MNT 4006	0.00038	0.00034	314.46	0.03677		0.00021	506.00	0.10452
MNT 4009		0.00023	131.40	0.01339		0.00011	151.46	0.01640
MNT 4010	0.00037	0.00042	79.77	0.02655				
MNT 4012		0.00053	233.16	0.04186		0.00011	176.67	0.01856
MNT 4015		0.00064	34.86	0.02994		0.00020	8.00	0.00161
MOG 4001		0.00073	45.50	0.03292		0.00027	161.00	0.04357
MOG 4002		0.00100	53.03	0.05648		0.00053	48.08	0.02558
MOG 4006	0.00083	0.00026	46.70	0.01190		0.00025	5.00	0.00123
MOG 4011		0.00051	45.50	0.02331				
MON 8002	0.00105	0.00135	79.93	0.10034	0.00121	0.00057	80.06	0.04601
MON 8003	0.00130	0.00066	77.61	0.02157	0.00034	0.00068	199.97	0.13506
MON 8004	0.00104	0.00052	91.74	0.03113		0.00004	41.55	0.00150
MOT 8001	0.00061	0.00049	85.94	0.03831	0.00041	0.00045	104.46	0.04727
MOT 8002	0.00042	0.00018	183.37	0.01148	0.00006	0.00023	121.58	0.02758
MOT 8003	0.00065	0.00043	69.29	0.02392	0.00008	0.00022	88.03	0.01973
MOY 4002	0.00045	0.00063	59.84	0.04838				
MOY 4003	0.00019	0.00028	55.00	0.01802		0.00014	40.00	0.00568
MOY 4005	0.00030	0.00001	361.52	0.00264				
MOY 4009	0.00052	0.00054	71.15	0.03871				
MRO 8012	0.00167	0.00084	97.12	0.07311	0.00140	0.00065	150.48	0.09804
MRO 8013	0.00115	0.00030	84.95	0.02439	0.00161	0.00039	60.67	0.02395
MRO 8022	0.00111	0.00128	62.81	0.06208	0.00082	0.00078	85.29	0.06616
MRO 8023	0.00127	0.00072	145.59	0.10133	0.00069	0.00179	91.76	0.16431
MRO 8024	0.00184	0.00048	74.27	0.03475	0.00213	0.00102	66.83	0.06796
MSD 8001	0.00111	0.00082	76.56	0.05759	0.00091	0.00003	87.47	0.00237
MTL 8013	0.00234	0.00078	97.41	0.03105		0.00006	102.89	0.00594
MTL 8014	0.00017	0.00012	104.43	0.01028		0.00005	83.26	0.00451
MTL 8015	0.00098	0.00051	114.82	0.04669	0.00057	0.00025	163.39	0.04149
MTL 8022	0.00070	0.00024	109.43	0.01181	0.00081			
MTL 8024	0.00012	0.00008	99.59	0.00580	0.00028	0.00010	62.97	0.00619
NBS 8011	0.00070	0.00051	68.66	0.02203	0.00330	0.00021	20.50	0.00441
NBS 8012	0.00052	0.00025	112.89	0.02898	0.00002	0.00011	232.80	0.02492
NBS 8013	0.00215	0.00048	39.48	0.01477		0.00000	291.00	0.00081
NBS 8021	0.00034	0.00002	95.00	0.00379	0.00016	0.00002	80.16	0.00182
NBS 8023	0.00021	0.00001	109.34	0.00393	0.00024	0.00023	87.21	0.02027
NED 8013	0.00060	0.00029	52.15	0.01435	0.00102	0.00013	69.85	0.00931
NED 8014	0.00026	0.00033	79.22	0.01981	0.00015	0.00017	91.58	0.01571
NED 8015	0.00148	0.00089	83.19	0.06818	0.00142	0.00029	85.60	0.02501
NED 8016	0.00125	0.00059	147.80	0.06662	0.00206	0.00043	77.65	0.03338
NED 8022	0.00110	0.00084	26.80	0.02081		0.00010	62.64	0.00636
NED 8024	0.00057	0.00033	51.39	0.01363	0.00077	0.00004	67.89	0.00238
NED 8025	0.00277	0.00065	107.68	0.06845	0.00136	0.00012	102.18	0.01175
NEV 8001	0.00182	0.00047	81.59	0.03734	0.00066	0.00005	93.79	0.00433

	5 Year Benchmark				Report Quarter Performance (Q1-2023)			
Circuit	MAIFI	SAIFI	CAIDI	SAIDI	MAIFI	SAIFI	CAIDI	SAIDI
NEW 8011	0.00044	0.00018	135.78	0.01834		0.00007	56.69	0.00390
NEW 8013	0.00207	0.00045	99.55	0.03237	0.00019	0.00006	505.71	0.02959
NEW 8014	0.00100	0.00062	92.00	0.04881	0.00012	0.00018	33.55	0.00620
NEW 8023	0.00061	0.00032	92.23	0.02734	0.00042	0.00031	43.08	0.01336
NEW 8025	0.00066	0.00031	159.08	0.04196		0.00018	35.57	0.00623
NEW 8032	0.00015	0.00024	81.70	0.01998				
NEW 8033	0.00078	0.00061	81.15	0.03393	0.00065	0.00004	209.99	0.00944
NEW 8034	0.00130	0.00121	57.43	0.06839	0.00129	0.00008	85.39	0.00700
NEW 8041	0.00212	0.00062	76.35	0.02987	0.00190	0.00177	42.57	0.07533
NEW 8042	0.00108	0.00056	98.59	0.05165	0.00068	0.00049	40.11	0.01968
NEW 8044	0.00098	0.00048	107.66	0.03597	0.00183	0.00197	14.51	0.02853
NIN 4001		0.00042	231.06	0.03644		0.00011	559.00	0.06319
NIN 4002		0.00156	31.12	0.04910	0.00111	0.00073	32.00	0.02349
NIN 4003	0.00134	0.00157	60.38	0.05305	0.00066	0.00002	83.00	0.00192
NIN 4004		0.00042	173.70	0.03815				
NIN 4005	0.00080	0.00109	73.64	0.06603				
NIN 4006	0.00295	0.00002	192.58	0.00471	0.00127	0.00250	17.33	0.04327
NIT 8007	0.00233	0.00065	90.21	0.07520	0.00174	0.00012	149.13	0.01864
NOF 4003	0.00056	0.00026	87.33	0.01972	0.00035	0.00002	187.98	0.00419
NOF 4004		0.00111	76.92	0.11608		0.00057	50.00	0.02856
NOF 4010	0.00045	0.00071	71.59	0.05470		0.00047	8.00	0.00377
NOT 8011	0.00004	0.00002	245.25	0.00130	0.00003	0.00001	73.00	0.00049
NOT 8013	0.00109	0.00049	34.95	0.01806	0.00003	0.00003	178.00	0.00489
NOT 8014	0.00123	0.00046	152.51	0.03799		0.00037	9.00	0.00330
NOT 8016	0.00041	0.00042	61.02	0.02571				
NOT 8021	0.00110	0.00063	102.78	0.04143	0.00075			
NOT 8022	0.00059	0.00049	56.75	0.01040	0.00227	0.00003	114.00	0.00318
NOT 8023	0.00004	0.00003	61.39	0.00210	0.00003	0.00001	332.00	0.00317
NOT 8024	0.00178	0.00105	119.79	0.09724	0.00189	0.00041	112.08	0.04613
NRB 8012	0.00039	0.00025	72.76	0.02435	0.00081	0.00000	68.00	0.00003
NRB 8013	0.00288	0.00030	70.30	0.01483	0.00178	0.00048	5.00	0.00241
NRB 8014	0.00219	0.00068	112.39	0.05665	0.00454	0.00184	39.47	0.07276
NRB 8015	0.00117	0.00061	88.15	0.03949	0.00346	0.00002	104.00	0.00215
NRB 8022	0.00258	0.00119	89.43	0.06005	0.00064	0.00005	206.00	0.00992
NRP 4001	0.00029	0.00029	41.00	0.01204				
NRP 4002	0.00047	0.00035	137.00	0.04846				
NRP 4003	0.00104	0.00172	45.89	0.08996		0.00003	125.00	0.00378
NRP 4004	0.00040							
NRP 4007	0.00068	0.00051	43.64	0.01042		0.00168	87.09	0.14642
NRP 4009		0.00025	43.02	0.01111		0.00001	237.00	0.00255
NRP 4010	0.00085	0.00147	38.83	0.04329	0.00126	0.00511	37.90	0.19373
NRP 4012	0.00019	0.00015	61.90	0.00922				
NRP 4014	0.00046	0.00043	92.82	0.02491	0.00095			
NRP 4015	0.00040	0.00039	30.22	0.01171				
NUT 4001		0.00008	191.31	0.00723				
NUT 4002		0.00006	257.29	0.01192	0.00015	0.00041	72.38	0.02947

	5 Year Benchmark				Report Quarter Performance (Q1-2023)			
Circuit	MAIFI	SAIFI	CAIDI	SAIDI	MAIFI	SAIFI	CAIDI	SAIDI
OAK 4004	0.00179	0.00061	150.90	0.04071	0.00348	0.00118	43.68	0.05162
OAK 4008	0.00222	0.00216	68.59	0.10917	0.00146	0.00148	23.81	0.03519
ORA 4001		0.00084	100.34	0.03252		0.00091	6.50	0.00594
ORA 4002		0.00034	137.44	0.02313		0.00024	118.43	0.02847
ORA 4003		0.00071	7.00	0.00500				
ORA 4006		0.00091	74.37	0.06782				
PAR 4002	0.00018							
PAR 4003		0.00010	216.88	0.01240				
PAR 4006		0.00015	78.27	0.01318	0.00015	0.00040	84.75	0.03414
PAS 4003	0.00070	0.00070	73.70	0.03265				
PAS 4007		0.00070	54.83	0.03844				
PAS 4008	0.00017	0.00021	35.12	0.00829		0.00008	6.00	0.00051
PAS 4011		0.00035	83.88	0.02030		0.00087	59.72	0.05222
PAS 4016	0.00048	0.00115	59.01	0.06618		0.00046	9.00	0.00416
PAS 4020	0.00066	0.00096	74.00	0.06564				
PAT 4003	0.00041	0.00054	89.80	0.04903		0.00091	80.70	0.07320
PAT 4008		0.00042	113.50	0.02505		0.00108	27.90	0.03018
PAT 4010		0.00007	391.13	0.02599	0.00008			
PAT 4011	0.00043	0.00043	9.50	0.00818				
PAT 4012	0.00046	0.00052	29.38	0.01746	0.00040			
PAT 4016					0.00190	0.00060	20.25	0.01220
PEH 8001	0.00028	0.00014	43.31	0.00607	0.00025	0.00014	33.39	0.00468
PEH 8004	0.00006	0.00004	66.19	0.00282	0.00005	0.00001	60.00	0.00060
PEH 8013	0.00164	0.00070	49.64	0.02179	0.00183			
PEH 8015	0.00396	0.00082	52.00	0.03991	0.00582	0.00063	27.32	0.01733
PEH 8022	0.00012	0.00005	32.21	0.00188				
PEH 8025	0.00007	0.00002	11.00	0.00018		0.00001	37.00	0.00031
PEK 8018	0.00043	0.00027	148.79	0.03679	0.00054	0.00083	49.47	0.04082
PEK 8021	0.00055	0.00007	88.96	0.00360	0.00041	0.00002	172.15	0.00404
PEK 8022	0.00134	0.00047	59.28	0.02088	0.00082	0.00000	298.00	0.00059
PEK 8023	0.00103	0.00105	89.28	0.07620		0.00077	40.35	0.03112
PEK 8026	0.00121	0.00040	148.11	0.03507	0.00046	0.00003	105.00	0.00288
PEK 8034		0.00000	107.56	0.00029	0.00012			
PEK 8035	0.00090	0.00089	113.77	0.05819	0.00104	0.00057	82.80	0.04732
PEK 8036	0.00030	0.00021	184.43	0.03676	0.00012	0.00010	114.92	0.01189
PIE 8011	0.00006	0.00009	82.40	0.00784	0.00004	0.00001	206.00	0.00213
PIE 8013	0.00104	0.00036	49.80	0.01542	0.00010	0.00019	33.32	0.00618
PIE 8014	0.00225	0.00072	69.75	0.05139	0.00115	0.00067	132.16	0.08858
PIE 8015	0.00083	0.00029	109.64	0.01346	0.00030	0.00004	127.80	0.00463
PIE 8022	0.00059	0.00018	72.64	0.01529	0.00012	0.00009	38.37	0.00330
PIE 8023	0.00164	0.00061	65.59	0.02577		0.00003	157.92	0.00396
PIN 4001		0.00069	416.48	0.07134		0.00002	72.00	0.00166
PIN 4002		0.00060	109.00	0.06557	0.00008			
PLA 4004		0.00008	81.00	0.00068				
PLA 4007	0.00055							
PLA 4008	0.00034	0.00052	23.00	0.01187				

	5 Year Benchmark				Report Quarter Performance (Q1-2023)			
Circuit	MAIFI	SAIFI	CAIDI	SAIDI	MAIFI	SAIFI	CAIDI	SAIDI
PLA 4010		0.00063	77.25	0.04234		0.00065	62.02	0.04021
PLA 4012	0.00015	0.00052	207.93	0.01965				
PLA 4013	0.00185	0.00032	84.62	0.01420		0.00025	5.00	0.00124
PLI 8003	0.00159	0.00057	116.08	0.03994	0.00102	0.00021	74.14	0.01582
PLI 8004	0.00117	0.00121	95.10	0.07267		0.00035	185.08	0.06534
PLI 8005	0.00114	0.00023	56.42	0.00614		0.00010	155.73	0.01512
PLI 8007	0.00089	0.00069	100.60	0.05460	0.00020	0.00026	36.28	0.00950
PLI 8008	0.00110	0.00051	86.91	0.04167	0.00005	0.00036	72.80	0.02631
PLI 8010	0.00042	0.00030	49.80	0.01154		0.00014	143.86	0.02033
PLI 8011	0.00011	0.00008	49.32	0.00342		0.00012	82.72	0.01014
PLI 8012	0.00032	0.00010	45.60	0.00300	0.00051	0.00010	53.00	0.00506
POH 8012	0.00006	0.00001	80.77	0.00172				
POH 8013	0.00056	0.00027	60.80	0.01980	0.00054	0.00014	97.57	0.01340
POH 8015	0.00064	0.00024	34.86	0.00972	0.00047	0.00001	16.00	0.00020
POH 8021	0.00027	0.00004	96.75	0.00147		0.00008	26.00	0.00199
POH 8022	0.00109	0.00037	88.63	0.02245	0.00001	0.00017	104.11	0.01724
POH 8023	0.00234	0.00058	158.46	0.03658		0.00001	139.00	0.00077
POH 8024	0.00058	0.00059	40.08	0.01575	0.00006	0.00009	68.05	0.00623
POH 8026	0.00036	0.00026	77.88	0.00839				
POL 4001					0.00142	0.00216	78.33	0.16929
POL 4003		0.00148	98.45	0.14543		0.00047	180.00	0.08411
POL 4004		0.00020	68.00	0.02754		0.00041	174.00	0.07085
POL 4005		0.00058	28.50	0.01668	0.00055	0.00055	191.00	0.10483
POL 4006		0.00081	13.84	0.01119		0.00041	201.00	0.08184
POL 4010		0.00056	40.13	0.02237		0.00064	201.00	0.12928
POL 4012		0.00026	46.00	0.00841	0.00024	0.00084	174.71	0.14679
POR 8021	0.00032	0.00008	31.98	0.00251	0.00017	0.00023	54.71	0.01235
PRI 4001		0.00008	226.67	0.00314				
RAV 8003	0.00086	0.00058	43.10	0.02941		0.00006	259.17	0.01589
RFL 8011	0.00111	0.00018	100.96	0.01326	0.00206	0.00047	33.17	0.01555
RFL 8012	0.00332	0.00051	51.71	0.02604	0.00278	0.00103	17.05	0.01762
RFL 8014	0.00097	0.00053	67.65	0.02622	0.00054	0.00002	466.09	0.00835
RFL 8021	0.00013	0.00011	83.14	0.00689				
RFL 8022	0.00003	0.00001	94.50	0.00104				
RFL 8023	0.00047	0.00013	137.93	0.00550	0.00031	0.00003	17.20	0.00044
RFL 8025	0.00018	0.00010	65.64	0.00359	0.00016	0.00001	18.00	0.00024
RFL 8032	0.00152	0.00072	72.01	0.03340	0.00014			
RFL 8034	0.00198	0.00149	46.29	0.06455	0.00102	0.00046	22.36	0.01036
RFL 8035	0.00200	0.00137	42.69	0.06029	0.00023			
RFL 8042	0.00022	0.00007	15.00	0.00146				
RFL 8044	0.00010	0.00001	54.00	0.00041				
RGW 4004		0.00006	107.00	0.00134				
RGW 4005	0.00019	0.00000	280.50	0.00219				
RGW 4006	0.00029	0.00015	88.83	0.00727		0.00030	13.00	0.00396
RGW 4007		0.00036	95.00	0.03427		0.00088	105.68	0.09300
RGW 4009		0.00022	84.72	0.01877				

	5 Year Benchmark				Report Quarter Performance (Q1-2023)			
Circuit	MAIFI	SAIFI	CAIDI	SAIDI	MAIFI	SAIFI	CAIDI	SAIDI
RGW 4012		0.00028	119.88	0.01813				
RGW 4013		0.00016	46.26	0.00602		0.00030	31.45	0.00936
RGW 4014		0.00010	102.50	0.00831		0.00032	104.31	0.03288
RGW 4015						0.00004	125.00	0.00537
RIS 4004	0.00041					0.00017	32.00	0.00553
RIS 4005		0.00027	11.00	0.00294		0.00040	28.17	0.01133
RIV 8006	0.00326	0.00086	70.60	0.05850	0.00071	0.00117	26.25	0.03065
RSL 4003	0.00079	0.00043	78.67	0.03386		0.00074	219.46	0.16325
RSL 4006		0.00157	103.11	0.16146	0.00023	0.00055	171.00	0.09344
RSL 4007		0.00057	371.62	0.12168		0.00104	161.68	0.16872
RSL 4008	0.00072	0.00090	85.96	0.07398		0.00068	184.00	0.12589
RUN 8001	0.00090	0.00034	106.78	0.01449	0.00027	0.00039	46.08	0.01784
RUN 8003	0.00059	0.00041	104.43	0.03428		0.00015	154.84	0.02280
RUN 8004	0.00096	0.00018	91.18	0.01730	0.00110	0.00044	20.21	0.00880
RUN 8005	0.00072	0.00041	142.43	0.02914	0.00127	0.00006	125.25	0.00813
RVR 8011	0.00200	0.00107	56.19	0.05534		0.00110	75.20	0.08237
RVR 8022	0.00114	0.00164	62.87	0.10572	0.00023	0.00062	48.98	0.03021
RVR 8031	0.00090	0.00078	93.07	0.08001	0.00138	0.00049	118.23	0.05783
SAD 8002	0.00253	0.00144	54.18	0.04421	0.00119	0.00062	58.75	0.03664
SAD 8003	0.00073	0.00045	116.37	0.03871	0.00195	0.00008	126.00	0.00968
SAD 8004	0.00030	0.00009	163.18	0.00324		0.00002	169.00	0.00283
SAD 8006	0.00026	0.00022	60.71	0.01385	0.00012			
SAD 8008	0.00157	0.00065	59.79	0.03864	0.00186	0.00151	91.70	0.13832
SAD 8032	0.00135	0.00062	56.12	0.03453	0.00005	0.00000	110.00	0.00018
SAD 8033	0.00018	0.00007	74.39	0.00644		0.00007	80.33	0.00547
SAD 8043	0.00156	0.00053	55.42	0.02807	0.00095	0.00051	19.68	0.01012
SAD 8044	0.00193	0.00102	113.24	0.08095	0.00202	0.00138	31.41	0.04329
SAD 8045	0.00148	0.00066	37.98	0.01923	0.00124	0.00098	177.68	0.17354
SDH 8021	0.00090	0.00064	60.73	0.03318	0.00095	0.00001	218.00	0.00217
SDH 8023	0.00137	0.00084	55.16	0.02451	0.00070	0.00071	67.49	0.04819
SDH 8024	0.00125	0.00083	63.93	0.03290	0.00067	0.00080	35.26	0.02826
SDH 8025	0.00112	0.00097	103.28	0.09314	0.00120	0.00092	112.64	0.10410
SDH 8026	0.00208	0.00087	67.62	0.04871	0.00059	0.00066	82.63	0.05429
SDH 8031	0.00199	0.00057	138.44	0.04389	0.00328	0.00172	44.87	0.07720
SDH 8033	0.00056	0.00019	97.72	0.01603	0.00056	0.00005	85.00	0.00409
SDH 8034	0.00048	0.00060	68.68	0.02592	0.00072	0.00047	29.67	0.01392
SDH 8035	0.00036	0.00047	112.19	0.04545		0.00001	88.00	0.00105
SMV 8011	0.00033	0.00019	125.85	0.00790	0.00032	0.00000		
SMV 8012	0.00078	0.00028	64.07	0.00648	0.00088			
SMV 8013	0.00092	0.00102	50.71	0.04201	0.00100	0.00024	46.79	0.01140
SMV 8014	0.00070	0.00046	59.04	0.03868	0.00051			
SMV 8021	0.00138	0.00035	50.01	0.01030		0.00012	97.26	0.01161
SMV 8022	0.00143	0.00066	25.70	0.01733		0.00001	323.00	0.00334
SMV 8023	0.00054	0.00058	48.42	0.01499	0.00008	0.00013	27.68	0.00361
SMV 8024	0.00087	0.00033	37.48	0.01267	0.00109	0.00046	22.48	0.01028
SMV 8025	0.00054	0.00044	47.51	0.01467	0.00012	0.00012	60.03	0.00693

	5 Year Benchmark				Report Quarter Performance (Q1-2023)			
Circuit	MAIFI	SAIFI	CAIDI	SAIDI	MAIFI	SAIFI	CAIDI	SAIDI
SOH 8022	0.00150	0.00056	100.93	0.04714	0.00140	0.00017	132.75	0.02251
SOO 4004	0.00048	0.00057	74.10	0.05188		0.00053	76.71	0.04033
SOO 4011		0.00013	251.89	0.03476		0.00005	328.83	0.01505
SOO 4012	0.00032	0.00035	71.33	0.02655		0.00049	85.95	0.04198
SOP 4007		0.00044	42.88	0.02005	0.00028			
SOP 4008		0.00049	143.00	0.06984				
SOP 4010								
SOS 8015	0.00200	0.00065	64.61	0.03737	0.00181	0.00064	54.48	0.03495
SOS 8016	0.00547	0.00197	60.38	0.12723	0.00203	0.00058	37.23	0.02142
SOS 8025	0.00206	0.00113	76.54	0.08468	0.00052	0.00039	141.96	0.05588
SPF 8012	0.00495	0.00183	96.55	0.08153	0.00262	0.00230	50.94	0.11708
SPF 8014	0.00013	0.00029	40.92	0.01176	0.00005	0.00016	126.91	0.02020
SPF 8015	0.00017	0.00010	74.71	0.00910	0.00007	0.00001	230.44	0.00293
SPF 8016	0.00018	0.00002	97.00	0.00536		0.00009	224.31	0.01991
SPF 8023	0.00025	0.00028	55.61	0.01552	0.00025	0.00028	92.64	0.02596
SPF 8024	0.00051	0.00018	192.74	0.00883		0.00005	141.00	0.00758
SPF 8025	0.00162	0.00073	58.72	0.02639	0.00415	0.00023	78.34	0.01833
STL 8011	0.00670	0.00456	21.12	0.10480	0.00279	0.00003	234.46	0.00653
STP 8001	0.00170	0.00087	53.11	0.02855	0.00276	0.00142	69.35	0.09840
STP 8002	0.00228	0.00071	95.01	0.02554	0.00245	0.00012	304.77	0.03518
STS 4003	0.00038	0.00032	194.00	0.06165				
STS 4005		0.00039	98.97	0.03381				
STS 4010	0.00087	0.00062	124.98	0.07707				
SUN 8011	0.00115	0.00024	83.20	0.00695	0.00023	0.00083	86.69	0.07215
SUN 8013	0.00033	0.00013	241.51	0.00757	0.00022	0.00029	120.74	0.03450
SUN 8021	0.00254	0.00051	55.14	0.01733	0.00118	0.00005	97.71	0.00471
SUN 8022	0.00215	0.00058	39.97	0.01920	0.00074	0.00003	95.10	0.00307
SUN 8024	0.00189	0.00054	89.19	0.03067	0.00096	0.00081	60.03	0.04867
SUN 8033	0.00063	0.00027	75.43	0.01624		0.00004	171.73	0.00642
SUN 8034		0.00018	137.95	0.01246	0.00045			
SUN 8035	0.00057	0.00037	39.61	0.01089		0.00004	96.65	0.00419
SUN 8043	0.00040	0.00030	148.42	0.02731	0.00120	0.00133	64.70	0.08619
SUN 8044	0.00102	0.00026	84.32	0.01284	0.00129	0.00099	38.52	0.03802
SUN 8045	0.00023	0.00015	110.80	0.01465	0.00229	0.00081	89.87	0.07264
SWT 8001	0.00183	0.00095	46.04	0.03740				
SWT 8002	0.00193	0.00219	34.63	0.07177				
TEA 4002	0.00109	0.00074	36.60	0.03528				
TEA 4004		0.00011	38.92	0.00422				
TEA 4007		0.00024	15.00	0.00367				
THO 8012	0.00157	0.00026	134.53	0.01768	0.00055	0.00004	139.07	0.00509
THO 8013	0.00103	0.00017	158.51	0.02317	0.00010	0.00011	221.27	0.02422
THO 8014		0.00000	142.43	0.00031				
THO 8022	0.00022	0.00010	51.16	0.00496	0.00011	0.00008	96.00	0.00745
THO 8024	0.00012	0.00002	175.42	0.00270	0.00005	0.00000		
THY 4003	0.00039	0.00064	101.17	0.08718		0.00051	31.06	0.01580
THY 4004	0.00045	0.00045	143.49	0.09226	0.00089	0.00007	115.00	0.00774

	5 Year Benchmark				Report Quarter Performance (Q1-2023)			
Circuit	MAIFI	SAIFI	CAIDI	SAIDI	MAIFI	SAIFI	CAIDI	SAIDI
THY 4005		0.00055	36.51	0.01943				
THY 4006		0.00037	87.00	0.03237				
THY 4007		0.00071	82.87	0.05104		0.00001	172.00	0.00199
THY 4008	0.00037	0.00030	71.99	0.02124	0.00050			
THY 4009	0.00054	0.00029	177.49	0.04075	0.00053			
THY 4010	0.00029	0.00038	69.42	0.03030		0.00021	159.49	0.03313
THY 4011	0.00020	0.00040	25.00	0.01151		0.00009	15.00	0.00130
THY 4012		0.00046	125.00	0.05790				
THY 4013		0.00070	100.68	0.07037		0.00048	41.02	0.01971
THY 4014	0.00033	0.00025	85.24	0.02894				
TNY 4001	0.00051	0.00046	205.55	0.08804		0.00060	37.92	0.02282
TNY 4002		0.00113	141.68	0.11170		0.00159	55.79	0.08866
TNY 4003		0.00058	126.49	0.05371				
TNY 4008		0.00037	154.08	0.03331	0.00054	0.00091	72.76	0.06602
TNY 4010	0.00146	0.00086	165.05	0.09743		0.00013	242.30	0.03240
TON 4003		0.00060	47.13	0.02846				
TON 4006	0.00056	0.00039	305.00	0.01609				
TON 4007	0.00043	0.00029	113.88	0.02519	0.00043			
TOT 4001	0.00012	0.00004	167.00	0.00605				
TOT 4002		0.00026	31.00	0.00772				
TOT 4007	0.00006	0.00004	92.32	0.00490		0.00003	6.00	0.00021
TUR 8001	0.00016	0.00013	70.57	0.00731	0.00032	0.00003	62.69	0.00212
TUR 8003	0.00013	0.00006	265.74	0.01014		0.00002	166.37	0.00324
TUR 8004	0.00173	0.00062	77.79	0.03887				
TUR 8015	0.00217	0.00043	86.32	0.03157	0.00201	0.00075	17.16	0.01283
TUR 8025	0.00220	0.00132	62.24	0.05542	0.00111	0.00041	94.26	0.03849
UN 4004								
UN 4006								
UN 4010								
UN 4011								
UNC 4001		0.00054	31.50	0.02586				
UNC 4006		0.00148	49.54	0.07565				
UNC 4007		0.00029	31.50	0.00912				
UNC 4009		0.00085	39.26	0.02840				
UNC 4010		0.00049	46.69	0.01912	0.00032	0.00032	10.00	0.00319
UNC 4012		0.00058	31.50	0.01840	0.00027			
VIL 8001	0.00144	0.00017	104.25	0.01185	0.00206	0.00065	143.32	0.09303
VNH 4002		0.00006	166.00	0.00969		0.00007	472.00	0.03344
VNH 4003	0.00045	0.00000	180.00	0.00008		0.00046	57.90	0.02680
VNK 4006								
VNK 4010	0.00086	0.00043	27.98	0.01197				
VNK 4012		0.00007	30.00	0.00639				
VNK 4013	0.00036	0.00036	53.50	0.01982		0.00035	16.11	0.00557
VNK 4015								
WAD 8011	0.00036	0.00031	126.21	0.03185	0.00115	0.00052	133.86	0.07027
WAD 8013	0.00078	0.00050	68.28	0.02292	0.00121	0.00193	59.82	0.11566

	5 Year Benchmark				Report Quarter Performance (Q1-2023)			
Circuit	MAIFI	SAIFI	CAIDI	SAIDI	MAIFI	SAIFI	CAIDI	SAIDI
WAD 8022	0.00148	0.00048	104.40	0.02581	0.00059	0.00062	24.98	0.01548
WAD 8025	0.00180	0.00078	84.43	0.04230		0.00016	121.84	0.01964
WAD 8041	0.00050	0.00072	69.26	0.02930	0.00080	0.00088	72.88	0.06448
WAN 8014	0.00083	0.00023	69.94	0.01007	0.00070	0.00050	91.20	0.04541
WAN 8015		0.00008	71.82	0.00558	0.00024	0.00000	121.00	0.00005
WAN 8022	0.00192	0.00027	90.57	0.01467	0.00137	0.00023	18.04	0.00412
WAN 8025	0.00132	0.00002	50.00	0.00275	0.00101	0.00005	90.00	0.00487
WAR 4001	0.00056	0.00067	82.16	0.04252		0.00063	103.16	0.06549
WAR 4002		0.00022	87.22	0.01686				
WAR 4003		0.00016	70.47	0.01096				
WAR 4004	0.00019	0.00020	162.75	0.01790		0.00018	183.59	0.03346
WAR 4005		0.00017	62.36	0.00972				
WAR 4006	0.00029	0.00030	42.38	0.01257		0.00002	166.00	0.00277
WAR 4007		0.00030	67.57	0.02050				
WAR 4008		0.00017	112.05	0.01953				
WAR 4009	0.00028	0.00037	51.79	0.01630				
WAV 4001		0.00024	31.00	0.00737		0.00013	68.00	0.00917
WAV 4004		0.00026	116.33	0.02406	0.00025			
WAV 4015	0.00072	0.00079	94.90	0.07106		0.00108	251.80	0.27159
WAV 4016	0.00016	0.00004	61.00	0.00125	0.00004	0.00008	15.53	0.00117
WAV 4018		0.00075	112.68	0.07451		0.00053	51.00	0.02681
WEW 8011	0.00113	0.00068	80.42	0.05172	0.00137	0.00112	56.09	0.06287
WEW 8014	0.00015	0.00008	105.50	0.00714	0.00038	0.00004	17.00	0.00062
WEW 8015	0.00015	0.00006	42.73	0.00252	0.00004	0.00004	83.00	0.00307
WEW 8021	0.00243	0.00140	76.89	0.11332	0.00273	0.00052	39.30	0.02057
WEW 8023	0.00033	0.00036	41.22	0.01499	0.00046	0.00039	19.15	0.00744
WEW 8025	0.00036	0.00016	68.31	0.00630	0.00034	0.00033	35.71	0.01184
WEW 8031	0.00013	0.00003	505.67	0.00932	0.00019			
WEW 8032	0.00001	0.00001	30.58	0.00025	0.00001			
WEW 8033	0.00256	0.00084	106.17	0.04947	0.00397	0.00323	74.22	0.23981
WEW 8034	0.00015	0.00014	121.88	0.01301				
WEW 8041	0.00025	0.00012	58.80	0.00446		0.00002	98.36	0.00172
WEW 8042	0.00093	0.00096	57.30	0.05564	0.00173	0.00029	116.58	0.03336
WEW 8044	0.00118	0.00086	37.91	0.03418	0.00065	0.00159	22.29	0.03550
WFL 8011	0.00118	0.00049	117.68	0.04186		0.00019	74.09	0.01407
WFL 8012	0.00138	0.00059	41.97	0.02723	0.00047	0.00032	150.55	0.04853
WFL 8021	0.00079	0.00017	32.00	0.00531	0.00027	0.00022	88.71	0.01935
WFL 8032	0.00215	0.00155	54.39	0.07771	0.00146	0.00077	51.86	0.03979
WFL 8034	0.00141	0.00061	161.91	0.09736		0.00004	105.07	0.00439
WFL 8041	0.00119	0.00079	105.88	0.08710	0.00135			
WMT 4002	0.00045	0.00016	98.05	0.01250		0.00006	43.00	0.00255
WMT 4004	0.00045	0.00009	153.91	0.00429	0.00006	0.00010	269.43	0.02799
WMT 4005	0.00056	0.00019	175.50	0.04236	0.00097	0.00022	93.73	0.02082
WMT 4006	0.00072	0.00025	94.41	0.02600		0.00053	33.53	0.01767
WMT 4007	0.00072	0.00039	152.14	0.10679	0.00105	0.00015	91.70	0.01332
WOA 4003		0.00054	122.98	0.01890		0.00000	916.89	0.00328

	5 Year Benchmark				Report Quarter Performance (Q1-2023)			
Circuit	MAIFI	SAIFI	CAIDI	SAIDI	MAIFI	SAIFI	CAIDI	SAIDI
WOD 4001	0.00020	0.00009	72.00	0.00915				
WOD 4004	0.00020	0.00008	102.90	0.00837				
WOD 4006	0.00025	0.00024	44.72	0.01106		0.00000	347.00	0.00138
WOD 4007	0.00017							
WOD 4008	0.00016	0.00010	50.52	0.00304		0.00017	15.00	0.00250
WOD 4009	0.00009	0.00009	36.56	0.00343				
WOD 4010	0.00026	0.00013	56.55	0.01473				
WOR 8011	0.00180	0.00039	121.88	0.04242	0.00118	0.00011	51.78	0.00554
WOR 8013	0.00247	0.00053	81.09	0.04137	0.00079	0.00078	241.56	0.18748
WOR 8017	0.00182	0.00163	65.21	0.09589		0.00003	65.50	0.00177
WOR 8018	0.00042	0.00019	120.65	0.02589	0.00253	0.00171	33.56	0.05726
WOR 8019	0.00123	0.00044	71.42	0.01697	0.00103	0.00018	6.00	0.00108
WOR 8021	0.00066	0.00023	213.28	0.02546		0.00004	205.86	0.00770
WOR 8022	0.00172	0.00039	99.97	0.03769		0.00028	39.80	0.01121
WOR 8024	0.00021	0.00004	320.00	0.01985	0.00060	0.00001	73.12	0.00049
WOR 8025	0.00220	0.00131	117.25	0.21998	0.00018	0.00034	46.94	0.01607
WOR 8034	0.00013	0.00004	84.33	0.00344	0.00037	0.00006	91.06	0.00591
WOR 8035	0.00103	0.00014	74.28	0.00648	0.00036	0.00009	65.71	0.00562
WOR 8037	0.00023	0.00005	205.68	0.01092	0.00022	0.00015	81.03	0.01209
WOR 8039	0.00284	0.00050	78.02	0.02839		0.00013	79.90	0.01037
WRY 4001		0.00018	124.36	0.02382		0.00003	253.00	0.00705
WRY 4005		0.00019	208.72	0.04428				
WRY 4006		0.00014	169.00	0.02343				
WRY 4010		0.00029	90.96	0.03278				
WRY 4011		0.00020	265.33	0.03944		0.00095	84.87	0.08080
WYN 4001	0.00033	0.00017	235.50	0.00272	0.00021	0.00010	118.00	0.01146
WYN 4002	0.00089	0.00086	54.65	0.05393	0.00044	0.00006	168.00	0.01003
WYN 4003	0.00086	0.00029	94.90	0.02237		0.00003	176.00	0.00448
WYN 4004	0.00056	0.00084	11.01	0.00973				
WYN 4005	0.00043	0.00034	100.00	0.02802	0.00076			
WYN 4006	0.00056					0.00001	62.00	0.00044
WYN 4007		0.00013	297.67	0.01586	0.00018			
WYN 4008	0.00017	0.00042	22.80	0.01149				
WYN 4009	0.00028	0.00030	68.92	0.02062		0.00002	174.00	0.00284
WYN 4010		0.00041	238.50	0.04976		0.00037	111.31	0.04111
YRD 8011	0.00017	0.00006	65.98	0.00208	0.00022	0.00004	130.25	0.00565
YRD 8012	0.00057	0.00030	98.22	0.03054	0.00064	0.00017	89.53	0.01479
YRD 8014	0.00076	0.00011	6.00	0.00068	0.00031	0.00006	41.59	0.00262
YRD 8021	0.00025	0.00027	62.77	0.01610	0.00103	0.00014	27.75	0.00382
YRD 8023	0.00072	0.00020	141.65	0.00763	0.00077	0.00020	13.66	0.00268
YRD 8024	0.00045	0.00057	44.61	0.02372	0.00094	0.00066	52.69	0.03500

Danielle Lopez
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PSEG Services Corporation

March 16, 2023

VIA ELECTRONIC MAIL ONLY
Carmen Diaz, Acting Secretary
Board of Public Utilities
44 South Clinton Avenue, 1st Flr.
P.O. Box 350
Trenton, New Jersey 08625-0350

Re: NEXT PHASE OF THE PSE&G GAS SYSTEM MODERNIZATION PROGRAM MONTHLY REPORT – FEBRUARY 2023

Dear Acting Secretary Diaz:

Enclosed for filing is the letter and enclosures providing Public Service Electric & Gas Company's (PSE&G's) monthly report for February 2023 on its Next Phase of the Gas System Modernization Program (GSMP II or the Program).

The GSMP II was approved by a Board Order dated May 22, 2018 in BPU Docket No. GR17070776. That Order adopted a Stipulation pursuant to which PSE&G is operating the Program. This report is filed pursuant to paragraph 43 of that Stipulation and is designed to address the first four items contained in Attachment C to that Stipulation.

The first three items are addressed in the attached materials. With regard to item 4, there were no funds or credits received from the United States government, the State of New Jersey, a county or a municipality, for work related to any of the Program projects.

Consistent with the Order issued by the Board in connection with In the Matter of the New Jersey Board of Public Utilities' Response to the COVID-19 Pandemic for a Temporary Waiver of Requirements for Certain Non-Essential Obligations, BPU Docket No. EO20030254, Order dated March 19, 2020, this document is being filed electronically with the Secretary of the Board and the Division of Rate Counsel. No paper copies will follow.

Very truly yours,

Danielle Lopez

cc - E-Mail Only:
Robert Brabston
Malike Cummings

Mike Kammer
Ilene Lampitt
Brian Lipman
Karen Forbes
Matko Illic
Maura Caroselli
Loni Diaz
Carol Artale
Pamela Owen

PSE&G - GAS SYSTEM MODERNIZATION PROGRAM
ATTACHMENT C - MONTHLY REPORT

1) PSE&G's overall approved GSMP II Rate Mechanism and Stipulated Base capital budget broken down by major categories, both budgeted and actual amounts.

GSMP II Major Project Categories	Overall Approved Program	Feb PTD Budget	Feb PTD Actual
Replacement Main $	$ 1,087,400,000	$ 1,087,400,000	$ 1,174,382,233
Replacement Service $	$ 482,000,000	$ 482,000,000	$ 403,567,244
Regulator Elimination $	$ 5,600,000	$ 5,600,000	$ 5,287,825
Total	$ 1,575,000,000	$ 1,575,000,000	$ 1,583,237,302

Stipulated Base II Major Project Categories	Overall Approved Program	Feb PTD Budget	Feb PTD Actual
Replacement Main $	$ 217,200,000	$ 217,200,000	$ 191,408,375
Replacement Service $	$ 34,800,000	$ 34,800,000	$ 45,947,312
Large Diameter HP Joints	$ 18,000,000		$ -
GSMP Meter Reconstruction $	$ 30,000,000	$ 48,000,000	$ 68,146,528
Total	$ 300,000,000	$ 300,000,000	$ 305,502,215

2) b. Expenditures incurred to date and amounts transferred to plant in-service, by project. Expenditures broken down by internal labor, materials, and other costs. Internal labor hours broken down by regular hours and overtime hours.

Expenditures Incurred To Date GSMP II Projects	Feb PTD Actual Internal Labor $	Feb PTD Actual Material $	Feb PTD Actual Other $	Feb PTD Actual Total $	Amount to Plant In-Service
Replacement Main	$ 209,490,466	$ 74,780,643	$ 890,111,124	$ 1,174,382,233	$ 1,122,729,271
Replacement Service	$ 76,542,273	$ 32,920,978	$ 294,103,993	$ 403,567,244	$ 403,397,947
Regulator Elimination	$ 1,180,725	$ 193,248	$ 5,094,577	$ 5,287,825	$ 2,242,714
Total	$ 287,213,464	$ 107,894,868	$ 1,189,309,694	$ 1,583,237,302	$ 1,528,369,931

GSMP II Internal Labor Hours	
Internal Labor - Regular Hours	2,935,078
Internal Labor - Overtime Hours	965,204

Expenditures Incurred To Date Stipulated Base II Projects	Feb PTD Actual Internal Labor $	Feb PTD Actual Material $	Feb PTD Actual Other $	Feb PTD Actual Total $	Amount to Plant In-Service
Replacement Main	$ 27,215,050	$ 18,948,831	$ 145,244,493	$ 191,408,375	$ 182,477,887
Replacement Service	$ 8,498,426	$ 872,286	$ 36,576,600	$ 45,947,312	$ 45,921,442
Large Diameter HP Joints	$ -	$ -	$ -	$ -	$ -
GSMP Meter Reconstruction	$ 22,302,357	$ 5,832,690	$ 40,011,481	$ 68,146,528	$ 68,146,528
Total	$ 58,015,834	$ 25,653,808	$ 221,832,574	$ 305,502,215	$ 296,545,856

Stip Base II Internal Labor Hours	
Internal Labor - Regular Hours	581,910
Internal Labor - Overtime Hours	216,054

PSE&G - GAS SYSTEM MODERNIZATION PROGRAM
ATTACHMENT C - MONTHLY REPORT

REPORT DATE: February 2023
2a - Description of projects
2c - Projected and actual miles of main installed
2d - Projected and actual number of services installed

	Project	Sub-Project	Project Completion Date	Units	Size Installed	Material Installed	2019 Quantity Completed	2020 Quantity Completed	2021 Quantity Completed	2022 Quantity Completed	Projected Quantity Jan 2023	Actual Quantity Jan 2023	Projected Quantity Feb 2023	Actual Quantity Feb 2023	2023 Estimated Quantity	Quantity Completed 2023 Year To Date	Total Program Quantity Completed To Date
GAS SYSTEM MODERNIZATION PROGRAM	Replace Facilities Blanket	Replacement Main	Dec-23	Feet of Main	2"	Plastic	746,745	1,166,556	1,060,930	386,873	2,416	42,005	957	54,332	3,372	96,337	3,457,441
					4"	Plastic	246,779	335,330	277,288	148,203	756	5,817	322	13,273	1,077	19,090	1,026,690
					6"	Plastic	80,521	115,300	105,458	31,856	395	6,192	165	257	560	6,449	339,584
					8"	Plastic	34,576	40,792	28,722	13,494	0	1,560	20	24	21	1,584	119,168
					12"	Plastic	-	-	-	-					-	-	-
					12"	Steel	-	17,397	5,021	846					-	-	23,264
					16"& 20"	Steel	-	5,889	7,531	8,099					-	-	21,519
	Replace Facilities Blanket	**Replacement Main**	**N/A**	**Feet of Main**	**N/A**	**N/A**	**1,108,621**	**1,681,264**	**1,484,950**	**589,371**	**3,566**	**55,574**	**1,464**	**67,886**	**5,030**	**123,460**	**4,987,666**
	Replace Facilities Blanket	Replacement Service	Dec-23	Services Replaced	≤ 2"	Plastic	14,653	18,218	27,320	20,456	1,151	626	994	705	2,145	1,331	81,978
					>2"	Plastic	2	4	4	6					-	-	16
	Replace Facilities Blanket	**Replacement Service**	**N/A**	**Services Replaced**	**N/A**	**N/A**	**14,655**	**18,222**	**27,324**	**20,462**	**1,151**	**626**	**994**	**705**	**2,145**	**1,331**	**81,994**
	Abandon Facilities Blanket	Abandon Regulator	Dec-23	Regulators Abandoned	N/A	N/A	22	32	59	35		3		9		12	160
	Abandon Facilities Blanket	**Abandon Regulator**	**N/A**	**Regulators Abandoned**	**N/A**	**N/A**	**22**	**32**	**59**	**35**		**3**		**9**		**12**	**160**
STIPULATED BASE	Replace Facilities Blanket	Replacement Main	Dec-23	Feet of Main	2"	Plastic	79,126	78,746	94,927	202,853	1,146	21,372	370	27,032	1,515	48,404	504,056
					4"	Plastic	30,415	19,023	20,923	88,704	462	4,004	341	3,575	803	7,579	166,644
					6"	Plastic	9,773	3,061	11,889	12,326	463	35	278	2,172	741	2,207	39,256
					8"	Plastic	277	284	775	15,097	201	904	17	2,054	218	2,958	19,391
					8"	Steel	-	-	-	-	-	-	-	-	-	-	-
					12"	Plastic	2	-	-	9	-	110	-	79	-	189	200
					12"	Steel	171	12,487	4,984	11,537	1,525	-	354		1,879	-	29,179
					16"	Steel	100	-	-	2,595	561	-	790	1,324	1,352	1,324	4,019
					20"	Steel	-	-	20	35	-	-	-		-	-	55
					24"	Steel	-	-	-	572	-	-	-		-	-	572
					42"	Steel	700	597	1,900	-	-	-	-		-	-	3,197
	Replace Facilities Blanket	**Replacement Main**	**N/A**	**Feet of Main**	**N/A**	**N/A**	**120,564**	**114,198**	**135,418**	**333,728**	**4,357**	**26,425**	**2,151**	**36,236**	**6,508**	**62,661**	**766,569**
	Replace Facilities Blanket	Replacement Service	Dec-23	Services Replaced	≤ 2"	Plastic	1,393	1,107	932	4,678	124	519	138	573	262	1,092	9,202
					>2"	Plastic	-	-	-	-					-	-	-
	Replace Facilities Blanket	**Replacement Service**	**N/A**	**Services Replaced**	**N/A**	**N/A**	**1,393**	**1,107**	**932**	**4,678**	**124**	**519**	**138**	**573**	**262**	**1,092**	**9,202**
	Large Diameter High Pressure Joints	Joints	Dec-23	HP Joints Encapsulated	N/A	N/A	-	-	-	-					-	-	-
	Large Diameter High Pressure Joints	**Joints**	**N/A**	**HP Joints Encapsulated**	**N/A**	**N/A**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**

Project Timeline			2019												2020												2021												2022												2023												2024											
Activity Name	**Start**	**Finish**	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
GSMP II																																																																											
GSMP Work	1/1/2019	5/31/2023																																																																										
GSMP Completion & Restoration Work	1/1/2024	6/30/2014																																																																										
Stipulated Base																																																																											
Year 1	1/1/2019	12/31/2019																																																																										
Year 2	1/1/2020	12/31/2020																																																																										
Year 3	1/1/2021	12/31/2021																																																																										
Year 4	1/1/2022	12/31/2022																																																																										
Year 5	1/1/2023	12/31/2023																																																																										

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PSEG Services Corporation

March 28, 2024

VIA ELECTRONIC MAIL ONLY
Sherri Golden, Board Secretary
Board of Public Utilities
44 South Clinton Avenue, 1st Flr.
P.O. Box 350
Trenton, New Jersey 08625-0350

Re: NEXT PHASE OF THE PSE&G GAS SYSTEM MODERNIZATION PROGRAM ("GSMP II EXTENSION") MONTHLY REPORT – JANUARY 2024

Dear Secretary Golden:

Attached hereto is Public Service Electric and Gas Company's ("PSE&G") monthly report for January 2024 on its Next Phase of the Gas System Modernization Program ("GSMP II").

GSMP II was approved by the New Jersey Board of Public Utilities (the "Board") by Order dated May 22, 2018 in BPU Docket No. GR17070776. That Order adopted a Stipulation pursuant to which PSE&G executed GSMP II. Subsequently on October 11, 2023, the Board issued an Order adopting a Stipulation to extend GSMP II under the terms and conditions described in the Stipulation ("GSMP II Extension" or the "Program"). This report is being filed pursuant to paragraph 41 of this Stipulation and is designed to address the first four items contained in its Attachment C.

The first three items are addressed in the attached materials. With regard to item 4, there were no funds or credits received from the United States government, the State of New Jersey, a county or a municipality, for work related to any of the Program projects.

Consistent with the Order issued by the Board in connection with In the Matter of the New Jersey Board of Public Utilities' Response to the COVID-19 Pandemic for a Temporary Waiver of Requirements for Certain Non-Essential Obligations, BPU Docket No. EO20030254, Order dated March 19, 2020, this document is being filed electronically with the Secretary of the Board and the Division of Rate Counsel. No paper copies will follow.

Very truly yours,

Danielle Lopez

cc - E-Mail Only:
Robert Brabston
Stacy Peterson
Ilene Lampitt
Brian Lipman
Karen Forbes
Matko Illic
Maura Caroselli
Loni Diaz
Carol Artale
Pamela Owen

PSE&G - GAS SYSTEM MODERNIZATION PROGRAM
ATTACHMENT C - MONTHLY REPORT

1) PSE&G's overall approved GSMP II Extension Rate Mechanism and Stipulated Base capital budget broken down by major categories, both budgeted and actual amounts.

GSMP II Extension Major Project Categories	Overall Approved Program	Jan PTD Budget	Jan PTD Actual
Replacement Main $	$ 599,808,000	$ 1,388,781	$ 1,137
Replacement Service $	$ 148,895,294	$ 232,918	$ -
Regulator Elimination $	$ 3,296,705	$ -	$ -
Total	$ 752,000,000	$ 1,621,699	$ 1,137

Stipulated Base II Major Project Categories	Overall Approved Program	Jan PTD Budget	Jan PTD Actual
Replacement Main $	$ 108,500,000	$ 255,805	$ -
Replacement Service $	$ 24,933,000	$ 105,754	$ -
Large Diameter HP Joints $	$ -	$ -	$ -
GSMP Meter Reconstruction $	$ 16,967,000	$ 46,246	$ -
Total	$ 150,400,000	$ 407,805	$ -

2) b. Expenditures incurred to date and amounts transferred to plant in-service, by project. Expenditures broken down by internal labor, materials, and other costs. Internal labor hours broken down by regular hours and overtime hours.

Expenditures Incurred To Date GSMP II Ext. Projects	Jan PTD Actual Internal Labor $	Jan PTD Actual Material $	Jan PTD Actual Other $	Jan PTD Actual Total $	Amount to Plant In-Service
Replacement Main	$ 807	$ -	$ 330	$ 1,137	$ 1,137
Replacement Service	$ -	$ -	$ -	$ -	$ -
Regulator Elimination	$ -	$ -	$ -	$ -	$ -
Total	$ 807	$ -	$ 330	$ 1,137	$ 1,137

GSMP II Internal Labor Hours	
Internal Labor - Regular Hours	12
Internal Labor - Overtime Hours	-

Expenditures Incurred To Date Stipulated Base II Ext. Projects	Jan PTD Actual Internal Labor $	Jan PTD Actual Material $	Jan PTD Actual Other $	Jan PTD Actual Total $	Amount to Plant In-Service
Replacement Main	$ -	$ -	$ -	$ -	$ -
Replacement Service	$ -	$ -	$ -	$ -	$ -
Large Diameter HP Joints	$ -	$ -	$ -	$ -	$ -
GSMP Meter Reconstruction	$ -	$ -	$ -	$ -	$ -
Total	$ -	$ -	$ -	$ -	$ -

Stip Base II Internal Labor Hours	
Internal Labor - Regular Hours	-
Internal Labor - Overtime Hours	-

PSE&G - GAS SYSTEM MODERNIZATION PROGRAM
ATTACHMENT C - MONTHLY REPORT

REPORT DATE: January 2024
2a - Description of projects
2c - Projected and actual miles of main installed
2d - Projected and actual number of services installed

	Project	Sub-Project	Project Completion Date	Units	Size Installed	Material Installed	Projected Quantity Jan 2024	Actual Quantity Jan 2024	2024 Estimated Quantity	2024 Quantity Completed	2025 Estimated Quantity	2025 Quantity Completed	2026 Estimated Quantity	2026 Quantity Completed	Total Program Quantity Completed To Date
GAS SYSTEM MODERNIZATION PROGRAM	Replace Facilities Blanket	Replacement Main	May-26	Feet of Main	2"	Plastic	-	-	**598,006**	**-**	**728,857**	**-**	**-**	**-**	**-**
					4"	Plastic	-	-	**177,556**	**-**	**202,051**	**-**	**-**	**-**	**-**
					6"	Plastic	-	-	**57,593**	**-**	**70,295**	**-**	**-**	**-**	**-**
					8"	Plastic	-	-	**35,904**	**-**	**31,502**	**-**	**-**	**-**	**-**
					12"	Plastic	-	-	**85,003**	**-**	**89,503**	**-**	**-**	**-**	**-**
					12"	Steel	-	-	**-**	**-**	**635**	**-**	**-**	**-**	**-**
					16"& 20"	Steel	-	-	**26,750**	**-**	**8,341**	**-**	**-**	**-**	**-**
	Replace Facilities Blanket	**Replacement Main**	**N/A**	**Feet of Main**	**N/A**	**N/A**	**-**	**-**	**980,812**	**-**	**1,131,184**	**-**	**-**	**-**	**-**
	Replace Facilities Blanket	Replacement Service	May-26	Services Replaced	≤ 2"	Plastic	-		**9,258**	**-**	**13,908**	**-**	**1,243**	**-**	**-**
					>2"	Plastic	-		**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Replace Facilities Blanket	**Replacement Service**	**N/A**	**Services Replaced**	**N/A**	**N/A**	**-**	**-**	**9,258**	**-**	**13,908**	**-**	**1,243**	**-**	**-**
	Abandon Facilities Blanket	Abandon Regulator	May-26	Regulators Abandoned	N/A	N/A		-	**29**	**-**	**44**	**-**		**-**	**-**
	Abandon Facilities Blanket	**Abandon Regulator**	**N/A**	**Regulators Abandoned**	**N/A**	**N/A**	**-**	**-**		**-**		**-**		**-**	**-**
STIPULATED BASE	Replace Facilities Blanket	Replacement Main	Jun-26	Feet of Main	2"	Plastic			**55,776**	**-**	**188,702**	**-**	**-**	**-**	**-**
					4"	Plastic			**20,465**	**-**	**49,006**	**-**	**-**	**-**	**-**
					6"	Plastic			**3,486**	**-**	**10,400**	**-**	**-**	**-**	**-**
					8"	Plastic			**609**	**-**	**539**	**-**	**-**	**-**	**-**
					8"	Steel			**-**	**-**	**-**	**-**	**-**	**-**	**-**
					12"	Plastic			**-**	**-**	**-**	**-**	**-**	**-**	**-**
					12"	Steel			**19,622**	**-**	**28,721**	**-**	**-**	**-**	**-**
					16"	Steel			**-**	**-**	**-**	**-**	**-**	**-**	**-**
					20"	Steel			**-**	**-**	**-**	**-**	**-**	**-**	**-**
					24"	Steel				**-**	**4,315**	**-**	**-**	**-**	**-**
					42"	Steel			**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Replace Facilities Blanket	**Replacement Main**	**N/A**	**Feet of Main**	**N/A**	**N/A**	**-**	**-**	**99,958**	**-**	**281,682**	**-**	**-**	**-**	**-**
	Replace Facilities Blanket	Replacement Service	Jun-26	Services Replaced	≤ 2"	Plastic	-	-	**739**	**-**	**2,687**	**-**	**1,100**	**-**	**-**
					>2"	Plastic	-		**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Replace Facilities Blanket	**Replacement Service**	**N/A**	**Services Replaced**	**N/A**	**N/A**	**-**	**-**	**739**	**-**	**2,687**	**-**	**1,100**	**-**	**-**
	Large Diameter High Pressure Joints	Joints	Jun-26	HP Joints Encapsulated	N/A	N/A			**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Large Diameter High Pressure Joints	**Joints**	**N/A**	**HP Joints Encapsulated**	**N/A**	**N/A**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**

Project Timeline			2024												2025												2026											
Activity Name	**Start**	**Finish**	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
GSMP II Extension																																						
GSMP Work																																						
GSMP Completion & Restoration Work																																						
Stipulated Base																																						
Year 1																																						
Year 2																																						
Year 3																																						
Year 4																																						
Year 5																																						

Danielle Lopez
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Law Department
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PSEG
Services Corporation

August 31, 2023

VIA ELECTRONIC MAIL ONLY
Sherri Golden, Board Secretary
Board of Public Utilities
44 South Clinton Avenue, 1st Floor
P.O. Box 350
Trenton, New Jersey 08625-0350

Re: Infrastructure Advancement Program – Semi Annual Report January 2023 to June 2023

Dear Secretary Golden:

Enclosed for filing is Public Service Electric and Gas Company's semi-annual Infrastructure Advancement Program report for the period January 2023 to June 2023.

The Infrastructure Advancement Program ("IAP") was addressed by a Board Order dated June 29, 2022 (June 29th Order) in Docket Nos. EO2111211 and GO21112121. That Order adopted a Stipulation pursuant to which PSE&G is operating the program known as IAP.

Paragraph 26 of that Stipulation requires reports on:

- The estimated total quantity of work and the quantity completed to date or, if the project work cannot be quantified with numbers, the major tasks completed, e.g., design phase, material procurement, permit gathering, phases of construction;
- The forecasted and actual IAP costs-to-date for the reporting period and for the Program-to-date; where project work is identified by major category (with the actual variances from forecasted amounts expressed in dollar and percentage terms);
- The estimated IAP Project completion date, and estimated completion dates for each IAP subprogram and the Program as a whole;
- Anticipated changes to IAP Projects, if any;
- Actual capital expenditures made by the utility in the normal course of business on similar project work, identified by major category; and
- Any other performance metric concerning the IAP required by the Board.
- For circuits improved within the Spacer Cable Conversion Project, Lashed Cable Replacement Project, and Spacer Upgrade Project, PSE&G will provide System Average Interruption Duration Index ("SAIDI") results for Major Event11 performance at the circuit level (redacted and confidential unredacted) for circuits affected by a Major Event during the reporting period and at the operating area level and system wide. The SAIDI results will be reported and measured against a baseline that reflects performance for each circuit

under Major Event conditions for the prior five (5) years from the Program start date. The report will include the SAIDI results at the circuit level for the reporting period.

- For circuits improved upon within the Spacer Cable Conversion Project, Lashed Cable Replacement Project, Spacer Upgrade Project, and Conventional Underground Cable Replacement Project, PSE&G will include non-Major Event performance (where a non-Major Event excludes all "Major Events" as defined at N.J.A.C. 14:5-1.2) including circuit designation (information to be provided redacted and confidential unredacted), that reflects non-Major Event conditions for the reporting period. In addition to SAIDI, the Company will report non-Major Event data for Customer Average Interruption Duration Index ("CAIDI") and System Average Interruption Frequency Index ("SAIFI"). The SAIDI results will be reported and measured against a baseline that reflects performance for each circuit under non-Major Event conditions for the prior five (5) years from the Program start date.

The reporting requirements listed in paragraph 26 of the Stipulation are addressed by the enclosed materials.

Please contact the undersigned with any questions or concerns.

Very truly yours,

Danielle Lopez

cc: ***Via Email only***
Brian Lipman
David Wand
Maura Caroselli
Karen Forbes
Stacy Peterson
Malike Cummings
Matko Illic
Caroline Vachier

INFRASTRUCTURE ADVANCEMENT PROGRAM

SEMI-ANNUAL REPORT

TO THE

BOARD OF PUBLIC UTILITIES

Reporting period: January 2023 to June 2023

Table of Contents

Metric 1 – Estimated Quantity of Work

For each Infrastructure Advancement Subprogram:

A. Estimated quantity of work

i. **For the Entire Subprogram**

ii. **Planned to date (based on forecasted estimates at the beginning of the reporting period)**

B. Quantity completed to date or, if the project cannot be quantified with numbers, the major tasks completed, e.g. design phase, material procurement, permit gathering, phases of construction;

NOTE: This quarterly report covers Program to date performance up to the 1st half of 2023 period - January 1, 2023 through June 30, 2023. At the end of the period, all subprograms/projects have advanced through varying stages of planning authorization and execution and completion. Where applicable, forecasted and actual units of work and/or major tasks completed are provided.

ELECTRIC PROGRAM

ELECTRIC INSIDE PLANT

Electric Life Cycle Stations

A. Estimated Quantity of Work:

i. **Project:** The estimated quantity of work for this Subprogram includes the modernization of 4kV switchgear at five (5) electric distribution 69/4kV substations, including replacing and upgrading breakers, disconnects, reactors, regulators, relays, and other infrastructure. The following five (5) substations are included within the project:

- Fortieth Street
- McLean Blvd
- Teaneck
- Tonnelle Ave
- Totowa

ii. **Planned to Date:** Major work planned to the end of June 2023:

Fortieth:

- Major Equipment POs issued
- KDR package approved
- Preliminary Vendor Drawings issued
- Detailed Engineering Start
- L&P package issued

McLean:

- Major Equipment POs issued
- KDR package approved
- Preliminary Vendor Drawings issued

Teaneck:

- Major Equipment POs issued
- KDR package approved
- Preliminary Vendor Drawings Issued

Tonnelle:

- Major Equipment POs issued
- KDR package approved
- Preliminary Vendor Drawings issued
- L&P package issued

Totowa:

- Major Equipment POs issued
- KDR package approved
- L&P package issued
- SCD permit issued
- Preliminary Vendor Drawings Issued

B. Quantity of Work Completed to Date:

Fortieth:

- Major Equipment POs issued
- KDR package approved
- Preliminary Vendor Drawings Issued
- Detailed Engineering Start
- L&P package issued

McLean:

- A&E contract and PO issued for detailed engineering
- Major Equipment POs issued
- KDR package approval
- Preliminary Vendor Drawings Issued

Teaneck:

- A&E contract and PO issued for detailed engineering
- Major Equipment POs issued
- KDR package approved
- Preliminary Vendor Drawings Issued

Tonnelle:

- A&E contract and PO issued for detailed engineering
- Major Equipment POs issued
- KDR package approved
- Preliminary Vendor Drawings Issued

Totowa:

- Major Equipment POs issued
- KDR package approval
- L&P package issued
- SCD permit issued
- Preliminary Vendor Drawings Issued

Electric Stations 26kV Oil Circuit Breakers (OCB) Replacement

A. Estimated Quantity of Work:

i. **Project:** The estimated quantity of work for this Subprogram includes the replacement of 36 Oil Circuit Breakers.

ii. **Planned to Date:** Major work planned to the end of June 2023:

Replacement of six 26kV Oil Circuit Breakers.

B. Quantity of Work Completed to Date:

Replaced four 26kV Oil Circuit Breakers.

ELECTRIC OUTSIDE PLANT

Electric Lashed Cable Replacement

A. Estimated Quantity of Work:

i. **Project:** The estimated quantity of work for this Subprogram includes replacing approximately 8 miles of existing lashed primary cable construction with spacer cable construction that is designed to a higher and more resilient standard.

ii. **Planned to Date:** Major work planned to the end of June 2023:

- Replacement of 1 mile of lashed primary cable with spacer cable.

B. Quantity of Work Completed to Date:

- January 2023 to June 2023 – Replaced 0.79 circuit miles.
- Program to date - Replaced 1.09 circuit miles.

Electric Open Wire to Spacer

A. Estimated Quantity of Work:

i. **Project:** This project will replace aging, 3-phase, open wire construction (cross arm and armless) with PSE&G's current standard, spacer cable type construction. Additionally, replacement work will also require the upgrading of auxiliary equipment as part of the conversion.

ii. **Planned to Date:** Major work planned to the end of June 2023:

- No work currently planned. This program does not begin until 2024.

B. Quantity of Work Completed to Date:

- January 2023 to June 2023 – Replaced 10.21 circuit miles.
- Program to date - Replaced 10.21 circuit miles.

Electric Spacer Hardware Upgrades

A. Estimated Quantity of Work:

i. **Project:** The estimated quantity of work for this Subprogram includes 160 miles of existing spacer type construction. This project will replace aging spacer units along existing construction with new hardware that is designed to a higher and more resilient standard. Also, worn, defective, or metallic tangent brackets will be replaced with a newer fiberglass tangent bracket. Messenger ground wire will be installed at every pole if not currently installed.

ii. **Planned to Date:** Major work planned to the end of June 2023:

- Completion of 40 circuit miles.

B. Quantity of Work Completed to Date:

- January 2023 to June 2023 – Completed 57 circuit miles.
- Program to Date – Completed 79 circuit miles.

Electric Conventional Underground (CUG) Cable Replacement

A. Estimated Quantity of Work:

i. **Project:** The estimated quantity of work for this Subprogram includes the replacement of 34 miles of conventional underground cable.

ii. **Planned to Date:** Major work planned to the end of June 2023:

- Civil work to repair crushed conduit.
- Complete all CUG's in Palisades & Central.

B. Quantity of Work Completed to Date:

- January to June 2023 – Replaced 1.81 circuit miles of cable.
- Program to date – Replaced 6.58 circuit miles of cable.

Electric Buried Underground Distribution (BUD) Cable Replacement

A. Estimated Quantity of Work:

i. **Project:** The estimated quantity of work for this Subprogram includes the replacement of 110 miles of BUD cable.

ii. **Planned to Date:** Major work planned to the end of June 2023:

- No Major Activities Planned.

B. Quantity of Work Completed to Date:

- January to June 2023 – Replaced 0.11 circuit miles of cable.
- Program to date – Replaced 0.11 circuit miles of cable.

Electric Capacitor Bank Upgrades

A. Estimated Quantity of Work:

i. **Project:** The estimated quantity of work for this Subprogram includes the replacement of 479 capacitors. The following stations have been identified for this project:

- Palisades Div. – Penhorn (76)
- Metropolitan Div. – West Caldwell (169)
- Central Div. – Pierson (95)
- Southern Div. – Levittown (139)

ii. **Planned to Date:** Major work planned to the end of June 2023:

- PO for 80 units to be issued by early May 2023.

B. **Quantity of Work Completed to Date:** Major Activities completed by end of June 2023:

- PO issued in April for delivery of 80 units in 2023.
- Completed station/circuit testing for 604 existing capacitors.

Electric Open Wire Secondary Upgrades

A. Estimated Quantity of Work:

i. **Project:** The estimated quantity of work for this Subprogram includes the replacement of approximately 50 miles over 139 circuits of Open Wire Secondary across the entire PSEG service territory with new secondary cable that have higher capacity and are more resistant to storms and tree contacts. In addition, in areas with lower rated 25kVa transformers in place, new larger 50kVa capacity transformer will be installed.

ii. **Planned to Date:** Major work planned to the end of June 2023:

- Planned to complete 16.8 miles through June out of total estimate of 37 miles for the year 2023.

B. Quantity of Work Completed to Date:

2023 construction completion metrics by division:

- Palisades –
  - 24 circuits worked
  - 60,682 feet of wire replaced
- Metropolitan –
  - 47 circuits worked
  - 45,610 feet of wire replaced
- Central –
  - 16 circuits worked
  - 29,819 feet of wire replaced
- Southern –
  - 18 circuits worked
  - 51,123 feet of wire replaced

GAS METERING & REGULATION (M&R) STATIONS

A. Estimated Quantity of Work:

i. **Project:** The estimated quantity of work for this Subprogram includes implementation of life cycle upgrades 4 Gas M&R Stations (Brooklawn, Hamilton, Hanover, and Hillsborough) listed in the Program Stipulation and life cycle upgrades at all 4 M&R Stations as part of the IAP Gas Subprogram.

ii. **Planned to Date:** Major work planned to the end of June 2023:

- Award Detailed Design Engineering to A/E firms for all 4 Stations.
- Start Detailed Design Engineering for all 4 Stations.
- Award material procurement PO to A/E firms (Brooklawn & Hillsborough)
- Finalize Piping & Instrumentation Diagram (P&ID) drawings packages (Brooklawn & Hillsborough)
- Start Site Plan drawings packages (Brooklawn & Hillsborough)

B. Quantity of Work Completed to Date:

- Started Detailed Design Engineering for all 4 stations.
- Completed P&ID drawings packages (Brooklawn & Hillsborough)
- Started KDR drawings package review (Brooklawn & Hillsborough)
- Started Interconnect Agreement with gas pipeline operators (Brooklawn & Hillsborough)
- Completed Site Plan drawings package (Brooklawn)
- Started Site Plan drawings package (Hillsborough)

Metric 2 – Estimated Program and Subprogram Completion Dates

The estimated IAP project completion date, and estimated completion dates for each IAP sub-program and the Program as a whole.

PROGRAM

Program	Subprogram	Forecast In-Service	Timeline for Completion*
IAP	Electric & Gas	Jun-26	Dec-26

SUBPROGRAMS

Program	Subprogram	Forecast In-Service	Timeline for Completion*
Electric	Life Cycle Projects	Sep-25	Mar-26
Electric	26kV Oil Circuit Breaker Replacement	Jun-26	Dec-26
Electric	Lashed Cable	May-26	Nov-26
Electric	Open Wire to Spacer	Dec-25	Jun-26
Electric	Spacer Hardware	Dec-23	Jun-24
Electric	CUG Cable	Jun-26	Dec-26
Electric	Capacitor Bank Upgrades	Jun-26	Dec-26
Electric	Open Wire Secondary Upgrades	Dec-23	Jun-24
Electric	BUD Cable	Jun-26	Dec-26
Gas	M&R Stations	Oct-25	Jul-26

*** Timeline for Completion is defined by the completion date of project closeout report.**

ELECTRIC INSIDE PLANT

Electric Life Cycle Stations

Project	Forecast In-Service	Timeline for Completion	Updates	Expected Changes
Tonnelle Ave Substation	Jan-25	Jul-25		
40th Street Substation	Feb-25	Aug-25		
Totowa Substation	Mar-25	Sep-25		
McLean Blvd Substation	Sep-25	Mar-26		
Teaneck Substation	Sep-25	Mar-26		

Electric Stations 26kV OCB Replacement

Project	Forecast In-Service	Timeline for Completion	Updates	Expected Changes
26kV OCB Replacement	Jun-26	Dec-26		

ELECTRIC OUTSIDE PLANT

Electric Lashed Cable Replacement

Project	Forecast In-Service	Timeline for Completion	Updates	Expected Changes
Lashed Cable Replacement	May-26	Nov-26		

Electric Open Wire to Spacer

Project	Forecast In-Service	Timeline for Completion	Updates	Expected Changes
Open Wire to Spacer	Dec-25	Jun-26		

PSEG

Electric Spacer Hardware Upgrades

Project	Forecast In-Service	Timeline for Completion	Updates	Expected Changes
Spacer Hardware Upgrades	Dec-23	Jun-24		

Electric Conventional Under Ground (CUG) Cable Replacement

Project	Forecast In-Service	Timeline for Completion	Updates	Expected Changes
CUG Cable Replace	Jun-26	Dec-26		

Electric Buried Underground Distribution (BUD) Cable Replacement

Project	Forecast In-Service	Timeline for Completion	Updates	Expected Changes
Open Wire Secondary Upgrades	Dec-23	Jun-24		

Electric Capacitor Bank Upgrades

Project	Forecast In-Service	Timeline for Completion	Updates	Expected Changes
Capacitor Bank Upgrades	Jun-26	Dec-26		

Electric Open Wire Secondary Upgrades

Project	Forecast In-Service	Timeline for Completion	Updates	Expected Changes
BUD Cable Replacement	Jun-26	Dec-26		

PSEG

GAS METERING & REGULATION (M&R) STATIONS

Project	Forecast In-Service	Timeline for Completion	Updates	Expected Changes
Brooklawn M&R	Nov-24	Jul-25		
Hillsborough M&R	Nov-24	Jul-25		
Hamilton M&R	Oct-25	Jul-26		
Hanover M&R	Oct-25	Jul-26		

Metric 3 – Circuit Performance - SAIDI/SAIFI/CAIDI

This metric includes data for completed circuits involved in the Major and Non-Major events occurred in the 1st half of 2023, from January 1st, 2023 to June 30th, 2023.

A. Reports included for **Major events** in 1st half of 2023 –

No Major Events occurred in the reporting period.

B. Reports included for **Non-Major Events** in 1st half of 2023 –

M3.B.a Conventional Underground Cable Replacement.
M3.B.b Spacer Hardware Upgrades.
M3.B.c Lashed Cable Replacement.
M3.B.d Open Wire to Spacer.

Detailed tables for this metric are included at the end of this report, page 24 and onwards.

Metric 4 – Semi Annual and Program To-Date Forecast and Actual Costs with Variance

ELECTRIC INSIDE PLANT

Electric Life Cycle Stations

- Accelerated Recovery

Semi-Annual Performance (2023-1, January to June) | **Program to Date (June, 2023)**

Cost	Forecast*	Actual	Variance ($)	Variance (%)		Cost	Forecast*	Actual	Variance ($)	Variance (%)
Total	$2,837,323	$3,175,314	$337,991	12%		**Total**	$3,422,858	$3,760,849	$337,991	10%

- Stipulated Base

Semi-Annual Performance (2023-1, January to June) | **Program to Date (June, 2023)**

Cost	Forecast*	Actual	Variance ($)	Variance (%)		Cost	Forecast*	Actual	Variance ($)	Variance (%)
Total	$0	$0	$0	0%		**Total**	$0	$0	$0	0%

Electric Stations 26kV OCB Replacement

- Accelerated Recovery

Semi-Annual Performance (2023-1, January to June) | **Program to Date (June, 2023)**

Cost	Forecast*	Actual	Variance ($)	Variance (%)		Cost	Forecast*	Actual	Variance ($)	Variance (%)
Total	$2,737,339	$1,534,065	-$1,203,275	-44%		**Total**	$3,344,624	$2,141,350	-$1,203,275	-36%

ELECTRIC OUTSIDE PLANT

Electric Lashed Cable Replacement
- Accelerated Recovery

Semi-Annual Performance (2023-1, January to June) | **Program to Date (June, 2023)**

Cost	Forecast*	Actual	Variance ($)	Variance (%)		Cost	Forecast*	Actual	Variance ($)	Variance (%)
Total	$1,539,599	$1,429,294	-$110,306	-7%		**Total**	$2,831,869	$2,721,563	-$110,306	-4%

Electric Open Wire to Spacer
- Accelerated Recovery

Semi-Annual Performance (2023-1, January to June) | **Program to Date (June, 2023)**

Cost	Forecast*	Actual	Variance ($)	Variance (%)		Cost	Forecast*	Actual	Variance ($)	Variance (%)
Total	$0	$9,265,330	$9,265,330	100%		**Total**	$0	$9,265,330	$9,265,330	100%

Infrastructure Advancement Program
Semi Annual Report, 2023-1

Electric Spacer Hardware Upgrades
- Accelerated Recovery

Semi-Annual Performance (2023-1, January to June) **Program to Date (June, 2023)**

Cost	Forecast*	Actual	Variance ($)	Variance (%)		Cost	Forecast*	Actual	Variance ($)	Variance (%)
Total	$3,193,321	$8,075,955	$4,882,634	153%		**Total**	$8,416,033	$13,298,667	$4,882,634	58%

- Stipulated Base

Semi-Annual Performance (2023-1, January to June) **Program to Date (June, 2023)**

Cost	Forecast*	Actual	Variance ($)	Variance (%)		Cost	Forecast*	Actual	Variance ($)	Variance (%)
Total	$0	$294,386	$294,386	100%		**Total**	$0	$294,386	$294,386	100%

Infrastructure Advancement Program
Semi Annual Report, 2023-1

Electric Conventional Under Ground (CUG) Cable Replacement

- Accelerated Recovery

Semi-Annual Performance (2023-1, January to June)

Cost	Forecast*	Actual	Variance ($)	Variance (%)
Total	$2,371,315	$0	-$2,371,315	-100%

Program to Date (June, 2023)

Cost	Forecast*	Actual	Variance ($)	Variance (%)
Total	$3,733,143	$1,361,827	-$2,371,315	-64%

- Stipulated Base

Semi-Annual Performance (2023-1, January to June)

Cost	Forecast*	Actual	Variance ($)	Variance (%)
Total	$0	$2,819,184	$2,819,184	100%

Program to Date (June, 2023)

Cost	Forecast*	Actual	Variance ($)	Variance (%)
Total	$0	$2,819,184	$2,819,184	100%

Electric Buried Underground Distribution (BUD) Cable Replacement

- Stipulated Base

Semi-Annual Performance (2023-1, January to June)

Cost	Forecast*	Actual	Variance ($)	Variance (%)
Total	$7,991,753	$11,207,594	$3,215,842	40%

Program to Date (June, 2023)

Cost	Forecast*	Actual	Variance ($)	Variance (%)
Total	$8,785,148	$12,000,989	$3,215,842	37%

Infrastructure Advancement Program
Semi Annual Report, 2023-1

Electric Capacitor Bank Upgrades
- Accelerated Recovery

Semi-Annual Performance (2023-1, January to June) | **Program to Date (June, 2023)**

Cost	Forecast*	Actual	Variance ($)	Variance (%)		Cost	Forecast*	Actual	Variance ($)	Variance (%)
Total	$363,852	$372,147	$8,295	2%		**Total**	$459,792	$468,086	$8,295	2%

- Stipulated Base

Semi-Annual Performance (2023-1, January to June) | **Program to Date (June, 2023)**

Cost	Forecast*	Actual	Variance ($)	Variance (%)		Cost	Forecast*	Actual	Variance ($)	Variance (%)
Total	$0	$0	$0	0%		**Total**	$0	$0	$0	0%

Electric Open Wire Secondary Upgrades
- Stipulated Base

Semi-Annual Performance (2023-1, January to June) | **Program to Date (June, 2023)**

Cost	Forecast*	Actual	Variance ($)	Variance (%)		Cost	Forecast*	Actual	Variance ($)	Variance (%)
Total	$4,701,733	$6,494,899	$1,793,166	38%		**Total**	$14,230,022	$16,023,189	$1,793,166	13%

GAS METERING & REGULATION (M&R) STATIONS

- Accelerated Recovery

Semi-Annual Performance (2023-1, January to June) | **Program to Date (June, 2023)**

Cost	Forecast*	Actual	Variance ($)	Variance (%)		Cost	Forecast*	Actual	Variance ($)	Variance (%)
Total	$2,005,642	$1,354,705	-$650,936	-32%		**Total**	$2,902,098	$2,251,161	-$650,936	-22%

- Stipulated Base

Semi-Annual Performance (2023-1, January to June) | **Program to Date (June, 2023)**

Cost	Forecast*	Actual	Variance ($)	Variance (%)		Cost	Forecast*	Actual	Variance ($)	Variance (%)
Total	$0	$0	$0	0%		**Total**	$0	$0	$0	0%

*Semi Annual forecast is as of January 1st, 2023.

PSEG

Similar Projects Comparable to IAP Subprograms

Actual capital expenditures made in the normal course of business on similar projects, identified by comparable IAP sub-program:

IAP Investment Category	Description	Applicable IAP Subprograms	Capital Spend on Comparable Non-IAP Subprograms
Hardening & Resilience	Harden infrastructure, thereby making it less susceptible to damage from major storm events, wind and vegetation contact. Strengthen the resiliency of the Company's delivery system.	* Electric Open Wire to Spacer * Electric Lashed Cable * Electric Spacer Hardware * Electric Open Wire Secondary	$ 4,446,037
Life Cycle	Reliability - LC replacements	* Electric Stations LC (4kV) Replacement * 26kV OCB Replacement * Capacitor Bank upgrades * Conventional Underground Cable replace * Buried Underground Cable replace * Gas M&R Station Modernization	$ 32,706,873
Total	**Capital Spend from July 2022 to June 2023**		**$ 37,152,910**

Detailed Tables for Metric 3 for Semi Annual Report 2023-1 – Non-Major Event Performance

Table M3.B.a – Conventional Underground (CUG) Cable Replacement

This report includes quarterly non-major event performance combining all events only for the circuits which are fully completed.

Blank cell indicates no outage for the circuit.
Note: The 0.00000 signifies there was an outage but the value is beyond 5 decimal place.

		Report Period Performance		
Circuit	**5 Year Benchmark SAIDI**	**SAIFI**	**CAIDI**	**SAIDI**
FMT 8014		0.00001	9.0	0.00011
FMT 8025				
RFL 8012	0.11690	0.00013	50.81	0.00636
LEO 8043	0.02105	0.00019	58.00	0.01075
LUM 8014	0.01924	0.00000	355.00	0.00058
NED 8016	0.06070	0.00002	84.00	0.00126
SPF 8022	0.10116	0.00077	17.00	0.01306
LAF 8011	0.24229	0.00001	9.00	0.00011

Table M3.B.b – Spacer Hardware Upgrades

This report includes quarterly non-major event performance combining all events only for the circuits which are fully completed.

Blank cell indicates no outage for the circuit.

Note: The 0.00000 signifies there was an outage but the value is beyond 5 decimal place

		Report Period Performance		
Circuit	**5 Year Benchmark SAIDI**	**SAIFI**	**CAIDI**	**SAIDI**
SPF 8022	0.24229			
ALD 8023	0.05707	0.00049	64.54	0.03133
GBK 8021	0.03092	0.00003	65.00	0.00206
RFL 8024	0.10316			
CLF 8022	0.09375	0.00001	119.00	0.00169
COR 8044	0.12235	0.00002	86.00	0.00161
JAC 8032	0.10803	0.00004	104.34	0.00445
KIN 8025	0.07501	0.00056	35.61	0.02008
LAU 8011	0.07228	0.00022	20.71	0.00453
RFL 8035	0.03883			
WEW 8021	0.09623	0.00010	45.64	0.00479

Table M3.B.c – Lashed Cable Replacement

This report includes quarterly non-major event performance combining all events only for the circuits which are fully completed.

Blank cell indicates no outage for the circuit.

Note: The 0.00000 signifies there was an outage but the value is beyond 5 decimal place

		Report Period Performance		
Circuit	**5 Year Benchmark SAIDI**	**SAIFI**	**CAIDI**	**SAIDI**
DUM 4007	0.00743			
MOG 4003	0.13365			
ORA 4002	0.01804	0.00003	212.13	0.00612

Table M3.B.d – Open Wire to Spacer

This report includes quarterly non-major event performance combining all events only for the circuits which are fully completed.

Blank cell indicates no outage for the circuit.

Note: The 0.00000 signifies there was an outage but the value is beyond 5 decimal place

		Report Period Performance		
Circuit	**5 Year Benchmark SAIDI**	**SAIFI**	**CAIDI**	**SAIDI**
ALD 8013	0.02803	0.00027	73.87	0.02000
GRN 4008	0.02731			

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March 14, 2024

VIA ELECTRONIC MAIL ONLY
Sherri Golden, Board Secretary
Board of Public Utilities
44 South Clinton Avenue, 1st Floor
P.O. Box 350
Trenton, New Jersey 08625-0350

Re: Infrastructure Advancement Program – Semi Annual Report July 2023 to December 2023

Dear Secretary Golden:

Enclosed for filing is Public Service Electric and Gas Company's semi-annual Infrastructure Advancement Program report for the period July 2023 to December 2023.

The Infrastructure Advancement Program ("IAP") was addressed by a Board Order dated June 29, 2022 (June 29th Order) in Docket Nos. EO2111211 and GO21112121. That Order adopted a Stipulation pursuant to which PSE&G is operating the program known as IAP.

Paragraph 26 of that Stipulation requires reports on:

- The estimated total quantity of work and the quantity completed to date or, if the project work cannot be quantified with numbers, the major tasks completed, e.g., design phase, material procurement, permit gathering, phases of construction;
- The forecasted and actual IAP costs-to-date for the reporting period and for the Program-to-date; where project work is identified by major category (with the actual variances from forecasted amounts expressed in dollar and percentage terms);
- The estimated IAP Project completion date, and estimated completion dates for each IAP subprogram and the Program as a whole;
- Anticipated changes to IAP Projects, if any;
- Actual capital expenditures made by the utility in the normal course of business on similar project work, identified by major category; and
- Any other performance metric concerning the IAP required by the Board.
- For circuits improved within the Spacer Cable Conversion Project, Lashed Cable Replacement Project, and Spacer Upgrade Project, PSE&G will provide System Average Interruption Duration Index ("SAIDI") results for Major Event11 performance at the circuit level (redacted and confidential unredacted) for circuits affected by a Major Event during the reporting period and at the operating area level and system wide. The SAIDI results will be reported and measured against a baseline that reflects performance for each circuit

under Major Event conditions for the prior five (5) years from the Program start date. The report will include the SAIDI results at the circuit level for the reporting period.

- For circuits improved upon within the Spacer Cable Conversion Project, Lashed Cable Replacement Project, Spacer Upgrade Project, and Conventional Underground Cable Replacement Project, PSE&G will include non-Major Event performance (where a non-Major Event excludes all "Major Events" as defined at N.J.A.C. 14:5-1.2) including circuit designation (information to be provided redacted and confidential unredacted), that reflects non-Major Event conditions for the reporting period. In addition to SAIDI, the Company will report non-Major Event data for Customer Average Interruption Duration Index ("CAIDI") and System Average Interruption Frequency Index ("SAIFI"). The SAIDI results will be reported and measured against a baseline that reflects performance for each circuit under non-Major Event conditions for the prior five (5) years from the Program start date.

The reporting requirements listed in paragraph 26 of the Stipulation are addressed by the enclosed materials.

Please contact the undersigned with any questions or concerns.

Very truly yours,

Danielle Lopez

cc: ***Via Email only***
Brian Lipman
David Wand
Maura Caroselli
Karen Forbes
Stacy Peterson
Matko Illic
Caroline Vachier

INFRASTRUCTURE ADVANCEMENT PROGRAM

SEMI-ANNUAL REPORT

TO THE BOARD OF PUBLIC UTILITIES

Reporting period: July 2023 to December 2023

Table of Contents

Metric 1 – Estimated Quantity of Work

For each Infrastructure Advancement Subprogram:

A. Estimated quantity of work

i. **For the Entire Subprogram**

ii. **Planned to date (based on forecasted estimates at the beginning of the reporting period)**

B. Quantity completed to date or, if the project cannot be quantified with numbers, the major tasks completed, e.g. design phase, material procurement, permit gathering, phases of construction;

NOTE: This quarterly report covers Program to date performance up to the 2nd half of 2023 period, July 1, 2023 through December 31, 2023. At the end of the period, all subprograms/projects have advanced through varying stages of planning authorization and execution and completion. Where applicable, forecasted and actual units of work and/or major tasks completed are provided.

ELECTRIC PROGRAM

ELECTRIC INSIDE PLANT

Electric Life Cycle Stations

A. Estimated Quantity of Work:

i. **Project:** The estimated quantity of work for this Subprogram includes the modernization of 4kV switchgear at five (5) electric distribution 69/4kV substations, including replacing and upgrading breakers, disconnects, reactors, regulators, relays, and other infrastructure. The following five (5) substations are included within the project:

- Fortieth Street
- McLean Blvd
- Teaneck
- Tonnelle Ave
- Totowa

ii. **Planned to Date:** Major work planned to the end of December 2023:

Fortieth:

- Major Equipment POs issued
- KDR package approved
- Preliminary Vendor Drawings issued
- Detailed Engineering Start
- L&P package issued

McLean:

- Major Equipment POs issued
- KDR package approved
- Preliminary Vendor Drawings issued

Teaneck:

- Major Equipment POs issued
- KDR package approved
- Preliminary Vendor Drawings Issued

Tonnelle:

- Major Equipment POs issued
- KDR package approved
- Preliminary Vendor Drawings issued
- L&P package issued

Totowa:

- Major Equipment POs issued
- KDR package approved
- L&P package issued
- SCD permit issued
- Preliminary Vendor Drawings Issued

B. Quantity of Work Completed to Date:

Fortieth:

- Major Equipment POs issued
- KDR package approved
- Preliminary Vendor Drawings Issued
- Detailed Engineering Start
- L&P package issued

McLean:

- A&E contract and PO issued for detailed engineering
- Major Equipment POs issued
- KDR package approval
- Preliminary Vendor Drawings Issued

Teaneck:

- A&E contract and PO issued for detailed engineering
- Major Equipment POs issued
- KDR package approved
- Preliminary Vendor Drawings Issued

Tonnelle:

- A&E contract and PO issued for detailed engineering
- Major Equipment POs issued
- KDR package approved
- Preliminary Vendor Drawings Issued

Totowa:

- Major Equipment POs issued
- KDR package approval
- L&P package issued
- SCD permit issued
- Preliminary Vendor Drawings Issued
- Civil Construction Started

Electric Stations 26kV Oil Circuit Breakers (OCB) Replacement

A. Estimated Quantity of Work:

i. **Project:** The estimated quantity of work for this Subprogram includes the replacement of 36 Oil Circuit Breakers.

ii. **Planned to Date:** Major work planned to the end of December 2023:

Replacement of ten 26kV Oil Circuit Breakers.

B. Quantity of Work Completed to Date:

Replaced Three 26kV Oil Circuit Breakers from July 2023 to December 2023

Replaced Seven 26kV Oil Circuit Breakers from program to date.

ELECTRIC OUTSIDE PLANT

Electric Lashed Cable Replacement

A. Estimated Quantity of Work:

i. **Project:** The estimated quantity of work for this Subprogram includes replacing approximately 8 miles of existing lashed primary cable construction with spacer cable construction that is designed to a higher and more resilient standard.

ii. **Planned to Date:** Major work planned to the end of December 2023:

- Replacement of 1 mile of lashed primary cable with spacer cable.

B. Quantity of Work Completed to Date:

- July 2023 to December 2023 – Replaced 0.6 circuit miles.
- Program to Date - Replaced 1.7 circuit miles.

Electric Open Wire to Spacer

A. Estimated Quantity of Work:

i. **Project:** This project will replace aging, 3-phase, open wire construction (cross arm and armless) with PSE&G's current standard, spacer cable type construction. Additionally, replacement work will also require the upgrading of auxiliary equipment as part of the conversion.

ii. **Planned to Date:** Major work planned to the end of December 2023:

- Work on Open Wire to Spacer was originally planned to start in 2024. However, work started ahead of schedule in 2023.

B. Quantity of Work Completed to Date:

- July 2023 to December 2023 – Replaced 6.9 circuit miles.
- Program to Date - Replaced 17.1 circuit miles.

Electric Spacer Hardware Upgrades

A. Estimated Quantity of Work:

i. **Project:** The estimated quantity of work for this Subprogram includes 160 miles of existing spacer type construction. This project will replace aging spacer units along existing construction with new hardware that is designed to a higher and more resilient standard. Also, worn, defective, or metallic tangent brackets will be replaced with a newer fiberglass tangent bracket. Messenger ground wire will be installed at every pole if not currently installed.

ii. **Planned to Date:** Major work planned to the end of December 2023:

- Completion of 61.5 circuit miles.

B. Quantity of Work Completed to Date:

- July 2023 to December 2023 – Completed 79.5 circuit miles.
- Program to Date – Completed 158.5 circuit miles.

Electric Conventional Underground (CUG) Cable Replacement

A. Estimated Quantity of Work:

i. **Project:** The estimated quantity of work for this Subprogram includes the replacement of 34 miles of conventional underground cable.

ii. **Planned to Date:** Major work planned to the end of December 2023:

- Civil work to replace existing crushed conduit.
- Complete all CUG's in Palisades & Central.

B. Quantity of Work Completed to Date:

- July 2023 to December 2023 – Replaced 1.1 circuit miles of cable.
- Program to Date – Replaced 3.2 circuit miles of cable.

Electric Buried Underground Distribution (BUD) Cable Replacement

A. Estimated Quantity of Work:

i. **Project:** The estimated quantity of work for this Subprogram includes the replacement of 110 miles of BUD cable.

ii. **Planned to Date:** Major work planned to the end of December 2023:

- HDD in Southern & Central Division
- Build MHC systems in Palisades and Metro Division
- Final test new cable with IMCORP

B. Quantity of Work Completed to Date:

- July 2023 to December 2023 – Replaced 3.6 circuit miles of cable.
- Program to Date – Replaced 3.7 circuit miles of cable.

Electric Capacitor Bank Upgrades

A. Estimated Quantity of Work:

i. **Project:** The estimated quantity of work for this Subprogram includes the replacement of 479 capacitors. The following stations have been identified for this project:

- Palisades Div. – Penhorn (76)
- Metropolitan Div. – West Caldwell (169)
- Central Div. – Pierson (95)
- Southern Div. – Levittown (139)

ii. **Planned to Date:** Major work planned to the end of December 2023:

- Complete existing capacitor bank circuit operational validations for targeted replacements.

B. **Quantity of Work Completed to Date:** Major Activities completed by end of December 2023:

- Work with vendor and System Protection group to develop revised circuit modeling for new advanced capacitor banks.
- Performed factory acceptance testing with both internal & external stake holders
- Developed final revision of construction standards for new advanced capacitor banks
- Initial circuit engineering completed in Palisades division for PEH8004 & HOM8025 circuits
- Conducted initial operational bench testing & SCADA programing
- Installation of 7 total advanced capacitor banks.

PSEG

Electric Open Wire Secondary Upgrades

A. Estimated Quantity of Work:

i. **Project:** The estimated quantity of work for this Subprogram includes the replacement of approximately 50 miles over 139 circuits of Open Wire Secondary across the entire PSEG service territory with new secondary cable that have higher capacity and are more resistant to storms and tree contacts. In addition, in areas with lower rated 25kVa transformers in place, new larger 50kVa capacity transformers will be installed.

ii. **Planned to Date:** Major work planned to the end of June 2023:

- Planned to complete 8.6 miles through December out of total estimate of 33.9 miles for the year 2023.

B. Quantity of Work Completed to Date:

2023 construction completion metrics by division:

Division	July to Dec 2023		Program To Date	
	Circuits	Wire (ft)	Circuits	Wire (ft)
Palisades	8	9,200	31	69,982
Metropolitain	14	9,738	51	49,203
Central	7	5,037	22	34,142
Southern	1	3,000	13	54,123

GAS METERING & REGULATION (M&R) STATIONS

A. Estimated Quantity of Work:

i. **Project:** The estimated quantity of work for this Subprogram includes implementation of life cycle upgrades 4 Gas M&R Stations (Brooklawn, Hamilton, Hanover, and Hillsborough) listed in the Program Stipulation and life cycle upgrades at all 4 M&R Stations as part of the IAP Gas Subprogram.

ii. **Planned to Date:** Major work planned to the end of June 2023:

- Award Detailed Design Engineering to A/E firms for all 4 Stations.
- Start Detailed Design Engineering for all 4 Stations.
- Award material procurement PO to A/E firms (Brooklawn & Hillsborough)
- Finalize Piping & Instrumentation Diagram (P&ID) drawings packages (Brooklawn & Hillsborough)
- Start Site Plan drawings packages (Brooklawn & Hillsborough)

B. Quantity of Work Completed to Date:

- Started Detailed Design Engineering for all 4 stations.
- Completed P&ID drawings packages (Brooklawn & Hillsborough)
- Started KDR drawings package review (Brooklawn & Hillsborough)
- Started Interconnect Agreement with gas pipeline operators (Brooklawn & Hillsborough)
- Completed Site Plan drawings package (Brooklawn)
- Started Site Plan drawings package (Hillsborough)

Metric 2 – Estimated Program and Subprogram Completion Dates

The estimated IAP project completion date, and estimated completion dates for each IAP sub-program and the Program as a whole.

PROGRAM

Program	Subprogram	Forecast In-Service	Timeline for Completion*
IAP	Electric & Gas	Jun-26	Dec-26

SUBPROGRAMS

Program	Subprogram	Forecast In-Service	Timeline for Completion*
Electric	Life Cycle Projects	Oct-25	Dec-26
Electric	26kV Oil Circuit Breaker Replacement	Jun-26	Dec-26
Electric	Lashed Cable	Feb-26	Aug-26
Electric	Open Wire to Spacer	Dec-25	Jun-26
Electric	Spacer Hardware	Mar-24	Sep-24
Electric	CUG Cable	Jun-26	Dec-26
Electric	Capacitor Bank Upgrades	Jun-26	Dec-26
Electric	Open Wire Secondary Upgrades	Jan-24	Jul-24
Electric	BUD Cable	Jun-26	Dec-26
Gas	M&R Stations	Oct-25	Jul-26

*** Timeline for Completion is defined by the completion date of project closeout report.**

ELECTRIC INSIDE PLANT

Electric Life Cycle Stations

Project	Forecast In-Service	Timeline for Completion	Updates	Expected Changes
Tonnelle Ave Substation	Sep-25	Mar-26		
40th Street Substation	Feb-25	Aug-25		
Totowa Substation	Sep-25	Apr-26		
McLean Blvd Substation	Oct-25	Apr-26		
Teaneck Substation	Oct-25	Oct-26		

Electric Stations 26kV OCB Replacement

Project	Forecast In-Service	Timeline for Completion	Updates	Expected Changes
26kV OCB Replacement	Jun-26	Dec-26		

ELECTRIC OUTSIDE PLANT

Electric Lashed Cable Replacement

Project	Forecast In-Service	Timeline for Completion	Updates	Expected Changes
Lashed Cable Replacement	Feb-26	Aug-26		

Electric Open Wire to Spacer

Project	Forecast In-Service	Timeline for Completion	Updates	Expected Changes
Open Wire to Spacer	Dec-25	Jun-26		

Electric Spacer Hardware Upgrades

Project	Forecast In-Service	Timeline for Completion	Updates	Expected Changes
Spacer Hardware Upgrades	Mar-23	Sep-24		

Electric Conventional Under Ground (CUG) Cable Replacement

Project	Forecast In-Service	Timeline for Completion	Updates	Expected Changes
CUG Cable Replace	Jun-26	Dec-26		

Electric Buried Underground Distribution (BUD) Cable Replacement

Project	Forecast In-Service	Timeline for Completion	Updates	Expected Changes
Open Wire Secondary Upgrades	Jan-24	Jul-24		

Electric Capacitor Bank Upgrades

Project	Forecast In-Service	Timeline for Completion	Updates	Expected Changes
Capacitor Bank Upgrades	Jun-26	Dec-26		

Electric Open Wire Secondary Upgrades

Project	Forecast In-Service	Timeline for Completion	Updates	Expected Changes
BUD Cable Replacement	Jun-26	Dec-26		

GAS METERING & REGULATION (M&R) STATIONS

Project	Forecast In-Service	Timeline for Completion	Updates	Expected Changes
Brooklawn M&R	Nov-24	Jun-25		
Hillsborough M&R	Nov-24	Jun-25		
Hamilton M&R	Oct-25	Jul-26		
Hanover M&R	Oct-25	Jul-26		

Metric 3 – Circuit Performance - SAIDI/SAIFI/CAIDI

This metric includes data for completed circuits involved in the Major and Non-Major events occurred in the 2nd half of 2023, from July 1st, 2023, to December 30th, 2023.

A. Reports included for **Major events** in 1st half of 2023 –

No Major Events occurred in the reporting period.

B. Reports included for **Non-Major Events** in 1st half of 2023 –

M3.B.a Conventional Underground Cable Replacement.
M3.B.b Spacer Hardware Upgrades.
M3.B.c Lashed Cable Replacement.
M3.B.d Open Wire to Spacer.

Detailed tables for this metric are included at the end of this report, page 24 and onwards.

Metric 4 – Semi Annual and Program To-Date Forecast and Actual Costs with Variance

ELECTRIC INSIDE PLANT

Electric Life Cycle Stations

- Accelerated Recovery

Semi-Annual Performance (2023-2, July to December) / **Program to Date (December, 2023)**

Cost	Forecast*	Actual	Variance ($)	Variance (%)		Cost	Forecast*	Actual	Variance ($)	Variance (%)
Total	$19,814,566	$14,452,945	-$5,361,621	-27%		**Total**	$23,575,415	$23,269,982	-$305,433	-1%

- Stipulated Base

Semi-Annual Performance (2023-2, July to December) / **Program to Date (December, 2023)**

Cost	Forecast*	Actual	Variance ($)	Variance (%)		Cost	Forecast*	Actual	Variance ($)	Variance (%)
Total	$0	$0	$0	0%		**Total**	$0	$0	$0	0%

Electric Stations 26kV OCB Replacement

- Accelerated Recovery

Semi-Annual Performance (2023-2, July to December) / **Program to Date (December, 2023)**

Cost	Forecast*	Actual	Variance ($)	Variance (%)		Cost	Forecast*	Actual	Variance ($)	Variance (%)
Total	$6,111,784	$3,043,727	-$3,068,057	-50%		**Total**	$8,253,134	$6,442,078	-$1,811,056	-22%

Infrastructure Advancement Program
Semi Annual Report, 2023-2

ELECTRIC OUTSIDE PLANT

Electric Lashed Cable Replacement - Accelerated Recovery

Semi-Annual Performance (2023-2, July to December)

Cost	Forecast*	Actual	Variance ($)	Variance (%)
Total	$1,584,849	$2,096,473	$511,624	32%

Program to Date (December, 2023)

Cost	Forecast*	Actual	Variance ($)	Variance (%)
Total	$4,306,412	$5,573,150	$1,266,738	29%

Electric Open Wire to Spacer - Accelerated Recovery

Semi-Annual Performance (2023-2, July to December)

Cost	Forecast*	Actual	Variance ($)	Variance (%)
Total	$14,236,230	$9,506,316	-$4,729,914	-33%

Program to Date (December, 2023)

Cost	Forecast*	Actual	Variance ($)	Variance (%)
Total	$23,501,560	$20,059,519	-$3,442,041	-15%

Electric Spacer Hardware Upgrades - Accelerated Recovery

Semi-Annual Performance (2023-2, July to December)

Cost	Forecast*	Actual	Variance ($)	Variance (%)
Total	$1,701,333	$1,406,947	-$294,386	-17%

Program to Date (December, 2023)

Cost	Forecast*	Actual	Variance ($)	Variance (%)
Total	$15,000,000	$15,000,000	$0	0%

- Stipulated Base

Semi-Annual Performance (2023-2, July to December) | **Program to Date (December, 2023)**

Cost	Forecast*	Actual	Variance ($)	Variance (%)		Cost	Forecast*	Actual	Variance ($)	Variance (%)
Total	$9,705,614	$10,661,601	$955,987	10%		**Total**	$10,000,000	$11,891,249	$1,891,249	19%

Electric Conventional Under Ground (CUG) Cable Replacement

- Accelerated Recovery

Semi-Annual Performance (2023-2, July to December) | **Program to Date (December, 2023)**

Cost	Forecast*	Actual	Variance ($)	Variance (%)		Cost	Forecast*	Actual	Variance ($)	Variance (%)
Total	$0	$0	0	0%		**Total**	$1,361,827	$1,409,223	$47,396	3%

- Stipulated Base

Semi-Annual Performance (2023-2, July to December) | **Program to Date (December, 2023)**

Cost	Forecast*	Actual	Variance ($)	Variance (%)		Cost	Forecast*	Actual	Variance ($)	Variance (%)
Total	$570,439	$702,843	$132,404	23%		**Total**	$3,389,623	$3,522,027	$132,404	4%

Electric Buried Underground Distribution (BUD) Cable Replacement

- Stipulated Base

Infrastructure Advancement Program
Semi Annual Report, 2023-2

Semi-Annual Performance (2023-2, July to December) **Program to Date (December, 2023)**

Cost	Forecast*	Actual	Variance ($)	Variance (%)		Cost	Forecast*	Actual	Variance ($)	Variance (%)
Total	$8,554,762	$10,549,99	$1,995,237	23%		**Total**	$20,555,751	$23,660,657	$3,104,906	15%

Electric Capacitor Bank Upgrades
- Accelerated Recovery

Semi-Annual Performance (2023-2, July to December) **Program to Date (December, 2023)**

Cost	Forecast*	Actual	Variance ($)	Variance (%)		Cost	Forecast*	Actual	Variance ($)	Variance (%)
Total	$2,627,853	$1,110,166	-$1,517,687	-58%		**Total**	$3,095,939	$1,578,253	-$1,517,68	-49%

- Stipulated Base

Semi-Annual Performance (2023-2, July to December) **Program to Date (December, 2023)**

Cost	Forecast*	Actual	Variance ($)	Variance (%)		Cost	Forecast*	Actual	Variance ($)	Variance (%)
Total	$0	$0	$0	0%		**Total**	$0	$0	$0	0%

Electric Open Wire Secondary Upgrades
- Stipulated Base

Semi-Annual Performance (2023-2, July to December) **Program to Date (December, 2023)**

Cost	Forecast*	Actual	Variance ($)	Variance (%)		Cost	Forecast*	Actual	Variance ($)	Variance (%)
Total	$4,701,733	$6,494,899	$1,793,166	38%		**Total**	$14,230,022	$16,023,189	$1,793,166	13%

GAS METERING & REGULATION (M&R) STATIONS

- Accelerated Recovery

Semi-Annual Performance (2023-2, July to December) | **Program to Date (December, 2023)**

Cost	Forecast*	Actual	Variance ($)	Variance (%)		Cost	Forecast*	Actual	Variance ($)	Variance (%)
Total	$5,365,848	$4,257,666	-$1,108,182	-21%		**Total**	$7,617,009	$7,563,309	-$53,700	-1%

- Stipulated Base

Semi-Annual Performance (2023-2, July to December) | **Program to Date (December, 2023)**

Cost	Forecast*	Actual	Variance ($)	Variance (%)		Cost	Forecast*	Actual	Variance ($)	Variance (%)
Total	$0	$0	$0	0%		**Total**	$0	$0	$0	0%

*Semi Annual forecast is as of July 1st, 2023.

PSEG

Similar Projects Comparable to IAP Subprograms

Actual capital expenditures made in the normal course of business on similar projects, identified by comparable IAP sub-program:

IAP Investment Category	Description	Applicable IAP Subprograms	Capital Spend on Comparable Non-IAP Subprograms
Hardening & Resilience	Harden infrastructure, thereby making it less susceptible to damage from major storm events, wind and vegetation contact. Strengthen the resiliency of the Company's delivery system.	* Electric Open Wire to Spacer * Electric Lashed Cable * Electric Spacer Hardware * Electric Open Wire Secondary	**$ 8,056,965.74**
Life Cycle	Reliability - LC replacements	* Electric Stations LC (4kV) Replacement * 26kV OCB Replacement * Capacitor Bank upgrades * Conventional Underground Cable replace * Buried Underground Cable replace * Gas M&R Station Modernization	**$ 33,457,391.82**
			$ -
Total	**Capital Spend from July 2022 to June 2023**		**$ 41,514,357.56**

Detailed Tables for Metric 3 for Semi Annual Report 2023-1 – Non-Major Event Performance

Table M3.B.a – Conventional Underground (CUG) Cable Replacement

This report includes quarterly non-major event performance combining all events only for the circuits which are fully completed.

Blank cell indicates no outage for the circuit.
Note: The 0.00000 signifies there was an outage but the value is beyond 5 decimal place.

		Report Period Performance		
Circuit	**5 Year Benchmark SAIDI**	**SAIFI**	**CAIDI**	**SAIDI**
FMT 8014	0.02823			
FMT 8025	0.05434			
HOM 8032	0.09953			
LAF 8011	0.11690	0.00004	181.99	0.00659
LEO 8043	0.02105			
LUM 8014	0.01924			
NED 8016	0.06070			
NED 8025	0.10790			
RFL 8012	0.10116			
SPF 8022	0.24229	0.00002	98.00	0.00164

Table M3.B.b – Spacer Hardware Upgrades

This report includes quarterly non-major event performance combining all events only for the circuits which are fully completed.

Blank cell indicates no outage for the circuit.

Note: The 0.00000 signifies there was an outage but the value is beyond 5 decimal place

		Report Period Performance		
Circuit	**5 Year Benchmark SAIDI**	**SAIFI**	**CAIDI**	**SAIDI**
ALD 8016	0.06029	0.00001	42.00	0.00027
ALD 8023	0.05707	0.00006	83.69	0.00466
BEN 8012	0.04059	0.00004	17.57	0.00064
CED 8011	0.09510	0.00008	90.00	0.00752
CED 8022	0.06019			
CLF 8022	0.09375	0.00007	152.16	0.01078
CLF 8024	0.03928	0.00094	67.74	0.06339
COR 8044	0.12235	0.00088	28.66	0.02525
DOR 8035	0.11826	0.00034	154.00	0.05302
GBK 8021	0.03092	0.00054	54.21	0.02926
HID 8044	0.12829	0.00004	323.45	0.01416
HNC 8012	0.15475	0.00014	9.00	0.00130
JAC 8032	0.10803	0.00028	38.73	0.01101
KIN 8025	0.07501			
LAU 8011	0.07228	0.00005	70.79	0.00378
LAU 8036	0.04759	0.00008	109.14	0.00856
LEO 8005	0.05526			
LEO 8041	0.11253	0.00004	52.79	0.00235
MAI 8011	0.14938	0.00017	84.79	0.01475
MAI 8012	0.12529	0.00007	59.51	0.00443
MAY 8015	0.08066			
MIN 8013	0.02501	0.00084	42.47	0.03556
NEW 8031	0.10913	0.00030	16.09	0.00476

RFL 8024	0.10316			
RFL 8035	0.03883			
RFL 8043	0.07250	0.00069	38.11	0.02638
SAD 8034	0.07762	0.00051	40.00	0.02043
SAD 8044	0.09608	0.00005	513.65	0.02739
SPF 8022	0.24229	0.00002	98.00	0.00164
WAN 8021	0.02172	0.00004	92.00	0.00414
WEW 8021	0.09623	0.00023	39.06	0.00905

Table M3.B.c – Lashed Cable Replacement

This report includes quarterly non-major event performance combining all events only for the circuits which are fully completed.

Blank cell indicates no outage for the circuit.

Note: The 0.00000 signifies there was an outage but the value is beyond 5 decimal place

		Report Period Performance		
Circuit	**5 Year Benchmark SAIDI**	**SAIFI**	**CAIDI**	**SAIDI**
DUM 4007	0.00743			
MOG 4003	0.13365			
ORA 4002	0.01804			

Table M3.B.d – Open Wire to Spacer

This report includes quarterly non-major event performance combining all events only for the circuits which are fully completed.

Blank cell indicates no outage for the circuit.

Note: The 0.00000 signifies there was an outage but the value is beyond 5 decimal place

		Report Period Performance		
Circuit	**5 Year Benchmark SAIDI**	**SAIFI**	**CAIDI**	**SAIDI**
ALD 8013	0.02803	0.00038	17.96	0.00690
CUT 8043	0.13239	0.00005	120.62	0.00629
GRN 4008	0.02731			
KIN 8015	0.12880	0.00002	116.00	0.00249
THY 4004	0.07558			
THY 4009	0.00954			

Test Year Electric Operations and Maintenance

in $000 **Schedule - PANEL-5(a)**

		Test Year Total June 2023 - May 2024
Distribution Operations	$	57,587
Distribution Maintenance	$	150,511
Total	**$**	**208,098**

Major Categories		
Corrective Maintenance	$	77,739
Vegetation Management	$	45,986
Inspections	$	14,326
Buildings & Grounds	$	14,121
Measurement / Meter Expense	$	8,856

Test Year Gas Operations and Maintenance

in $000 **Schedule - PANEL-5(b)**

		Test Year Total June 2023 - May 2024
Distribution Operations	$	109,442
Distribution Maintenance	$	37,407
Gas Transmission	$	5,518
Total	**$**	**152,367**
Major Categories		
Safety	$	60,212
Measurement	$	5,422
Gas Markouts	$	12,770
Inspections and Surveys	$	11,323
Main & Service Maintance	$	16,418

STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

In the Matter of the Petition of
Public Service Electric and Gas Company
for Approval of an Increase in Electric and Gas
Rates and for Changes in the Tariffs for
Electric and Gas Service, B.P.U.N.J.
No. 17 Electric and B.P.U.N.J. No. 17
Gas, and for Changes in Depreciation Rates,
Pursuant to N.J.S.A. 48:2-18,
N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1, and
for Other Appropriate Relief

BPU Docket Nos. ER23120924 and GR23120925

DIRECT TESTIMONY
OF
CLIFFORD PARDO
9+3 UPDATE

VICE-PRESIDENT OF TAX AND ASSISTANT
CONTROLLER

April 15, 2024
P-4 R-1

TABLE OF CONTENTS

Direct Testimony
Of
Clifford Pardo
Vice-President of Tax and Assistant Controller
PSEG Services Corporation

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Clifford Pardo. My business address is 80 Park Plaza, Newark, New Jersey.

Q. By whom are you employed and in what capacity?

A. I am employed by PSEG Services Corporation as Vice-President of Tax and Assistant Controller. My professional credentials are attached as Schedule CP-1.

Q. What is the purpose of your testimony?

A. In this proceeding, I am testifying on behalf of Public Service Electric and Gas Company ("PSE&G," "Public Service," or "the Company"). The purpose of my testimony is to present and support tax expense, accumulated deferred income taxes ("ADIT"), modifications to the existing Tax Adjustment Credit ("TAC"), the consolidated tax ratemaking adjustment, and other tax issues arising in this proceeding. Specifically, my testimony is comprised of the following sections:

- Section I provides an introduction;
- Section II summarizes the impacts of the 2017 Tax Cuts and Jobs Act ("TCJA") and 2022 Inflation Reduction Act ("IRA"), and their impacts on this rate proceeding;
- Section III presents current and deferred tax expense and ADIT included in this test period;
- Section IV discusses modifications to the TAC; and

- Section V provides the consolidated tax ratemaking adjustment and presents a computation of that adjustment.

Q. Do you sponsor any schedules as part of your prepared testimony?

A. Yes. I sponsor the following schedules that were prepared or compiled under my direct supervision:

- Schedule CP-1 describes my professional qualifications and business experience;
- Schedule CP-2 R-1 details the computation of income tax expense for electric and gas for the test year;
- Schedule CP-3 R-1 details the computation of accumulated deferred income taxes for electric and gas for the test year;
- Schedule CP-4 details the computation of the estimated annual net Mixed Service Deduction and the Historic Mixed Service ADIT balance; and
- Confidential Schedule CP-5 R-1 details the computation of the CTA.

II. <u>IMPACT OF TCJA AND IRA</u>

A) TCJA

Q. Does TCJA have implications for this proceeding?

A. Yes. On December 22, 2017, the President signed into law a bill entitled "To provide for reconciliation pursuant to titles II and V of the concurrent resolution on the budget for fiscal year 2018", more commonly known as the "Tax Cuts and Jobs Act" or "TCJA." Below I describe the major provisions of TCJA and discuss their impacts on this proceeding.

Q. Please describe the implications to PSE&G of the reduction in the federal corporate income tax rate.

A. Effective January 1, 2018 the TCJA reduced the federal corporate income tax rate from 35% to 21%. This rate change had a number of implications, including:

- Reducing PSE&G's tax expense after 2017;
- Increasing PSE&G's operating income by lowering tax expense;
- Creating a portion of PSE&G's 2017 ADIT balance in excess of what is needed to offset future tax liabilities (excess deferred income taxes or "EDIT"); and
- Altering the after tax cost of debt as well as the revenue gross-up factor and the interest synchronization computation.

Q. What are deferred income taxes and how do they impact customers?

A. PSE&G, through the ratemaking process, charges customers current and deferred income tax expense. Current tax expense represents the tax expense expected to be paid to the government for that tax year. Deferred tax expense represents a future tax liability that will be paid when related temporary differences between book and taxable income reverse.

Q. Can you provide an example?

A. An example of such a temporary difference is the difference created by accelerated depreciation. In the case of accelerated depreciation, deductible tax depreciation exceeds book depreciation in the early portion of an asset's life, but then in the later portion of that asset's life, book depreciation exceeds tax depreciation. In total, the amount of depreciation is the same; just the timing is different. Deferred taxes spread the tax benefit of depreciation over the book life of the property, so that every dollar of book depreciation charged to customers carries a tax benefit. This deferred tax also reduces rate base so that customers receive the benefit of the cost-free capital.

Q. How did the TCJA create excess deferred income taxes?

A. Deferred taxes are calculated using the tax rate in effect at the time the deduction is claimed. TCJA was enacted in 2017, and reduced that tax rate from 35% to 21% starting in 2018. Because the tax rate has permanently declined to 21%, when those timing differences reverse, the amount of tax owed will be computed at the new lower 21% rate, not 35%. As a result, a portion of PSE&G's December 31, 2017 ADIT balance was in excess of what is needed to offset future tax liabilities and thus must be returned to customers.

Q. Are there requirements on how the EDIT is returned to customers?

A. Yes, depending on the deduction that caused the ADIT balance. These excess deferred taxes fall into two categories: (1) those restricted by the normalization provisions of the TCJA (sometimes referred to as "protected" EDIT); and (2) those that are not (sometimes referred to as "unprotected" EDIT).

Q. How is the protected EDIT returned to customers?

A. The protected excess deferred taxes must be returned to customers using the Average Rate Assumption Method ("ARAM"). The ARAM provision provides for the reversal of EDIT on a vintage and class basis as the related timing differences reverse, using the weighted average tax rate at which deferred taxes were established.

Q. How is the unprotected EDIT returned to customers?

A. By way of contrast to the protected EDIT, the unprotected excess deferred taxes can be returned to customers over any reasonable period. As approved by the Board on October 29, 2018 at the conclusion of the Company's prior rate case, the Company has been refunding unprotected EDIT over an approximately five-year period through December 31, 2023[1], with a slight remaining balance to be refunded in 2024, in accordance with the IRS Private Letter Ruling ("PLR") discussed below.

Q. How does TCJA address accelerated and "bonus" depreciation?

A. While TCJA provides for 100% depreciation for capital expenditures beginning September 27, 2017, regulated utilities are not eligible for this 100% expensing. Beginning in 2018, only regular Modified Accelerated Cost Recovery System ("MACRS") depreciation may be claimed by regulated utilities.

Q. Does TCJA contain any other changes relevant to this case?

A. No.

B) IRA

Q. Does the Inflation Reduction Act of 2022 impact the current rate proceeding?

A. The IRA enacted a new 15% corporate alternative minimum tax ("CAMT") and made material changes to energy tax credit law. Since enactment, the U.S. Treasury has issued various proposed regulations and Notices that provide interim guidance regarding several provisions of the IRA. The foundation of the CAMT is U.S. GAAP income, the computation starts with net book income to which IRS prescribed adjustments are made. This is referred to

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[1] *I/M/O the Petition of Public Service Electric and Gas Company for Approval of an Increase in Electric and Gas Rates and for Changes in Tariffs for Electric and Gas Service, B.P.U.N.J. No. 16 Electric and B.P.U.N.J. No. 16 Gas, and for Changes in Depreciation Rates, Pursuant to N.J.S.A. 48:2-18, N.J.S.A 48:2-21 and N.J.S.A. 48:2-21.1, and for Other Appropriate Relief*, BPU Docket Nos. ER18010029 & GR18010030; *I/M/O the New Jersey Board of Public Utilities' Consideration of the Tax Cuts and Jobs Act of 2017*; BPU Docket No. AX18010001; *I/M/O Public Service Electric and Gas Company for Approval of Revised Rates (Effective on an Interim Basis April 1, 2018) to Reflect the Reduction Under the Tax Cuts and Jobs Act of 2017*, BPU Docket No. ER18030231, Decision and Order Adopting Initial Decision and Stipulation (October 29, 2018) (the "2018 Rate Case Order") at 9-11.

as adjusted financial statement income ("AFSI"). Companies whose three-year historical average AFSI exceeds $1 billion is subject to CAMT from that point forward. In any given year a company will pay the IRS the higher of the CAMT or regular tax. The Notices related to the CAMT state that Treasury anticipates issuing additional guidance along with proposed and final regulations. Many aspects of the IRA remain unclear and in need of further guidance; therefore, the impact the IRA will have on PSE&G's financial statements and this proceeding is subject to continued evaluation and the issuance of additional authoritative guidance.

Q. Does the Company believe PSE&G will be subject to the CAMT?

A. Yes, based on the guidance U.S. Treasury has released through Q1, 2024. However, this could change based on the issuance of additional authoritative guidance or interpretation of existing guidance. Based on the understanding as of Q1, 2024 , the Company calculated a CAMT liability for 2023 of $55,294,627 for the electric utility and $50,622,621 for gas distribution, or a total for PSE&G of $105,917,249. For clarity, these amounts represent the amount by which the CAMT liability exceeds the regular tax liability. See the revised response to RCR-A-0087 UPDATE for the calculation of the CAMT for the utility. This calculation was not part of the Company's initial filing but was recorded in PSE&G's audited books and recorded in December 2023.

Q. What is the impact of the CAMT on income tax expense?

A. There is no change to PSE&G's income tax expense and cost of service as a result of the CAMT. The CAMT amounts noted above increase current tax expense but are fully offset by a reduction in deferred taxes with no net change to total income tax expense. However, the reduction in deferred taxes results in a decrease in accumulated deferred income taxes and increase in the Company's rate base.

Q. Is the Company seeking recovery of the CAMT in this proceeding?

A. Due to the uncertainty of the rules, not at this time. The Company is still awaiting additional guidance that could increase, decrease or eliminate the CAMT liability for PSE&G. Rather, the Company is proposing to recover any impact of the CAMT through the TAC, once the final rules are clearer, as described in more detail in the testimony of Company Witness Stephen Swetz. There is no impact from the CAMT in the Company's ADIT balance or income tax expense used to set base rates in this proceeding. Further, while Mr. Swetz has adjusted the TAC schedules to allow for recovery on the working capital impact of any CAMT payments, the Company is not including any amount of the CAMT at this time while it awaits additional guidance on the rules.

III. TAX EXPENSE AND ACCUMULATED DEFERRED INCOME TAXES

Q. Have you determined the appropriate income tax expense component of operating income for the filed test period?

A. Yes. I have computed a total income tax expense for the test period of $25 million for electric and a total income tax benefit of ($29) million for gas. This is comprised of a current tax benefit of ($8) million for electric and a current tax expense of $11 million for gas, and a deferred tax expense of $33 million for electric and a deferred tax benefit of $40 million for gas. The details of this determination are shown on Schedule CP-2 R-1, which shows current tax expense and significant components of deferred tax expense. I provided this tax expense to Mr. McFadden for inclusion in his Schedule MPM–28 R-1. The income tax expense includes a tax benefit for bad debt write offs, which is excluded in a pro forma adjustment in the testimony of Mr. McFadden, and is included in Schedule MPM-53 R-1.

Q. Did you prepare a schedule showing the balance of ADIT associated with utility plant?

A. Yes. It can be found at Schedule CP–3 R-1. In the schedule, I have broken utility-plant-related ADIT down into the following categories:

- ***Accelerated depreciation and other*** – includes the federal deferred taxes that either arise or reverse through depreciation deductions (including bonus depreciation) allowed pursuant to sections 167 and 168 of the Internal Revenue Code ("IRC").
- ***Safe Harbor Adjusted Repair Expense ("SHARE") deductions*** – includes federal deferred taxes associated with projects that are claimed as deductible repair expenses pursuant to IRC section 162 but are capital assets for financial reporting purposes. This deduction is described in more detail below.
- ***Mixed Service tax deduction*** – includes existing federal deferred taxes associated with projects that historically claimed a tax deduction for Mixed Service costs under IRC 162. This deduction is described in more detail below.
- ***NJ corporate business tax*** – includes all deferred taxes provided for the NJ Corporate Business Tax.

Mr. McFadden has reflected these deferred taxes as a rate base reduction in Schedule MPM–03 R-1.

<u>SHARE Deduction</u>

Q. What is a SHARE deduction?

A. The SHARE deduction is an acronym for the repair deductions discussed below.

Q. What are repair deductions?

A. On September 12, 2011, the IRS released Revenue Procedure 2011-43, which was later modified in Revenue Procedure 2014-16, detailing a safe harbor method for determining repair deductions for electric transmission and distribution property. Generally, for book and tax purposes, costs are either capitalized into the depreciable basis of an asset or currently expensed for book purposes and deducted for tax purposes. For tax purposes, costs associated with a unit of property are considered deductible repair expenses and not capitalized unless they are incurred for either a) betterment of the property, b) restoration of the property, or c) to adapt the unit of property to a new or different use as determined under the Revenue Procedure.

Q. How do the repair deduction rules apply?

A. These rules apply to all vintages of property and permit immediate expensing of all costs associated with projects considered a deductible repair expense pursuant to IRC section 162, resulting in a tax reduction in the year incurred, but are capital assets for financial reporting and ratemaking purposes. PSE&G has claimed enhanced repair deductions since 2010 for both its electric and gas distribution operations (referred to as a "SHARE deduction"). SHARE deductions are considered unprotected.

Q. Has the IRS provided additional guidance on the Gas SHARE deductions?

A. Yes. In April 2023, the Treasury released Revenue Procedure 2023-15 associated with determining the repair deduction for gas transmission and distribution property.

The impact, if any, of this Revenue Procedure is in process of being determined and possibly may require additional authoritative guidance. The Company reserves the right to propose an adjustment to the TAC to capture the impact of Revenue Procedure 2023-15 including any further guidance issued.

Q. How is the SHARE deduction returned to customers?

A. The SHARE deduction is returned to customers through the TAC in two ways: 1) amortization of the historic SHARE balance and 2) flow-back of the current net SHARE tax benefit. The historic SHARE was a component of the Company's ADIT in the 2018 base rate case. Per the Stipulation of Settlement approved by the Board in the 2018 Rate Case Order, the balance is being flowed-back to customers over a 10-year period, with one-third of the balance returned in the first five years and the two-thirds remaining balance returned in the remaining five years.[2] The current SHARE is calculated as the on-going, annual SHARE tax deduction less the book depreciation associated with SHARE deductions multiplied by the federal tax rate. It is contemporaneously flowed back to PSE&G's customers.

Q. Is the SHARE deduction the same each year?

A. No. The SHARE deduction has the potential to significantly vary year-to-year based on the actual plant activity and mix of capital projects placed in service each year that qualifies as repair, which causes volatility in the SHARE deduction.

Mixed Service Deduction

Q. What is a Mixed Service deduction?

A. IRC section 263A governs which costs are capitalizable, deductible, or both, referred to in Treasury Regulation Section 1.263A-1(e)(4)(ii)(C) as "Mixed Service costs." That Treasury regulation defines Mixed Service costs as service costs that are partially allocable to production or resale activities (capitalizable) and partially allocable to nonproduction or non-

[2] 2018 Rate Case Order at 9.

resale activities (deductible). Mixed Service costs are typically thought of as general and administrative costs.

Q. Can you provide an example of a Mixed Service deduction?

A. A company's personnel department may incur costs to recruit employees engaged in the production of self-constructed assets (capitalizable) as well as costs to recruit employees engaged in nonproduction activities (deductible).

Q. How does the Mixed Service deduction impact ADIT?

A. Treasury Regulation section 1.263A applies to all vintages of property and permits immediate deduction of all costs associated with projects pursuant to IRC section 162, resulting in a tax deduction in the year incurred, but are capital assets for financial reporting and ratemaking purposes. ADIT results from the timing difference between financial reporting, which is depreciated over the life of the asset, and tax reporting, which is immediately deducted. Mixed Service deductions are unprotected and not subject to the tax normalization rules.

Q. Is there more than one directive on how to calculate the Mixed Service deduction?

A. Yes. The IRS has issued a number of Industry Director Directives ("IDDs") related to the computation of the Mixed Service deduction. Generally, the regulated utility industry follows IDD No. 5 (LMSB 04-0809-033, 2009), which is based on the simplified service cost method.

Q. Are you proposing a change in the regulatory treatment of the Mixed Service deduction in this proceeding?

A. Yes. As described below, the Company proposes to return both the historic and current Mixed Service deduction to customers through the TAC in the same manner as done for the SHARE.

Q. Do you have any workpapers or schedules supporting your current Mixed Service forecast?

A. Yes. See Schedule CP-4 for the calculation.

Deferred vs Flow-thru Accounting

Q. What is deferred tax accounting and how does it differ from flow-thru accounting?

A. Generally Accepted Accounting Principles ("GAAP"), codified as ASC 740, require comprehensive inter-period tax allocation for all temporary differences between book and tax accounting. Simply stated, a temporary difference is an item of income or expense, for which the difference in basis or timing of recognition in income differs between tax purposes and financial reporting purposes. When a temporary difference is reflected in the computation of taxable income in a different period than it is for financial reporting purposes, there is an impact on the timing of taxation, and GAAP requires that a deferred tax expense or benefit be recorded on the income statement to reflect the future reversal of that temporary difference. A deferred tax expense results in an increase in ADIT liabilities on the balance sheet, and the liability reverses as the Company repays the temporary benefit to the government in the form of higher tax payments in the future. This is what I refer to as deferred tax accounting.

Q. Can you describe flow-through accounting?

A. To state it simply, flow-through accounting puts the utility on a tax return basis (cash basis) for tax recovery in the ratemaking process. Tax expense or benefit of the particular item will flow to customers in the year in which the taxes are reflected in the tax return. Deferred tax accounting, in contrast, matches the tax impact of an item of expense or income with the recovery of that item from customers.

Q. Is either the flow-through or deferred tax accounting method required?

A. Neither method is required in setting rates, subject to two exceptions.

First, for ratemaking purposes, when the tax normalization rules apply, deferred tax accounting is required. Normalization rules apply to deductions associated with accelerated depreciation claimed pursuant to IRC sections 167 and 168. The deduction for accelerated depreciation will be forfeited if the normalization rules are violated by flowing back tax depreciation benefits to customers too quickly. The normalization rules do not apply to deductions claimed under any other section of the Code, such as the SHARE and Mixed Service deductions that are claimed under IRC section 162.

The second exception is that N.J.S.A. 48:2-21.34 requires deferred tax accounting in setting utility rates for all temporary differences used in computing New Jersey ("NJ") State income tax. Therefore, no ADIT computed at the NJ rate may be flowed through, and instead, normalization would be required for the NJ State income tax portion of the SHARE and Mixed Service deductions.

IV. TAX ADJUSTMENT CREDIT

Q. Can you please describe the TAC?

A. The prior base rate proceeding established a separate Electric and Gas TAC ("ETAC" and "GTAC") as set forth on Attachment C of the Stipulation of Settlement approved in the 2018 Rate Case Order. The 2018 Rate Case Order approved the following eight components of the TAC:

- A one-time refund of the excess income tax recovery from January - March 2018 was issued during the two-month period November and December 2018 and included interest based upon the Company's interest rate obtained on its commercial paper and/or bank credit lines utilized in the preceding month;[3]
- Refund of the protected excess deferred tax balance, which is flowed back to customers under the ARAM or any other method as required by the IRS;
- Refund of the unprotected excess deferred tax balance over an approximately five (5) year period through December 31, 2023, with the annual amortization as shown in Attachment C of the Stipulation;
- Refund of the historic SHARE balance as of October 31, 2018 over a 10 year period, with one-third of the balance returned over the first approximately 5 years through December 31, 2023, and the balance returned over the remaining 5 year period ending December 31, 2028;
- Return on the increase in rate base at the Company's after-tax WACC from the flow-through of rate base related excess deferred taxes (comprised of all protected excess

[3] These amounts have been flowed back to customers and has no impact on the current rate proceeding.

deferred taxes, the historic SHARE, and a portion of the unprotected excess deferred taxes as shown in Attachment C of the Stipulation);

- Payment of interest at the Company's after-tax WACC on the balance of the non-rate base related excess deferred taxes until fully refunded over the approximately 5-year period;
- Flow-through of the estimated current period SHARE deduction, plus or minus true-ups from prior periods, calculated as the actual SHARE tax deduction less all associated SHARE book depreciation, multiplied by the Federal tax rate. Any true ups from prior periods will be flowed back to customers in the next appropriate period. Note, this adjustment is inclusive of expenses that made up the ADR repair allowance deduction previously in base rates such that all repair related flow through will be done through the TAC; and
- A revenue gross-up of the net tax flow-through.

The mechanics of the TAC are discussed in the Direct Testimony of Mr. Steven Swetz. Additionally, Attachment C of the Stipulation of Settlement adopted by the Board in the 2018 Rate Case Order set forth the EDIT and SHARE tax benefit balances to be flowed back to customers monthly for the period Jan 2018 through December 2019 and the annual flow back of the protected and unprotected excess deferred taxes for years 2020 through 2029.

Q. Have the balances of the Protected and Unprotected Excess ADIT changed since the 2018 Rate Case Order?

A. Yes. The balances for the Protected and Unprotected Excess ADIT, which were approved to be refunded in the 2018 Rate Case Order, changed for four reasons:

1) A reclassification between the protected and unprotected balance;

2) An ADIT adjustment as a result of the 2017 federal and state return to accruals ("RTA");

3) The result of the IRS ruling on the Company's PLR requests with regard to a change in accounting method and the treatment of cost of removal expenditures, which is discussed in more detail below; and

4) An IRS audit settlement of tax years prior to 2018.

The first two adjustments were included in the Company's 2019 TAC filing and subsequently adjusted to reflect the immaterial impact of the federal benefit of state taxes that resulted from the 2017 state return to accrual.[4] The IRS guidance on the Company's PLR request was not available at the time of the Company's 2019 TAC filing as it was issued in April 2020. The Company incorporated the results of the PLR requests into the final approved TAC rates approved by the Board on July 16, 2020. There has been no change to the Company's historic SHARE balance. The Company has settled its 2011 through 2016 tax return audit with the IRS and reflected any changes to the excess deferred taxes as a result of the settlement in the fourth quarter of 2020. These impacts were included in the 2021 TAC filing.[5]

Q. Do the first two adjustments (reclassification and 2017 RTA) approved in the 2019 TAC filing affect the current filing?

A. Yes. While the adjustments to the balances occurred in 2018, the relative amortization related to these adjustments are being amortized through 2023.

[4] *I/M/O the Petition of Public Service Electric and Gas Company for Approval of Changes in Its Electric Tax Adjustment Credit and Gas Tax Adjustment Credit ("2019 TAC Filing")*, BPU Docket Nos. ER19091302 and GR19091303 (filed September 26, 2019).

[5] *I/M/O the Petition of Public Service Electric and Gas Company for Approval of Changes in its Electric Tax Adjustment Credit and Gas Tax Adjustment Credit ("2021 TAC Filing")*, BPU Docket Nos. ER21101201 & GR21101202 (filed October 29, 2021) at Attachment 1 at 10.

Q. Please explain what are the PLR reclassifications between protected and unprotected deferred income taxes?

A. In compliance with the Company's Base Rate Case Order, PSE&G sought a PLR from the IRS that would give guidance as to whether excess deferred income tax associated with accounting changes to repair deductions and mixed service costs are protected in nature and subject to normalization rules. In addition, PSE&G also required a PLR from the IRS regarding its post-1981 cost or removal and whether amounts were subject to normalization rules and if it is to be treated as a separate temporary difference or part of the overall depreciation temporary difference.

Q. Did PSE&G obtain those private letter rulings?

A. Yes. In April 2020, the IRS issued a ruling to PSE&G that held both the deficient deferred taxes related to COR and the excess deferred taxes associated with accounting method changes related to repair deductions and the capitalization of mixed service costs are unprotected and not subject to the tax normalization rules.

Q. What excess amounts will be amortized pursuant to those PLRs?

A. Pursuant to the guidance in the PLR, PSE&G is flowing back $75 million in total net pre-tax credits to customers. Of that amount, approximately $41 million and $34 million in excess deferred income taxes will be amortized to electric and gas customers, respectfully, through 2024.

Q. Are these amounts currently being amortized back to customers?

A. Yes. On July 16, 2020, the Board approved PSE&G's Updated 2019 TAC filing including the reclassification pursuant to the IRS guidance that these deficient deferred taxes related to COR and the excess deferred taxes are not subject to the tax normalization rules. As such, these amounts have been reclassified and are being amortized through the TAC effective July 16, 2020, as approved by the Board.

Q. What are the benefits associated with the TAC?

A. There are several benefits associated with the TAC:

- Utilizing the TAC allows for an uneven method of amortization, which the Company could not do in a traditional base rate amortization without an annual base rate case.
- It provides a mechanism to stop the amortization of historical ADIT once the repair-related ADIT is fully returned to customers, to avoid possible IRS normalization violations.
    - If the Company were to over-amortize the SHARE-deduction-related ADIT balance, the excess amortization arguably would come from the depreciation-related ADIT, which is protected by the normalization rules. Reversing that deferred tax would result in a normalization violation and the possibility of significant penalties. Use of the TAC eliminates that risk.
- The TAC provides a mechanism that will permit the recovery of IRS audit adjustments, changes, or subsequent clarifications to tax law, or other major tax changes, if any.
    - For example, while the IRS has not challenged the Company's SHARE deductions, tax deductions of this magnitude are routinely scrutinized. Given the size of these deductions and the IRS's policy of auditing multiple years at a time, a final disallowance could be material. Because the tax benefit of any deductions will have already been passed to customers, any IRS disallowance and interest thereon would need to be recovered from customers. The TAC will provide the mechanism to ensure timely recovery.

Q. What is the status of the Excess Deferred Tax balance to be flowed back through the TAC?

A. The reduction in the federal tax rate generated a total of $1 billion of excess deferred taxes. Through the end of 2022, the balance remaining of protected EDIT to be flowed back to customers is approximately $882 million and unprotected EDIT is approximately $203 million. For the test period, the flow back to customers is included in this filing.

Q. Are there any adjustments to the TAC as originally approved in the 2018 rate case?

A. Yes. PSE&G proposes the following adjustments, which are described in more detail later in my testimony:

1) In addition to continuing to flow back the benefit of the historic SHARE deduction, the Company proposes to flow back to customers the net federal tax benefit associated with the historical Mixed Service ADIT balance over approximately five years.

2) The Company proposes to add the current Mixed Service deduction net benefit to the current SHARE deduction net benefit already included in the TAC, but both at a pre-determined, fixed annual amount, with any excess to be flowed back to customers in a subsequent rate case;

3) To better match the seasonal flow of Company pre-tax income, the Company began to amortize the monthly flow back of EDIT and SHARE on a seasonal basis in the 2023 TAC filing to match pre-tax income as described in the 2023 TAC cost recovery

proceeding.[6] In this proceeding, the Company is aligning the return calculation with the seasonal amortization methodology; and

4) The Company proposes to recover/refund the annual impact of the CAMT liability as a result of the IRA through the TAC.

I discuss each proposed change below.

1) Historic Mixed Service

Q. Why are you proposing to flow back the historic Mixed Service deduction through the TAC?

A. The historic Mixed Service deduction is an unprotected deferred tax liability that can be flowed back to customers. This is similar to the current mechanism to flow back the historic SHARE to customers with the exception that it would be over an approximate three-year period instead of 10 years as approved in the last rate case for the historic SHARE. The historic Mixed Service balance is part of ADIT and reducing the Company's rate base. As the tax benefit is flowed back to customers, the ADIT balance declines and the Company's rate base increases. In the same manner as approved for the historic SHARE, the Company can refund this tax benefit to customers on an accelerated basis and earn a return on the increased rate base as a result of the refunds. The TAC allows for the accelerated refund of the Mixed Service net tax benefit while earning its allowed return as its rate base increases. The projected Mixed Service historic ADIT balance as of August 31, 2024 is approximately $366 million, and grossed up to revenues would represent a benefit to customers of $509 million. See Schedule CP-4 for the

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[6] *I/M/O the Petition of Public Service Electric and Gas Company for Approval of Changes in Its Electric Tax Adjustment Credit and Gas Tax Adjustment Credit ("2023 TAC Filing")*, BPU Docket Nos. ER23090634 and GR23090635 (filed September 1, 2023) (the "2023 TAC Filing").

historic Mixed Service deduction that the Company proposes to be flowed through to customers through the TAC.

2) Annual SHARE and Mixed Service Deduction

Q. Are you proposing to flow back the annual Mixed Service deduction to customers as well?

A. Yes. As described below, the Company proposes that a fixed annual flow back amount be refunded to customers for both the annual SHARE and Mixed Service deductions.

Q. What is the annual Mixed Service and SHARE flow back?

A. The annual SHARE flow back is the annual Federal repair tax deduction less the associated book depreciation multiplied by the federal tax rate. Likewise, the annual Mixed Service flow back is the annual federal Mixed Service tax deduction less the associated book depreciation multiplied by the federal tax rate.

Q. Can you please discuss the proposal to limit the flow-back of the annual net SHARE and Mixed Service deductions?

A. To ensure that PSE&G customers receive the full benefit of these deductions while minimizing fluctuations in Distribution Customers' bills, the Company proposes to flow back a fixed annual benefit of $38 million and $18 million related to the annual SHARE and Mixed Service deduction, respectively, or a combined impact of $56 million. The actual SHARE and Mixed Service deductions will continue to be calculated and tracked annually. To the extent the actual benefit is higher than the proposed flow back amount, the excess would be added to the ADIT balance and flowed back to customers in a subsequent rate case.

Q. What is the benefit of this approach to limit the flow back amounts?

A. A fixed flow back amount will reduce the rate volatility and revenue requirement swings currently occurring in the existing TAC. The Current SHARE fluctuates annually and has seen significant swings, typically recorded in December. In addition, deferring the difference between the actual and proposed flow back amount can increase ADIT and provide an additional unprotected balance to be refunded to customers in a future rate case.

Q. Can you provide a simple example of how the deferral will work?

A. Yes. Assume this proposal is accepted and allows for a net SHARE deduction of $100 be flowed back to customers. However, the actual benefit is $150. The $50 additional benefit would be added to the existing ADIT balance, reduce rate-base, and be flowed back to customers in a subsequent rate case.

3) Monthly Amortization Pattern

Q. Can you please describe why the monthly amortization pattern of EDIT and SHARE flowback has changed and the impact to the return calculation?

A. As described in the Company's 2023 TAC Filing, the Company has changed the monthly amortization pattern to reflect the seasonality of pre-tax income. Historically, approximately 33% of the Company's revenue is generated in the first quarter each year. However, the tax benefits from flowing back the EDIT and SHARE were amortized on a straight-line basis, which caused a monthly mismatch. As a result, in 2023 the Company changed the monthly amortization of the EDIT and SHARE flowback to follow the seasonal pattern as the Company generates pre-tax income. The full-year total to be flowed to customers is not impacted. For the impact to the return calculation, see Schedule SS-ETAC-

1E R-1 for electric and Schedule SS-GTAC-1G R-1 for gas in the Direct Testimony of Mr. Swetz.

4) CAMT

Q. Why do you propose to recover the CAMT through the TAC?

A. There still remains uncertainty on the calculation/rules of the CAMT and its impact to PSE&G as the industry awaits additional guidance from the US Treasury. The TAC allows the Company to adjust annually for any impact resulting from additional US Treasury guidance and interpretation of existing guidance. Further, the TAC provides for a return on the increase in rate base as deferred taxes decline. The CAMT will work in the same way where the Company would calculate a return on the change in rate base as a result of the change in deferred taxes in the annual TAC filings.

Revised TAC

Q. Has the TAC been modified to reflect all of the changes you describe above?

A. Yes. Please see Schedule SS-ETAC-1E R-1 and Schedule SS-GTAC-1G R-1 of Mr. Swetz's testimony for the updated TAC reflecting:

1) The continued refund of the protected EDIT under ARAM;
2) The continued refund of the Historic SHARE (increased to reflect 2/3 of the October 31, 2018, balance as approved in the 2018 base rate case;
3) The new flow back of the Historic Mixed Service Deduction proposed to be added in this proceeding;
4) The adjustment to deferred taxes and rate base as a result of the CAMT;
5) The return on the flow backs as they are returned to customers and the change in deferred taxes as a result of the CAMT; and

6) The fixed flowback of the combined Current SHARE and Current Mixed Service deductions to account for the forecasted future deductions.

V. CONSOLIDATED TAX ADJUSTMENT

Q. What is a Consolidated Tax Adjustment?

A. To state it simply, a Consolidated Tax Adjustment ("CTA") is a ratemaking adjustment designed to pass some or all the benefit of tax savings generated by nonregulated subsidiaries of a consolidated return filing group to the regulated affiliate.

Q. What is the Board's policy regarding CTAs?

A. On January 23, 2014, the Board issued an order opening Docket EO12121072, a generic proceeding to review the applicability and computation of the CTA. On November 22, 2014, the Board issued an order ("November 22 Order") in that docket setting out key computational requirements with respect to the CTA. On December 17, 2014, the Board reaffirmed the January 2014 Order. The Board found that it is appropriate to include a Consolidated Tax Adjustment in utility base rate filings and found that the current CTA policy shall remain in effect with the following modifications:

1) The review period for the calculation shall be for five calendar years including any complete year that is included in the test year;
2) The calculated tax adjustment based on that review period shall be allocated so that the revenue requirement of the company is reduced by 100% of the adjustment; and
3) Transmission assets of the EDCs would not be included in the calculation of the CTA.

Q. Have you included a computation of the CTA that is consistent with Board Order?

A. Yes I have. In Confidential Schedule CP–5 R-1, I have provided the detailed computation using the approved Board Order. The resulting CTA reduces rate base by approximately $3 million for electric and $0 for gas. These reductions have been considered in this rate proceeding. Mr. McFadden has included this amount in rate base as shown in Schedule MPM–3 R-1.

Q. Does this conclude your testimony at this time?

A. Yes, it does.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Schedule CP-2 R-1

	Electric Distribution	Gas Distribution	Total
a - Current Federal Tax Exp	103,400,202.55	$54,561,228.00	$157,961,430.55
b - Current State Tax Exp	11,407,112.81	$21,499,245.27	$32,906,358.08
c - Deferred Federal Tax Exp	(114,033,361.28)	($123,009,443.69)	($237,042,804.97)
d - Deferred State Tax Exp	20,381,239.04	$3,353,178.86	$23,734,417.90
e - ITC Expense	(4,524,880.64)	($736,758.92)	($5,261,639.56)
Total Tax Expense	$16,630,312.48	($44,332,550.48)	($27,702,238.00)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
Schedule CP-3 R-1
Accumulated Deferred Income Taxes
RR9N3 - 0013

ACCUMULATED DEFERRED TAXES - ELECTRIC
($000)

	Actuals 12/31/2022 Balance	Actuals 12/31/2023 Balance	Estimated 5/31/24 Balance	Estimated 11/30/24 Balance	Estimated 12/31/24 Balance
Depreciation & Other	$ (1,069,347)	$ (1,036,682)	$ (1,046,404)	$ (1,057,296)	$ (1,058,631)
Repair Deduction	$ (73,434)	$ (63,879)	$ (54,662)	$ (45,193)	$ (43,476)
Mixed Service Deduction	$ (163,425)	$ (171,400)	$ (177,473)	$ (184,759)	$ (185,974)
NJ Corporate Business Tax	$ (386,253)	$ (389,758)	$ (415,893)	$ (447,036)	$ (451,937)
Total Electric Accumulated Deferred Taxes	$ (1,692,459)	$ (1,661,719)	$ (1,694,431)	$ (1,734,284)	$ (1,740,018)
Proforma Adjustments:					
Adjusted Electric Accumulated Deferred Taxes	$ (1,692,459)	$ (1,661,719)	$ (1,694,431)	$ (1,734,284)	$ (1,740,018)

ACCUMULATED DEFERRED TAXES - GAS
($000)

	Actuals 12/31/2022 Balance	Actuals 12/31/2023 Balance	Estimated 5/31/24 Balance	Estimated 11/30/24 Balance	Estimated 12/31/24 Balance
Depreciation & Other	$ (898,319)	$ (864,423)	$ (866,690)	$ (870,232)	$ (870,942)
Repair Deduction	$ (203,465)	$ (179,963)	$ (170,362)	$ (162,013)	$ (160,346)
Mixed Service Deduction	$ (147,688)	$ (155,979)	(162,293)	$ (169,869)	$ (171,132)
NJ Corporate Business Tax	$ (441,059)	$ (489,050)	$ (507,569)	$ (529,471)	$ (533,229)
Total Gas Accumulated Deferred Taxes	$ (1,690,531)	$ (1,689,415)	$ (1,706,913)	$ (1,731,586)	$ (1,735,649)
Proforma Adjustments:					
Adjusted Gas Accumulated Deferred Taxes	$ (1,690,531)	$ (1,689,415)	$ (1,706,913)	$ (1,731,586)	$ (1,735,649)

EXHIBIT P-4 R-1

Schedule CP-5 R-1

CONFIDENTIAL

STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

In the Matter of the Petition of
Public Service Electric and Gas Company
for Approval of an Increase in Electric and Gas
Rates and for Changes in the Tariffs for
Electric and Gas Service, B.P.U.N.J.
No. 17 Electric and B.P.U.N.J. No. 17
Gas, and for Changes in Depreciation Rates,
Pursuant to N.J.S.A. 48:2-18,
N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1, and
for Other Appropriate Relief

BPU Docket Nos. ER23120924 & GR23120925

DIRECT TESTIMONY
OF
MICHAEL J. ADAMS
9+3 UPDATE

Submitted on Behalf
of
PUBLIC SERVICE ELECTRIC AND GAS COMPANY

April 15, 2024
P-8 R-1

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
DIRECT TESTIMONY
OF
MICHAEL J. ADAMS
SENIOR VICE PRESIDENT, CONCENTRIC ENERGY ADVISORS, INC.

I. INTRODUCTION AND WITNESS QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Michael J. Adams. My business address is 293 Boston Post Road West, Suite 500, Marlborough, Massachusetts 01752.

Q. By whom are you employed and in what position?

A. I am a Senior Vice President with Concentric Energy Advisors, Inc. ("Concentric").

Q. Please describe Concentric.

A. Concentric is a management consulting and economic advisory firm focused on the North American energy and water industries. Concentric specializes in regulatory and litigation support, transaction-related financial advisory services, energy market strategies, market assessments, energy commodity contracting and procurement, economic feasibility studies, and capital market analyses and negotiations.

Q. What are your responsibilities in your current position?

A. As a Senior Vice President my responsibilities include assisting clients in identifying and addressing business issues. My primary areas of focus have been regulatory-, financial- and accounting-related issues.

Q. Please describe your education.

A. I have an MBA from the University of Illinois – Springfield and a Bachelor of Science in Accounting from Illinois College. I am a member of the American Institute of Certified Public Accountants and the Illinois Society of Certified Public Accountants.

Q. Please describe your qualifications.

A. I have over thirty-five years of direct experience in the public utility industry. I have worked for an investor-owned utility, a regulatory agency, and most recently as a consultant to the energy industry. I have managed and/or participated in a wide variety of consulting engagements. A statement of my background and qualifications is attached as Schedule MJA-LL-1.

Q. Have you ever testified in a regulatory proceeding?

A. Yes. I have provided expert testimony or reports before the Arizona Corporation Commission; Arkansas Public Service Commission; the Connecticut Public Utilities Regulatory Authority, the Federal Energy Regulatory Commission (FERC); the Georgia Public Service Commission; the Hawaii Public Utilities Commission; the Idaho Public Utilities Commission; the Illinois Commerce Commission; the Kentucky Public Service Commission; the Maine Public Utilities Commission; the Maryland Public Service Commission; the Massachusetts Department of Public Utilities; the Missouri Public Service Commission; the Montana Public Service Commission, the New Hampshire Public Utilities Commission; the New Mexico Public Regulation Commission; the State of New Jersey Board of Public Utilities; the Oklahoma Corporation Commission; the Ontario Energy Board; the Pennsylvania Public Utility Commission; Public Utilities Commission of the State of South Dakota; the Tennessee Public Utility

Commission; the Texas Public Utility Commission; the Virginia State Corporation Commission; and the West Virginia Public Service Commission.

My testimonies typically address issues related to affiliate transactions, cash working capital, cost of service/revenue requirement, shared services, accounting, cost allocations and/or regulatory policies and practices.

II. PURPOSE AND SCOPE

Q. What is the purpose of your direct testimony?

A. I have been asked by Public Service Electric and Gas Company ("PSE&G" or the "Company") to prepare and discuss a lead-lag study that was used to develop Cash Working Capital ("CWC") factors that were ultimately used to calculate the cash working capital requirements for the Company's electric and gas operations. I also discuss the analysis of the Company's net assets and liabilities, which are a separate source of working capital. The Company has included the results of the lead lag study and the net asset and liabilities analyses in its rate base. Discussion of the studies follow.

III. CASH WORKING CAPITAL

Q. Please define what you mean by the phrase "cash working capital requirement."

A. The cash working capital requirement is the amount of funds the Company is required tomaintain on hand to finance the day-to-day operations of the Company.

Q. Are you sponsoring any schedules in this proceeding related to your analysis of pseg's cash working capital requirement?

A. Yes. Schedules MJA-LL-2 through MJA-LL-3 set forth the results of the lead lag study and Net Assets and Liabilities analyses, respectively. Schedules MJA-LL-6 to -MJA-LL-18 are the workpapers supporting the lead-lag study and Net Assets and Liabilities analyses, respectively. The schedules were prepared under my direction and supervision and are accurate and complete to the best of my knowledge and belief.

IV. LEAD-LAG STUDY

Q. For what period was the lead-lag study performed?

A. The lead-lag study analyzed the Company's cash transactions and invoices for the twelve months ended December 31, 2022. The leads and lags were applied to expense amounts for the Test Year.

Q. How should the results of the cash working capital analysis and the net assets and liabilities be treated for ratemaking purposes?

A. The cash working capital requirements calculated using the CWC factors from the lead-lag study and the results of the net assets and liabilities analyses should be included as part of PSE&G's electric and gas operations rate base for ratemaking purposes.

Q. Is the analysis of the revenue lags and expense leads typically referred to as a lead-lag study?

A. Yes. Cash working capital requirements are typically determined by lead-lag studies that are used to analyze the lag time between the date customers receive service and the date the customers' payments are available to the Company. This lag is offset by a lead time during which the Company receives goods and services but pays for them at a later date. The "leads" and "lags" are both measured in days. The dollar-weighted lead and lag days are then divided by 365 to determine a daily CWC factor. The CWC factor is multiplied by the appropriate annual test year cash expenses to determine the amount of cash working capital required for operations. The resulting amount of cash working capital is included as part of the Company's rate base. The test year operating expenses to which the leads and lags were applied in this proceeding are described in the testimony of Company witness Mr. McFadden.

Q. What are the various leads and lags that were considered in the cash working capital analysis?

A. Two broad categories of leads and lags were considered: 1) lags associated with the collection of revenues owed to the Company ("revenue lags"); and 2) lead times associated with the payments for goods and services received by the Company, as well as the various taxes and other expenses paid by the Company ("expense leads").

Q. What is a revenue lag?

A. A revenue lag refers to the elapsed time between the delivery of the Company's product (i.e., electricity and/or gas) and its ability to use the funds received as payment for the delivery of the product.

Q. What is an expense lead?

A. An expense lead refers to the elapsed time from when a good or service is provided to the Company to the point in time when the Company pays for the good or service and the funds are no longer available to the Company.

Q. What was the source of information you employed to determine the leads and lags in your cash working capital analysis?

A. Information from the Company was utilized, including data from Accounts Receivables, Accounts Payable, Customer Service, Human Resources, Payroll, and Tax systems. The information derived from these sources, together with the analysis of specific transactions, led to the determination of the appropriate number of lead-lag days for PSE&G's New Jersey electric and gas operations.

A. Revenue Lag

Q. How was the revenue lag determined?

A. The revenue lag measures the number of days from the date service was rendered by the Company until the date payment was received from customers and such funds were deposited and available to the Company. In the calculation, the revenue lag was divided into four distinct components: 1) service lag; 2) billing lag; 3) collection lag; and 4) bank float. An explanation of each component of the revenue lag follows.

Q. What is meant by service lag?

A. The service lag refers to the number of days from the mid-point of the service period to the meter reading date for the service period. Using the mid-point methodology, the service lag was determined to be 15.21 days (365 days in the year divided by 12 months divided by 2).

Q. What is meant by billing lag?

A. Billing lag refers to the average number of days from the date on which the meter was read until the customer was billed. The billing lag was determined by analyzing the Company's monthly billing schedules and meter reading records. The average billing lag was determined to be 1.72 days. Refer to Schedule MJA-LL-6 for the calculation of the billing lag.

Q. What is meant by collection lag?

A. The collection lag refers to the average amount of time from the date when the customer received a bill to the date that the Company received payment from its customer. For purposes of the cash working capital analyses, the Company's actual customer receivables during the twelve months ended September 30, 2023 were analyzed to determine the collection lag. Based on weighted average data from the Company and by considering accounts receivables balances by days aged, the average collection lag was determined to be 50.65 days. Due to potential impacts from the pandemic during the test period of the study, the twelve months ended September 30, 2023 was used to reflect current customer payment patterns post-pandemic.

Q. Explain the calculation of the Company's collection lag.

A. The Company's monthly accounts receivable data was categorized into aging "buckets" of 0-30 days, 31-60 days, 61-90 days, 91-120 days and 120+ days outstanding. For purposes of calculating the collection lag, it was assumed that the customers will pay their bills ratably over the month. Therefore, the midpoint of the first month was determined to be 15 days (*i.e.*, 30 divided by 2). The same assumption that customers will pay their bills ratably over the course of the month was applied to each aging bucket. It was further assumed that customers will pay their bills ratably over the course of the second month (the month that is 31-60 days after the bill was issued). Therefore, the midpoint of payments received 31-60 days after the bill was issued is 45 days (*i.e.*, 30 days outstanding from the first month plus the 15-day midpoint of the second month = 45 days). This same theory applies to the use of 75 days for payments that were received 61-90 days after the bill is issued as well as the use of 105 days for the 91-120 days period. Receivables outstanding for 120 days or longer were conservatively capped at 120 days. The accounts receivable dollars in each bucket were then multiplied by the midpoint of each bucket to calculate the collections lag. Refer to Schedule MJA-LL-7 for the calculation of the collections lag.

Q. What does bank float represent?

A. Bank float represents the elapsed time from when customers' payments were deposited at the bank to when such funds were available to the Company. Based upon an analysis of the availability of deposited funds in the months of February, March and April 2022, the bank float was determined to be 0.92 days. Refer to Schedule MJA-LL-7 for the calculation of the bank float lag.

Q. Please summarize the calculation of revenue lag days.

A. The overall revenue lag, by lag component, is summarized in the following table.

Revenue Lag by Component	
Service Lag	15.21
Billing Lag	1.72
Collections Lag	50.65
Bank Float	0.92
Total Lag	**68.50**

Q. Has the Company included Energy Sales Taxes in its revenues when determining its total revenue requirement?

A. Yes. New Jersey energy sales taxes are included as a separate line item added to the revenue requirement in the determination of the total revenue requirement. The New Jersey energy sales tax is included as part of the revenue requirement lag. Customers are billed the Energy Sales Tax, known as the Sales and Use Tax (SUT), by the Company and the Company remits the charges to the State. The Company is required to remit these dollars to the State in advance of their collection and the timing difference between the remittance to the State and the collection from customers represents a working capital requirement.

B. Expense Leads

Q. What expense-related leads were considered in the lead-lag analysis?

A. Lead times associated with the following expense categories were considered in the lead-lag study: a) Salaries and Wages; b) Incentive Compensation; c) Pensions and Employee Benefits; d) Other O&M; e) Purchased Power and Gas Supply Costs; f) Taxes Other than Income Taxes; g) Federal and State Income Taxes; h) Interest on Long-Term Debt; i) Service Company Expenses; j) New Jersey Energy Sales Tax; and k) depreciation and amortization expense and operating income.

Q. Provide an explanation of the expense lead associated with the Company's salaries and wages including incentive compensation.

A. Considering PSE&G's various payroll periods (i.e., weekly and bi-weekly) and incentive compensation paid to employees, the salaries and wages expense lead was determined to be 25.38 days. Refer to Schedule MJA-LL-8 for the calculation of the salaries and wages expense lead.

Q. What employee benefits does the company provide to its empoyees and what are the expense leads associated with such benefits?

A. The Company provides benefits for its employee associated with medical, dental, group life insurance, disability (short-term disability and long-term disability), workers' compensation, other post-employment benefits ("OPEB"), pension and 401(k) matching. Using the amounts paid/contributed by the Company, the timing of the payments, and the period each payment was applied for each benefit category, the dollar-weighted expense lead for each of the benefits was determined to be as follows: medical 12.86 days; dental 2.94 days; group life insurance 15.03 days;

short-term and long-term disability 45.89 days; OPEB 0 days; pension 15.17 days; 401(k) matching 12.57 days and workers' compensation 1.63 days. Refer to Schedule MJA-LL-9 for the calculations of the individual employee benefits expense leads.

Q. What are "other O&M expenses" and how was the expense lead calculated for such expenses?

A. The Company engages in transactions with vendors for a variety of purposes including facility maintenance, system maintenance, customer service, as well as other services. Accounts payable data was analyzed in order to calculate a lead time associated with the payment for services related to other O&M activities. The analysis indicated that on average, invoices were paid by the Company 36.10 days after receipt. Where appropriate, this lead time includes a service lead time. Refer to Schedule MJA-LL-10 for the calculation of the Other O&M expense lead.

Q. What expense lead was applied to purchased power in the study?

A. The Company purchases power from two separate groups: Basic Generation Service ("BGS") suppliers and Non-Utility Generators ("Purchased Electric Power"). BGS is the Company's default supply obligation for all its customers that do not choose to obtain electric power from a third-party supplier. Purchased Electric Power requires the Company to purchase power from qualifying facilities that generate less than 20MW. Based on an analysis of the service periods and payment dates for the Company's purchase of power from the two separate groups during the period examined, a weighted expense lead of 35.83 days was determined. Refer to Schedule MJA-LL-11 for the calculation of the purchased power expense lead.

Q. What is the expense lead time associated with the Company's Natural Gas Expenses?

A. The Company purchases natural gas for distribution to its gas customers. Based on an examination of the service periods and payment dates for the Company's purchases of natural gas, a weighted expense lead time of 35.63 days was determined. Refer to Schedule MJA-LL-12 for the calculation of the natural gas expense lead..

Q. What are the various general taxes considered in the Cash working capital analysis?

A. The following general taxes were considered in the study: a) Real Estate Taxes; b) Payroll Taxes; and c) Newark City Tax. Each of the taxes are described below.

Q. Explain the lead days associated with each type of general taxes in the cash working capital analysis.

A. The treatment of each category of general taxes in the study is described below:

Real Estate Tax: The Company makes payments to various taxing authorities in the State of New Jersey. Taking the periods for which the tax is assessed, as well as the timing of the actual payment dates and amounts into consideration for the property tax payments, a dollar-weighted expense lead of negative 39.09 days was determined. Refer to Schedule MJA-LL-13 for the calculation of the Real Estate tax expense lead.

Payroll Tax: Based on an analysis of the pay periods and dates for the Company's payment of payroll taxes (FICA, social security/medicare, federal and state unemployment taxes), a weighted expense lead of 16.96 days was determined. Refer to Schedule MJA-LL-13 for the calculation of the Payroll tax expense lead.

Newark City Tax: Residents of Newark pay a flat city income taxon earned income in addition to the New Jersey state income tax and federal income tax. Non-residents who work in Newark also pay a local income tax. This tax is imposed on employers. Based on the periods for which the tax is assessed, as well as the timing of the actual payment dates and amounts taken into consideration for the Newark City Tax a dollar-weighted expense lead of 75.46 days was calculated. Refer to Schedule MJA-LL-13 for the calculation of the Newark City tax lead.

Taking the above into account, a weighted average expense lead of 6.95 days was calculated for taxes other than income taxes.

Q. How did your study address federal income taxes?

A. The lead time associated with federal income tax payments was based on the provisions of the Internal Revenue Code which requires estimated tax payments of 25 percent of total income taxes due each quarter of the current year. The first quarter payment is due by April 15th, while the second, third and fourth quarter payments are due on June 15th, September 15th, and December 15th, respectively. Taking this schedule into consideration a lead time of 37.88 days for federal income taxes was determined. Refer to Schedule MJA-LL-14 for the calculation of the federal income tax expense lead.

Q. How did you address state income taxes?

A. The expense lead for state income taxes was calculated based on the statutory tax due dates for Corporation Business Tax. Estimated payments are due on the 15th day of April, May, June, and December. This resulted in a calculated expense lead of negative 47.25 days. Refer to Schedule MJA-LL-14 for the calculation of the state income tax expense lead.

Q. Please describe how lead times associated with the Company's long-term interest expenses were addressed by the study.

A. The Company made semi-annual interest payments on its long-term debt throughout the test year. Using the midpoints of the semi-annual service periods, a dollar-weighted lead of 91.8 days for long-term interest payments was determined. Refer to Schedule MJA-LL-15 for the calculation of the interest expense lead.

Q. Provide a description of how service company expenses were addressed by the study.

A. Using the monthly invoices for charges to PSE&G from PSEG Services Corporation, a weighted-average service company expense lead of 35.91 days was determined. Refer to Schedule MJA-LL-16 for the calculation of the service company expense lead.

Q. How did your study address New Jersey energy sales tax?

A. "Charges for utility service provided and usually billed by New Jersey's public utility energy companies also are subject to the 6.625% New Jersey Sales Tax. These charges have been fully subject to the New Jersey Sales Tax since January 1, 1998".[1] The lead time for the New Jersey energy sales tax was calculated based on the midpoint of the tax liability period to the payment date, weighted by the actual amount paid. This resulted in a lead time of negative 48.71 days. Refer to Schedule MJA-LL-17 for the calculation of the New Jersey Energy Sales tax expense lead.

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[1] New Jersey Treasury, Division of Taxation. NJ Division of Taxation - New Jersey Sales and Use (state.nj.us)

Q. Did you include depreciation, amortization, and deferred tax expense in the lead-lag study?

A. Yes. PSEG has historically been authorized to apply an expense lead to expenses such as depreciation, amortization, and deferred tax expense. When these expenses reduce rate base, the Company is deprived of the return that investment in rate base affords. If there is a lag between the reduction in rate base and the receipt of revenues recovering the expense, a carrying cost is incurred by the Company for the time of the lag. As such, it is appropriate for these expenses to be part of a working capital allowance.

The lead-lag study includes depreciation, amortization, and deferred tax expenses with an expense lag of 15.2 days (i.e., based on the mid-month convention, 365/12/2). There remains a lag between when assets in rate base are reduced through depreciation and when the Company receives cash from ratepayers for services provided. Therefore, it is appropriate for the Company to be compensated for the use of cash to keep the Company whole.

Q. Was the topic of including depreciation in cash working capital a topic addressed by Robert L. Hahne in "Accounting for Public Utilities"?

A. Yes, it was.

Q. Please describe how Mr. Hahne concluded that depreciation should be handled in a lead-lag study.

A. Mr. Hahne stated as follows: [2]

> Depreciation expense reflects a zero lag. This zero lag is a noncash charge and therefore cannot produce a need for cash working capital.[3]

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[2] *Accounting for Public Utilities*, Hahne, Robert L., Chapter 5, Section 5.04, Cash Working Capital.

[3] Id.

This noncash treatment is based on the assumptions that there is no cash outlay associated with depreciation costs that investor funding is not required to pay these expenses. In fact, there was a related cash outlay when the properties were built. The sequence of events is as follows:

1. Investor funds are expended to construct a facility;
2. The facility is used to provide services with concurrent recording of a portion of the costs as depreciation expense;
3. Customers are billed for the depreciation costs incurred; and
4. Customers pay their bills with cash outlays by investors, ends with cash recovery by investors. In the interim, investors are funding the provision of utility services, and such funding must be recognized in rate base.

As the expenses are recorded, equal revenues are *recoverable* from ratepayers as reimbursement to investors and the accumulated provisions are deducted from rate base. The rate base reduction presumes that *recovery* of the recorded depreciation reserves has occurred. If the presumed recovery actually existed, there would be no justification for inclusion of the depreciation expense in cash working capital. The *recovery* assumption, however, is not correct. When the depreciation expense is recorded, the recovery is in the form of an increase in the accounts receivable from customers. The expense is recorded in one period. The actual recovery occurs later (after the service, billing, and collection period recognized in other lead-lag components). In the interim, the investor has not realized the recovery of capital that is imputed by the deduction of recorded depreciation expense. The funds due and payable to investors are being held by ratepayers, and the ratepayers should reimburse the investors for the time value of unpaid amounts due.

Q. Has the BPU Historically included depreciation in the determination of regulated utilities' cash working capital requirements?

A. Yes. The BPU has historically approved the inclusion of depreciation in the determination of cash working capital. The Company's inclusion of depreciation in the determination of its cash working capital requirement is consistent with the BPU's previous treatment and decisions.

Q. If depreciation expense were correctly included in the cash working capital requirement, as you have proposed, is the Company's depreciation expense being recovered via the proposed cash working capital allowance?

A. No. Depreciation expense is **not** being recovered via the cash working capital allowance, nor is there a double recovery of the expense. It is merely the timing difference that by appropriately including depreciation in the cash working capital determination allows investors the opportunity to be fully and fairly compensated for investment in utility assets from the time cash is expended until the time cash is recovered from customers. The Board has hitorically approved the inclusion of non-cash items in the lead-lag study, such as depreciation expense.

Q. Is it your recommendation that the Company should be permitted to include depreciation expense in the cash working capital analysis at zero expense lead, as the BPU has allowed in prior rate proceedings?

A. Yes, it is. Such treatment is consistent with past BPU practice.

Q. Is it your recommendation that the Company should be permitted to include amortization in the same manner as depreciation?

A. Yes, it is. Including amortization expense and assigning a zero lead to the expense recognizes that investor funding occurred but it has not yet been recovered from customers.

Q. How was operating income treated in the lead-lag study?

A. Operating income was included in the lead-lag study with an expense lead of zero days.

Q. Please explain why operating income was included in the study with a zero day lead.

A. A zero day lead was assigned to operating income, or return on invested capital, because operating income is earned when service is provided to the Company's customers, and belongs to investors when earned. As shown in the calculation of the revenue lag, operating income is not collected when earned. Therefore, a zero day lag was assigned to operating income to reflect that the Company's income has not been recovered from customers.

Q. How was pension and OPEB expense treated in the cash working capital analysis?

A. The OPEB expense in the lead-lag study is calculated using a zero-day expense lead, because the ratepayer is receiving a benefit from PSE&G's inclusion of the net OPEB liability in the Net Assets and Liabilities analyses. Since part of pensions and OPEB are included in the Net Assets and Liabilities Analyses, Concentric considered how these expenses are booked and reflected in operating expenses. The lead days for pension expense do not include the cash contributions to the trust because the cash contribution is included in the Net Assets and Liabilities Analyses. The pension expense that is booked and reflected in operating expenses has a 15.17 lead day.

Q. Based upon the results of the lead-lag study and the level of expense sponsored by the company, what level of cash working capital requirements should be included in PSE&G's rate base?

A. PSE&G's cash working capital requirement was determined to be $536,788,596 for PSEG's electric operations. The cash working capital requirement for PSEG's gas operations is $324,760,756.

V. NET ASSETS AND LIABILITIES

Q. What does a net assets and liabilities analysis measure and how is it measured?

A. Under a net assets and liabilities analysis, certain liabilities are subtracted from particular assets. The difference in the liabilities and the assets is assumed to be the working capital requirement.

Q. What are the results of PSE&G's net assets and liabilities analyses?

A. Under a net assets and liabilities analysis, the assets require working capital while the liabilities are sources of working capital. The amounts in the selected assets and liabilities accounts are shown in Schedule MJA-LL-3. The amounts in these accounts were not considered when analyzing the leads and lags for operating expenses, but they have a direct relationship with the electric and gas distribution rate base of PSEG. The amounts included in current assets are other accounts receivable, special deposits, other prepayments, miscellaneous deferred debits and other post-retirement benefits.

Other miscellaneous accounts receivable are predominantly damage claims related to electric pole repairs, and other receivables such as billings for reimbursable repair work. Such expenditures are required to be made in the day-to-day operations of the Company, but are not charged to utility operations and therefore, were not included in the lead-lag study. These expenditures are eventually reimbursed by the State or other agencies. There is, however, a continuing working capital investment required for such expenditures until reimbursement is received.

Post-retirement benefits represent the asset/liability associated with the expense recognition of SFAS 106 and the associated recovery of costs from customers. This has significantly increased the Other Post Retirement Benefits net asset/liability since the conclusion of the Company's last BPU approved base rate case and is primarily due to the liability account decreasing since 2018 by approximately $800 million. See the testimony of Company witness Mr. McFadden for details on ways the Company has reduced its liability.

Energy Sales Tax and prepayments to the State of New Jersey for annual sales tax liability have been excluded from this analysis as they are included in the lead-lag study. The only prepayment included in this analysis is credit facilities fees. Special deposits represent the Company assets created as a result of the cumulative effect of annual pension funding in excess of SFAS No. 87 (pension accounting) expense and the timing of non-qualified pension costs.

The liability section of Schedule MJA-LL-3 includes the recognition of OPEB benefits as previously discussed.

The majority of the accounts payable amount reflects the recording of payables for contractors and other material and supply ("M&S") inventories. Since the other M&S balance is included as a separate component of Working Capital, it is necessary to reduce Working Capital requirements by the amounts included in other M&S inventory, which have not been paid.

PSE&G's net assets and liabilities analysis, as shown on Schedule MJA-LL-3 is $348,093,735 for electric and $261,255,338 for gas.

VI. CONCLUSION

Q. Does this conclude your direct testimony?

A. Yes, it does.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2022

(THOUSANDS)

Method (1)	Electric (2)	Gas (3)	Total (4)
1. Amount Required to Recover Cost of Service	$536,789	$324,761	$861,549
2. Net Assets and Liabilities	348,094	261,255	609,349
3. Total Other Cash Working Capital	$884,882	$586,016	$1,470,898

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SUMMARY OF NET CASH WORKING CAPITAL
REQUIRED FOR COST OF SERVICE
FOR THE TWELVE MONTHS ENDING May 31, 2024

	Electric			Gas		
	Adjusted Test Year Amount	Lag Days	Weighted Amount	Adjusted Test Year Amount	Lag Days	Weighted Amount
Revenue Requirment :						
Revenue Requirement	$ 4,036,842,034	68.50	$ 276,531,485,329	$ 2,409,797,360	68.50	$ 165,075,778,943
New Jersey Energy Sales Tax	297,844,640	68.50	20,402,933,760	133,929,592	68.50	9,174,436,046.41
Total Revenue Requirement	$ 4,334,686,674	68.50	$ 296,934,419,089	$ 2,543,726,952	68.50	$ 174,250,214,989
Requirements:						
Supply Costs	2,127,612,968	35.83	76,237,639,300	978,129,420	35.63	34,848,467,643
Salaries and Wages	223,232,915	25.38	5,664,556,453	211,445,888	25.38	5,365,459,537
Pension & Benefits						
Pension	(20,522,303)	15.17	(311,409,193)	(14,251,191)	15.17	(216,250,192)
OPEB	(12,155,497)	-	0	(9,791,483)	-	0
Medical Insurance	21,461,494	12.86	275,937,779	21,986,398	12.86	282,686,642
Dental Insurance	763,376	2.94	2,245,392	773,115	2.94	2,274,039
Group Life Insurance	237,090	15.03	3,563,008	254,539	15.03	3,825,231
Benefits Outside Services	0	-	0	0	-	0
Thrift and 401k Plans	5,846,758	12.57	73,465,352	5,918,030	12.57	74,360,895
Disability	471,412	45.89	21,634,878	469,157	45.89	21,531,414
Workers' Compensation	1,545,553	1.63	2,511,523	1,649,948	1.63	2,681,166
Total Pension&Benefits	(2,352,118)	(28.90)	67,948,739	7,008,513	24.40	171,109,195
Uncollectibles	83,604,441	-	0	35,846,361	-	0
Service Company Expense	122,375,814	35.91	4,394,605,602	96,269,618	35.91	3,457,112,876
Other O&M	460,876,606	36.10	16,638,839,101	223,086,995	36.10	8,054,018,295
Depreciation & Amortization	348,224,998	-	0	270,083,787	-	0
Subtotal Operating Expenses	1,015,081,859	20.70	21,033,444,703	625,286,761	18.40	$11,511,131,171
Income Taxes						
Federal	(15,158,039)	37.88	(574,110,741)	(69,184,975)	37.88	(2,620,380,913)
State	31,788,352	(47.25)	(1,501,999,625)	24,852,424	(47.25)	(1,174,277,040.14)
Total Income Taxes	16,630,312	(124.80)	(2,076,110,366)	(44,332,550)	85.60	(3,794,657,953.50)
Taxes Other Than Income	26,071,470	6.95	181,321,871	18,289,662	6.95	127,200,951
New Jersey Energy Sales Tax	297,844,640	(48.71)	(14,508,336,058)	133,929,592	(48.71)	(6,523,855,974)
Interest Expense	155,590,706	91.75	14,275,447,273	152,133,799	91.75	13,958,276,077
Operating Income	474,973,922	-	0	461,835,866	-	0
	954,480,738	(0.10)	(51,566,914)	766,188,920	9.90	7,561,621,054
Total Cost of Service Requirement	4,334,686,674	23.30	100,875,911,914	2,543,726,952	21.90	55,663,130,647
Average Daily Cost of Service Requirement	11,875,854			6,969,115		
Net Lag Days		45.20			46.60	
Cash Working Capital Requirement			$ 536,788,596			$ 324,760,756

STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

In the Matter of the Petition of Public Service Electric and Gas Company for Approval of an Increase in Electric and Gas Rates and for Changes in the Tariffs for Electric and Gas Service, B.P.U.N.J. No. 17 Electric and B.P.U.N.J. No. 17 Gas, and for Changes in Depreciation Rates, Pursuant to N.J.S.A. 48:2-18, N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1, and for Other Appropriate Relief

BPU Docket Nos. ER23120924 & GR23120925

DIRECT TESTIMONY
OF
STEPHEN SWETZ

SENIOR DIRECTOR – CORPORATE RATES AND REVENUE REQUIREMENTS
ON
ELECTRIC COST OF SERVICE AND RATE DESIGN

April 15, 2024
P-9E R-1

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
DIRECT TESTIMONY
OF
STEPHEN SWETZ
SENIOR DIRECTOR – CORPORATE RATES AND REVENUE REQUIREMENTS
ON
ELECTRIC COST OF SERVICE AND RATE DESIGN

Q. Please state your name, affiliation and business address.

A. My name is Stephen Swetz, and I am the Senior Director – Corporate Rates and Revenue Requirements for PSEG Services Corporation. My principal place of business is 80 Park Plaza, Newark, New Jersey 07102. My credentials are set forth in the attached Schedule SS-El.

Q. Please describe your responsibilities as Senior Director - Corporate Rates and Revenue Requirements.

A. In this position I have, among other things, responsibility for the development of rates and tariffs for Public Service Electric and Gas Company ("PSE&G" or "Company").

Q. Have you previously testified in proceedings before the New Jersey Board of Public Utilities ("Board" or "BPU")?

A. Yes. I have both submitted written testimony and testified live before the BPU in a number of proceedings that are identified in Schedule SS-E1 R-1.

SCOPE OF TESTIMONY

Q. What is the purpose of your direct testimony in this proceeding?

A. The purpose of my direct testimony is to support the Company's proposed changes to its rates for Electric Service, which are designed to recover the revenue requirements for the electric distribution business as presented in this filing. My testimony provides the Company's embedded cost of service study ("Company COSS") used as the basis for development of the new electric rates and the proposed rate design for each rate schedule in PSE&G's Electric Tariff. I also present an alternative embedded cost of service study ("the Staff COSS") as required under the 2018 Rate Case Order, and explain why that COSS should not be used to set rates in this case.[1]

Additionally, I sponsor other studies and modifications to the Company's Tariff for Electric Service ("Tariff") including the following:

- The establishment of a Storm Recovery Charge ("SRC") to recover major storm costs as a component of a proposed Distribution Adjustment Charge ("DAC") that was previously proposed as part of the COVID-19 cost recovery proceeding;[2]
- The results of Residential and Commercial & Industrial Electric Vehicle ("EV") Cost of Service Studies that were required by the CEF-EV Order.[3] As a result of these COSSs, the Company proposes the following:
    - A Residential Time of Use ("TOU") Program and associated Rate Schedules; and

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[1] *I/M/O the Petition of Public Service Electric and Gas Company for Approval of an Increase in Electric and Gas Rates and for Changes in Tariffs for Electric and Gas Service, B.P.U.N.J. No. 16 Electric and B.P.U.N.J. No. 16 Gas, and for Changes in Depreciation Rates, Pursuant to N.J.S.A. 48:2-18, N.J.S.A 48:2-21 and N.J.S.A. 48:2-21.1, and for Other Appropriate Relief*, BPU Docket Nos. ER18010029 & GR18010030; *I/M/O the New Jersey Board of Public Utilities' Consideration of the Tax Cuts and Jobs Act of 2017*; BPU Docket No. AX18010001; *I/M/O Public Service Electric and Gas Company for Approval of Revised Rates (Effective on an Interim Basis April 1, 2018) to Reflect the Reduction Under the Tax Cuts and Jobs Act of 2017*, BPU Docket No. ER18030231, Decision and Order Adopting Initial Decision and Stipulation (October 29, 2018) (the "2018 Rate Case Order"), paragraph 25.

[2] *I/M/O the New Jersey Board of Public Utilities Response to the COVID-19 Pandemic*, BPU Docket No. AO20060471, PSE&G filing titled *I/M/O the Petition of Public Service Electric and Gas Company for Approval of Incremental COVID-19 Costs for Recovery Through a New Special-Purpose Clause, and for Authorization to Recover Uncollectible Costs for Gas Through the Societal Benefits Charge* (July 17, 2023).

[3] *I/M/O the Petition of Public Service Gas and Electric Co. for Approval of its Clean Energy Future – Electric Vehicle and Energy Storage ("CEF-EVES") Program on a Regulated Basis*, B.P.U. Docket No. EO18101111, Decision and Order Approving Stipulation (January 27, 2021) ("CEF-EV Order").

    - An optional Direct Current Fast Charge ("DCFC") Distribution kWh Charge to replace corresponding Distribution kW Charges for premises that solely serve DCFC charging facilities;
- Permit residential TOU rates (RLM or proposed RS-TOU) to serve residential EV charging at non-residential premises (such as a detached garage on a residential property);
- Changes to Streetlighting Rate Schedules, which makes Light Emitting Diode ("LED") luminaires the default offering and closes Non-LED luminaires for new installations; and
- Tax Adjustment Credit ("TAC") modifications.

I also sponsor the Company's proposed Tariff, which is attached to the Company's transmittal letter as Schedule 1.

SCHEDULE INDEX

Q. Do you sponsor any schedules as part of your direct testimony?

A. Yes. I sponsor the following schedules that were prepared and/or compiled by me or under my direction and supervision:

SCHEDULE DESCRIPTION	NUMBER
Qualifications of Stephen Swetz	SS-E1 R-1
Basis of Calculations Schedules	
Actual and Weather Normalized Billing Determinants	SS-E2 R-1
COSS Adjustments	SS-E3 R-1
Cost of Service Schedules	
Illustration of Cost Segmentation Methodology	SS-E4 R-1

OVERVIEW OF THE COMPANY'S RATE FILING AND BASIS OF CALCULATIONS AND ANALYSES

Overview

Q. What terminology does your direct testimony use regarding revenue and rates?

A. Throughout this testimony, the revenue or percentage increase for "Distribution" is based only on revenue from the Service Charge and the kilowatt-hour ("kWh") and per kilowatt ("kW") Distribution Charge(s) indicated in the particular rate schedule. The term "Delivery" refers to revenue from the Service Charge and Distribution Charges as indicated on the particular rate schedule, plus the revenue from all of the applicable adjustment clauses. The "Total Bill" equals the Delivery Charges plus electric supply, and is calculated as if all customers were supplied on Basic Generation Service ("BGS").

Q. Please describe the electric distribution services provided by the Company.

A. The Company provides electric distribution services under the following Rate Schedules:

(i) Rate Schedule RS is the Company's primary residential rate schedule;

(ii) Rate Schedule RHS is a closed service that was available to residential customers where electricity was the sole source of heating;

(iii) Rate Schedule RLM is a time of use rate available to residential customers;

(iv) Rate Schedule WH is a closed service that was available to premises with controlled water heating installations;

(v) Rate Schedule WHS is available for controlled water heating storage or for the electric heating elements of a water heating service connected to an active solar collection system;

(vi) Rate Schedule HS is a closed service that was available to permanently installed comfort building heating equipment;

(vii) Rate Schedule GLP is for general purposes at secondary distribution voltages;

(viii) Rate Schedule LPL is for general purposes at secondary voltages where the customer's measured peak demand exceeds 150 kW and also at primary distribution voltages;

(ix) Rate Schedule HTS is for general purposes at subtransmission, transmission and high voltages;

(x) Payment Schedule PEP is applicable to electricity produced from a Qualifying Facility as defined in the Public Utility Regulatory Policies Act of 1978 and delivered to the Company;

(xi) Rate Schedule BPL is service for dusk to dawn street lighting and area lighting to a body politic from Company-owned lighting facilities;

(xii) Rate Schedule BPL-POF is a closed service for dusk to dawn street lighting and area lighting to a body politic from publicly-owned lighting facilities; and

(xiii) Rate Schedule PSAL is service for dusk to dawn private street lighting and outdoor area lighting from Company-owned lighting facilities.

Q. Please provide an overview of the Company's filing in this proceeding.

A. As described more fully by Company witness Mr. Michael McFadden, PSE&G is seeking to increase its base distribution rates by approximately $535 million annually for its electric distribution business. Included in this filing, and as discussed further by Mr. McFadden and Company witness Mr. Cliff Pardo, the Company proposes to make certain modifications to the Company's TAC, including flowing back Mixed Service deductions to customers. This change will reduce electric rates by approximately $88 million annually. In addition, the Company is proposing the SRC to recover major storm costs, increasing rates by approximately $39 million annually. My testimony provides support on how these changes will impact rates.

<u>Residential Rate Affordability</u>

Q. How have your Electric distribution rates changed since the 2018 base rate case?

A. The distribution component of a Residential Electric customer bill for a customer using 7,800 kWh per year has increased at a CAGR of 1.5%, well below the statewide comparable average of 5.0%. and below inflation levels. This modest increase is driven primarily by rate increases from the ES II Program to modernize the Company's electric system and to make it more reliable and resilient.

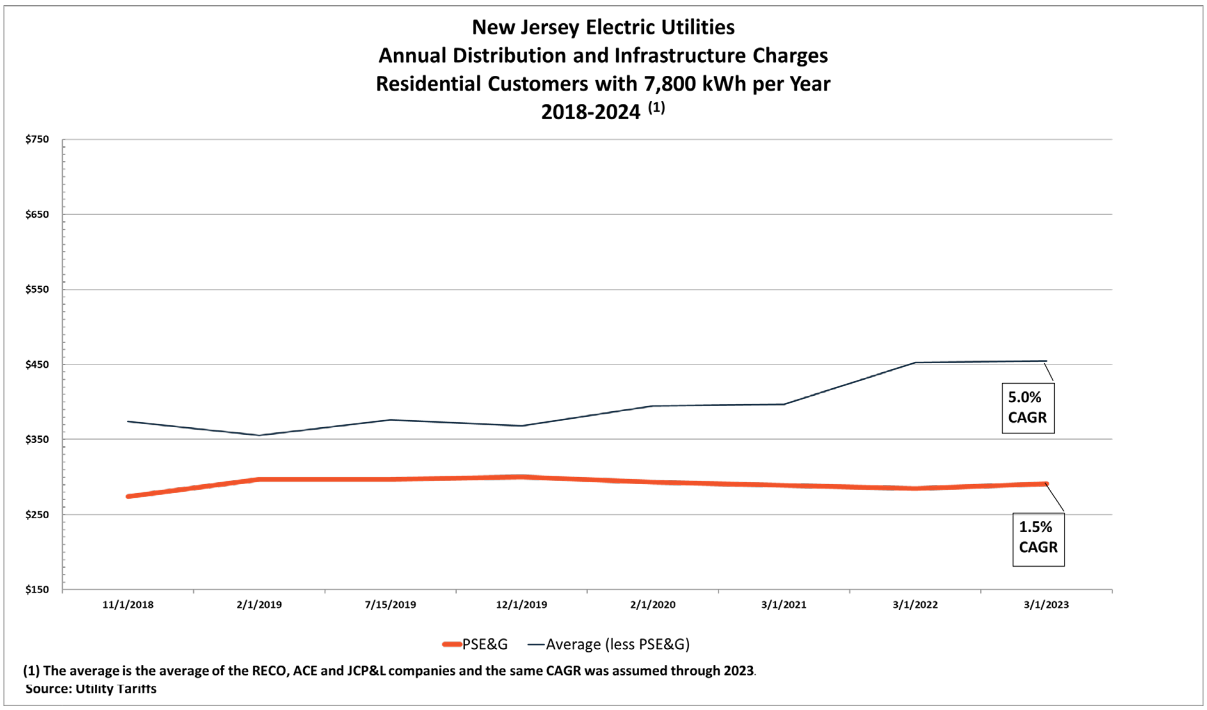


Figure 1

With respect to the Company's electric distribution rates, as can be seen in the chart, applying the State-wide average electric usage of 7,800 kWh per year for a typical residential customer to each utility (even though the average usage for PSE&G's typical residential customer is lower), the distribution portion of the bill for PSE&G, which is the subject of this proceeding, is approximately $291 per year, the second lowest among the State electric utilities and lower than the $455 per year average of the other NJ electric utilities. Further, the Company's compound annual growth rate ("CAGR") of this cost since our last rate case is 1.5%, less than half of the average increase of other New Jersey utilities of approximately 5.0%.

Q. PSE&G's bills are lower on Distribution Charges, but how does PSE&G compare on a total bill basis?

A. PSE&G continues to be lower than the average compared to its peers. In NJ, PSE&G remains on the lower cost side compared to peers in terms of the total electric bill. As shown in Figure 2 below, PSE&G is almost 15% lower than the average.

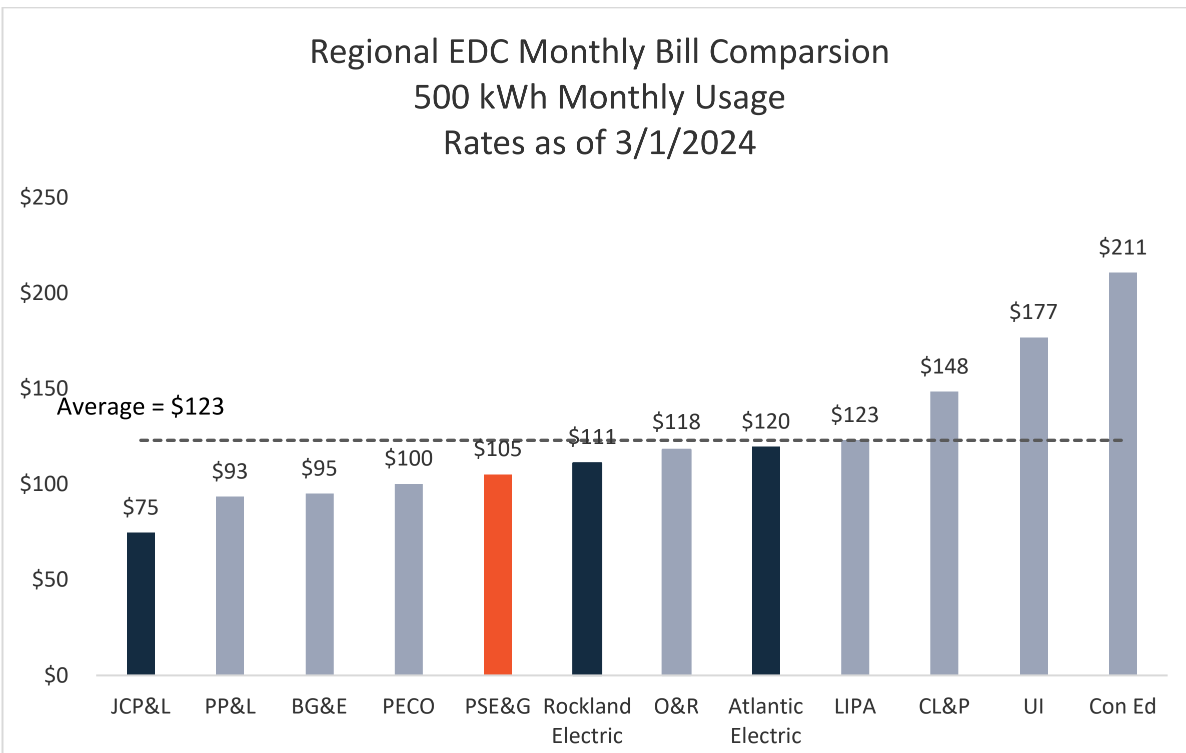


Figure 2

Q. How long has it been since PSE&G's last base rate case?

A. PSE&G filed its last base rate case on January 12, 2018, with new rates effective November 1, 2018. Since that time, every other NJ electric utility has filed at least two base rate cases.

Q. Why has PSE&G not filed a rate case until now?

A. As discussed in more detail below, this is primarily due to the Company's efforts to control costs. PSE&G takes very seriously its responsibility to customers to manage costs prudently and be good stewards of the electric distribution system and the customer funds needed to operate and maintain it effectively. This is achieved by regularly benchmarking Company costs and employee performance and creating appropriate employee incentives to continue to improve upon historic success.

Q. Please describe the efforts the Company has undertaken to protect lower-income customers from the impact of rate increases.

A. The Company is very focused on this vulnerable segment of our customer base. PSE&G's Energy Efficiency programs include incentives targeted to its lower income customers, with specific opportunities for both low and moderate income customers, who often face the highest energy burdens. The Company specifically seeks to provide energy savings opportunities to these customers in order to lower their energy burdens, as participants in the EE programs are expected to benefit from long term energy and bill savings, as well as health and safety improvements. The Company implements the State's Comfort Partners program to customers with incomes up to 250% of the Federal Poverty Level; that program provides free comprehensive energy savings solutions as well as upgrades to address health and safety problems in the home. PSE&G also recently filed its updated Clean Energy Future – Energy Efficiency II Program, which proposes to transfer administration of the Comfort Partners program to the Company in order further reduce market confusion and streamline the process for lower-income customers to take advantage of energy efficiency programs;[4] PSE&G believes this change in administration of the Comfort Partners program will significantly improve customer access to energy efficiency and allow the Company more flexibility in serving the needs of lower-income customers. Also as part of the Clean Energy Future – Energy Efficiency II Program, PSE&G proposed to continue to target low and moderate income customers by providing comprehensive energy assessments and free direct install of energy efficient measures and services to income qualified households with higher incentives and opportunities for no-interest financing for health and safety improvements to these customers (the Comfort Partners program does not include financing, as all measures are paid for by the program and free to eligible customers), and to continue to provide enhanced opportunities for customers in overburdened communities. PSE&G also offers higher incentives for high efficiency heating and cooling systems and continues to provide financial incentives to both property owners and tenants to install high efficiency equipment in apartments and other multifamily properties. The Company promotes the use of these programs to our customers through bill inserts and community outreach, conducting this communication in multiple languages where possible and appropriate.

Q. Are there other assistance programs for lower-income customers outside of PSE&G's energy efficiency programs, and if so, please describe those programs and who is eligible.

A. The Company also advocates at the State and Federal level for various grants provided to lower-income customers, including the Low-Income Home Energy Assistance Program

[4] *I/M/O The Petition of Public Electric and Gas Company for Approval of its Clean Energy Future-Energy Efficiency II (CEF-EE I) Program on A Regulated Basis*, BPU Docket No. QO23120874 (filed December 1, 2023).

("LIHEAP"), Lifeline and Tenants Lifeline Program ("Lifeline"), and the Universal Service Fund ("USF"). LIHEAP is a Federal Block Grant program that helps low-income individuals and households pay for their winter heating bills, medically necessary cooling benefits, and weatherization. The Lifeline Program helps customers pay their utility bills with a $225 annual utility credit. To be eligible, a customer must be at least age 65, or at least age 18 and collecting Social Security Disability. In addition, a single person must make less than $42,000, or a couple less than $49,000 annually. USF is a statewide program administered by the Department of Community Affairs that allows program recipients to pay no more than 3% of their income for electric and 3% for natural gas, or 6% for total electric, including electric heating for customers at or below 60% of the State median income. PAGE is a program for customers earning up to 500% of the Federal Poverty Limits and offers a grant of up to $700 per utility service. NJ SHARES is for customers earning up to 400% of the Federal Poverty Limit and is funded by customer donations which are matched by PSE&G.

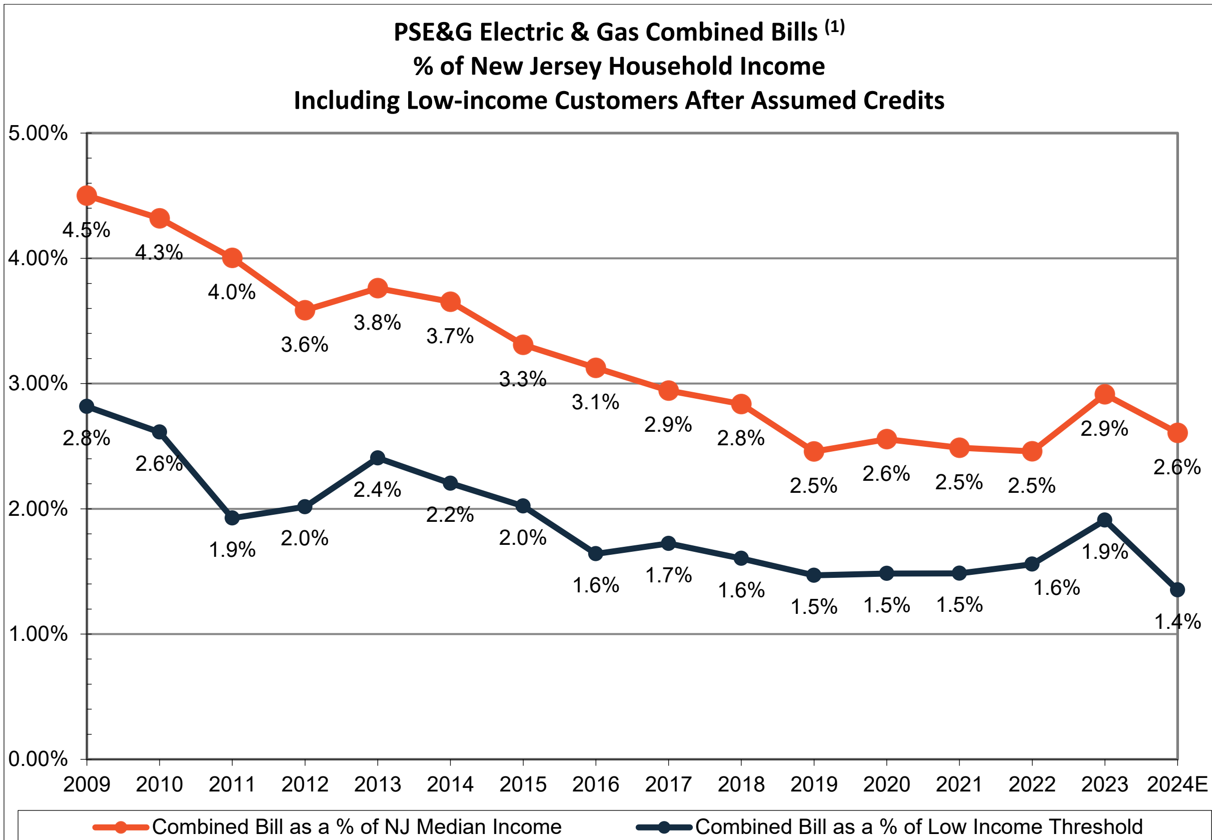
PSE&G has more customers eligible for these low-income programs on a proportionate basis compared with other New Jersey utilities. This customer segment receives special focus.

Q. Are there steps PSE&G has taken during the COVID-19 pandemic to help these customers?

A. Yes. PSE&G, its customers, and New Jersey have faced unprecedented challenges as a result of the COVID-19 global pandemic that created difficult economic circumstances. In response to these challenges, PSE&G developed a comprehensive payment assistance outreach plan utilizing employees and contractors and conducted an external media campaign designed to provide customers opportunities to garner financial assistance and enter into deferred payment arrangements to avoid shut off.

Q. Has the Company considered the impact of electric rates on these customers?

A. Yes. As illustrated in Figure 3 below, the relative cost of PSE&G's services to a typical combined (that is, electric and gas) residential lower-income customer has dropped significantly since 2009 and is essentially flat as compared with rates following the conclusion of the Company's 2018 base rate case.



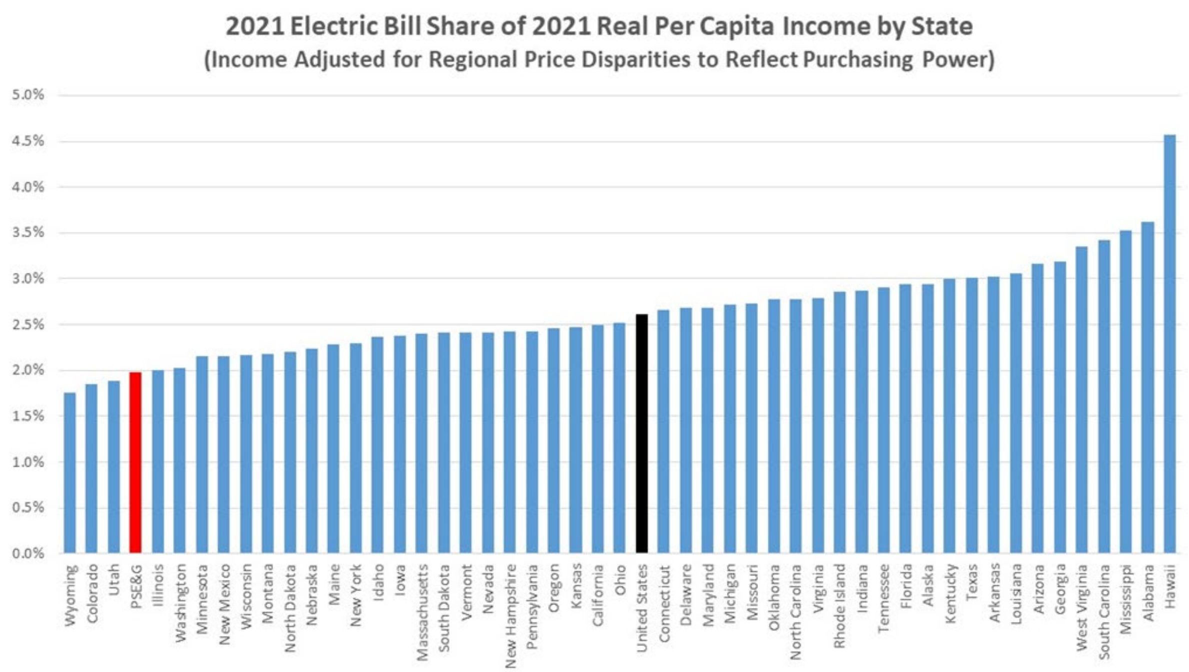
(1) Based on a typical residential electric customer using 740 kilowatt-hours per summer month and 6,920 kilowatt-hours on an annual basis using rates as of June 1 for each year and a typical residential gas heating customer using 172 therms per winter month and 1,040 therms on an annual basis using rates as of January 1 of each year. Notes: NJ Median income source https://fred.stlouisfed.org/series/MEHOINUSNJA646N. 2023 and 2024E are not available, therefore assume 3% annual increase per year over 2022. Income level of USF, the lowest threshold of the three low-income programs, is 175% of the Federal Poverty Line. Assumes the customer also qualifies for LIHEAP and Lifeline. 2022 results were adjusted to normal levels of customer assistance, which was elevated in 2022 due to funds received through the American Recovery Plan.

Figure 3

This chart compares the bill as a percentage of income for a typical combined electric and gas residential customer relative to New Jersey's median income and relative to the income threshold below which customers are considered low-income. As can be seen, for the average residential customer, the cost of service is less than 3% of median income. For lower-income customers, the cost of the bill after LIHEAP, USF, and Lifeline grants relative to an income level of 60% of State median income (the level at which a customer is eligible for these grants), is around 2% today. So, even with this proposed rate increase, the cost of electricity and gas for all of the Company's customers, including low-income customers, remains a very small portion of overall income for those able to take advantage of these programs.

Q. How does this utility bill portion of overall income compare to other states?

A. Very well. As shown in Figure 4 below, PSE&G's residential electric bill as a percentage of per capita income for NJ is in the top quartile compared to the other states in the US. In other words, PSE&G's total bill represents less share of a customer's wallet than the relative utility bill share in most other states.



Source: U.S. Dept. of Commerce, Bureau of Economic Analysis, "Regional Data GDP and Personal Income", June 2023
U.S. Dept. of Energy , Energy Information Agency, "Sales (consumption, revenue, prices & customers", retrieved July 2023.

Figure 4

While PSE&G's bills as a percentage of overall NJ income is very favorable compared to most other states, the Company recognizes the current economic environment and the ongoing need to control costs. PSE&G has and will continue to control costs as much as possible to maintain affordable rates for customers without sacrificing reliability.

Q. How does the current RS Service Charge compare to other utilities?

A. As shown in Figure 5 below, PSE&G's monthly RS electric service charge is the second lowest compared to similar electric utilities in the region.

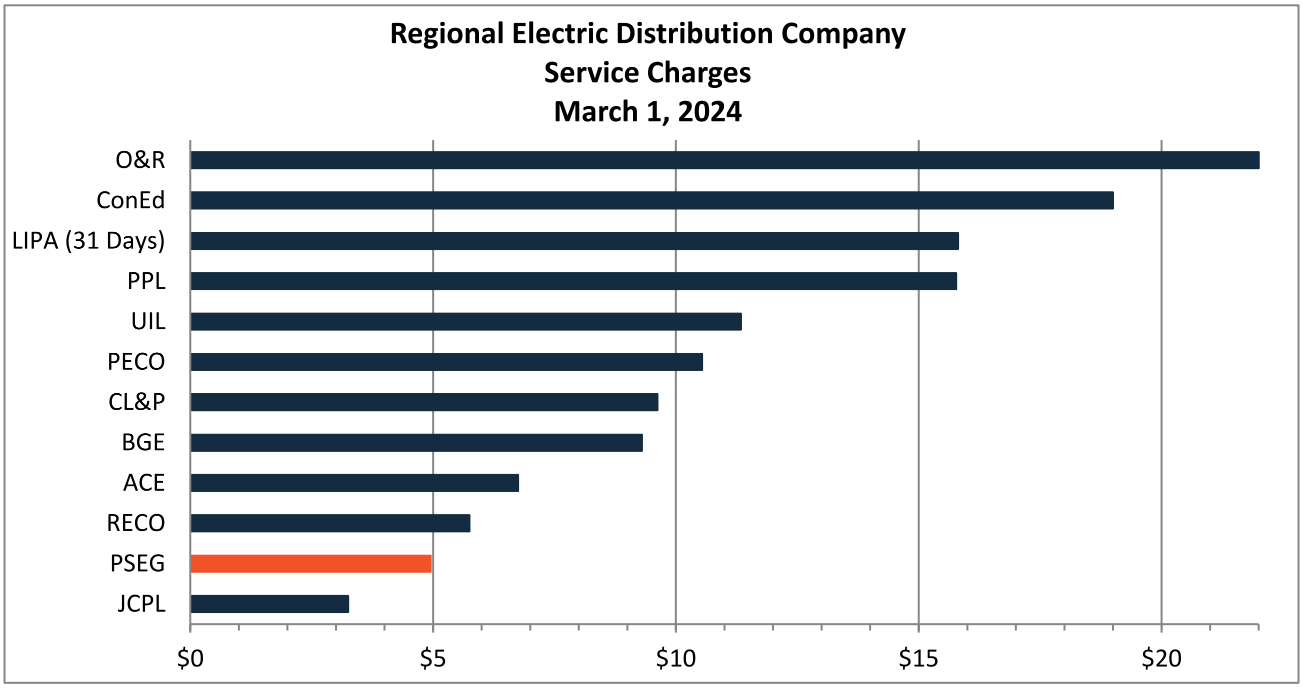


Figure 5

Q. What are the periods used for the COSSs and Rate Design that you are sponsoring in this proceeding?

A. The COSSs presented in this testimony are based upon the period January 1 to December 31, 2022. The only variations from actual costs in the COSS period were the requested overall Rate of Return value, proposed rate base adjustments such as working capital requirements, the proposed *pro forma* adjustments, and adjustments to synchronize the number of customers and usage used in the COSS to those used in the Company's rate design. These adjustments, along with the rate design presented in this testimony, are based upon the Test Year of June 1, 2023 through May 31, 2024 (hereafter "Test Year").

Q. What billing determinants will be used to determine the revenue requirement and rates that are being established in this proceeding?

A. The billing determinants used to establish rates and the revenue requirement allocation for each rate class in this proceeding will be the actual Test Year billing determinants as adjusted for normal weather. For the initial filing and any updates (prior to the final filing) with all actual data, the billing determinants will be a mix of weather normalized actual and forecasted billing determinants. Weather normalized billing determinants are calculated by adjusting actual recorded monthly electric sales to account for the effects of abnormal weather. A summary of the actual billing determinants, the weather normalized billing determinants, and the variation of each determinant from normal for the Test Year period is shown in Schedule SS-E2 R-1.

Weather Normalization of Billing Determinants

Q. What weather pattern is used to weather normalize actual billing determinants?

A. The Company utilizes a twenty-year weather pattern as measured at Newark Liberty International Airport covering the period ended December 31, 2021.

Scope of the Cost of Service Study

Q. Please describe the COSSs that the Company is presenting in this proceeding.

A. The Company is presenting two COSSs in this proceeding – its recommended COSS, referred to as the "Company COSS" – and an additional COSS based on a methodology developed by BPU Staff, referred to as the "Staff COSS." As discussed more fully below, the Company does not support the use of the Staff COSS to establish rates in this proceeding, but is submitting the study in compliance with the 2018 Rate Case Order. The COSSs discussed in this testimony are for the electric distribution portion of the Company's operations. Thus, the COSSs are generally "wires only" analyses for the regulated electric delivery business. They do not include the costs for the Company's Transmission business, which is under the jurisdiction of the Federal Energy Regulatory Commission ("FERC"), nor any electric production or supply costs. Although PSE&G remains responsible to provide BGS, the determination of rates charged to end-use customers for this service are addressed in other proceedings.

<u>Adjustments to Accounting Data</u>

Q. Did you make any adjustments to the accounting data used in the COSSs?

A. Several adjustments to the 2022 accounting data used in the COSSs were necessary prior to its use. These adjustments and the FERC Account associated with each of these adjustments are shown in Schedule SS-E3 R-1.

In the rate design process, the unit charges associated with these adjustments will be added back as appropriate in each rate schedule to assure full recovery of all expenses. The Company COSS and the Staff COSS each include these adjustments to costs and billing determinants.

<u>COST OF SERVICE STUDY ("COSS") OVERVIEW</u>

<u>Introduction</u>

Q. What is the first step in developing new electric rates?

A. The first step in developing new electric rates is the preparation of an appropriate COSS. The Company COSS was used to both separate costs by functional segments and to apportion (or allocate) these segmented costs to the rate classes or sub-classes based upon each class's responsibility for that cost.

Q. What is the objective of an COSS?

A. The objective of the COSS is to measure the cost responsibility of each rate/class and distribution function (functionalization).

<u>Cost Allocation Concepts</u>

Q. Please describe the cost allocation concepts used in the Company's COSS.

A. Inherent in any COSS is the allocation to rate classes of many costs which by their nature are difficult to relate precisely to cost causation. Cost causation describes the cause-and-effect relationship between customer requirements, load profiles, and usage characterization, and the costs incurred by the utility to serve those requirements. Experts will differ on the best way in which many costs should be allocated among customer classes. The key is to determine which approach makes the most sense in terms of best answering the question of what caused the cost, and then to apply the result in a reasoned, balanced manner. At all times, it is important to recognize that the COSS is intended to be a guide to appropriate ratemaking, and that one objective of ratemaking is that the end result should be a reasonable one.

The development of a COSS requires an understanding of the operating characteristics of the utility system. Electric distribution company facilities, such as substations, wires, and transformers, are planned and constructed to provide reliable service on a least-cost basis. distribution planners must design distribution systems with sufficient wire and transformation capacity to meet customers' peak loads while, of course, maintaining safety and reliability.

Each portion of the electric distribution system is nominally designed to carry the expected peak electric loads, without concern for the loadings in other hours or periods of the year. Although it is mathematically possible to develop an allocator of costs based upon virtually any attribute or formula, the use of a method that has little or no relation to the underlying cost causation is simply flawed. If the adopted approach reasonably tracks cost causation and the guidance is applied with a reasoned, balanced view, fair and equitable delivery rates to all classes of delivery customers will be the end result.

As I discuss later, I have used the results from the Company COSS as a guide in developing rates, but tempered the final rate design to provide a reasonable balance between the goal of moving each rate schedule towards costs and the goal of holding the increases to reasonable percentage increases based upon the resulting customer impacts.

General Cost Allocation and Functionalization Methodology

Q. What is the basis for the cost allocation and functionalization methodologies used in the Company COSS?

A. The Company COSS incorporates a method identical to that as used by the Company in its prior electric base case and is based on the concepts and theories recommended in Chapter 6 of the current NARUC Electric Utility Cost Allocation Manual ("NARUC Manual") regarding the classification and allocation of electric distribution plant. Although much has changed in the industry since this document was published, the methodology presented is still valid and relevant to evaluating the costs for today's electric distribution business.

The NARUC Manual outlines the general methodology to be used on page 90 as follows:

> *When a utility installs distribution plant to provide service to a customer and to meet the individual customer's peak demands requirements, the utility must classify distribution plant data separately into demand- and customer-related costs.*

And later on that same page 90:

> *Distribution plant Accounts 364 through 370 involve demand and customer costs. The customer component of distribution facilities is that portion of costs which varies with the number of customers. Thus, the number of poles, conductors, transformers, services, and meters are directly related to the*

number of customer's on the utility's system…each primary plant account can be separately classified into a demand and customer component.

The NARUC Manual then discusses the allocation of the demand related distribution costs on page 97 in the middle of the first paragraph:

The load diversity at distribution substations and primary feeders is usually high. For this reason, customer-class peaks are normally used for the allocation of these facilities. The facilities nearer the customer, such as secondary feeders and line transformers, have a much lower diversity. They are normally allocated according to the individual customer's maximum demands.

Q. What are the fundamentals of classifying and allocating the costs of providing distribution service that are described in the NARUC Manual?

A. The methodology presented in the NARUC Manual presents three key distribution Cost of Service fundamentals for classifying and allocating costs incurred to provide each customer distribution service:

1. Distribution costs have no energy related component
2. The load diversity as experienced by specific facilities or equipment determines the cost allocation method that should be used
3. Poles, conductors, line transformers, services, and meters have a customer component

Q. Please describe these three fundamentals and how they are used in the Company COSS.

A. The first fundamental, the absence of an energy related component, is very basic. With the limited exception of electrical losses, the amount of energy, as measured by kWh consumption, has no impact on the planning, design or installation of any electric distribution plant. Therefore, kWh consumption has not been included in the Company's methodology as the basis of allocation of distribution costs.

The second fundamental, load diversity as experienced by specific facilities or equipment, is somewhat subtle. Electric distribution facilities are designed based on various criteria depending upon the function of each particular piece of equipment.

On one extreme, a piece of equipment that connects a customer to the electric system (such as a service drop) is sized to handle the expected peak load of that customer, regardless of when that peak load might occur. For example, for some residential customers this peak might be a hot summer night when they have their central air conditioner at full power, all the lights in the house are turned on, and the refrigerator is running. For other residential customers without many appliances, the peak might occur on Christmas morning when decorations are lit and the furnace fan on the gas heating unit turns on. Similar effects would be seen for all types of industrial and commercial customers as well, with the occurrence of the peak load varying, in effect, by customer.

On the other extreme, an electric distribution substation is designed to handle the peaks expected at that specific substation at the time of peak demand at that location. At these locations, a customer's peak demand, the number of customers served, or even kWh usage for any specific customer or any combination of customers, is immaterial. The only value that matters is the expected peak demand at that substation. For the Company's service territory, given the combined loads of customers, equipment installed, and the local climate, these peaks are customarily observed in the late afternoon of a hot summer day.

The effect of varying diversity is a continuum between these two extreme points of the electric distribution system. To determine the effects of such variations in load diversity between the substation and the service drop, or to develop a unique cost allocation methodology to account for each different type of diversity of load, would be a vast and impracticable task. In practice, any methodology used must strike a balance between one that is both theoretically ideal and one that can actually be implemented. The methodology presented in this testimony strikes this balance and is consistent with the underlying basis for the installation and design of the distribution system by the Company's distribution planners.

Q. Does the Company agree with the third fundamental identified by NARUC -- that certain facilities such as poles, conductors, line transformers, services, and meters have a customer component?

A. Yes. The Company agrees with the third key point identified in the NARUC Manual, that a portion of distribution facilities are customer related. However, due to the complexities and resources required to perform a study of the portion of facilities that should be classified as customer related, and the likelihood that such a study would show a need for increased residential charges that would far exceed what the Company is proposing in this proceeding, the Company has not undertaken a study to quantify this customer-related portion for this proceeding, but may do so in future rate cases.

Q. How is the PSE&G electric distribution system segmented or functionalized in the Company COSS?

A. As explained in more detail below, the Company COSS segments the electric distribution utility plant into six distinct segments – Access, Local Delivery, System Delivery, Street Lighting, Customer Service, and Measurement. Of these six segments, the Access, Local Delivery, and System Delivery segments are much larger than the other three and form the core of the distribution business.

Q. Please describe the Access, Local Delivery, and System Delivery segments in more detail and provide an overview of how you have allocated the costs of these segments.

A. The Access segment is limited to the electric service drop to individual customers; the Local Delivery segment is comprised of plant that is shared among a small number of customers, and the assets comprising the System Delivery segment serve a large number of customers. Consistent with the second and third NARUC fundamentals discussed above, I have allocated the Local Delivery costs based on the sum of customer individual peak demands. This allocation follows the NARUC cost causation principle that facilities that are electrically close to customers are sized to carry the sum of undiversified customer peak loads.

Because System Delivery facilities are electrically farther from the customers, and see only highly diversified customer demands, I have allocated these facilities' costs solely on the basis of each rate class's contribution to the system peak, or what is termed each rate class's Coincident Peak ("CP"). The sum of customer peaks for Local Delivery costs and rate class CPs for System Delivery costs forms a reasonable basis for the allocation of costs to each rate class because they represent the underlying basis of the cost causation for the type of equipment that comprises each distinct segment.

Because subtransmission and primary circuits have characteristics partially consistent with Local Delivery and partially consistent with System Delivery assets, a cost separation methodology for allocating these costs was developed in consultation with the Company's distribution planners. For subtransmission circuits, the function of which is primarily to distribute power between substations and only secondarily to serve 26 kV customers (on Rate Schedule HTS-subtransmission), an analysis of the loads determined that a 21.1% - 78.9% spilt between the functions of Local Delivery and System Delivery was appropriate.

The function of primary circuits, however, was determined to be more evenly split between providing Local Delivery and System Delivery functions. A primary circuit carries power from a substation to customers who are typically served through transformers along its length. The portion nearest the substation connection has a highly diversified load because it carries the load attributed to all customers on that particular circuit. It thus performs a function similar to that of the substation, and thus could be considered primarily a System Delivery asset and should be largely allocated on the CP of the classes served. On the other extreme, the portion of the circuit that is electrically farthest away from the substation may serve only one customer and must be designed to handle the peak demand of that specific customer, resulting in zero load diversity. It thus could be considered a Local Delivery asset and allocated on the sum of the customer peaks for the classes served. Along the length of the primary circuit, the diversity gradually shifts from the highly diversified load at one end to the undiversified load at the other end. As a result, I have utilized a 50% - 50% split between Local Delivery and System Delivery to segment and allocate all primary circuits' costs as a representation of the average diversity and dual functionality of this equipment.

The remaining segment, the Access segment, is allocated via a special study of the costs of service drops by rate class as discussed more fully below.

<u>Functionalization of the Six Segments</u>

Q. What is the first step in the process of performing an COSS?

A. As the first step in that process, the COSS unbundles total costs into the six distinct functional segments that I previously discussed – Access, Local Delivery, System Delivery, Street Lighting, Customer Service, and Measurement.

Q. Once these functional segments are developed, how are they used?

A. These separate functions (or segments) assist in the development of individual rate schedule components, such as the Service Charge. Once the plant and expenses are functionalized to the proper segment, the allocation process spreads the cost responsibility to the rate classes.

Q. What items are included in each of these segments?

A. The list below describes what is included in each of the six segments:

- The Access segment includes the plant and operation and maintenance ("O&M") costs related to the electric service drop.
- The Local Delivery segment includes all equipment (plant and O&M) related to the local distribution facilities.
- The System Delivery segment includes all equipment (plant and O&M) related to the "bulk" system distribution facilities.
- The Street Lighting segment is limited to the luminaires, brackets, and poles used only for street lighting purposes (the latter termed "street lighting poles").
- The Customer Service segment includes all costs relating to billing, inquiry, sales, service, and collection activity.
- The Measurement segment includes the costs for meter reading, meter plant, and meter O&M.

Q. Are all costs included in these six segments?

A. Yes, all costs are functionalized to one or more of these of six segments.

<u>**Access Segment**</u>

Q. Please discuss the Access segment in greater detail.

A. The Access segment is the initial link between the shared or common distribution system and the customer's own electric system, comprised of the electric service drop whose gross plant is recorded in FERC Account E369. Service drops are illustrated as a thick dashed line on Schedule SS-E4 R-1. The embedded costs for this segment are allocated across the rate classes based on an analysis of current unit costs, determined from typical service drop lengths and wire types as estimated by the Company's distribution planners. In situations where various size services are used to provide service to customers on the same rate schedule but with different peak loads, only the relative cost of the minimum size service is functionalized to this segment. The remainder is functionalized to the Local Delivery Segment for recovery through kWh or kilowatt ("kW") charges and is not included in the costs to be recovered by Service Charges.

Local Delivery Segment

Q. Please discuss the Local Delivery segment in greater detail.

A. As discussed above, the Local Delivery facilities are the portions of the distribution system that are used to serve multiple customers and are also electrically and physically closest to the point of connection with individual customers' service drops. These facilities include the following types of plant:

- All secondary wire other than that used for customer service drops and for street lighting service,
- All line transformers; including all pole top units, pad mounts, underground, and network transformers,
- 21.1% of the Company's 26 Kilovolt ("kV") circuits - including poles, conductors and devices (only applicable to customers served at subtransmission voltages),
- 50% of the Company's primary circuits - including poles, conductors, and devices, and
- The portion of the service drop and meters in excess of the relative minimum amounts.

Although many customers share these facilities, the load carrying capacity of individual transformers, lines, and circuits is driven primarily by the sum of the undiversified peak demand of individual customers. Therefore, the majority of investment in the Local Delivery segment has been allocated to the rates based on the sum of the customers' individual peak demands.

As I have previously mentioned, although the Company agrees with NARUC that a portion of these facilities is customer-related and should be allocated based on the number of customers served, it is not proposing an allocation method based on this fundamental in this proceeding but may do so in future rate case proceedings. The outcome of such an allocation study would likely indicate that residential customers cause a higher proportion of costs than indicated by the methods used in preparing the Company COSS.

Investment in line transformers was allocated to the rate classes based on the average embedded costs, on a dollar per kVA basis, that were derived from a study that linked the actual transformer serving each customer with the Company's accounting records. This study is provided in the workpapers that support this testimony. Facilities related to the Local Delivery segment are illustrated as a thin solid line on Schedule SS-E4 R-1. A detailed discussion of the segmentation and allocation of each FERC Plant Account related to this segment is discussed in Appendix-E1.

<u>System Delivery Segment</u>

Q. Please discuss the System Delivery segment in greater detail.

A. The System Delivery segment is used for the portions of the distribution system that are planned to meet large, very diversified loads from many sizes, classes, and types of customers. Thus, this segment is composed of the portion of the distribution system facilities that is electrically farthest from individual customers and is sometimes referred to as the bulk distribution system. It is comprised of the following type of facilities:

- Switching stations and substations (the distribution portions only),

- 78.9% of the Company's 26 kV circuits - including poles, conductors, and devices, and
- 50% of the Company's primary circuits - including poles, conductors, and devices.

The costs for these System Delivery facilities are allocated across applicable rate classes based on the classes' contribution to the system CP, because the CP criteria is used as the planning criteria for this type of investment. Facilities relating to the System Delivery segment are illustrated as a thick solid line on Schedule SS-E4 R-1. As with the prior segment, a detailed plant-by-plant discussion of the segmentation and allocation is discussed in Appendix-E1.

Street Lighting Segment

Q. Please discuss the Street Lighting segment in greater detail.

A. This segment comprises the investment for street lighting luminaires, street lighting poles (poles used exclusively for street lighting), and other miscellaneous devices such as street lighting brackets and/or shrouds, and all associated O&M expenses for this equipment. Where a pole is used solely to provide street lighting, termed a "street lighting pole," one section of secondary wire was also segmented to this function for each pole so identified.

All investment and expenses in the Street Lighting segment were directly assigned to the three street lighting Rate Schedules of BPL, BPL-POF, and PSAL based upon the number and type of lights and poles billed under each rate schedule.

Customer Service Segment

Q. Please discuss the Customer Service segment in greater detail.

A. This segment encompasses all costs related to Customer Service type functions, such as costs related to billing, payment receipt and processing, collection activity, and other account maintenance type costs, with the exception of meter reading costs, which are included in the Measurement segment. These costs are allocated to the rate classes based upon a separate study of Customer Service functions.

Measurement Segment

Q. Please discuss the Measurement segment in greater detail.

A. This segment includes costs for meter reading and the investment and O&M related to the meters themselves. Meter reading costs are allocated to the rate classes based upon a separate embedded cost analysis of Customer Service functions. Given that new Advanced Metering Infrastructure ("AMI") meters are relatively the same cost for customers in each rate class, the meter investment is allocated across the rates based upon the relative installed cost of new meters.

Modeling Procedures

Q. Please describe the COSS modeling procedures as well as how all COSS items are segmented and functionalized.

A. The COSS was developed based upon the weather normalized billing determinants and costs for each of the rate schedules for the COSS test period as defined above. The revenues received by each rate class were calculated (or target balanced) such that the resulting Rate of Return ("ROR") for each rate class equals the Company's proposed overall ROR. Schedule SS-E5 R-1 contains the complete details of these final COSS model results, Schedule SS-E6 R-1 presents a summary report of the revenue requirements by functional segment, while

Schedule SS-E7 R-1 shows the revenue requirements by function (or segment) for each rate class.

The detailed description of how all COSS items are modeled, segmented, and functionalized is discussed in Appendix-E1. In Appendix-E1, a description is provided of how each of the major plant categories (gross plant) is segmented or functionalized. I then discuss the procedures used for Common and General plant, depreciation reserve, adjustments to rate base, operating revenues, O&M expenses for utility plant, A&G expenses, depreciation and amortization expenses, pro forma expense adjustments, and finally, taxes.

Schedule SS-E5 R-1 shows the details of the COSS used to calculate distribution revenue requirements by rate schedule. This study was used in the development of the proposed rates. These results are summarized by revenue requirements for each rate schedule and by segment in Schedule SS-E6 R-1.

Q. Please summarize the results of the Company COSS.

A. Schedule SS-E5 R-1 shows the details of how each plant and expense item was separated into each of the six segments and allocated to each category of customers for each of the various rate classifications based upon the extent to which those groups of customers caused the costs, along with the results of the allocation for each plant and expense item. Schedule SS-E6 R-1 shows a high-level summary of expenses, plant, and revenue requirements for each of the six functional segments, while Schedule SS-E7 R-1 is a summary report of the rate related revenue requirement for each rate class in total.

The revenue requirements reported in Schedules SS-E5 R-1, SS-E6 R-1 and SS-E7 R-1 do not include the costs or revenue requirements associated with adjustment clauses and New Jersey Sales and Use Tax ("SUT"). These costs, however, will be collected from customers directly through the appropriate charges, as I will discuss in the Rate Design portion of this testimony.

Synchronizing the Cost of Service Study to the Rate Design

Q. Please explain how the Company COSS was synchronized with the proposed rate design.

A. As previously noted, the Company COSS is based on the period of January 1, 2022 through December 31, 2022, while the rate design is based on the Test Year of June 1, 2023 through May 31, 2024. It is not possible to use the COSS results directly in the rate design process because the number of customers, kilowatt-hours delivered, as well as plant and expenses are slightly different between these two time periods. To properly execute the rate design process, the Company COSS results must be adjusted slightly to correspond to the rate design test year period. The methodology used to synchronize the COSS results is included in Schedule SS-E8 R-1. Because the primary difference is in the number of customers and amount of energy delivered, each functional segment's revenue requirement from Schedule SS-E7 R-1 was multiplied by the ratio of either the number of customers or kilowatt-hours delivered for the rate design test year to the value during the COSS year. The development of these sync factors is shown on page 1 of Schedule SS-E8 R-1. The revenue requirements associated with the Street Lighting Segment (Col 1), Local Delivery Segment (Col 3), and the System Delivery Segment (Col 4) were adjusted by the ratio of the kWh delivered in these two periods. The revenue requirements associated with the Access Segment (Col 2), Customer Service Segment (Col 5) and the Measurement Segment (Col 6) were adjusted by the ratio of the number of customers in these two periods, except for rate classes BPL, BPL-POF, and PSAL, which were adjusted by the kWh sync factor described above for all functional segments. These steps are shown on lines 1 to 15 of page 2 of Schedule SS-E8 R-1. The resulting adjusted COSS functionalized revenue requirements are each then adjusted on an equal percentage basis so that the total equals the proposed revenue requirements, as set forth on lines 21 to 35 of page 2 of Schedule SS-E8 R-1. It is these final adjusted functionalized revenue requirements that are used in the rate design process.

RATE DESIGN

Introduction

Q. What are your objectives for developing proposed electric rates?

A. The proposed electric rates have been developed to meet several objectives. The primary purpose is to provide recovery of revenues equal to the amount of the proposed revenue requirement. Additionally, this recovery should be effectuated on an equitable basis that provides correct price signals to individual customers based on the cost to serve those customers. The final objective is that rates should be simple and understandable for the customer.

Q. Why is it important to send correct price signals to individual customers based upon the cost to serve those customers?

A. I cannot overemphasize the need for development and implementation of correct price signals to customers. Distribution pricing must follow the underlying demand-based cost causation. Rates designed following this methodology will be equitable and will provide the ability for appropriate demand response from customers who are able to change usage patterns to achieve economic savings as a result of the price signals provided.

Q. What determines the cost to serve customers?

A. The Company COSS presents an allocation among customer groups of the embedded costs to provide regulated utility services and determines the cost to serve customers.

Q. Are the proposed new rates based solely on the results of the Company COSS?

A. No. The COSS is a guide to appropriate ratemaking; its results are not applied in a strict mathematical manner to design proposed rates. While the goal is to move rates toward a full cost basis, the achievement of that goal must be balanced against the need to achieve reasonable end results as I discuss more fully below.

Q. Do the rates included in your testimony include or exclude New Jersey SUT?

A. The proposed rates discussed in the next sections of my testimony and associated Schedules exclude SUT unless specifically indicated. However, the appropriate prices both without and with SUT are included in the Proof of Revenue by Rate Schedule in Schedule SS-E11 R-1 as well as the proposed Tariff Sheets set forth in Schedule 1 of the transmittal letter, and all other schedules that reference rates charged to customers.

<u>**Limitations on Rate Changes**</u>

Q. Did you apply limits in designing proposed rates in this proceeding, and, if so, why?

A. Yes. To achieve an overall goal of designing just and reasonable rates, I applied the principle of "gradualism" to temper the rate increases indicated by the results of the Company COSS. To apply the principle of gradualism, I employed a number of limits on the size of the rate increases that are proposed.

Q. Please describe the rate increase limits used in developing the proposed electric rates.

A. The first limit is that the proposed overall percentage revenue increase will be shared among all customer classes. Although a primary goal is to move the distribution rates for each rate class toward costs as indicated by the Company COSS, no class will receive less than 50%, nor more than 125% of the overall average distribution percentage increase. In addition, no class will receive more than 150% of the overall average percentage bill increase. These rate increase limits were selected to provide a reasonable balance between the goal of moving towards costs, and the need to achieve equity among customers. The calculation and percentage values of these limits are shown on page 1 of Schedule SS-E9 R-1.

Q. Are there any exceptions to the proposed limits?

A. Yes. Much of the revenue requirement increase has been driven by grid investments that are unrelated to BPL and PSAL luminaries and poles. BPL luminaires and poles current distribution revenue is nearly at its cost to serve, therefore the proposed minimum distribution revenue percentage increase was lowered from 19.742% to 10 PSAL luminaires and poles current distribution is higher than its cost to serve, so its BPL luminaires and poles current distribution revenue is nearly at its cost to serve, therefore proposed minimum distribution revenue percentage increase was also lowered 10%. is 20.607%, which increases its revenue almost equal to its cost to serve.

<u>**Inter Class Revenue Increase Allocations**</u>

Q. Please describe the process for allocating the proposed distribution increase to each rate class.

A. Page 1 of Schedule SS-E9 R-1 shows the calculation of the overall average percentage increase for distribution and total electric bills, as well as the calculation of the upper and lower limits to be used in the inter class revenue increase allocation on Schedule SS-E9 R-1, page 2.

Page 2 of Schedule SS-E9 R-1 shows the proposed inter-class allocation of the revenue increase. The Rate Schedules are indicated in Column 1, while Column 2 is the Proposed Distribution Revenue Requirement based upon the Company COSS results that were synchronized to the rate design test year. Column 3 is the Present Distribution Revenue, while Column 4 shows the increase that would occur if the synchronized Company COSS results were used directly – hence the use of the word "Unlimited" in the column heading. Column 5 is the present total electric bill calculated as if all customers were supplied at BGS rates. Column 6 is the percentage increase in distribution if the unlimited increase in dollars (from Column 4) were applied to the rates; that is, the percentage increase to each rate schedule if these COSS based increases were applied without constraints. The result of the proposed allocation of the Company's revenue requirement increase to the rate classes, consistent with the principles outlined in the previous section, Limitations on Rate Changes, is presented in Column 7 and Column 9. Specifically, Column 7 shows the percentage increase and Column 9 shows the Proposed Distribution Revenue Increase by Rate Class. Column 8 shows the proposed total bill percentage increase if all customers were supplied at BGS rates.

The final step was to calculate the proposed distribution revenue increases for all rates other than Rate Schedules BPL and PSAL. These calculations and the application of the limits were performed in an Excel spreadsheet utilizing the "Goal Seek" function to both meet all of the requirements of the limits and properly allocate any revenue shortfall between the rates, while recovering the full requested increase in distribution revenue.

Page 3 of Schedule SS-E9 R-1 continues the proposed inter-class allocation from page 2. Column 2 carries over the Proposed Distribution Revenue Increase from Column 9 of page 2 and adds on the revenue impacts of TAC (from Column 3) and the proposed DAC (from Column 4). Column 5 shows the resulting net distribution revenue increase including TAC and DAC, while Column 6 shows the proposed total bill percentage increase if all customers were supplied at BGS rates.

Q. How should the rate design be affected if the Board approves an amount other than the Company's overall revenue increase request?

A. If the Board approves an amount other than the Company's overall revenue increase request, the increase to each of the classes should be allocated in proportion to the proposed distribution revenue increase shown in Column 9 of Schedule SS-E9 R-1, page 2.

<u>General Rate Design Principles and Methodology</u>

Q. Please describe the general rate design principles and methodology used in developing the proposed electric rates.

A. The rate design methodology presented in this testimony follows the philosophy of the cost allocation methodology used in the Company COSS in order to align, as closely as practicable, the rates (prices charged to customers) with the underlying costs of serving those customers. This is a key element in the Company's rate design and its importance cannot be overstated. The rate design process is not just to recover the proper amount of revenue from each class, but, to the extent practicable, from individual customers as well, thereby preventing the subsidization of one customer by another. An appropriate rate design will provide correct price signals that reflect how customers' individual facilities impact the costs of the electric distribution system. Only by giving due recognition to what it costs to serve customers can the customers make the correct economic decisions.

The Service Charges for all rates that have service charges were set to move towards the sum of the revenue requirements indicated in the Company COSS for the Customer Service, Measurement and Access segments. With the exception of Rate Schedule RS and RHS, the change in these Service Charges were limited to the same general inter rate class limits of no more than 150% of the overall average distribution percentage increase. The proposed Service Charge change for Rate Schedules RS and RHS will be discussed later in my testimony.

These limits were selected to provide a reasonable balance between the goal of moving each rate component toward costs, and the goal of avoiding unreasonable bill impacts. Any shortfall in Service Charge revenue resulting from these limits was transferred to the remaining Local Delivery based charges of the particular rate schedule. These calculations are as shown in Schedule SS-E10 R-1.

The Distribution Charges for each rate class were set, subject to the limits on the percentage change previously discussed, to recover all the revenue requirements of the Local and System Delivery segments plus any shortfall created from limitations on the proposed Service Charges. The specific unit rate charges (the per kWh or per kW charge) in each rate class are designed to recover the revenue requirements of the Local Delivery segment from annual billing determinants, while the revenue requirements for System Delivery are designed to be recovered only through summer billing determinants. Because the Company's system peak has consistently occurred during the summer period, the summer kWh is the best billing determinant to send the price signal to the customer that is most closely aligned with cost causation. For example, for a rate designed only around non-blocked kWh charges, such as Rate Schedule HS, the winter charge per kWh is the Local Delivery segment revenue requirement divided by the annual kWh use (the annual billing determinant). The summer charge per kWh is the System Delivery segment revenue requirement divided by the summer kWh use (the summer billing determinant), plus the Local Delivery segment revenue requirement divided by the annual kWh use (the annual billing determinant).

For the demand Rate Schedules GLP, LPL and HTS, the Company is proposing to continue two separate demand charges as currently applied. The first, the Annual Demand Charge, is a charge per kW for the monthly maximum kW that will be applicable in every month and is based on each rate class's portion of the Local Delivery segment costs divided by the sum of the customers' monthly peak demands. For Rate Schedule GLP, these applicable demands are the customer's monthly measured peak demands over the entire year. For Rate Schedule LPL-Secondary ("LPL-S") and LPL-Primary ("LPL-P"), these applicable demands are the customer's monthly measured peak demands occurring during any time period over the entire year. For Rate Schedule HTS-Subtransmission ("HTS-S") and HTS-High Voltage ("HTS-HV"), the applicable demands are the customers' single highest demand that occurs at any time during the entire year, also referred to as a "ratcheted demand."

The second demand charge, the Summer Demand Charge, is a charge per kW of the monthly peak demand but is only applicable in the four summer billing months – June through September. This charge is based on each rate schedule's share of the System Delivery segment cost divided by the appropriate kW peak demands for the summer period only. For Rate Schedule GLP, these applicable demands are the customers' monthly peak demands for the summer billing months only (June to September billing months). For Rate Schedules LPL-S, LPL-P, and HTS-S, these applicable demands are the customers' monthly peak demands occurring during the on-peak periods in the four summer billing months.

The recovery of distribution revenue requirements through demand charges for those rate classes that are assessed demand charges is consistent with the Company's historical and current rate structure. Put into the context of the total electric bill for the average customer based upon annualized weather normalized rates, the portion of revenue that is collected through distribution demand charges remains small and ranges from approximately 17% for Rate Schedule GLP to 5% for Rate Schedule HTS-HV.

The limits for the changes in charges for individual luminaires and poles under Rate Schedules BPL, BPL-POF and PSAL will be discussed later in the discussion on the specific changes made to these Rate Schedules.

<u>RATE SCHEDULE SPECIFIC CHANGES</u>

<u>Rate Schedule Residential Service ("RS")</u>

Q. Please describe the rate design for Rate Schedule RS.

A. The rate design for Rate Schedule RS is shown starting on page 4 of Schedule SS-E11 R-1. The current rate is comprised of a monthly Service Charge, plus distribution charges based on monthly kWh use, with the charges differentiated using a two-block rate structure in the summer period.

As indicated in Schedule SS-E10 R-1 - Service Charge Calculations, (line 2), the Company COSS indicates that a significant increase in the monthly Service Charge is warranted. Consistent with the principle of cost causation, balanced by the principle of gradualism, the Company proposes that the Service Charge be increased by 1.5 times the average distribution increase to move the service charge closer to actual cost. The present kWh charges are blocked at 600 kWh per month. The winter rates are identical for both blocks, whereas the summer rates have an inclining block rate, where the second block (for usage greater than 600 kWh per month) is $0.003821 per kWh greater than the rate for the first block.

As previously described, the Company COSS results indicate that the summer charges should be greater than the winter charges because System Delivery revenue requirements should be recovered through summer kWh charges and Local Delivery revenue requirements should be recovered over the entire year. In the Company's previous base rate case, the summer kWh charges were set at an inclining block rate structure whereby the second block was $0.003821 per kWh (without SUT) higher than the first block. There is no underlying cost basis for an inclining block rate structure for the recovery of distribution costs. In fact, analysis based on load profile data shows that higher use customers have a higher load factor which would support a lower per kWh charge for the second block or a "declining block" rate structure. Despite the evidence that supports a declining block rate structure, consistent with the principle of gradualism, the Company proposes to keep the first and second blocks the same and not request a declining block rate structure.

Even with the proposed revenue increase, the proposed RS rate class revenue is significantly below cost. In addition, the current Summer Distribution kWh Charge is significantly lower than the cost to serve while the Winter Distribution kWh Charge is somewhat higher than the cost to serve. The proposed revenue increase less the proposed Service Charge increase will be added proportionately to the current system and local delivery costs. Therefore, the Company is proposing to limit the amount of the scaled system delivery costs to collected in the summer to 60% via the Summer Distribution kWh Charge and the remaining 40% of the system delivery costs collected with the local delivery costs equally over both Summer and Winter Distribution kWh Charges. As a result, the remaining distribution revenue increase for RS from page 2 of Schedule SS-E9 R-1, less the Service Charge revenue increase, will be recovered as described above through both the Summer and Winter Distribution kWh Charges.

The results of the Rate Schedule RS rate design appear on page 5 of the Proof of Revenue in Schedule SS-E11 R-1. The general format of the calculations is described on the first page of that Schedule. The calculation of the annual electric supply cost utilized in the Proof of Revenue for this and all other rate schedules is based upon all customers purchasing electricity on the appropriate BGS service. The magnitude of the BGS values remain constant in both sides in the Proof of Revenue (Schedule SS-E11 R-1) and their inclusion allows the proposed rate changes to be viewed in the context of a customer's overall bill.

Typical Rate Schedule RS customer bill impacts resulting from these changes are shown on pages 1-3 of Schedule SS-E12 R-1.

<u>Rate Schedule Residential Heating Service ("RHS")</u>

Q. Please describe the rate design for Rate Schedule RHS.

A. The rate design for Rate Schedule RHS is shown starting on page 6 of Schedule SS-E11 R-1. In general, the structure of Distribution Charges for customers on RHS remains the same as it is currently. The rate is comprised of a monthly Service Charge, plus distribution charges based on monthly kWh use, with the charges continuing to be differentiated using a two-block configuration in the summer and winter periods. This Rate Schedule remains closed, grandfathered to specific customers as it has been since January 1993.

As indicated on Schedule SS-E10 R-1 Service Charge Calculations, (line 3), the direct use of the Company COSS revenue requirements would indicate that a significant increase in the monthly Service Charge is warranted. In the past, the Service Charge for Rate Schedule RHS has been set equal to the Service Charge for Rate Schedule RS. Consistent with the principle of cost causation, the Company proposes to maintain this relationship such that the Service Charge would be increased by an amount equal to the treatment proposed in the Rate Schedule RS Service Class

The kilowatt-hour charges are presently blocked at 600 kWh per month, with a declining rate structure block in the winter and an inclining block rate structure in the summer. The Proposed Distribution Revenue for RHS from page 2 of Schedule SS-E9 R-1 less the Service Charge revenue was designed to be recovered through the Distribution kWh charges. This remaining balance of revenue requirement was apportioned between Local Delivery and System Delivery based on the revenue requirements for these segments from the Company COSS. The Local Delivery portion of the remaining balance of revenue was divided by the sum of the total annual kWh for all usage. The proposed Winter Distribution Charges were designed to maintain the current declining block differential of ($0.017600). The Summer

Distribution Charges were designed to recover both the System Delivery portion of the remaining balance of revenue and the summer portion of the Local Delivery revenue. The Company is proposing to set identical rates for both summer blocks, thus eliminating the inclining block rate structure. As is the case with the RS rate class, there is no underlying cost basis for an inclining block rate structure for the recovery of summer distribution costs. In fact, an analysis based on load profile data shows that higher use customers also have a higher load factor based on their individual customer peaks, which would support a declining block rate structure for higher use customers. Consistent with the principle of gradualism, the Company proposes to keep the first and second blocks the same.

Typical Rate Schedule RHS customer bill impacts as a result of these changes are shown on page 4 of Schedule SS-E12 R-1.

<u>Rate Schedule Residential Load Management Service (“RLM”)</u>

Q. Please describe the rate design for Rate Schedule RLM.

A. The Company is proposing to close Rate Schedule RLM to new customers when the proposed Residential TOU Pilot Program becomes available to customers. The current rate design for the Rate Schedule RLM is shown starting on page 8 of Schedule SS-E11 R-1. The structure of distribution charges for customers on Rate Schedule RLM remains similar to what it is currently. The rate is comprised of a monthly Service Charge, plus time differentiated charges based solely on total monthly kWh use in each of two time periods. The Company COSS indicated that a small decrease in the Service Charge was warranted for this Rate Schedule. Applying the limits I discussed previously, the Company is proposing to maintain the current Service Charge.

The Proposed Distribution Revenue for Rate Schedule RLM from page 2 of Schedule SS-E9 R-1 less the Service Charge revenue was designed to be recovered through the

Distribution kWh charges. This remaining balance was apportioned between Local Delivery and System Delivery based on the revenue requirements for these segments from the Company COSS. The Local Delivery portion of the remaining balance was divided by the sum of the total annual kWh for all usage. The System Delivery portion is proposed to be recovered during the Summer On-Peak period only, consistent with the methodology detailed earlier.

Typical Rate Schedule RLM customer bill impacts as a result of these changes are shown on page 6 of Schedule SS-E12 R-1.

Rate Schedule Water Heating Service ("WH")

Q. Please describe the rate design for Rate Schedule WH.

A. The rate design for Rate Schedule WH is shown starting on page 10 of Schedule SS-E11 R-1. This Rate Schedule also remains closed and is grandfathered to specific premises, as it has been since October 1980.

There currently is no Service Charge for service under this rate schedule and none is proposed. The unit charge has been set equal to the Proposed Distribution Revenue for Rate Schedule WH from page 2 of Schedule SS-E9 R-1 divided by the total billed kWh.

Rate Schedule Water Heating Storage Service ("WHS")

Q. Please describe the rate design for Rate Schedule WHS.

A. The rate design for Rate Schedule WHS is shown starting on page 12 of Schedule SS-E11 R-1. The Company is proposing no change in the structure of Distribution Charges for this Rate Schedule. The rate comprises a monthly Service Charge plus non-differentiated distribution charges based solely on monthly kWh use.

As indicated in Schedule SS-E10 R-1 Service Charge Calculations, (line 6), the Company COSS indicates that a significant increase in the monthly Service Charge is warranted. The Company, however, proposes that the Service Charge should only be increased consistent with the limits discussed previously. The charge was not moved closer to actual costs in order to minimize the percentage increase in the total bill for customers with very small usage.

The Proposed Distribution Revenue for Rate Schedule WHS from page 2 of Schedule SS-E9 R-1, less the Service Charge revenue, was designed to be recovered through the Distribution kWh charges.

Rate Schedule Building Heating Service ("HS")

Q. Please describe the rate design for Rate Schedule HS.

A. The rate design for Rate Schedule HS is shown starting on page 14 of Schedule SS-E11 R-1. This Rate Schedule is presently closed and is grandfathered to premises receiving service as of August 1, 2003.

As indicated in Schedule SS-E10 R-1 Service Charge Calculations, (line 7), the Company COSS indicates that an increase in the monthly Service Charge is warranted. The Company proposes however that the Service Charge should only be increased consistent with the limits previously discussed. The charge was not moved closer to actual costs in order to minimize the percentage increase in the total bill for customers with very small usage.

The summer/winter price differential follows the kWh-only rate price philosophy as previously discussed. The Proposed Distribution Revenue for Rate Schedule HS from page 2 of Schedule SS-E9 R-1, less the Service Charge revenue, was designed to be recovered through the Distribution kWh charges. This remaining balance was apportioned between Local Delivery and System Delivery based on the revenue requirements for these segments from the Company COSS. The Local Delivery portion of the remaining balance was divided by the sum of the total annual kWh for all usage. The System Delivery portion is recovered through the summer period Distribution kWh charges only.

<u>Rate Schedule General Lighting And Power Service ("GLP")</u>

Q. Please describe the rate design for Rate Schedule GLP.

A. The rate design for Rate Schedule GLP is shown starting on page 16 of Schedule SS-E11 R-1. The Service Charge has generally been set based on the per customer revenue requirements for the Access, Customer Service and Measurement segments and increased in accordance with the limits previously discussed. The Service Charge for unmetered accounts was set based on the per customer revenue requirements for the Access and Customer Service segments because this sub-class has no meters or meter reading expenses. The Service Charge for Rate Schedule GLP-Night Use was set equal to the standard GLP Service Charge. Previously, the GLP Night Use Service Charge was set equal to the Rate Schedule LPL-Secondary Service Charge because previous generation interval meters were required. With the implementation of the advanced metering infrastructure project, the standard GLP meter will be able to provide the interval data to bill the Night Use Provision. These calculations are shown on lines 11-14 of Schedule SS-E10 R-1.

The proposed Distribution Revenues for Rate Schedule GLP from page 2 of Schedule SS-E9 R-1, less the Service Charge revenue, are designed to be recovered through the Distribution kW and kWh Charges. The current relationship in the recovery of Distribution costs between kW and kWh charges is being maintained in the proposed rate design. The amount allocated to be recovered through kWh charges was apportioned between Local Delivery and System Delivery based on the revenue requirements for these segments from the Company COSS.

The amount allocated to be recovered through kW charges was apportioned between Local Delivery and System Delivery based on the revenue requirements for these segments from the Company COSS. The Annual Peak Demand charge was calculated as the Local Delivery segment costs divided by the sum of the Rate Schedule GLP customers' billed Monthly Peak Demands.

The second demand charge, termed the Summer Demand Charge, is calculated as the System Delivery segment cost divided by the sum of the Rate Schedule GLP customers' billed Monthly Peak Demands for the four summer months, June through September.

The Company proposes to retain the provision for unmetered Police, Recall or Fire Alarm Service with all charges increased at the average Rate Schedule GLP distribution percentage increase.

Typical Rate Schedule GLP customer bill impacts as a result of these changes are shown on pages 8 and 9 of Schedule SS-E12 R-1.

Q. What other changes are you proposing to Rate Schedule GLP?

A. To correct an issue from the rate design approved in the 2018 Rate Case Order, the Company proposes to adjust the current GLP rates to rates that would have been in place as intended in 2018. From this new baseline, the proposed rate adjustments based on proposed revenue requirements can be calculated. The prior rate design inverted the intended distribution kWh Summer and Winter rates, and the implemented kWh Winter rate was lower than intended.

<u>Rate Schedule Large Power And Lighting Service ("LPL")</u>

Q. Please describe the rate design for Rate Schedule LPL.

A. The rate designs for Rate Schedules LPL-Secondary and LPL-Primary are shown starting on pages 20 and 24, respectively, of Schedule SS-E11 R-1.

The Service Charge has been set based on the per customer revenue requirements for the Access, Customer Service and Measurement segments and is shown in Schedule SS-E10 R-1 and increased in accordance with the limits previously discussed.

The Company proposes to continue the current provision that provides a reduced Service Charge for the closed provision for grandfathered LPL-Primary customers expected to have a peak demand of less than 100 kW. The Service Charge for this sub-class has been set based on the sum of the per customer revenue requirements for the Rate Schedule GLP Access segment, Rate Schedule GLP Customer Service segment, and the Rate Schedule LPL-Primary Measurement segment, subject to the limits I discussed earlier.

The Proposed Distribution Revenues from LPL-Secondary and LPL-Primary service as set forth on page 2 of Schedule SS-E9 R-1, less the applicable Service Charge revenues, were designed to be recovered through the Distribution kilowatt charges. These remaining balances were apportioned between Local Delivery and System Delivery based on the revenue requirements for these segments from the Company COSS.

The Annual Peak Demand charge was calculated equal to the Local Delivery segment costs from the Company COSS divided by the sum of the LPL customers' billed Monthly Peak Demands that occur at any time during each month.

The second demand charge, termed the Summer Demand Charge, is calculated by dividing the System Delivery segment cost by the appropriate sum of the On-Peak Monthly Peak Demands for the four summer months, June through September.

Typical Rate Schedule LPL customer bill impacts as a result of these changes are shown on pages 12 and 14 of Schedule SS-E12 R-1.

Rate Schedule High Tension Service ("HTS")

Q. Please describe the proposed rate design for Rate Schedule HTS.

A. The rate design for Rate Schedules HTS-Subtransmission and HTS- High Voltage are shown starting on pages 28 and 32, respectively, of Schedule SS-E11 R-1.

The Service Charges and kW demand charges have been calculated and are proposed to apply on a similar basis for Rate HTS-Subtransmission and Rate HTS-High Voltage and Rate Schedule LPL. The only slight difference is that because customers on Rate Schedule HTS-High Voltage are served directly from transmission facilities, there are no System Delivery revenue requirements, and thus there is no Summer Demand Charge necessary for Rate Schedule HTS.

Typical Rate Schedule HTS-S customer bill impacts as a result of these changes are shown on page 16 of Schedule SS-E12 R-1.

Payment Schedule Purchased Electric Power ("PEP")

Q. Is the Company proposing a change to Payment Schedule PEP?

A. The Company is proposing no changes to the Payment Schedule PEP.

ELECTRIC VEHICLE ("EV") COST OF SERVICE STUDIES ("COSS")

Residential Study

Q. Please describe how the Residential EV COSS was developed.

A. The residential electric vehicle ("Res-EV") COSS was developed using 12 months of electric vehicle charger data from August 1, 2022 through July 31, 2023. This period was utilized in place of the 2022 calendar year cost of service test year as the data was readily available and allowed for the largest sample size of customers with a full year of charging data.

The data was collected in 15-minute increments with each increment consisting of total kWh usage, average kW demand, and peak kW demand. Each increment was summed to hourly data, by customer and date. The final data set included data from 826 residential EV charging customers.

From this set of data, the sum of the individual customer peaks was totaled, as well as the coincident peak usage that occurred during the Company system peak that occurred Tuesday, August 9, 2022 from 4-5pm. Sum of peak data was used to determine the EV customer contribution to Local Delivery costs and Coincident Peak data was used to determine the respective contribution to System Delivery Costs. From here, ratios were calculated to the total RS rate class Local Delivery and System Delivery functions.

Q. What were the results of the study?

A. Based on COSS results, the RS Local Delivery costs are equal to $481,937,668 with a Res-EV Sum of Peaks ratio of 16,651 kW / 11,830,661 kW = 0.1407% or $678,295. Similarly, the total RS System Delivery costs are equal to $308,233,692 with a Res-EV Coincident Peak ratio of 34 kW / 4,362,852 kW = 0.0008% or $2,404 for a total Res-EV Local and System Delivery revenue requirement of $664,204. Over the year of usage, total Res-EV energy usage equaled 2,921,627 kWh, resulting in a COS energy rate of $0.227341per kWh, which is significantly above the proposed class average RS Rate Schedules Distribution kWh rate of approximately $0.058523 per kWh.

Q. Based on these results, are you proposing alternative rates for Residential EV charging?

A. Yes. As part of the proceeding, the Company is proposing a Residential TOU Program, which will offer off-peak rates that are significantly lower than current RS or RLM off-peak rates. Details on this Program are described further below in my testimony.

Commercial & Industrial ("C&I") EV COSS

Q. Please describe how the C&I EV COSS was developed.

A. The C&I EV COSS was performed in a similar matter to the Residential EV COSS, with the only exception being the date range and source of the data. C&I data consisted of data from July 1, 2022 through June 30, 2023 from 34 DCFC customers.

Based on COSS results, the LPL-S Local Delivery costs are equal to $105,678,423 with an DCFC-EV Sum of Peaks ratio of 17,678 kW / 2,893,512 kW = 0.6110% or $645,660. Similarly, the total LPL-S System Delivery costs are equal to $129,958,748 with a DCFC Coincident Peak ratio of 6,187 kW / 1,946,767 kW = 0.3178% or $413,018 for a total DCFC Local and System Delivery revenue requirement of $1,058,678. Over the year of usage, total DCFC kWh equaled 30,361,295 kWh resulting in an effective COS energy rate of 0.034869 per kWh.

Q. Based upon the C&I COSS for DCFC customers, what does the Company propose?

A. The current rate structure for LPL-S is highly correlated to cost causation and is the ideal rate for all customers this size. However, to support the state's goal of promoting EV adoption and to ease cost burdens on DCFC customers during this early phase of market introduction of DCFC facilities, the Company is proposing a Distribution kWh charge to replace its Distribution Summer and Annual Demand kW charges for customer premises that only serve as DCFC facilities. Details of the proposed rate can be found on page - 58 - later in my testimony.

PROPOSED RESIDENTIAL TOU RATES

Overview

Q. Do you propose to include a Residential TOU Rates in PSE&G's tariff for electric service?

A. Yes. The Company will offer two new Residential TOU rates as described by Company witness Ahmad Faruqui, Principal Emeritus with The Brattle Group. The proposed tariff provision is consistent with the mechanism described by Mr. Faruqui and can be found in Figure 4 Summary of Current and Proposed RS Rate on page 13 of Exhibit P-10.

Q. Did you assist Mr. Faruqui in developing the proposed rates?

A. Yes. Mr. Faruqui and I worked closely in developing the proposed residential TOU rates which are discussed in more detail below.

Q. As part of the RS-TOU rates, are there any proposed changes to existing rate schedules?

A. The RS-TOU rates have been developed in a manner that provides for the closing of the RLM Rate Schedule to new customers once the RS-TOU is made available.

Q. Is it reasonable for the Board to consider approval of the proposed RS-TOU rates and corresponding rate design that you are proposing in this proceeding?

A. Yes. It is reasonable for the Board to consider the approval of the Proposed RS-TOU and corresponding rate design. The proposed RS-TOU rates align with cost causation, using cost-based rates developed by a COSS and rate design, as the Company is proposing in this filing, and sends the correct economic signals to customers, allowing them to make accurate economic decisions regarding their electricity usage and, as result, helps reduce future investment requirements and thus reduces future rates for all other customers. Adoption of the proposed RS-TOU rates will serve to encourage the most efficient use of electricity possible at a fair and equitable cost. Cost based rates provide a more fair and equitable allocation of costs across customers, support the correct economic customer decision making process regarding energy usage and related investments, and help keep rates more affordable.

<u>Rate Design Detail</u>

Q. What is the Company's proposal for new TOU rates?

A. The Company proposes two new voluntary residential TOU rates: a Two Period TOU Rate ("RS-TOU 2P") and a Three Period TOU Rate ("RS-TOU 3P").

The RS-TOU 2P has two periods, on-peak from 4pm to 9pm weekdays excluding PJM Holidays and off-peak all other hours.

The RS-TOU 3P rate has three periods, on-peak from 4pm to 9pm weekdays excluding PJM Holidays (same as RS-TOU 2P), off-peak from 12am to 6am and mid-peak for all other times.

Q. What are the objectives used to design these TOU rates?

A. The first objective of the TOU rates is to create rates that would provide customers with time of use pricing options that give customers options to move some of their discretionary, relative to timing, usage to non-peak times, where lower pricing could be offered reflecting the lower costs to serve during off peak times. These time-dependent price options may be of interest to those customers for whom the off-peak pricing meets their usage patterns or for those customers willing to modify their usage pattern to take advantage of the lower non-peak rates.

Q. What is the overall rate design philosophy for the proposed RS-TOU rates?

A. As described in the testimony of Mr. Faruqui, the overall rate design philosophy is to design the TOU rates to be revenue neutral to the aggregate RS Rate Schedule. This implies that the goal is that if the entire RS Rate Schedule would be served on either the RS-TOU 2P or 3P rate with no change is usage, the revenue collected from all customers would be the same.

Q. Can you describe the components of the proposed RS-TOU rates and how they were developed

A. Below is description of each rate component and the basis of how they were developed.

1. **Service Charge**: With the implementation of AMI meters, there is no difference in metering cost from a customer on the RS Rate Schedule. Therefore, the proposed service charge for both the RS-TOU 2P and RS-TOU 3P rates will be identical the RS Rate Schedule service charge.

2. **Distribution Energy kWh Charges**: System Delivery Distribution costs are allocated to customers based upon the customers contribution to Coincident Peak Demand. Since PSE&G uses energy (kWh) charges instead of demand or obligation charges to recover this cost, the closest rate to collect these costs would be the Summer on-peak kWh charge. However, this would result in a very high summer on-peak kWh charge. To mitigate the difference between the summer and winter charge and still have the price signal aligned with cost causation, the System Delivery component was allocated 1.5 times more to the Summer on-peak vs. the on-peak winter period. Then an adjustment factor was used to ensure that the System Delivery Costs in the proposed RS-TOU rates are equal to the System Delivery costs embedded in the proposed RS Distribution kWh rates.

   Local Delivery Distribution costs are allocated to rate schedules by the sum of customers' individual peaks in the rate class. Since individual customer peaks can happen at any time and consistent with the current RS Rate Schedules rate design, the Company proposes to recovery this cost over all energy usage. However, to still send the proper price signals to customers and to minimize the mid and off-peak rates, these costs were also ratioed between time periods. For the RS-TOU 3P rate, the on and mid-peak rates were designed to be two times the off-peak rate. To keep the on-peak rates the same between the 2P and 3P rates, the on-peak contribution of Local Delivery costs designed for the 3P rates was used for the RS-TOU 2P rate with the balance of Local Delivery cost recovered in the longer RS-TOU 2P off-peak period. Then an adjustment factor was used to ensure that the Local Delivery Costs in the proposed RS-TOU rates are equal to the System Delivery costs embedded in the proposed RS Distribution kWh rates.

The proposed RS-TOU Distribution kWh rates without and with SUT are shown below in Table 1.

9n3		$/kWh - w/o SUT		9n3		$/kWh - w/ SUT	
Rate	Period	Summer	Winter	Rate	Period	Summer	Winter
Distribution	on peak	0.194959	0.143019	Distribution	on peak	0.207875	0.152494
3P	mid peak	0.039137	0.039137	3P	mid peak	0.041730	0.041730
	off-peak	0.019568	0.019568		off-peak	0.020864	0.020864
Distribtuion	on peak	0.194959	0.143019	Distribtuion	on peak	0.207875	0.152494
2P	off peak	0.034330	0.034330	2P	off peak	0.036604	0.036604

Table 1

The calculation for these distribution rates can be found in workpaper WP-SS-TOU.xlsx.

3. **Supply Charges:** Since Supply rates are determined in BGS proceedings, I developed estimated Transmission and Generation rates, which are revenue neutral to RS rates, to calculate total bill impacts for these proposed rates. The development of the supply rates can also be found in workpaper WP-SS-TOU.xlsx. The Company intends to propose corresponding generation and transmission RS-TOU rates in future BGS proceedings.

Program Details

Q. Which customers could utilize the proposed RS-TOU rates?

A. Any residential customer could choose to be served under this proposed rate.

Q. Would customers be defaulted to RS-TOU rates?

A. No. These rates will be entirely voluntary opt-in options, with no customers defaulted into or required to move to these rates.

Q. Would customers be able to move back to the RS Rate Schedule?

A. The Company proposes that for each residential customer that opts into one of the two new RS-TOU rates, at the end of the initial 12 month period, the Company will provide each customer with reporting showing his or her 12 month bill on the new RS-TOU rate and what this 12 month bill would have been on the RS Rate Schedule. The customer will be offered a one-time refund of the difference if the 12 month bill on the RS-TOU rate was higher compared to the RS Rate Schedule. This initial 12 month look back provision is incorporated to encourage customers to be more willing to try the RS-TOU rates knowing they will not be financially disadvantaged, and after the initial 12 month period, customers can chose to revert back to the RS Rate Schedule if they wish. The initial 12 month look back provision would only be available to customers who take service under either RS TOU rate during the first 24 months that the rate is available to customers.

Q. Is there any requirement to stay on the rate for any period of time?

A. There will be a requirement for customer to stay on the new RS-TOU rate for a period of 12 months. After being on the rate for a minimum of 12 months, customers would also be able to choose to switch back to the RS Rate Schedule at any time.

Q. What is the estimated implementation cost for these new T OU rates?

A. The new AMI meter system provides more detailed metering data that enables TOU rates and creates the ability to bill time of use rates in the Customer System. Once the proposed rates are approved as part of the rate case, new billing logic that meets stringent financial testing and SOX control standards will require an IT programming, testing and training effort. Also, the 12 month look back provision adds a layer of programming complexity as well. The initial estimate to be able to implement the proposed TOU rates is approximately $1.9 million.

Additionally, IT system changes are required to enable changes to a customer's rates without the need to change the customer's meter. This capability had previously been planned for a later phase of AMI use case deployment and is not currently not one of the 22 AMI Use Cases included in the CEF-EC program.[5] To support efficiency in administration of the proposed TOU rates, PSE&G recommends including these system changes in the CEF-EC program for deployment by the end of 2024, and requests the BPU's support for this approach.[6]

Q. What would be the time frame to be able to offer new RS TOU rates?

A. The project to implement the new RS-TOU Program would begin upon the effective date of this filing. It is currently estimated to take nine to twelve months after approval of the filing to make the RS-TOU Program available to customers.

Q. Is the Company proposing a customer communications plan for introducing the availability of the new RS-TOU Program and associate rate options?

A. In the several months before the RS-TOU rates become available, the Company will perform an initial awareness communications plan to all residential customers utilizing varied channels such as the web, bill messages, bill inserts, and digital advertisements at an estimated

[5] See testimony of Company witness Johnson regarding the 22 AMI Use Cases that are part of the CEF-EC program.
[6] This work can be managed within the existing CEF-EC program budget.

cost of $2.0 million. After the kickoff campaign, additional awareness campaigns would be done at regular intervals for the next two years at an estimated $500,000 per year. Additionally, there will be certain targeted communications to those customers identified as likely to be interested in the TOU rates, such as EV customers.

Q. What assumptions has the Company made regarding customer adoption of TOU rates?

A. The Company has proposed entirely voluntary adoption for residential TOU rates and not made any assumptions or targets for residential customer signups. It is assumed that the TOU rates will be of interest to price sensitive customers with usage that allows them to move that usage to off-peak periods. Some percentage of EV owners looking to save money would be likely adopters.

Q. Will there be increased expenses associated with the introduction and support of TOU rates?

A. Yes. Aside from the implementation and communication costs, there will be additional incremental costs related to supporting customers through these TOU options. While self-serve options such as an online rate analyzer will be available, it is anticipated that TOU options will drive increased calls from customers with questions. Additionally, the transitional items being offered, providing the 12 months bill comparison, possible refunds, and ability to change rates, will drive incremental calls and additional work in the billing department to support customers through this transition as customers get comfortable with TOU rates. In the initial three years of the TOU introduction, these incremental expenses are estimated to be in the range of $1.7 million to $3.3 million annually, including risk and contingency.

Q. Has the Company incorporated these RS-TOU rates into the calculated revenue requirement?

A. No. These rates have been designed to be revenue neutral with the proposed RS Rate Schedule, so there was no need for a change to the calculated revenue requirement based on the new TOU rates.

Q. How will the revenue collected under the RS-TOU 2P and RS-TOU 3P Rate Schedules be treated for the Conservation Incentive Program ("CIP")?

A. Since these TOU rates have been developed to be revenue neutral relative to the RS Rate Schedule, the Company is proposing to treat the new TOU Rate Schedule as customers served under the RS Rate Schedule. Therefore, the net distribution per customer will be based upon the RS Rate Schedule revenue per customer and the Company will have the same financial incentive to serve a residential customer either on the RS or RS-TOU rates.

Q. Can you please summarize all the estimated expected costs to implement the RS-TOU?

A. All of the estimated expected costs to implement Residential TOU for the first three years is estimated to total $12.4 million.

Q. How does the Company propose to recover the implementation costs associated with the new RS-TOU rates?

A. The Company proposes that the implementation costs be deferred with all the corresponding regulatory assets earning carrying charges at the Company's latest approved WACC. These costs and corresponding regulatory assets would be reviewed for prudency and cost recovery in the next base rate case.

Q. How does the Company propose to recover the customer support and customer communication and education expense costs associated with the new RS-TOU rates?

A. The Company proposes that the implementations costs be deferred and reviewed for prudency and recovery in the Company's next base rate case.

PROPOSED DCFC DISTRIBUTION KILOWATT-HOUR CHARGE

Q. Have you proposed a new Distribution kWh charge for customers who receive service solely as a DCFC facility serviced under the LPL-S Rate Schedules in lieu of the current annual and summer demand charges?

A. Yes.

Q. Can you please describe the charge?

A. As described in the C&I EV COSS section on page 49 earlier in my testimony, the kWh cost-based rate based upon the historic usage of 34 DCFC customers is $0.034869 per kWh without SUT. To develop a Distribution kWh rate that is comparable to the current Annual and Summer Demand Charge for the LPL-S Rate Schedule, the rate is adjusted for the ratio of the proposed LPL-S Annual and Summer Demand Revenue of $219,900,000 versus its cost to serve of $235,637,170 or 0.93321. As a result, the proposed DCFC Distribution kWh charge is $0.032540 per kWh without SUT ($0.034696 per kWh with SUT).

STREETLIGHTING CHANGES

LED Street Lighting

Q. Is the Company proposing changes to Streetlighting Rate Classes?

A. The Company proposes to no longer offer standard, non-LED streetlights in the BPL (Body Politic Lighting Service) and PSAL (Private Street and Area Lighting Service) Rate Schedules for new installations. The Company would continue to provide only maintenance and electric delivery service for existing non-LED luminaires that began taking service prior to the Board's approval of this proposal. The Company will not proactively replace functioning non-LED luminaires.

Q. Why is the Company proposing this?

A. This is being done to encourage the transition to energy efficient LED luminaires and the anticipated lack of availability and the cost of non-LED luminaires, upon approval by the Board.

Q. Other than the changes to the charges under the Street Lighting Rate Schedules, what other changes is the Company proposing as part of this filing?

A. The Company proposes that during any future maintenance activities on an existing non-LED Luminaire (bulb, photocell, or fixture failures), the Company may, at its sole discretion, replace a non-LED streetlight luminaire with an equivalent LED streetlight luminaire.

Q. What are the changes to the Streetlighting Tariff?

A. PSE&G proposes to close all non-LED Luminaires within the BPL and PSAL Rate Schedules and add new LED Luminaires.

Q. Are there energy efficiency and environmental benefits from the deployment of LED Luminaires?

A. Yes. LED luminaires are environmentally friendly as they reduce energy consumption and therefore carbon dioxide emissions. Also, LED luminaires are effective at managing light pollution.

Q. What are the implications with respect to the streetlight assets associated with the replacement of the non-LED luminaires with LED luminaires?

A. PSE&G's current streetlighting rate schedules provides that "Public Service has the right to replace obsolete luminaires, poles and all other associated equipment with equivalent equipment without the consent of its customers." PSE&G considers all non-LED luminaires that have an LED equivalent to be obsolete equipment and subject to replacement with an equivalent LED Luminaire, opportunistically when repairs or replacements are needed.

PSE&G proposes a change to the tariff to move all obsolete fixtures to the closed section of their respective tariffs.

Q. How will the change from non-LED luminaire to new LED luminaire fixture due to any type of failure (bulb/photocell/luminaire) in the normal course be handled from an accounting perspective?

A. The non-LED luminaire will be retired in the normal course of business.

Q. Will the company incur incremental costs by replacing existing non-LED luminaires failures with an LED luminaire?

A. While the Company manages its current non-LED inventory prudently and will try to minimize the amount inventory in anticipation of the changes discussed above, it is likely there would some amount of obsolete inventory that would result in an inventory write-off and associated incremental expense.

Q. How does the Company propose to recover these costs?

A. PSE&G proposes to defer these costs for recovery in the Company's next base rate case.

<u>Rate Schedule Body Politic Lighting Service ("BPL")</u>

Q. Please describe the rate design for Rate Schedule BPL.

A. As stated previously in my testimony, the Company is proposing to close the non-LED luminaires in the BPL Rate Schedule upon approval by the Board. Since the Company is proposing closed all non-LED luminaires and its present revenue is close to its cost to serve, , the Company proposes to limit the Distribution Charge utilizing the standard increase limits and to increase the Monthly Charges for poles and luminaires by an overall increase of 10% of revenue .

The results of the Rate Schedule BPL rate design are shown on page 37 of Schedule SS-E11 R-1. The general format of the calculations is described on the first page of that Schedule.

In accordance with the Stipulation approved by the BPU in Docket No. ET01120830, the Company offers four distinct service offerings of luminaires and poles under rate schedule BPL, each necessitating a unique set of prices, as follows:

- Specialty luminaires and poles having more than 50 units in service or new LED luminaires,
- LED luminaires and poles that are currently in the Tariff
- Current specialty luminaires and poles;
- Standard and luminaires and poles no longer available.

The first service offering is for LED luminaires and poles that are currently billed as specialty units and meet the 50-unit breakpoint discussed above or new LED luminaires that will take the place of equivalent non-LED units. These facilities are proposed to be offered as standard units whose price will be listed in the tariff. The units are referred to in the workpapers as “Tariff New.” Units already installed and being billed to customers will continue to be billed at the current customer specific charges already established. The individual tariff prices for these units are the greater of either the levelized annual revenue requirement of current costs calculated at Company’s proposed overall rate of return, or the highest price charged to an existing specialty customer.

The second service offering is for luminaires and poles that appear in the Rate Schedule BPL as Standard items and are referred in the workpapers as “Tariff Existing” Since we are proposing to close all non-LED luminaires, only the exiting tariff LED luminaries and poles are in this set. Unit prices for these facilities were first calculated for different luminaire or pole types based on the levelized annual revenue requirement of current costs calculated at the Company's proposed overall rate of return. Proposed changes in the individual Standard pole charges were limited to a range to ensure an aggregate increase 10% to all luminaire and pole revenue.

The third service offering is for current Specialty units, which are referred to in the workpapers as "Specialty." Units of this type already installed and being billed to customers will continue to be billed at the current customer specific charges. New Specialty units will be offered for installation after the conclusion of this proceeding and will follow the same customer specific formula as detailed in the Rate Schedule. The only change proposed for this service offering is an updated Maintenance Charge as set forth in the Rate Schedule.

The final type of offering is for current standard units that are no longer available for new installations. As previously discussed, this will include all non-LED luminaires such as Incandescent, Mercury Vapor, Metal Halide, High Pressure Sodium or Induction, units as well as some obsolete LED units. These are referred to in the workpapers (and in the Tariff) as "Tariff Closed" units.

For these proposed "Tariff Closed" standard non-LED luminaries, prices were adjusted to ensure that the total bill for the new LED equivalents would be equal to or lower than the proposed non-LED total bill. The remaining non-standard Tariff Closed items were adjusted to ensure that the overall luminaire and pole increase will be limited to a range to ensure an aggregate increase of 10% to all luminaire and pole revenue.

The final proposed individual LED luminaire and pole charges for "Tariff Existing" items were determined through iteration, subject to the limits discussed above, such that the overall proposed distribution revenue target for Rate Schedule BPL from page 2 of Schedule SS-E9 R-1 was achieved.

The distribution costs related to the use of the electric distribution system to deliver electricity to the streetlights are calculated by dividing the revenue requirements from the Local Delivery and System Delivery segments by the total kWh delivered. The Maintenance Charges that are listed in Rate Schedule BPL for use in calculating specialty prices and included in the charges for standard luminaires and poles were updated based on the latest information from the Company's accounting records.

<u>Rate Schedule Body Politic Lighting Service From Publicly Owned Facilities ("BPL-POF")</u>

Q. Please describe the rate design for Rate Schedule BPL-POF.

A. The Company closed this Rate Schedule at the conclusion of the 2018 Rate Case. and the rate class is grandfathered to premises receiving service only up to the date of October 31, 2018. Under Rate Schedule BPL-POF, the Company continues to provide only maintenance and electric delivery service for existing publicly owned street lighting systems that began taking service prior to the closing date of October 31, 2018. The Rate Schedule includes monthly charges for those luminaire types presently being served.

The distribution costs for this service are related to the use of the electric distribution system to deliver electricity to the streetlights and are calculated by dividing the revenue requirements from the Local Delivery and System Delivery segments divided by the total kWh delivered.

The fixed per unit charge for each luminaire is designed to provide for recovery of only the maintenance costs associated with providing service. The Company has no investment in the luminaires because all equipment is supplied, installed, and owned by the customer. The unit prices for each luminaire type were set in a manner identical to that of the Maintenance

Charge for Rate Schedule BPL to recover the Proposed Distribution Revenue for Rate Schedule BPL-POF as set forth in page 2 of Schedule SS-E9 R-1.

The Company proposes this class receive the increase as shown in Column 7 of Page 2 of Schedule SS-E9 R-1. Similar to Rate Schedules BPL and PSAL, the Company proposes to increase the Distribution Charge per kWh utilizing the standard increase limits, the Monthly Charges per Unit to recover the remainder of the revenue for this rate schedule.

<u>Rate Schedule Private Street and Area Lighting Service ("PSAL")</u>

Q. Please describe the rate design for Rate Schedule PSAL.

A. The rate design used for Rate Schedule PSAL individual luminaires and poles is similar to the method used for Rate Schedule BPL individual luminaires and poles. The only difference is that because this type of lighting service is optional, as customers may install their own systems that provide comparable lighting, it is appropriate that overall pricing of Rate Schedule PSAL should not be limited to the cost based revenue requirements as indicated by the COSS. The only difference for PSAL compared to BPL is the proposed changes for individual Standard pole charges were limited to a range to ensure an aggregate increase of 20.607% to all luminaire and pole revenue. This is shown on Column 7 of Page 2 of Schedule SS-E9 R-1.

The distribution costs for this service are related to the use of the electric distribution system to deliver electricity to the streetlights and are calculated by dividing the revenue requirements from the Local Delivery and System Delivery segments by the total kWh delivered.

RATE DESIGN FOR FUTURE ADJUSTMENT BETWEEN BASE RATE CASES

Q. Will the same method for revenue changes being proposed in this proceeding be used for future rate adjustments for IIP Proceedings and similar base rate adjustment programs prior to the conclusion of the next base rate?

A. While the method would be similar, the Company is proposing minor modifications that were used in similar rate adjustments since the 2018 base rate case.

Q. What modifications is the Company proposing?

A. Since the Streetlighting Rate Schedules (BPL, BPL-POF and PSAL) Luminaire and Pole Charges are specifically intended to recover the costs for those assets and have no cost relationship to investments being made in the Company's IIP proceedings and similar base rate adjustment programs, the Company proposes to exclude the luminaire and pole revenue from being included in the interclass revenue allocation for the corresponding future rate increases. Only the Distribution Charge revenue for the Streetlighting Rate Schedules would be included utilizing the same interclass revenue increase limits and the same rate design method specifically to the Distribution Charges proposed in this proceeding.

TAX ADJUSTMENT CREDIT ("TAC")

Q. Please briefly describe the TAC Mechanism.

A. The TAC mechanism was established in the 2018 Rate Case Order, to flow back certain tax benefits to customers.

Q. Please briefly describe PSE&G's proposed TAC adjustments.

A. As described in more detail in the testimony of Mr. Pardo, the Company is proposing the following adjustments to the TAC:

1) In addition to continuing to flow back the benefit of the historic Safe Harbor Adjusted Repair Expense ("SHARE") deduction, the Company proposes to flow back to

customers the net federal tax benefit associated with the historical Mixed Service accumulated deferred income taxes ("ADIT") balance over approximately five years.

2) The Company proposes to add the current Mixed Service deduction net benefit to the current SHARE deduction net benefit already included in the TAC, but both at a pre-determined, fixed annual amount, with any excess to be flowed back to customers in a subsequent rate case; and

3) To better match the seasonal flow of Company pre-tax income, the Company began to amortize the monthly flow back of excess deferred income taxes ("EDIT") and SHARE on a seasonal basis in the 2023 TAC filing to match pre-tax income as described in the 2023 TAC cost recovery proceeding. In this proceeding, the Company is aligning the return calculation with the seasonal amortization methodology.

4) To anticipate additional guidance along with proposed and final regulations on the Inflation Reduction Act's newly enacted 15% corporate alternative minimum tax ("CAMT") and material changes to energy tax credit law, the Company may propose an adjustment to the TAC or other mechanism to capture the impact of further U.S. Treasury guidance on the CAMT, if such guidance is applicable to PSE&G. Any proposed amortizations would be included in columns 17-20 in worksheet 'RevReq-E' of WP-SS-TAC-1.xlsx.

Q. Does the Company have an amortization schedule for the proposed amortizations?

A. Yes, the proposed amortizations are included in summary format in rows 167-170 in worksheet 'RevReq-E' of WP-SS-TAC-1.xlsx for 2025 through 2028.

Q. How does the Company propose to modify the TAC revenue requirement formula based upon the changes discussed previously?

A. The TAC revenue requirement formula is calculated monthly and will be modified with the ***bolded items*** below:

TAC Revenue Requirement = (Amortization of Protected ADIT Balance +(Amortization of Historic SHARE ADIT) Balance + ***(Amortization of Historic MSC Deduction ADIT Balance*** *+ After-tax Return on Cumulative Historic SHARE Deduction ADIT Change +* ***After-tax Return on Cumulative Historic MSC Deduction ADIT Change*** *+* ***Pre-set*** *SHARE Deduction Flow-Through +* ***Pre-Set MSC Deduction Flow-Through*** *+ IRS Audit Electric Adjustments + Other Major Electric Tax Adjustments) +* ***(Amortization of CAMT*** *+ After-tax Return on CAMT) * Electric Revenue Factor*

See Schedule SS-TAC-2E R-1 for the monthly net revenue requirement calculations.

Q. What is the TAC amount for the initial period after base rates are projected to take effect in this proceeding?

A. The electric net revenue requirement for the initial 16-month period of September 1, 2024 through December 31, 2025 is a credit to electric customers of $161.9 million or $123.0 million on an annualized basis. See Schedule SS-TAC-1 R-1.

DISTRIBUTION ADJUSTMENT CHARGE AND STORM RECOVERY CHARGE ("SRC")

SRC Mechanism

Q. Please briefly describe the Company's proposed SRC.

A. As described in the testimony of Mr. McFadden, the Company is proposing a SRC to:

1. Recover the deferred major storm costs that have been incurred since 2018 with interest.
2. Defer and then recover future major storm costs, including interest, through subsequent true-up filings.

Q. Please describe the methodology used to calculate the SRC recovery.

A. The Company is proposing a new Distribution Adjustment Charge ("DAC") clause in its electric tariff with the SRC as a new component of the DAC. The DAC was proposed by the Company in its COVID-19 cost recovery filing where COVID-19 Recovery Charge would also be a component of the DAC. The details of the SRC and the recovery mechanism are described below. The following formula describes the SRC mechanism:

SRC Balance = Prior Month SRC Balance – SRC Revenue + Incremental Deferred Major Storm Costs + Interest Expense

Q. How will the SRC be charged or refunded to customers?

A. The Company proposes to charge or refund the SRC through a new component of the Company's proposed DAC in the Company's electric tariff. The charges will be applied to each kWh of a customer's usage and will apply to all electric customers.

<u>SRC Components</u>

Q. What is the Initial SRC Balance?

A. The Initial SRC Balance is the total incremental deferred major storm costs associated with major storms since the Company's last Base Rate Case in 2018 prior to the implementation of the SRC rate.

Q. What are the "Incremental Deferred Major Storm Expenses?"

A. The Incremental Deferred Major Storm Costs are those monthly costs that occur after the implementation of the SRC rate.

Q. What is the "Interest Expense?"

A. The Interest Expense is the monthly carrying costs related to the SRC Balance. It is calculated as following ((Prior Month SRC Balance + (– SRC Revenue + Monthly Activity + Prior Month SRC Balance)) / 2) x (Annual Interest Rate / 12). In calculating the Interest Expense, the annual interest rate is based upon the Company's interest rate obtained on its commercial paper and/or bank credit lines utilized in the preceding month. If both commercial paper and bank credit lines have been utilized, the weighted average of both sources of capital shall be used. In the event that neither commercial paper nor bank credit lines were utilized in the preceding month, the last calculated rate will be used. The interest rate shall not exceed PSE&G's overall rate of return as authorized by the Board as utilized in calculating revenue requirements for the corresponding period. The calculation of the monthly interest can be found in Schedule SS-SRC-1E R-1, Page 1.

Q. How does the Company propose to calculate the initial SRC Rate?

A. The Company proposes to set the initial SRC Rate to recover these costs over a three-year period including interest. The rate will be a rate applied to all electric customer. See Schedule SS-SRC-1E R-1, Page 2 for the calculation.

Q. When does the Company propose to submit subsequent SRC filings to change the SRC?

A. The Company plans to submit a periodic SRC filing to change the SRC rate if warranted based upon the projected SRC over/under balance.

Q. When will storm costs be reviewed for prudency?

A. The Company proposes that all storm costs will be reviewed as part of subsequent SRC filings.

Q. When is the initial implementation of the SRC anticipated to occur?

A. The SRC is proposed to be effective September 1, 2024 corresponding to the change in base rates as a result of this proceeding. If the Board approves new base rates earlier or later than September 1, 2024, the initial rate period and corresponding rate will be adjusted accordingly from the effective date of the Board Order.

Q. What is the SRC amount for the initial period after base rates are projected to take effect in this proceeding?

A. The electric net revenue requirement for the initial annual period of September 1, 2024 through August 31, 2025 is a charge to electric customers of $38.5 million. See Schedule SS-SRC-1E R-1.

<u>TARIFF CHANGES</u>

Q. Are you proposing any further changes to the proposed tariff?

A. Yes. Please refer to the Guide to Electric Tariff Changes, Exhibit P-1 Schedule 2.

<u>LOSSES</u>

Q. Is the Company proposing to update electric losses?

A. No, the Company is not proposing any update to electric losses in this proceeding.

<u>CLEAN ENERGY FUTURE – ELECTRIC VEHICLE ("CEF-EV") FUTURE RATE ADJUSTMENT MECHANISM</u>

Q. Why is the Company proposing a future rate adjustment mechanism in the filing?

A. In accordance with the CEF-EV Order, the Company anticipates that expenditures on the CEF-EV program will extend more than six months beyond the end of the test year and require annual rate adjustment filings. As stated in the CEF-EV Order, paragraph 24:

> CEF-EV investment that is not likely to be in-service by the end of six (6) months after the end of the test year, shall be deferred and placed in a regulatory asset. The Signatory Parties agree the Next Base Rate Case will remain open so that CEF-EV investment placed in service more than six (6) months after the end of the test year in the Next Base Rate Case will be reviewed and placed into rates, if deemed reasonable and prudent, as soon as practicable after the associated infrastructure has been placed into service, through annual roll-in filings following the Next Base Rate Case. The annual roll-in filings will include three (3) months of forecast data that will be trued-up with actual data no later than 20 days after the end of the final forecast month. The annual roll-in filing will request that new rates be implemented three (3) months after the end of the final forecast month. The

schedule of such annual roll-in filings shall be determined in the Company's Next Base Rate Case.

Q. What costs will be included in the future CEF-EV rate adjustments?

A. The CEF-EV Order permits the Company to recovery the following assets in future rate adjustments.

1. Portions of Pole to Meter ("PTM") investments that would have been collected via Contribution in Aid of Construction ("CIAC") payments from CEF-EV participants.
2. The regulatory assets from the deferral of the Behind the Meter ("BTM") rebates to CEF-EV participants.
3. The regulatory asset from the deferral of the Depreciation and Amortization expense associated with the assets from Item 1 and 2 above.
4. IT Investments that were made to support the program
5. The regulatory asset from the deferred return on the Items 1 through 3 above.
6. The regulatory asset from deferred Program O&M expense

Q. How does PSE&G propose to calculate the revenue requirements?

A. PSE&G proposes to calculate the revenue requirements associated with the CEF-EV's costs using the following formula:

*Revenue Requirements = ((Rate Base * Rate of Return) + Net of Tax Amortization and/or Depreciation + Tax Adjustment)* Revenue Factor*

This calculation is similar to the calculations utilized in PSE&G's Infrastructure Programs as approved by the Board in their respective Board Orders. The Company proposes to recover the revenue requirements through annual rate adjustment filings as described below, consistent with the Order approving the Program.

Q. Please describe the components and defined terms in PSE&G's proposed revenue requirement calculation.

A. The following is a description of each term proposed in PSE&G's revenue requirement calculation.

The term "Rate of Return" is PSE&G's overall weighted average cost of capital ("WACC") for the Program. PSE&G is proposing a return on its CEF-EV rate base based upon an authorized return on equity ("ROE"), Long Term Debt, Customer Deposits and corresponding capital structure including income tax effects. The Company proposes to utilize the latest WACC authorized by the Board in the Company's base rate case proceeding(s). See Schedule MPM-04 for the calculation of the proposed WACC utilized in the revenue requirement calculation. Any change in the WACC authorized by the Board in any subsequent electric, gas, or combined base rate case would be reflected in the appropriate corresponding rate adjustment filing explained in more detail below. Any changes to current Federal or State tax rates would also be reflected in an adjustment to the WACC. Additionally, the Company is proposing that for these future CEF-EV rate adjustments, the embedded cost of long-term debt should be the actual rate at the time the Company submits its update for actual results in the associated proceeding.

The term "Rate Base" refers to Gross Plant from the assets described earlier less the associated accumulated depreciation and/or amortization and less Accumulated Deferred Income Taxes ("ADIT"). Gross Plant is equal to all the assets described above and Allowance of Funds Used during Construction ("AFUDC") – both debt and equity components.

ADIT is calculated as Book Depreciation (Tax Basis) less Tax Depreciation, multiplied by the Company's effective tax rate, which is currently 28.11%. Cost of Removal expenditures are depreciated 100% in the year incurred for tax purposes. Please see Table 2 below for the book and tax depreciation rates for each asset, which were approved in the CEF-EV Order.

Asset	Annual Book Depreciation Rates	Tax Depreciation Years/Type[7]
Pole to Meter	2.00%	20 / MACRS
IT Investments	3.33%	3 / SL
Regulatory Asset (excl. O&M)	3.33%	Expense
Regulatory Asset - O&M	20%	Expense

*Based on investment based weighted average of EV Depreciation Rates

Table 2

Any future changes to the book, or tax depreciation rates, such as, but not limited to, reinstatement of "bonus depreciation" during the construction period of the Program and at the time of each base rate adjustment, will be reflected in the accumulated depreciation and/or ADIT calculation described above. The "Net of Tax Depreciation and/or Amortization" allows for recovery of the Company's investment in the Program assets over the useful book life of each asset class. For Plant in Service investment, the net of tax depreciation expense is calculated as the depreciation expense multiplied by one minus the current tax rate. Any future changes to the book depreciation or tax rates during the construction period of the Program and at the time of each base rate adjustment, would be reflected in the net of tax depreciation expense calculation described above.

The term "Tax Adjustment" refers to any applicable tax items that may impact the revenue requirement calculation for the Program.

The "Revenue Factor" adjusts the Revenue Requirement Net of Tax for federal and state income taxes, the BPU and Rate Counsel ("RC") Annual Assessments Fees. The tax rates reflect the current federal tax rate of 21%. The BPU/RC Assessment Expenses consist of

[7] "MACRS" = Modified Accelerated Cost Recovery System, "SL" = Straight Line

payments, based upon a percentage of revenues collected (updated annually), to the State based on the electric and gas intrastate operating revenues for the utility. The Company has utilized the respective BPU and RC assessment rates based on the 2023 fiscal year assessment. Any future changes impacting the revenue factor during the construction period of the Program and at the time of each base rate adjustment, would be reflected in the revenue factor described above.

Q. Do you provide a schedule showing a sample calculation of the revenue requirements?

A. Yes. See Schedule SS-CEF-EV-1 R-1 for a sample calculation of future revenue requirements for the CEF-EV program.

Q. How does the Company propose to recover the revenue requirements as described above?

A. The Company proposes to recover the revenue requirements associated with the Program via new CEF-EV rate components of its Infrastructure Investment Program Charges ("IIPCs") for the Electric Tariff. While not an IIP, this mechanism will allow for the inclusion of the CEF-EV rate adjustments into base rates.

The filing schedule based upon the Initial Filing date along with corresponding timing for, Investment as Of, Update for Actuals Filing, and Rates Effective dates for all electric and electric rate adjustment filings, assuming Board approval of this proceeding by September 1, 2024, is listed in the table below.

Each Initial Filing shall provide the actual cost and forecast for investment data, revenue requirement calculations, proposed CEF-EV rates, and related data to support rates based on CEF-EV costs.

The Update for Actuals Filing, updates all forecasted cost and investment data, revenue requirement calculations, proposed CEF-EV rates, and related information from the Initial

Filing to data based on all actual historical data. CEF-EV investments included in rates in the Update for Actuals Filing shall only include CEF-EV investment not in the Company's base rates and actually placed in-service according to the schedule below.

The Rates Effective dates for each filing below shall be as indicated in Table 3 below – the first day of the month following five months following the due date of the Initial Filing. The Company proposes three rate adjustment filings with dates to be determined based upon 60 days notice prior to the initial filing. Table 3 below shows the Company's proposed filing timeline for each rate adjustment filing.

CEF-EV Rate Adjustment Schedule			
Initial Filing	**Investment as Of**	**Update for Actuals Filing**	**Rates Effective No Earlier Than**
TBD	TBD + 2 mo	TBD + 3 mo	TBD + 5 mo + 1 Day

Table 3

Q. What rate design is the Company proposing to use for this base rate adjustment?

A. The Company proposes to use the rate design from the most recently approved base rate case proceeding.

Q. What will be the source of the capital expenditures you use to calculate the revenue requirements for future CEF-EV adjustments?

A. The actual and projected monthly cash flows for the Program will be provided in separate testimony from the CEF-EV Program witness.

Q. Will the Company continue to calculate a monthly investment deferral on CEF-EV investments that are recovered in base rates or future rate adjustments?

A. No. Once investment is included in customer rates through a base rate case proceeding or future rate adjustments, it will be excluded from the CEF-EV Monthly Investment Deferral calculation described above.

Q. How will the CEF-EV Regulatory Asset be reflected in subsequent base rate case proceedings?

A. Consistent with the CEF-EV Order, the Company will continue to seek recovery of and on the unamortized CEF-EV Regulatory Asset. This will include any Deferred Monthly Investment not yet recovered in rates and return on the unamortized CEF-EV Regulatory Balance as a component of rate base in the same manner as any other Utility Plant.

STAFF COSS METHODOLOGY

Q. Please explain why you are conducting the Staff COSS.

A. In the 2018 Rate Case proceeding, the Company agreed to perform a COSS in the manner prescribed by Staff. In accordance with this requirement, the Staff COSS and the summary of the resulting functional revenue requirements by rate class are being submitted with the Company's rate case filing. Specifically, Schedule SS-E13 R-1 contains the details of the complete COSS utilizing Staff's Method, Schedule SS-E14 R-1 is the Summary Report by Functional Segment based on Staff's Method, Schedule SS-E15 R-1 is the Functional Cost Summary of the Cost of Service Study results based on Staff's Method, and Schedule SS-E16 R-1 contains the Service Charge Calculations based on Staff's direction.

In the Stipulation that resolved the 2018 Rate Case, the parties made it clear that they were not agreeing that the Staff COSS was appropriate, was consistent with cost causation principles, or would be a useful guide in determining just and reasonable rates. Specifically, the Stipulation stated (at 11-12):

> All parties will be free to submit any number of alternative cost of service methodologies for the Board's consideration in future cases. The Company and

any Signatory to this agreement will have the right to file and support any COSS method it considers appropriate.[8]

Q. Does the Company believe that the Staff COSS provides a reasonable foundation for establishing just and reasonable rates in this proceeding?

A. No. The Staff COSS Methodology is not an appropriate methodology to use to establish just and reasonable rates because it does not achieve a result that is tied to cost causation. Instead, the Staff COSS method goes to great and often extraordinary lengths to allocate and functionalize costs away from residential customers and onto the shoulders of commercial and industrial customers. While it may be reasonable to moderate the level of increase to be borne by residential customers, the vehicle for doing so should not be a COSS that transfers costs to businesses operating in the Company's service territory. The Company has taken reasonable steps to moderate the increase in rates for Rate Schedules RS and GLP customers with its gradualism-based recommendations that limit the increases for those classes.

Q. What is the primary reason that you believe that the Staff COSS is inappropriate?

A. The fundamental error in Staff's Method for the vast majority of costs is that it proceeds from an assumption that a significant portion of the cost of electric distribution assets should be allocated to the rate classes based on the amount of energy consumed by each class. This general method is applied to virtually all assets in FERC Accounts E360 to E368, which comprise about 81% of the Company's total gross electric plant.

The method used in the Staff COSS to functionalize and allocate most costs has existed for many years and is usually referred to as the "Average and Excess" methodology. However, historically the "Average and Excess" method was used to allocate costs of electric generation

[8] 2018 Rate Case Order at Stipulation ¶ 25.

plant and gas production facilities where arguably there is an energy component because there is investment beyond that necessary to provide capacity at the time of peak load. There is no linkage between this methodology and electric distribution plant costs or operations. Contrary to the assumptions underlying the Average and Excess method, the Company's distribution planners and designers plan and install facilities to meet the peak demands of customers. The design of those facilities is not based on the amount of energy (kWh) they consume.

Chapter 6 of the NARUC Manual, which the Company has generally relied on for functionalization and allocation concepts, describes in detail various methods of functionalizing (or classifying) and allocating electric distribution plant. Table 6-1 on Page 87 of the NARUC Manual shows the general classification of each of the distribution plant accounts into either a demand related or customer related component. More specifically, Part II of this Chapter, which starts on page 90 discusses various allocation techniques and calculations, begins as follows:

> *"When the utility installs distribution plant to provide service to a customer and to meet the individual customer's peak demand requirements, the utility must classify distribution plant data separately into demand- and customer-related costs."*

Nowhere in the NARUC Manual does a suggestion appear that the cost of electric distribution facilities should be classified or allocated on the basis of energy usage.

The Staff COSS suggests that because distribution facilities carry the "average" load of customers, costs should be allocated based on the average load or even the number of kWh that flow through the wires. This methodology unreasonably ignores the fact that the vast majority of the costs of the distribution system are not caused by its average use. If the system were designed to transport deliveries at only the average amount of electricity, or the amount of energy that is transported and delivered on an annual basis, it would be a much different system. However, no responsible designer of an electric distribution system would ever design a system that would permit delivery of only the average daily or average annual use. Electric distribution system costs are incurred to serve the expected peak load or any particular circuit.

Q. Do you have particular concerns with the manner in which the Staff COSS methodology classifies and allocates the costs of particular electric distribution accounts?

A. Yes. These concerns are as follows:

<u>Accounts E360 to E362, E365, E366, E367 and E368</u>

These accounts include land, local distribution headquarters, substations, overhead conductors and devices, underground conduit, underground conductors and devices, and line transformers. Staff's COSS requires both the costs of this plant and the expenses associated with this plant to be separated into energy-related and demand-related components and allocated across the rate schedules using a kWh allocation for the energy-related portion and CP allocator for the demand costs, respectively. Staff's proposed classification and allocation ignores the fact that there is no relationship between the costs incurred for these plant items and the amount of energy consumed by various rate classes over an annual period.

<u>Accounts C389 to C399 – Common Plant and E303 Intangible Plant</u>

In Staff's COSS the plant and associated depreciation reserve booked to C389-C399 – Common Plant and to C303 – Intangible Plant associated with meter reading was separated into a customer related and demand related component. The allocation of the customer related portion is the same as the Company's methodology, but the demand related portion was allocated using the class non-coincident peak ("NCP") allocator.

The class NCP is a measure of the peak of each class of customers, regardless of when it occurs. Although used in past cost allocation studies by the Company, it is less accurate than the use of both the actual CP and actual sum of individual customer demands. There is no reason to use an approximate substitute (the NCPs) when the real drivers (the CPs and sum of individual customer demands) are available. For these reasons, Staff's method of allocation of Common and Intangible Plant is unreasonable.

<u>Accounts E902 – Meter Reading Expenses & E903 - Customer Records and Collection</u>

Under the Staff COSS, expenses booked to these accounts are separated into a customer-related and demand-related component via a 50% - 50% split. Staff's 50% - 50% spilt between customer-related and demand-related components is not supported by any explanation or cost justification. Classifying basically fixed meter reading costs as demand-related for recovery through variable energy or demand charges violates the most fundamental cost classification and allocation principles. The amount of energy used has no bearing on the cost to read a meter. The majority of the time a meter reader spends is not the actual reading of the meter, but simply travelling from one meter to another. Itis independent of the type, size, or usage of the customers in that class. The variable that drives the total meter reading related costs booked to these accounts is the number of customers. Staff's classification of meter reading expenses as demand costs should be disregarded.

<u>Subsequent Base Case Requirements</u>

Q. Do you believe that the Company should be required to complete the Staff COSS in subsequent base rate case filings?

A. No. The Company is requesting that this requirement not be included for the filing of its next base rate case.

Q. Does this conclude your direct testimony?

A. Yes. It does.

APPENDIX E1 - DETAILED REVIEW OF COST OF SERVICE STUDY

Set forth below are details concerning the COSS Modeling Procedures as well as the functionalization and allocation of particular costs in the Company COSS.

Modeling Procedure

After expenses or plant investment-related costs have been entered into the COSS model, usually by FERC account or groups of accounts, one modeling allocator is also entered which performs two functions. The allocator shows:

1. Which of the six segments, or functions, the particular plant or expense item has been attributed to, and
2. The basis on which the particular plant or expense item has been allocated across the rate classes.

The COSS model starts the calculation procedure by allocating the respective plant and expense items to rate classes. Rate revenues for each rate class are then target balanced such that the resulting ROR for each of these rate classes achieves the Company's proposed overall ROR. The model continues by separating all plant and expense items into the appropriate functional segment by rate class, according to the modeling allocator assigned to the particular plant or expense item.

ALLOCATOR NAMING CONVENTION

For consistency and simplicity of bookkeeping, a naming convention has been developed for the modeling allocators.

Direct Allocators

All modeling allocators that end in a dash and a number (such as SUMPK@PRI-04) are direct allocators, meaning that they:

1. Allocate the plant or expense item based on an external constant as indicated by the name of the modeling allocator. For example, the "SUMPK@PRI " in the above allocator denotes the sum of all customers' greatest peak demands as observed at the primary lines, and
2. Segments, or functionalizes, the plant or expense item into one of the six segments as indicated by the trailing number. For example, the "-04" from the above allocator denotes the Local Delivery segment. The segment numbering method used in our analysis is as follows:
    - Segment #2 – Street Lighting
    - Segment #3 – Access
    - Segment #4 – Local Delivery
    - Segment #5 – System Delivery
    - Segment #6 – Customer Service
    - Segment #7 – Measurement

Note that segment #1 is not used.

<u>Indirect Allocators</u>

All modeling allocators that do not end in a dash and a number (such as A&GEXP) are indirect allocators, meaning that they will both segment and allocate costs in the same proportion as other individual or groups of plant or expense items. The names of these modeling allocators are an indication of the items upon which this process takes place. In this example, the A&GEXP allocator segments and allocates costs in the same proportion as the Administrative and General ("A&G") expenses in aggregate.

ALLOCATION DETAILS

Intangible Plant

Electric intangible plant (Accounts E301 to E303) was not included in the study.

Production Plant

There is no Production Plant on the Company's books.

Transmission Plant

All of transmission plant (Accounts E350 to E359) is excluded from the Cost of Service study as I have previously discussed since it is not related to the regulated electric distribution business.

Distribution Plant

The majority of Distribution Plant (Accounts E360 to E374) (Schedule SS-E5 R-1, pages 1-2, lines 9 to 20) have been functionalized as follows:

- Substations, poles, wires, circuits and transformers have been functionalized either to the Local Delivery or the System Delivery segments
- Electric services have been functionalized to the Access segment
- Meters to the Measurement segment
- All electric street lighting related equipment to the Street Lighting segment

After this functionalization was completed, each account was then examined to determine the proper allocation of the functionalized costs across rate classes. Investment segmented as Local Delivery was allocated consistent with the prior discussion, to the applicable rates based on the sum of the applicable customers' individual peak demands other than specific exceptions as noted.

Investment segmented to the System Delivery segment was allocated across the applicable rate schedules based on each applicable class's contribution to the coincident peak (also known as the CP). The details of the functionalization and allocation for each of the major Distribution Plant accounts are as follows:

E360 - Land & Land Rights

The investment in land or right-of-ways related to directly providing service to the few customers on Rate HTS-HV was directly assigned to this rate. The investment in this Account associated with substations follows the functionalization and allocation of the substations (recorded in Account E362 Station Equipment). The remaining investment in this account is attributed to local distribution headquarters, which follows the functionalization and allocation of all distribution plant in aggregate.

E361 - Structures and Improvements

The portion of investment in this account associated with substations follows the functionalization and allocation of Account E362 Station Equipment. The remaining portion is attributed to local distribution headquarters plant and follows the functionalization and allocation of all distribution plant in aggregate.

E362 - Station Equipment

Distribution investment in switching stations was segmented to the System Delivery segment and allocated to all customers served at 26 kV (on Rate HTS-sub) and the remainder of the load for primary and secondary customers based on their contribution to CP.

The distribution plant attributed to High Voltage substations (termed class H substations) was also segmented to the System Delivery segment. These substations convert either 69 kV, 138 kV or 230kV power directly to primary voltages (usually 13 kV). Since this type of substation only provides service to primary and secondary customers, the investment was allocated across rates serving customers at primary and secondary voltages based on the CPs of these rate classes.

Plant recorded for all other substations, referred to as the subtransmission classes (A, B, D, and other classes of substations), were segmented to the System Delivery segment and allocated across the rate classes serving primary and secondary voltage customers based on the CPs of these rate classes.

E364 - Poles, Towers & Fixtures

Poles were first analyzed to determine their specific use. Those poles used for street lighting purposes were segmented to the Street Lighting segment and directly assigned to rates BPL and PSAL based upon the type of plant and number of each type being billed under each applicable rate. Although an analysis was performed to determine the portion of E364 directly related to providing service to customers on Rate HTS-HV, no assets were found.

The remaining pole investment was separated into three categories, based on its use, to deliver either secondary, primary and/or subtransmission voltages to customers. An analysis was performed utilizing the Graphic Information System ("GIS") facilities mapping system to determine the type and number of conductors attached to every distribution pole in the system.

The total investment in poles used to carry secondary voltage conductors was segmented to the Local Delivery segment and allocated to all secondary customers based upon the sum of individual secondary customer peak demands, consistent with the methodology previously explained. For pole configurations carrying conductors of several operating voltages, the appropriate secondary portion of the pole investment was segmented to the Local Delivery segment and allocated as stated above.

The portion of the investment in poles used to carry primary voltage conductors was segmented 50% to the Local Delivery segment and 50% to the System Delivery segment.

The plant segmented to the Local Delivery segment was allocated to all customers served at secondary or primary voltages based upon the sum of individual customer peak demands of these classes. Those investments segmented to the System Delivery segment were allocated to all customers served at secondary or primary voltages based on these classes' contribution to the system CP. To simplify modeling, a combined allocator named "PRIMARYLINES" was developed to perform this segmentation and allocation in one step.

Finally, the portion of the investment in poles used for carrying subtransmission voltage conductors was segmented 21.1% to the Local Delivery segment and 78.9% to the System Delivery segment, consistent with the methodology previously discussed. The subtransmission plant segmented to Local Delivery was directly assigned to Rate HTS-Subtransmission, while the investment segmented to System Delivery was allocated to customers served through non-Class H substations served at secondary, primary or subtransmission voltages based on these classes contribution to the system CP, consistent with the methodology previously discussed. Similar to what was done above, a combined allocator named "SUBTRANSLINES" was developed to perform this segmentation, assignment and allocation in one step.

E365 - Overhead Conductors and Devices

This account is comprised primarily of various types of wire and other overhead equipment of various plant types (i.e. #2 Al wire, #3 Al wire, 4kV single phase lighting arrestor, etc.).

The investment in conductors (wire) associated with dedicated street lighting poles (those used solely for street lighting) was first directly assigned to the Street Lighting segment in Rates PSAL or BPL based upon the number of overhead street lighting-only poles in each rate class. This investment was estimated as the typical pole-to-pole length of secondary wire most commonly used for street lighting purposes for each of these street lighting poles.

The remaining equipment was first separated into the voltage class in which it is used - secondary, primary, subtransmission or high voltage and was then segmented and allocated in a method similar to that discussed above for poles. Investment in equipment whose normal operation voltage could not be determined or is used for all voltages (such as grounding wire) was allocated in the same proportion as the total of Account E365 equipment whose operating voltage could be determined.

The one exception to this method is the investment in conductors and other associated equipment used to serve customers on HTS-HV which was segmented to the Access segment since it effectively comprises the service drop to these customers. This investment was then directly assigned to this rate class. Although an analysis was performed to determine the portion of E365 directly related to providing service to customers on Rate HTS-HV, no assets were found.

E366 - Underground Conduit

These investments follow the functionalization and allocation of Account E367 underground Conductors and Devices.

E367 - Underground Conductors and Devices

A detailed segmentation and allocation was performed on a similar basis as done for investments booked to Account E365 - Overhead Conductors.

E368 - Line Transformers

Investments in line transformers were functionalized to the Local Delivery segment. The embedded costs of all line transformers in service were linked to the customers being served by each type and size of transformer. The average cost, in dollars per kVA, of transformer capacity was multiplied by the sum of the peak demand of each customer class to arrive at a calculated total transformer investment by rate class. This value was then used as an allocator of booked transformer investment.

E369 - Services

Investment in electric services was first classified as either minimum or excess investment. This is done since the magnitude of the customer's use or peak demand in some cases requires the use of a larger size service wire. Since the increase in costs above that of the minimum sized service is driven by customer demands, they are more appropriately demand related costs. They are termed excess costs and are segmented to the Local Delivery Segment to be recovered through the rate component where other demand related costs are recovered. The minimum investment was determined for subsets of each rate class, as the installed cost of a service utilizing the minimum wire size installed for customers in that subclass. This portion was segmented to the Access Segment for recovery through the Service Charge. The subsets analyzed for Rate RS were comprised of the various type of housing stock, including single family detached, single family attached, two family, three to four family homes, five to nine family homes, and structures of ten or greater residential units. For the demand rates of GLP and LPL, the subsets were determined by electrical demand. The excess investment was determined as the additional cost, over the minimum cost, of the typical service utilizing the wire size most commonly installed for customers on each rate class subset.

<u>E370 - Meters</u>

Given that new AMI meters are relatively the same cost for customers in each rate class, the meter investment booked in FERC Account E370 was segmented to the Measurement segment and allocated across the rates based upon the relative installed cost of new meters.

E373 – Street Light and Signal Systems

The costs charged to this account include all street lighting luminaires, decorative street lighting poles, and miscellaneous devices such as shrouds and brackets. All costs related to street lighting luminaires and miscellaneous devices have been segmented to the Street Lighting segment and are directly assigned to the two street lighting Rate Schedules BPL and PSAL based upon the number and type of luminaires and other devices billed under each rate. Local municipalities are only charged for the luminaires used for public street lighting in overhead areas since the luminaires can be mounted on already existing distribution poles. Since this is not the case in declared underground zones, in order not to burden the municipality with the expense of the underground street lighting poles, standard underground poles have been provided at no charge. The investment related to these poles provided at no charge has been segmented and allocated in the same proportion as distribution plant excluding meters. The investment in poles for other than these purposes have been segmented to the Street Lighting Segment and directly assigned to the two street lighting Rate Schedules BPL and PSAL based upon the number and type of poles billed under each rate.

Asset Retirement Obligations

The amounts for Asset Retirement Obligations (or AROs) booked to Account E374 was found to be almost exclusively related to poles and towers booked to Account E364, thus were functionalized and allocated in the same proportion as performed for the plant in Account E364.

General, Common and Other Plant

An accounting code, or Business Code, associated with the actual gross plant balances indicating the department to which the plant is assigned was used to segment both the general

(Accounts E389 to E399) and common (Accounts C389 to C399) plant account items (Schedule SS-E5 R-1, page 1). Each Business Code was then grouped by function to be allocated based on cost causation. For example; a Description for office furniture and equipment was added to the Customer Service segment and allocated in the same proportion as all Customer Service activities. In other cases, where some of the facilities, such as vehicles, etc. used by the Customer Operations Department are shared between groups that are responsible for meter reading and those that provide general customer service (collections, phone inquiry, walk-in payment centers, etc.), these investments were further split in the Cost of Service Study between the Measurement segment and the Customer Service segment based on the proportion of work performed by each group. In general, all general and common investments were allocated to the rate schedules in the same proportion as the overall respective plant accounts for each segment. Items for which no reasonable functionalization could be determined were classified as "unassigned" and allocated in the same proportion as its associated plant account. In other words, unassigned general plant followed general plant and unassigned common plant followed common plant (general plant, common plant and other plant are shown on Schedule SS-E5 R-1, pages 11-12.

Depreciation Reserve

The depreciation reserve associated with each Account was segmented and allocated in the same proportion as its associated plant account (Schedule SS-E5 R-1, pages 15-18, lines 1 to 93).

Adjustments to Develop Rate Base

Adjustments to net plant used to develop Rate Base consist primarily of capital added since the end of the COS year, working capital and deferred taxes for the distribution utility.

Most capital additions used allocated based upon distribution plant with other additions allocated to total net plant. The capital rate base adjustment associated with the CEF-EC program were allocated based upon the underlying meter costs for the RS and GLP rate schedules. In addition, approximately $440M of distribution net plant additions associated with CEF-EC were reclassified into the CEF-EC adjustment, with a total CEF-EC adjustment of approximately $670 million. The underlying components of working capital were analyzed and segmented according to their individual use. Working capital requirements associated with Material and Supplies, Cash, Prepayments, and Working Funds were allocated and segmented in the same proportion as the sum of O&M and capital additions (essentially cash outlays) through the use of the allocator termed "EXPENDITURES." Deferred taxes were segmented and allocated in proportion to the related plant values. These adjustments are indicated in Schedule SS-E5 R-1, pages 19-20, lines 1 to 36.

Operating Revenues

The values indicated in Schedule SS-E5 R-1, pages 3-4, line 56 entitled "Rate Revenue from Customers" are the portion of the total target balanced revenue requirements necessary to be recovered from rate-related revenues (from service charges, distribution charges, minimum charges, etc.) at the proposed overall ROR, plus the increase in non-rate-related revenues. The effects of other non-rate-related revenues are booked to Accounts E450 to E456 and are shown in Schedule SS-E5 R-1, pages 21-22, lines 10 to 11.

Production Expenses

Similar to the production plant items, there are no production expenses (Accounts E500 to E557) remaining on the Company's books.

Transmission O&M Expenses

Similar to Transmission Plant, these items were excluded from the Cost of Service study.

Distribution O&M Expenses

O&M expenses (Accounts E580 to E598) were generally segmented and allocated in the same proportion as their associated plant account(s) (Schedule SS-E5 R-1, page 23-24, lines 14 to 48).

Customer Accounts, Service and Sales Expense

Expenses from a wide range of customer contact activities are booked to Accounts E901 to E916. A separate analysis was performed on the costs charged to each of these accounts to determine the best functionalization fit. The details of this account-by-account functionalization can be found on Schedule SS-E5 R-1, pages 25-28, lines 59 to 109. The costs in each of these accounts related to meter reading were segmented to the Measurement segment and allocated on the basis of the costs to read meters for each rate class. The portion related to billing was segmented to the Customer Service segment and allocated on the relative costs of billing by rate class. The portion related to account maintenance activities (including answering general questions, setting up new accounts, remittance processing, and collection activities) was segmented to the Customer Service segment and allocated on the relative costs of performing these activities by rate class. The portion of these expenses related to general regulated utility responsibilities was segmented to the Local Delivery segment and allocated on the relative costs of performing these activities by rate class. The portion of Customer Records and Collection costs (Account E903 and E905) associated with costs to disconnect customers for non-payment of bills (and their eventual reconnection) were segmented to the Customer Service segment and allocated based upon the number of customers.

Where Customer Accounts expenses are recovered through the Societal Benefits Charge ("SBC"), such expenses were excluded from the Cost of Service study as indicated in Schedule SS-E3 R-1.

<u>Administrative and General ("A&G") Expenses</u>

These expenses (Accounts E920-935) include an eclectic mix of types of expenditures, which were analyzed separately to determine the best functionalization fit. The details of this item-by-item functionalization can be found on Schedule SS-E5 R-1, pages 27-28, lines 115 to 127.

<u>Depreciation and Amortization Expenses</u>

All depreciation and amortization expenses were segmented and allocated in the same proportion as their associated plant accounts (Schedule SS-E5 R-1, pages 29-30, lines 1 to 29).

<u>Pro Forma Expense Adjustments</u>

The pro forma adjustments the Company is proposing are summarized in Schedule MPM-29 and detailed as Adjustments #1 to #24 in Schedules MPM-30 through MPM 53of Mr. McFadden's direct testimony in this proceeding. With the exception of the pro forma adjustments discussed below, the balance of the adjustments related to electric distribution are included in the Cost of Service Study (Schedule SS-E5 R-1, pages 31-32, lines 11 to 45)

Each pro forma adjustment included in the Cost of Service Study was segmented and allocated in the same proportion as the associated plant or O&M account(s). The Cost of Service modeling of Pro-Forma #3 associated with Interest Synchronization, Pro-Forma #5 associated with Electric COLI Interest Expense, and Pro-Forma #7 associated with Gains and

Losses on Sales of Property all include the added income tax effects on revenue requirements as an additional expense.

Pro-Forma #6 associated with Weather Normalization, Pro-Forma #15 associated with Energy Strong II/IAP, Pro-Forma #19 associated with CEF-CE, Pro-Forma #21 associated with CIP, and Pro-Forma #22 associated with TAC are excluded from the Cost of Service Study (Schedule SS-E5 R-1) since these adjustments would be classified as revenue adjustments and do not impact distribution costs.

Taxes

All Taxes and Tax Deductions were segmented and allocated in the same proportion as their associated plant or O&M account(s). Details of these allocations are indicated on Page 35-44of Schedule SS-E5 R-1.

CREDENTIALS
OF
STEPHEN SWETZ
SR. DIRECTOR-CORPORATE RATES AND REVENUE REQUIREMENTS

My name is Stephen Swetz and I am employed by PSEG Services Corporation. I am the Sr. Director - Corporate Rates and Revenue Requirements where my main responsibility is to contribute to the development and implementation of electric and gas rates for Public Service Electric and Gas Company (PSE&G, the Company).

<u>WORK EXPERIENCE</u>

I have over 30 years of experience in Rates, Financial Analysis and Operations for three Fortune 500 companies. Since 1991, I have worked in various positions within PSEG. I have spent most of my career contributing to the development and implementation of PSE&G electric and gas rates, revenue requirements, pricing and corporate planning with over 20 years of direct experience in Northeastern retail and wholesale electric and gas markets.

As Sr. Director of the Corporate Rates and Revenue Requirements department, I have submitted pre-filed direct cost recovery testimony as well as oral testimony to the New Jersey Board of Public Utilities and the New Jersey Office of Administrative Law for base rate cases, as well as a number of clauses including infrastructure investments, renewable energy, and energy efficiency programs. A list of my prior testimonies can be found on pages 3 and 4 of this document. I have also contributed to other filings including unbundling electric rates and Off-Tariff Rate Agreements. I have had a leadership role in various economic analyses, asset valuations, rate design, pricing efforts and cost of service studies.

I am an active member of the American Gas Association's Rate and Strategic Issues Committee, the Edison Electric Institute's Rates and Regulatory Affairs Committee and the New Jersey Utility Association (NJUA) Finance and Regulatory Committee.

EDUCATIONAL BACKGROUND

I hold a B.S. in Mechanical Engineering from Worcester Polytechnic Institute and an MBA from Fairleigh Dickinson University.

LIST OF PRIOR TESTIMONIES

Company	Utility	Docket	Testimony	Date	Case / Topic
Public Service Electric & Gas Company	E	ER24020073	written	Feb-24	Elecric Conservation Incentive Program (ECIP)
Public Service Electric & Gas Company	E/G	ER23120924 & GR23120925	written	Dec-23	Base Rate Proceeding / Cost of Service & Rate Design
Public Service Electric & Gas Company	E/G	QO23120874	written	Dec-23	Clean Energy Future - Energy Efficiency II Program
Public Service Electric & Gas Company	E/G	G018101112 and EO18101113	written	Nov-23	Clean Energy Future - Energy Efficiency Extension 2 Program
Public Service Electric & Gas Company	E	ER23110783	written	Nov-23	Infrastructure Advancement Program (IAP) - First Roll-In
Public Service Electric & Gas Company	E/G	ER23050273	written	Nov-23	Energy Strong II Program (Energy Strong II) - Fifth Roll-In
Public Service Electric & Gas Company	E/G	ER - 23090634 & GR - 23090635	written	Sep-23	Tax Adjustment Clauses (TACs)
Public Service Electric & Gas Company	E/G	GR23070448	written	Jul-23	COVID-19 Filing
Public Service Electric & Gas Company	E/G	ER23070423 & GR23070424	written	Jul-23	Green Programs Recovery Charge (GPRC)-Including CA, EEE, EEE Ext, S4A, SLII, S4AE, SLIII, EEE Ext 2, S4AEII, EE2017, and CEF-EE
Public Service Electric & Gas Company	E	ER - ER23060412	written	Jul-23	SPRC 2023
Public Service Electric & Gas Company	G	GR23060330	written	Jun-23	Margin Adjustment Charge (MAC) / Cost Recovery
Public Service Electric & Gas Company	G	GR23060332	written	Jun-23	Conservation Incentive Program (GCIP)
Public Service Electric & Gas Company	E	ER23050273	written	May-23	Energy Strong II Program (Energy Strong II) - Fourth Roll-In
Public Service Electric & Gas Company	G	GR23030102	written	Mar-23	Gas System Modernization Program III (GSMPIII)
Public Service Electric & Gas Company	E	ER23020061	written	Feb-23	Elecric Conservation Incentive Program (ECIP)
Public Service Electric & Gas Company	E/G	GR23010050	written	Jan-23	Remediation Adjustment Charge-RAC 30
Public Service Electric & Gas Company	E/G	GR23010009 and ER23010010	written	Jan-23	Societal Benefits Charge (SBC) / Cost Recovery
Public Service Electric & Gas Company	G	GR22120749	written	Dec-22	Gas System Modernization Program II (GSMPII) - Eighth Roll-In
Public Service Electric & Gas Company	E/G	ER22110669 & GR22110670	written	Nov-22	Energy Strong II Program (Energy Strong II) - Third Roll-In
Public Service Electric & Gas Company	E/G	ER22100667 & GR22100668	written	Oct-22	Tax Adjustment Clauses (TACs)
Public Service Electric & Gas Company	E/G	EO18101113 & GO18101112	written	Sep-22	Clean Energy Future - Energy Efficiency Extension Program
Public Service Electric & Gas Company	E/G	ER22070413 & GR22070414	written	Jul-22	Green Programs Recovery Charge (GPRC)-Including CA, DR, EEE, EEE Ext, EE17, S4AII, S4AEXT, S4AEXT II, SLII, SLIII / Cost Recovery
Public Service Electric & Gas Company	E	ER22060408	written	Jul-22	SPRC 2022
Public Service Electric & Gas Company	G	GR22060409	written	Jun-22	Gas System Modernization Program II (GSMPII) - Seventh Roll-In
Public Service Electric & Gas Company	G	GR22060367	written	Jun-22	Margin Adjustment Charge (MAC) / Cost Recovery
Public Service Electric & Gas Company	G	GR22060362	written	Jun-22	Conservation Incentive Program (GCIP)
Public Service Electric & Gas Company	E/G	GR22030152	written	Mar-22	Remediation Adjustment Charge-RAC 29
Public Service Electric & Gas Company	E	ER22020035	written	Feb-22	Elecric Conservation Incentive Program (ECIP)
Public Service Electric & Gas Company	G	GR21121256	written	Dec-21	Gas System Modernization Program II (GSMPII) - Sixth Roll-In
Public Service Electric & Gas Company	E	ER21121242	written	Dec-21	Solar Successor Incentive Program (SuSI)
Public Service Electric & Gas Company	E/G	EO21111211 & GO21111212	written	Nov-21	Infrastructure Advancement Program (IAP)
Public Service Electric & Gas Company	E/G	ER21111209 & GR21111210	written	Nov-21	Energy Strong II Program (Energy Strong II) - Second Roll-In
Public Service Electric & Gas Company	E/G	ER21101201 & GR21101202	written	Oct-21	Tax Adjustment Clauses (TACs)
Public Service Electric & Gas Company	E/G	ER21070965 & GR21070966	written	Jul-21	Green Programs Recovery Charge (GPRC)-Including CA, DR, EEE, EEE Ext, EE17, S4AII, S4AEXT, S4AEXT II, SLII, SLIII / Cost Recovery
Public Service Electric & Gas Company	G	ER21060952	written	Jun-21	Weather Normalization Charge / Cost Recovery
Public Service Electric & Gas Company	G	GR21060949	written	Jun-21	Gas System Modernization Program II (GSMPII) - Fifth Roll-In
Public Service Electric & Gas Company	E	ER21060948	written	Jun-21	SPRC 2021
PSEG New Haven LLC	PSEG New Haven LLC	21-06-40	written	Jun-21	PSEG 2022 AFRR
Public Service Electric & Gas Company	G	GR21060882	written	Jun-21	Margin Adjustment Charge (MAC) / Cost Recovery
Public Service Electric & Gas Company	E	ER21050859	written	May-21	Community Solar Cost Recovery
Public Service Electric & Gas Company	G	GR20120771	written	Dec-20	Gas System Modernization Program II (GSMPII) - Forth Roll-In
Public Service Electric & Gas Company	E/G	GR20120763	written	Dec-20	Remediation Adjustment Charge-RAC 28
Public Service Electric & Gas Company	E	ER20120736	written	Nov-20	Energy Strong II Program (Energy Strong II) - First Roll-In
Public Service Electric & Gas Company	E/G	ER20100685 & GR20100686	written	Oct-20	Tax Adjustment Clauses (TACs)
Public Service Electric & Gas Company	E	ER20100658	written	Oct-20	Non-Utility Generation Charge (NGC) / Cost Recovery
Public Service Electric & Gas Company	E/G	ER20060467 & GR20060468	written	Jun-20	Green Programs Recovery Charge (GPRC)-Including CA, DR, EEE, EEE Ext, EE17, S4AII, S4AEXT, S4AEXT II, SLII, SLIII / Cost Recovery
Public Service Electric & Gas Company	G	GR20060464	written	Jun-20	Gas System Modernization Program II (GSMPII) - Third Roll-In
Public Service Electric & Gas Company	E	ER20060454	written	Jun-20	Solar Pilot Recovery Charge (SPRC-Solar Loan I) / Cost Recovery
Public Service Electric & Gas Company	G	GR20060470	written	Jun-20	Weather Normalization Charge / Cost Recovery
Public Service Electric & Gas Company	G	GR20060384	written	Jun-20	Margin Adjustment Charge (MAC) / Cost Recovery
Public Service Electric & Gas Company	E	ER20040324	written	Apr-20	Transitional Renewable Energy Certificate Program (TREC)
Public Service Electric & Gas Company	E/G	GR20010073	written	Jan-20	Remediation Adjustment Charge-RAC 27
Public Service Electric & Gas Company	G	GR19120002	written	Dec-19	Gas System Modernization Program II (GSMPII) - Second Roll-In
Public Service Electric & Gas Company	E/G	ER19091302 & GR19091303	written	Aug-19	Tax Adjustment Clauses (TACs)
Public Service Electric & Gas Company	E/G	ER19070850	written	Jul-19	Societal Benefits Charge (SBC) / Cost Recovery
Public Service Electric & Gas Company	E/G	ER19060764 & GR19060765	written	Jun-19	Green Programs Recovery Charge (GPRC)-Including CA, DR, EEE, EEE Ext, S4AII, S4AEXT, S4AEXT II, SLII, SLIII / Cost Recovery
Public Service Electric & Gas Company	G	GR19060766	written	Jun-19	Gas System Modernization Program II (GSMPII) - First Roll-In
Public Service Electric & Gas Company	G	GR19060761	written	Jun-19	Weather Normalization Charge / Cost Recovery
Public Service Electric & Gas Company	E	ER19060741	written	Jun-19	Solar Pilot Recovery Charge (SPRC-Solar Loan I) / Cost Recovery
Public Service Electric & Gas Company	E/G	EO18060629 & GO18060630	oral	Jun-19	Energy Strong II / Revenue Requirements & Rate Design
Public Service Electric & Gas Company	G	GR19060698	written	May-19	Margin Adjustment Charge (MAC) / Cost Recovery
Public Service Electric & Gas Company	E	ER19040523	written	May-19	Non-Utility Generation Charge (NGC) / Cost Recovery
Public Service Electric & Gas Company	E/G	EO18101113 & GO18101112	oral	May-19	Clean Energy Future - Energy Efficiency Program Approval
Public Service Electric & Gas Company	E	ER19040530	written	Apr-19	Madison 4kV Substation Project (Madison & Marshall)
Public Service Electric & Gas Company	E/G	EO18101113 & GO18101112	written	Dec-18	Clean Energy Future - Energy Efficiency Program Approval
Public Service Electric & Gas Company	E/G	GR18121258	written	Nov-18	Remediation Adjustment Charge-RAC 26
Public Service Electric & Gas Company	E	EO18101115	written	Oct-18	Clean Energy Future - Energy Cloud Program (EC)
Public Service Electric & Gas Company	E	EO18101111	written	Oct-18	Clean Energy Future-Electric Vehicle And Energy Storage Programs (EVES)
Public Service Electric & Gas Company	G	GR18070831	written	Jul-18	Gas System Modernization Program (GSMP) - Third Roll-In

LIST OF PRIOR TESTIMONIES

Company	Utility	Docket	Testimony	Date	Case / Topic
Public Service Electric & Gas Company	E/G	ER18070688 & GR18070689	written	Jun-18	Green Programs Recovery Charge (GPRC)-Including CA, DR, EEE, EEE Ext, S4All, S4AEXT, S4AEXT II, SLII, SLIII / Cost Recovery
Public Service Electric & Gas Company	E	ER18060681	written	Jun-18	Solar Pilot Recovery Charge (SPRC-Solar Loan I) / Cost Recovery
Public Service Electric & Gas Company	G	GR18060675	written	Jun-18	Weather Normalization Charge / Cost Recovery
Public Service Electric & Gas Company	E/G	EO18060629 & GO18060630	written	Jun-18	Energy Strong II / Revenue Requirements & Rate Design
Public Service Electric & Gas Company	G	GR18060605	written	Jun-18	Margin Adjustment Charge (MAC) / Cost Recovery
Public Service Electric & Gas Company	E/G	ER18040358 & GR18040359	written	Mar-18	Energy Strong / Revenue Requirements & Rate Design - Eighth Roll-in
Public Service Electric & Gas Company	E/G	ER18030231	written	Mar-18	Tax Cuts and Job Acts of 2017
Public Service Electric & Gas Company	E/G	GR18020093	written	Feb-18	Remediation Adjustment Charge-RAC 25
Public Service Electric & Gas Company	E/G	ER18010029 & GR18010030	written	Jan-18	Base Rate Proceeding / Cost of Service & Rate Design
Public Service Electric & Gas Company	E	ER17101027	written	Sep-17	Energy Strong / Revenue Requirements & Rate Design - Seventh Roll-in
Public Service Electric & Gas Company	G	GR17070776	written	Jul-17	Gas System Modernization Program II (GSMP II)
Public Service Electric & Gas Company	G	GR17070775	written	Jul-17	Gas System Modernization Program (GSMP) - Second Roll-In
Public Service Electric & Gas Company	G	GR17060720	written	Jul-17	Weather Normalization Charge / Cost Recovery
Public Service Electric & Gas Company	E/G	ER17070724 & GR17070725	written	Jul-17	Green Programs Recovery Charge (GPRC)-Including CA, DR, EEE, EEE Ext, S4All, S4AEXT, S4AEXT II, SLII, SLIII / Cost Recovery
Public Service Electric & Gas Company	E	ER17070723	written	Jul-17	Solar Pilot Recovery Charge (SPRC-Solar Loan I) / Cost Recovery
Public Service Electric & Gas Company	G	GR17060593	written	Jun-17	Margin Adjustment Charge (MAC) / Cost Recovery
Public Service Electric & Gas Company	E/G	ER17030324 & GR17030325	written	Mar-17	Energy Strong / Revenue Requirements & Rate Design - Sixth Roll-in
Public Service Electric & Gas Company	E/G	EO14080897	written	Mar-17	Energy Efficiency 2017 Program
Public Service Electric & Gas Company	E/G	ER17020136	written	Feb-17	Societal Benefits Charge (SBC) / Cost Recovery
Public Service Electric & Gas Company	E/G	GR16111064	written	Nov-16	Remediation Adjustment Charge-RAC 24
Public Service Electric & Gas Company	E	ER16090918	written	Sep-16	Energy Strong / Revenue Requirements & Rate Design - Fifth Roll-in
Public Service Electric & Gas Company	E	EO16080788	written	Aug-16	Construction of Mason St Substation
Public Service Electric & Gas Company	E	ER16080785	written	Aug-16	Non-Utility Generation Charge (NGC) / Cost Recovery
Public Service Electric & Gas Company	G	GR16070711	written	Jul-16	Gas System Modernization Program (GSMP) - First Roll-In
Public Service Electric & Gas Company	G	GR16070617	written	Jul-16	Weather Normalization Charge / Cost Recovery
Public Service Electric & Gas Company	E/G	ER16070613 & GR16070614	written	Jul-16	Green Programs Recovery Charge (GPRC)-Including CA, DR, EEE, EEE Ext, S4All, S4AEXT, SLII, SLIII / Cost Recovery
Public Service Electric & Gas Company	E	ER16070616	written	Jul-16	Solar Pilot Recovery Charge (SPRC-Solar Loan I) / Cost Recovery
Public Service Electric & Gas Company	G	GR16060484	written	Jun-16	Margin Adjustment Charge (MAC) / Cost Recovery
Public Service Electric & Gas Company	E	EO16050412	written	May-16	Solar 4 All Extension II (S4Allext II) / Revenue Requirements & Rate Design
Public Service Electric & Gas Company	E/G	ER16030272 & GR16030273	written	Mar-16	Energy Strong / Revenue Requirements & Rate Design - Fourth Roll-in
Public Service Electric & Gas Company	E/G	GR15111294	written	Nov-15	Remediation Adjustment Charge-RAC 23
Public Service Electric & Gas Company	E	ER15101180	written	Sep-15	Energy Strong / Revenue Requirements & Rate Design - Third Roll-in
Public Service Electric & Gas Company	E/G	ER15070757 & GR15070758	written	Jul-15	Green Programs Recovery Charge (GPRC)-Including CA, DR, EEE, EEE Ext, S4All, S4AEXT, SLII, SLIII / Cost Recovery
Public Service Electric & Gas Company	E	ER15060754	written	Jul-15	Solar Pilot Recovery Charge (SPRC-Solar Loan I) / Cost Recovery
Public Service Electric & Gas Company	G	GR15060748	written	Jul-15	Weather Normalization Charge / Cost Recovery
Public Service Electric & Gas Company	G	GR15060646	written	Jun-15	Margin Adjustment Charge (MAC) / Cost Recovery
Public Service Electric & Gas Company	E/G	ER15050558	written	May-15	Societal Benefits Charge (SBC) / Cost Recovery
Public Service Electric & Gas Company	E	ER15050558	written	May-15	Non-Utility Generation Charge (NGC) / Cost Recovery
Public Service Electric & Gas Company	E/G	ER15030389 & GR15030390	written	Mar-15	Energy Strong / Revenue Requirements & Rate Design - Second Roll-in
Public Service Electric & Gas Company	G	GR15030272	written	Feb-15	Gas System Modernization Program (GSMP)
Public Service Electric & Gas Company	E/G	GR14121411	written	Dec-14	Remediation Adjustment Charge-RAC 22
Public Service Electric & Gas Company	E/G	ER14091074	written	Sep-14	Energy Strong / Revenue Requirements & Rate Design - First Roll-in
Public Service Electric & Gas Company	E/G	EO14080897	written	Aug-14	EEE Ext II

Actual & Weather Normalized
Billing Determinants
Filing "9 and 3"

			Actual Determinants	Weather Normalized (WN) Determinants	Variation From WN
1	**RS**	**Delivery**			
2		Service Charges	23,803.607	23,803.607	0.00
3		kWhr 0-600 June - September	3,513,703	3,482,326	-31,376.49
4		kWhr 0-600 October - May	5,852,680	6,040,970	188,289.37
5		kWhr Over 600 June - September	1,962,907	1,917,408	-45,498.65
6		kWhr Over 600 October - May	1,661,191	1,726,010	64,818.85
7		Total kWhrs	12,990,481	13,166,714	176,233.08
8					
9		**Supply**			
10		BGS 0-600 June - September	3,361,440	3,331,905	-29,534.46
11		BGS 0-600 October - May	5,612,889	5,793,410	180,521.38
12		BGS Over 600 June - September	1,894,417	1,850,958	-43,458.77
13		BGS Over 600 October - May	1,572,305	1,634,036	61,731.10
14		Total BGS	12,441,050	12,610,309	169,259.26
15					
16					
17	**RHS**	**Delivery**			
18		Service Charges	76.301	76.301	0.00
19		kWhr 0-600 June - September	12,556	12,463	-92.30
20		kWhr 0-600 October - May	26,958	29,202	2,243.71
21		kWhr Over 600 June - September	6,003	5,914	-88.84
22		kWhr Over 600 October - May	31,681	34,610	2,929.14
23		Total kWhrs	77,197	82,189	4,991.71
24					
25		**Supply**			
26		BGS 0-600 June - September	11,163	11,087	-76.21
27		BGS 0-600 October - May	23,782	25,657	1,875.12
28		BGS Over 600 June - September	6,501	6,414	-86.39
29		BGS Over 600 October - May	32,351	35,450	3,098.57
30		Total BGS	73,796	78,608	4,811.09

Actual & Weather Normalized
Billing Determinants
Filing "9 and 3"

			Actual Determinants	Weather Normalized (WN) Determinants	Variation From WN
1	**RLM**	**Delivery**			
2		Service Charges	#REF!	136.453	#REF!
3		kWhr June - September On-Peak	37,352	36,917	-435.50
4		kWhr June - September Off-Peak	40,882	40,467	-415.09
5		kWhr October - May On-Peak	42,858	44,164	1,306.28
6		kWhr October - May Off-Peak	57,397	59,183	1,785.99
7		Total kWhrs	178,489	180,730	2,241.68
8					
9		**Supply**			
10		BGS June - September On-Peak	35,282	34,909	-372.48
11		BGS June - September Off-Peak	40,422	41,613	1,191.17
12		BGS October - May On-Peak	38,709	38,361	-347.42
13		BGS October - May Off-Peak	54,254	55,896	1,642.02
14		Total BGS	168,666	170,780	2,113.29
15					
16					
17	**WH**	**Delivery**			
18		kWhr June - September	157	157	0.00
19		kWhr October - May	394	394	0.53
20		Total kWhrs	551	551	0.53
21					
22		**Supply**			
23		BGS June - September	155	155	0.00
24		BGS October - May	383	383	0.50
25		Total BGS	537	538	0.51
26					
27					
28	**WHS**	**Delivery**			
29		Service Charges	0.110	0.110	0.00
30		kWhr June - September	1.895	1.895	0.00
31		kWhr October - May	5.030	5.030	0.00
32		Total kWhrs	6.925	6.925	0.00
33					
34		**Supply**			
35		BGS June - September	1.895	1.895	0.00
36		BGS October - May	5.030	5.030	0.00
37		Total BGS	6.925	6.925	0.00

Actual & Weather Normalized
<u>Billing Determinants</u>
Filing "9 and 3"

			Actual Determinants	Weather Normalized (WN) Determinants	Variation From WN
1	**HS**	**Delivery**			
2		Service Charges	8.561	8.561	0.00
3		kWhr June - September	2,416	2,394	-22.56
4		kWhr October - May	7,661	8,280	619.55
5		Total kWhrs	10,077	10,674	596.98
6					
7		**Supply**			
8		BGS June - September	1,944	1,931	-13.42
9		BGS October - May	5,858	6,344	485.32
10		Total BGS	7,803	8,274	471.90
11					
12					
13	**GLP**	**Delivery**			
14		Service Charges	3,375.479	3,375.479	0.00
15		Annual Demand	26,560	26,770	209.82
16		June - September Demand	9,699	9,664	-34.64
17		kWhr Other - June - September	2,603,595	2,594,772	-8,823.21
18		kWhr Other - October - May	4,647,412	4,717,230	69,818.05
19		kWhr Night Use - June - September	4,798	4,776	-21.72
20		kWhr Night Use - October - May	8,289	8,305	16.48
21		Total kWhrs	7,264,093	7,325,083	60,989.59
22					
23		**Supply**			
24		Generation Capacity Obl - June - Septemb	6,834	6,788	-45.53
25		Generation Capacity Obl - October - May	13,358	13,511	152.45
26		Transmission Capacity Obl	18,263	18,357	93.50
27		BGS June - September	1,892,199	1,877,715	-14,484.16
28		BGS October - May	3,383,499	3,423,883	40,384.10
29		BGS Night Use - June - September	3,358	3,327	-31.29
30		BGS Night Use - October - May	6,036	6,043	6.65
31		Total BGS	5,285,093	5,310,968	25,875.30

Actual & Weather Normalized
Billing Determinants
Filing "9 and 3"

			Actual Determinants	Weather Normalized (WN) Determinants	Variation From WN
1	**LPL-S**	**Delivery**			
2		Service Charges	115.127	115.127	0.00
3		Annual Demand	25,725	25,830	104.69
4		June - September Demand	9,262	9,215	-47.17
5		kWhr On-Peak - June - September	1,745,921	1,736,207	-9,714.38
6		kWhr Off-Peak - June - September	1,882,832	1,872,573	-10,258.44
7		kWhr On-Peak - October - May	3,148,853	3,177,651	28,798.12
8		kWhr Off-Peak - October - May	3,355,401	3,388,028	32,627.64
9		Total kWhrs	10,133,007	10,174,460	41,452.95
10					
11		**Supply**			
12		**Peak Load Share 0 - 499**			
13		Generation Capacity Obl - June - Septemb	2,776	2,770	-6.05
14		Generation Capacity Obl - October - May	5,233	5,277	44.42
15		Transmission Capacity Obl	6,985	7,017	32.35
16		BGS On-Peak - June - September	995,323	986,692	-8,631.66
17		BGS Off-Peak - June - September	570,003	567,722	-2,280.92
18		BGS On-Peak - October - May	1,992,507	2,010,333	17,825.91
19		BGS Off-Peak - October - May	1,046,536	1,055,976	9,439.84
20		Total BGS	4,604,369	4,620,722	16,353.17
21					
22		**Peak Load Share 500+**			
23		Generation Capacity Obl - June - Septemb	561	560	-1.21
24		Generation Capacity Obl - October - May	1,183	1,192	9.07
25		Transmission Capacity Obl	1,535	1,541	6.91
26		BGS June - September	258,582	257,776	-805.62
27					
28		BGS October - May	460,290	463,914	3,624.15
29					
30		Total BGS	718,872	721,690	2,818.53

Actual & Weather Normalized
Billing Determinants
Filing "9 and 3"

		Actual Determinants	Weather Normalized (WN) Determinants	Variation From WN
LPL-P	**Delivery**			
	Service Charges	9.395	9.395	0.00
	Annual Demand	6,861	6,861	0.00
	June - September Demand	2,463	2,463	0.00
	kWhr On-Peak - June - September	501,564	501,564	0.00
	kWhr Off-Peak - June - September	611,774	611,774	0.00
	kWhr On-Peak - October - May	889,783	889,783	0.00
	kWhr Off-Peak - October - May	1,053,220	1,053,220	0.00
	Total kWhrs	3,056,341	3,056,341	0.00
	Supply			
	Generation Capacity Obl - June - Septemb	485	485	0.00
	Generation Capacity Obl - October - May	919	919	0.00
	Transmission Capacity Obl	1,231	1,231	0.00
	BGS June - September	108,270	108,270	0.00
	BGS October - May	131,915	131,915	0.00
	Total BGS	240,184	240,184	0.00
HTS-S	**Delivery**			
	Service Charges	2.237	2.237	0.00
	Annual Demand	12,059	12,059	0.00
	June - September Demand	3,246	3,246	0.00
	kWhr June - September	2,125,645	2,125,645	0.00
	kWhr October - May	2,631,375	2,631,375	0.00
	Total kWhrs	4,757,020	4,757,020	0.00
	Supply			
	Generation Capacity Obl - June - Septemb	493	493	0.00
	Generation Capacity Obl - October - May	926	926	0.00
	Transmission Capacity Obl	1,277	1,277	0.00
	BGS June - September	304,415	304,415	0.00
	BGS October - May	561,557	561,557	0.00
	Total BGS	865,972	865,972	0.00

Actual & Weather Normalized
Billing Determinants
Filing "9 and 3"

Line			Actual Determinants	Weather Normalized (WN) Determinants	Variation From WN
1	**HTS-HV**	**Delivery**			
2		Service Charges	0.125	0.125	0.00
3		Annual Demand	3,230	3,230	0.00
4		kWhr June - September	202,466	202,466	0.00
5					
6		kWhr October - May	251,866	251,866	0.00
7					
8		Total kWhrs	454,332	454,332	0.00
9					
10		**Supply**			
11		Generation Capacity Obl - June - Septemt	1	1	0.00
12		Generation Capacity Obl - October - May	4	4	0.00
13		Transmission Capacity Obl	11	11	0.00
14		BGS June - September	16,311	16,311	0.00
15					
16		BGS October - May	63,187	63,187	0.00
17					
18		Total BGS	79,498	79,498	0.00
19					
20					
21	**BPL**	**Delivery**			
22		Lamp Charge:			
23		High Pressure Sodium	2,219.184	2,219.184	0.00
24		Metal Halide	286.644	286.644	0.00
25		Incandescent	142.200	142.200	0.00
26		Mercury Vapor	1,881.180	1,881.180	0.00
27		Fluorescent	-	-	0.00
28		Pole Charge	721.980	721.980	0.00
29		kWhr June - September	75,127	75,127	0.00
30		kWhr October - May	208,148	208,148	0.00
31		Total kWhrs	283,276	283,276	0.00
32					
33		**Supply**			
34		BGS June - September	61,732	61,732	0.00
35		BGS October - May	182,603	182,603	0.00
36		Total BGS	244,335	244,335	0.00

Actual & Weather Normalized
Billing Determinants
Filing "9 and 3"

			Actual Determinants	Weather Normalized (WN) Determinants	Variation From WN
1	**BPL-POF**	**Delivery**			
2		Lamp Charge:			
3		High Pressure Sodium	124.548	124.548	0.00
4		Metal Halide	1.476	1.476	0.00
5		Incandescent	6.048	6.048	0.00
6		Mercury Vapor	4.140	4.140	0.00
7		Fluorescent	0.024	0.024	0.00
8		Pole Charge	-	-	0.00
9		kWhr June - September	3,632	3,632	0.00
10		kWhr October - May	10,719	10,719	0.00
11		Total kWhrs	14,352	14,352	0.00
12					
13		**Supply**			
14		BGS June - September	3,513	3,513	0.00
15		BGS October - May	10,465	10,465	0.00
16		Total BGS	13,978	13,978	0.00
17					
18					
19	**PSAL**	**Delivery**			
20		Lamp Charge:			
21		High Pressure Sodium	719.940	719.940	0.00
22		Metal Halide	175.920	175.920	0.00
23		Incandescent	0.960	0.960	0.00
24		Mercury Vapor	241.812	241.812	0.00
25		Fluorescent	-	-	0.00
26		Pole Charge	361.188	361.188	0.00
27		kWhr June - September	36,506	36,506	0.00
28		kWhr October - May	95,599	95,599	0.00
29		Total kWhrs	132,104	132,104	0.00
30					
31		**Supply**			
32		BGS June - September	32,074	32,074	0.00
33		BGS October - May	87,351	87,351	0.00
34		Total BGS	119,425	119,425	0.00

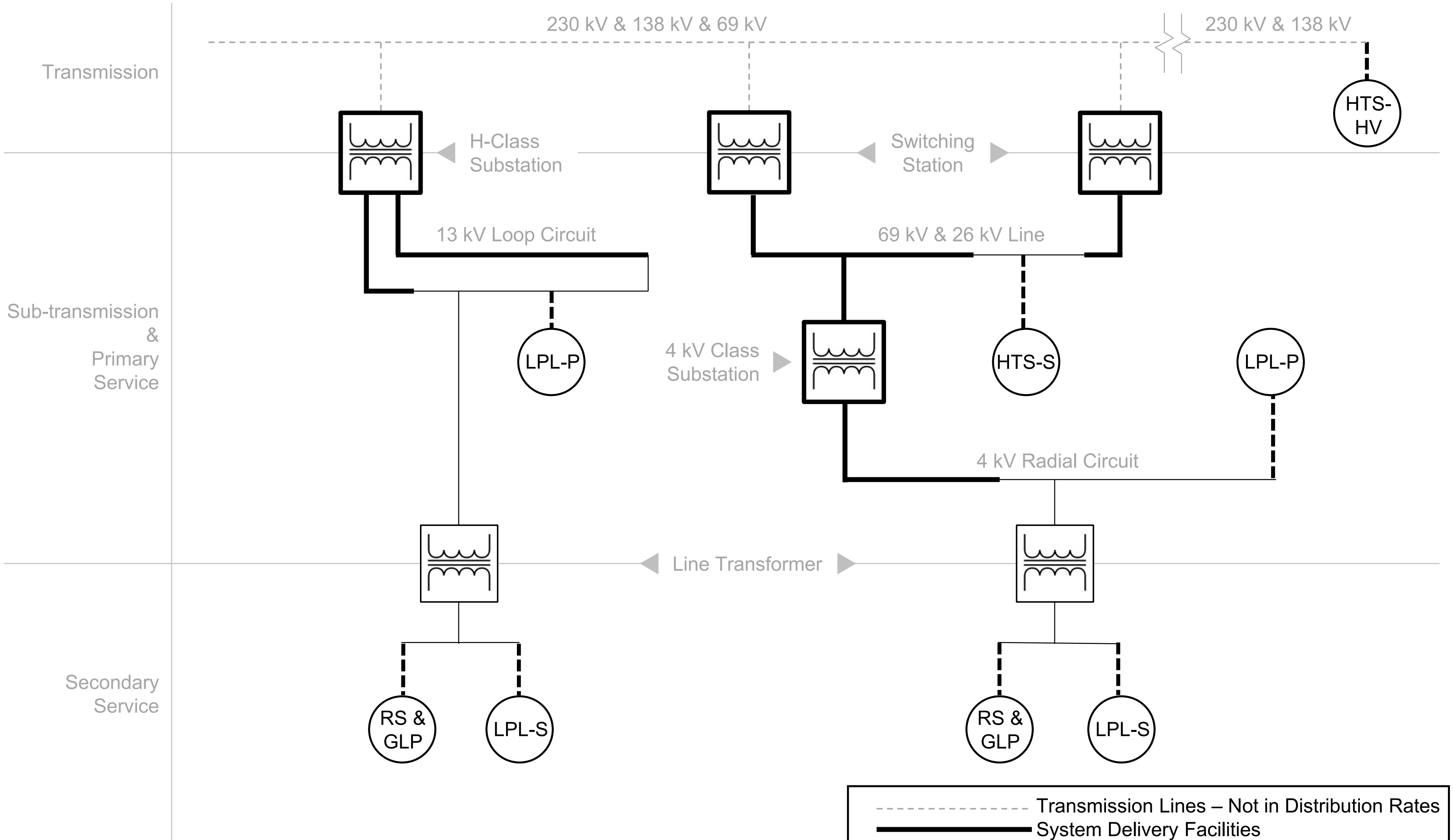
COS Adjustments

Listing of plant and expense items listed in the BPU Report but not included in the COS modeling for reasons as indicated

line	FERC Account		Amount	Related to:
	Expenses			
1	E555 & E556 - Power supply expenses	$	1,882,177,949	BGS, NGC, & ZEC
3	E904 - Uncollectible Accounts	$	74,356,162	SBC
4	E905 - Misc Customer Accounts	$	132,818,250	USF/Lifeline
5	E908 - DSM Amortization	$	141,442,126	DSM Amortization
	Amortizations			
7	E407.3 - RAC Amortization	$	24,795,430	RAC Amortization
8	E908 - BRC Amortization	$	48,257,435	E-BRC Amortization
	Interest Charges			
9	E431 - Expense on Clauses	$	1,682,922	Interest Expense on all clauses
	Current Tax Adjustments & Deductions			
10	CECL Reserve	$	(158,427)	CECL
11	COVID Deferrals	$	(2,144,328)	COVID
12	Clause - Deferred Fuel	$	(542,814)	BGS
13	Clause - RAC (Environmental Clean Up)	$	1,574,751	RAC
14	Clause - Societal Benefits Clause (AAP)	$	624,526	SBC
15	Clause - Demographic Studies	$	5,963	GPRC
16	Clause - Navigant Studies	$	46,365	GPRC
	Deferred Taxes			
17	CECL Reserve	$	158,427	CECL
18	COVID Deferrals	$	2,144,328	COVID
19	Clause - Deferred Fuel	$	542,814	BGS
20	Clause - RAC (Environmental Clean Up)	$	(1,574,751)	RAC
21	Clause - Societal Benefits Clause (AAP)	$	(624,526)	SBC
22	Clause - Demographic Studies	$	(5,963)	GPRC

Exhibit P-9E R-1
Schedule SS-E4 R-1

Graphical Representation of Electrical System Layout and Illustration of 2022 Electric COS Segmentation Methodology



PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	S	**SUMMARY OF RESULTS**									
2	S	**DEVELOPMENT OF RETURN**									
3	S										
4	S	**RATE BASE**									
5	S	Plant in Service									
6	S	Production Plant E310-E346	CALCULATED	0	0	0	0	0	0	0	0
7	S	Transmission Plant E350-E359	CALCULATED	0	0	0	0	0	0	0	0
8	S	Distribution Plant									
9	S	Land & Structures E360-E361	CALCULATED	293,570,614	145,535,507	607,179	1,456,815	3,366	53	157,829	4,855,885
10	S	Station Equipment E362	CALCULATED	1,565,418,169	714,060,742	2,292,183	8,029,772	0	0	500,149	0
11	S	Poles, Towers, and Fixtures E364	CALCULATED	1,027,443,483	543,114,479	2,675,325	4,941,739	0	0	1,130,805	10,299,169
12	S	OH Conductors and Devices E365	CALCULATED	2,856,184,590	1,507,287,026	6,811,401	14,481,863	0	0	2,644,403	6,852,510
13	S	UG Conductors E366	CALCULATED	512,107,003	280,617,273	1,383,575	2,551,877	3	0	584,708	2,012,335
14	S	UG Conduits and Devices E367	CALCULATED	1,431,183,475	784,240,015	3,866,673	7,131,720	8	0	1,634,080	5,623,864
15	S	Line Transformers E368	CALCULATED	1,591,690,631	1,136,331,766	8,618,064	7,219,368	0	0	1,519,865	4,931,400
16	S	Services E369	CALCULATED	535,269,333	341,702,741	2,001,736	3,344,330	17,930	280	0	0
17	S	Meters E370	CALCULATED	365,421,442	283,399,339	913,072	1,525,483	240,822	3,757	103,705	0
18	S	Street Lighting E373	CALCULATED	499,027,153	32,782,049	169,794	295,554	127	2	49,305	342,779,606
19	S	Asset Retirement Obligations E374	CALCULATED	96,512,525	51,017,258	251,306	464,200	0	0	106,222	967,449
20	S	Other Distribution and Unallocated Plant	CALCULATED	0	0	0	0	0	0	0	0
21	S	Total Distribution Plant	CALCULATED	10,773,828,418	5,820,088,197	29,590,307	51,442,720	262,256	4,091	8,431,071	378,322,216
22	S	General Plant E389-E399	CALCULATED	429,584,593	228,514,914	1,183,591	2,060,226	885	14	343,694	15,614,435
23	S	Common Plant C389-C399	CALCULATED	126,654,044	87,400,522	333,738	567,199	6,907	107	35,966	1,435,377
24	S	Intangible Plant E301-E303, E399, C303-C390	CALCULATED	126,923,895	94,841,006	329,148	554,187	9,288	143	12,483	295,763
25	S	Total Plant in Service	CALCULATED	11,456,990,950	6,230,844,640	31,436,784	54,624,332	279,335	4,355	8,823,214	395,667,792
26	S										
27	S	Less: Reserve for Depreciation and Amorization	CALCULATED	3,099,332,698	1,730,330,862	8,737,683	14,901,854	107,752	1,679	2,361,921	97,434,992
28	S	Plus: Rate Base Additions									
29	S	Working Capital	CALCULATED	1,183,336,038	664,490,052	3,059,359	5,427,043	76,070	1,185	799,493	46,417,462
30	S	Plant Held for Future Use	CALCULATED	489,291	266,099	1,343	2,333	12	0	377	16,898
31	S	Capital Stimulus	CALCULATED	0	0	0	0	0	0	0	0
32	S	Other Rate Base Additions		2,066,897,171	1,291,455,710	5,563,542	9,569,655	484,985	7,565	1,290,042	49,613,310
33	S	Plus: Rate Base Deductions									
34	S	Customer Advances	CALCULATED	-63,907,492	-36,036,364	-168,842	-299,006	-4,274	-67	-44,019	-2,166,415
35	S	Unbilled Revenue	CALCULATED	0	0	0	0	0	0	0	0
36	S	Deferred Income Taxes and Credits	CALCULATED	-1,717,952,304	-934,338,220	-4,714,068	-8,190,907	-41,912	-653	-1,323,003	-59,321,888
37	S	Other Rate Base Deductions		-40,898,861	-21,583,452	-97,535	-207,372	0	0	-37,866	-98,124
38	S										
39	S	TOTAL RATE BASE		9,785,622,095	5,464,767,603	26,342,900	46,024,225	686,464	10,706	7,146,316	332,694,043
40	S										
41	S										
42	S										
43	S										
44	S										
45	S										
46	S										
47	S										
48	S										
49	S										
50	S	**SUMMARY OF RESULTS**									

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
1	S	**SUMMARY OF RESULTS**								
2	S	**DEVELOPMENT OF RETURN**								
3	S									
4	S	**RATE BASE**								
5	S	Plant in Service								
6	S	Production Plant E310-E346	CALCULATED	0	0	0	0	0	0	0
7	S	Transmission Plant E350-E359	CALCULATED	0	0	0	0	0	0	0
8	S	Distribution Plant								
9	S	Land & Structures E360-E361	CALCULATED	9,992	1,494,083	64,215,985	50,674,255	12,335,104	12,212,381	12,182
10	S	Station Equipment E362	CALCULATED	0	0	373,571,272	307,077,645	79,100,612	80,785,795	0
11	S	Poles, Towers, and Fixtures E364	CALCULATED	104,180	2,886,640	196,638,373	159,785,302	41,257,161	64,610,311	0
12	S	OH Conductors and Devices E365	CALCULATED	220,559	8,709,908	603,313,016	492,004,642	126,433,892	87,425,369	0
13	S	UG Conductors E366	CALCULATED	53,911	881,281	101,503,167	82,463,239	21,271,683	18,783,951	2
14	S	UG Conduits and Devices E367	CALCULATED	150,665	2,462,911	283,670,511	230,459,698	59,447,890	52,495,436	5
15	S	Line Transformers E368	CALCULATED	224,770	2,148,246	222,857,213	207,839,938	0	0	0
16	S	Services E369	CALCULATED	0	0	173,970,914	12,601,784	1,049,662	579,957	0
17	S	Meters E370	CALCULATED	0	0	65,588,236	7,601,215	2,877,589	2,231,405	936,819
18	S	Street Lighting E373	CALCULATED	4,609	97,549,871	12,139,877	9,279,168	2,053,508	1,923,610	73
19	S	Asset Retirement Obligations E374	CALCULATED	9,786	271,155	18,471,153	15,009,373	3,875,476	6,069,146	0
20	S	Other Distribution and Unallocated Plant	CALCULATED	0	0	0	0	0	0	0
21	S	Total Distribution Plant	CALCULATED	778,473	116,404,096	2,115,939,717	1,574,796,259	349,702,577	327,117,359	949,079
22	S	General Plant E389-E399	CALCULATED	32,130	4,804,328	84,623,844	64,682,602	14,314,455	13,408,968	506
23	S	Common Plant C389-C399	CALCULATED	6,284	1,332,635	22,959,377	9,882,482	1,526,297	1,153,953	13,202
24	S	Intangible Plant E301-E303, E399, C303-C390	CALCULATED	5,100	1,292,845	22,313,239	6,548,658	556,111	148,132	17,792
25	S	Total Plant in Service	CALCULATED	821,986	123,833,904	2,245,836,177	1,655,910,001	366,099,439	341,828,412	980,578
26	S									
27	S	Less: Reserve for Depreciation and Amorization	CALCULATED	223,683	31,039,060	616,155,185	420,676,004	92,737,788	84,253,932	370,301
28	S	Plus: Rate Base Additions								
29	S	Working Capital	CALCULATED	478,803	17,180,636	222,369,324	157,365,269	34,734,931	30,666,597	269,815
30	S	Plant Held for Future Use	CALCULATED	35	5,289	95,912	70,719	15,635	14,598	42
31	S	Capital Stimulus	CALCULATED	0	0	0	0	0	0	0
32	S	Other Rate Base Additions		109,795	15,371,457	398,775,600	206,047,773	45,703,542	42,784,110	120,085
33	S	Plus: Rate Base Deductions								
34	S	Customer Advances	CALCULATED	-17,045	-766,989	-12,204,883	-8,602,235	-1,883,565	-1,707,374	-6,415
35	S	Unbilled Revenue	CALCULATED	0	0	0	0	0	0	0
36	S	Deferred Income Taxes and Credits	CALCULATED	-123,256	-18,566,670	-336,765,426	-248,278,471	-54,890,818	-51,249,891	-147,120
37	S	Other Rate Base Deductions		-3,158	-124,721	-8,639,083	-7,045,213	-1,810,458	-1,251,879	0
38	S									
39	S	TOTAL RATE BASE		1,043,476	105,893,845	1,893,312,437	1,334,791,838	295,230,918	276,830,640	846,685
40	S									
41	S									
42	S									
43	S									
44	S									
45	S									
46	S									
47	S									
48	S									
49	S									
50	S	**SUMMARY OF RESULTS**								

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
51	S	**DEVELOPMENT OF RETURN**	CALCULATED								
52	S										
53	S	**RATE BASE**	CALCULATED	9,785,622,095	5,464,767,603	26,342,900	46,024,225	686,464	10,706	7,146,316	332,694,043
54	S										
55	S	**OPERATING REVENUES**									
56	S	Rate Revenues from Customers	CALCULATED	1,899,915,237	1,071,330,372	5,019,520	8,889,191	127,057	1,979	1,308,648	64,405,668
57	S	Other Operating Revenues	CALCULATED	25,104,439	12,072,850	56,565	100,173	1,432	22	21,196	725,789
58	S	Revenues from Other Sources	CALCULATED	0	0	0	0	0	0	0	0
59	S	Less: Provisions for Rate Refunds	CALCULATED	0	0	0	0	0	0	0	0
60	S	TOTAL OPERATING REVENUES		1,925,019,676	1,083,403,222	5,076,085	8,989,364	128,489	2,001	1,329,844	65,131,457
61	S										
62	S	**OPERATING EXPENSES**									
63	S	Operation and Maintenance Expense									
64	S	Production Expense	CALCULATED	0	0	0	0	0	0	0	0
65	S	Transmission Expense	CALCULATED	0	0	0	0	0	0	0	0
66	S	Distribution Expense	CALCULATED	178,009,259	83,117,180	371,999	791,052	7,103	111	130,759	9,114,824
67	S	Customer Accounts Expense	CALCULATED	94,394,062	70,356,872	244,210	409,157	6,408	100	7,918	209,752
68	S	Customer Service & Information Expense	CALCULATED	5,318,001	4,196,182	14,170	25,852	936	14	1,649	11,564
69	S	Sales Expense	CALCULATED	40,922	29,919	96	204	2	0	14	205
70	S	Administrative and General Expense	CALCULATED	33,695,393	16,266,189	119,905	198,689	-1,744	-27	47,218	1,018,906
71	S	Total Operation and Maintenance Expense	CALCULATED	311,457,637	173,966,343	750,380	1,424,953	12,706	197	187,558	10,355,250
72	S	Depreciation Expense	CALCULATED	286,771,855	156,133,565	786,764	1,366,959	6,818	106	220,165	9,875,199
73	S	Amortization Expense	CALCULATED	21,391,564	14,703,437	56,497	96,056	1,130	17	6,312	253,642
74	S	Taxes Other Than Income Taxes	CALCULATED	-11,551,217	-7,187,659	-27,956	-50,679	-1,041	-16	-4,982	-442,317
75	S	Proforma Expense Adjustments	CALCULATED	82,048,703	51,852,648	214,230	373,247	24,420	380	45,086	2,187,525
76	S	State Income Taxes	CALCULATED	119,869,746	66,297,922	323,675	565,555	7,057	110	89,168	4,137,391
77	S	Federal Income Taxes	CALCULATED	231,691,305	128,341,590	624,630	1,092,027	14,441	225	171,805	7,998,819
78	S	Provision for Deferred Income Taxes	CALCULATED	144,525,616	86,705,422	358,976	646,416	11,129	173	75,185	5,647,547
79	S	Income Taxes Deferred in Prior Years	CALCULATED	0	0	0	0	0	0	0	0
80	S	Investment Tax Credit Adjustement (Net)	CALCULATED	0	0	0	0	0	0	0	0
81	S	TOTAL OPERATING EXPENSES		1,186,205,208	670,813,268	3,087,196	5,514,535	76,661	1,193	790,297	40,013,057
82	S										
83	S	**OPERATING INCOME (RETURN)**		738,814,468	412,589,954	1,988,889	3,474,829	51,828	808	539,547	25,118,400
84	S	Plus Operating Income Adjustment	CALCULATED	0	0	0	0	0	0	0	0
85	S	TOTAL NET OPERATING INCOME		738,814,468	412,589,954	1,988,889	3,474,829	51,828	808	539,547	25,118,400
86	S										
87	S	**RATE OF RETURN ON RATE BASE (PRESENT)**		7.55%	7.55%	7.55%	7.55%	7.55%	7.55%	7.55%	7.55%
88	S	**INDEX RATE OF RETURN (PRESENT)**		1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
89	S										
90	S	**EQUALIZED RETURN AT PROPOSED ROR**									
91	S										
92	S	**DEVELOPMENT OF RETURN (EQUALIZED RATE LEVELS**									
93	S										
94	S	**RATE BASE**	CALCULATED	9,785,622,095	5,464,767,603	26,342,900	46,024,225	686,464	10,706	7,146,316	332,694,043
95	S										
96	S	**RATE OF RETURN**		7.55%	7.55%	7.55%	7.55%	7.55%	7.55%	7.55%	7.55%
97	S										
98	S	**RETURN (RATE BASE * 7.40% ROR)**		738,814,468	412,589,954	1,988,889	3,474,829	51,828	808	539,547	25,118,400
99	S	**PLUS:**	CALCULATED								
100	S	**OPERATING EXPENSES**									

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
51	S	**DEVELOPMENT OF RETURN**	CALCULATED							
52	S									
53	S	**RATE BASE**	CALCULATED	1,043,476	105,893,845	1,893,312,437	1,334,791,838	295,230,918	276,830,640	846,685
54	S									
55	S	**OPERATING REVENUES**								
56	S	Rate Revenues from Customers	CALCULATED	506,728	22,801,929	362,840,766	255,737,125	55,996,770	50,758,783	190,699
57	S	Other Operating Revenues	CALCULATED	5,710	369,325	5,876,963	4,142,196	906,985	822,144	3,089
58	S	Revenues from Other Sources	CALCULATED	0	0	0	0	0	0	0
59	S	Less: Provisions for Rate Refunds	CALCULATED	0	0	0	0	0	0	0
60	S	TOTAL OPERATING REVENUES		512,439	23,171,254	368,717,729	259,879,321	56,903,755	51,580,928	193,788
61	S									
62	S	**OPERATING EXPENSES**								
63	S	Operation and Maintenance Expense								
64	S	Production Expense	CALCULATED	0	0	0	0	0	0	0
65	S	Transmission Expense	CALCULATED	0	0	0	0	0	0	0
66	S	Distribution Expense	CALCULATED	353,726	4,114,111	32,897,377	34,084,705	7,301,654	5,703,617	21,041
67	S	Customer Accounts Expense	CALCULATED	3,818	990,615	16,627,629	5,004,352	416,960	102,501	13,770
68	S	Customer Service & Information Expense	CALCULATED	214	34,498	876,964	140,606	11,945	3,040	367
69	S	Sales Expense	CALCULATED	4	555	9,167	677	61	17	1
70	S	Administrative and General Expense	CALCULATED	6,290	112,894	8,675,067	3,558,055	1,803,260	1,890,032	660
71	S	Total Operation and Maintenance Expense	CALCULATED	364,051	5,252,672	59,086,204	42,788,394	9,533,880	7,699,207	35,840
72	S	Depreciation Expense	CALCULATED	20,562	3,103,283	56,193,328	41,376,181	9,137,198	8,528,035	23,691
73	S	Amortization Expense	CALCULATED	1,054	220,339	3,894,065	1,684,932	266,593	205,364	2,124
74	S	Taxes Other Than Income Taxes	CALCULATED	-684	-184,389	-1,945,564	-1,294,601	-233,706	-176,094	-1,529
75	S	Proforma Expense Adjustments	CALCULATED	4,227	779,709	15,228,901	8,104,278	1,695,978	1,515,431	22,643
76	S	State Income Taxes	CALCULATED	11,848	1,303,461	23,254,074	16,699,491	3,698,670	3,471,274	10,049
77	S	Federal Income Taxes	CALCULATED	23,519	2,520,606	44,902,167	32,164,309	7,126,027	6,691,689	19,451
78	S	Provision for Deferred Income Taxes	CALCULATED	9,079	2,180,588	25,159,465	17,579,552	3,389,182	2,745,308	17,594
79	S	Income Taxes Deferred in Prior Years	CALCULATED	0	0	0	0	0	0	0
80	S	Investment Tax Credit Adjustement (Net)	CALCULATED	0	0	0	0	0	0	0
81	S	TOTAL OPERATING EXPENSES		433,656	15,176,269	225,772,640	159,102,537	34,613,821	30,680,214	129,863
82	S									
83	S	**OPERATING INCOME (RETURN)**		78,782	7,994,985	142,945,089	100,776,784	22,289,934	20,900,713	63,925
84	S	Plus Operating Income Adjustment	CALCULATED	0	0	0	0	0	0	0
85	S	TOTAL NET OPERATING INCOME		78,782	7,994,985	142,945,089	100,776,784	22,289,934	20,900,713	63,925
86	S									
87	S	**RATE OF RETURN ON RATE BASE (PRESENT)**		7.55%	7.55%	7.55%	7.55%	7.55%	7.55%	7.55%
88	S	**INDEX RATE OF RETURN (PRESENT)**		1.00	1.00	1.00	1.00	1.00	1.00	1.00
89	S									
90	S	**EQUALIZED RETURN AT PROPOSED ROR**								
91	S									
92	S	**DEVELOPMENT OF RETURN (EQUALIZED RATE LEVELS**								
93	S									
94	S	**RATE BASE**	CALCULATED	1,043,476	105,893,845	1,893,312,437	1,334,791,838	295,230,918	276,830,640	846,685
95	S									
96	S	**RATE OF RETURN**		7.55%	7.55%	7.55%	7.55%	7.55%	7.55%	7.55%
97	S									
98	S	**RETURN (RATE BASE * 7.40% ROR)**		78,782	7,994,985	142,945,089	100,776,784	22,289,934	20,900,713	63,925
99	S	**PLUS:**	CALCULATED							
100	S	**OPERATING EXPENSES**								

PUBLIC SERVICE ELECTRIC & GAS COMPANY
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12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
101	S	Total Operation and Maintenance Expense	CALCULATED	311,457,637	173,966,343	750,380	1,424,953	12,706	197	187,558	10,355,250
102	S	Depreciation Expense	CALCULATED	286,771,855	156,133,565	786,764	1,366,959	6,818	106	220,165	9,875,199
103	S	Amortization Expense	CALCULATED	21,391,564	14,703,437	56,497	96,056	1,130	17	6,312	253,642
104	S	Taxes Other Than Income Taxes	CALCULATED	-11,551,217	-7,187,659	-27,956	-50,679	-1,041	-16	-4,982	-442,317
105	S	Proforma Expense Adjustments	CALCULATED	82,048,703	51,852,648	214,230	373,247	24,420	380	45,086	2,187,525
106	S	Income Taxes	CALCULATED	351,561,051	194,639,512	948,305	1,657,582	21,498	335	260,973	12,136,210
107	S	Provision for Deferred Income Taxes	CALCULATED	144,525,616	86,705,422	358,976	646,416	11,129	173	75,185	5,647,547
108	S	Income Taxes Deferred in Prior Years	CALCULATED	0	0	0	0	0	0	0	0
109	S	Investment Tax Credit Adjustement (Net)	CALCULATED	0	0	0	0	0	0	0	0
110	S	**TOTAL OPERATING EXPENSES**		1,186,205,208	670,813,268	3,087,196	5,514,535	76,661	1,193	790,297	40,013,057
111	S										
112	S	**EQUALS TOTAL COST OF SERVICE**		1,925,019,676	1,083,403,222	5,076,085	8,989,364	128,489	2,001	1,329,844	65,131,457
113	S										
114	S	**LESS:**									
115	S	Other Operating Revenues	CALCULATED	25,104,439	12,072,850	56,565	100,173	1,432	22	21,196	725,789
116	S	Revenues from Other Sources	CALCULATED	0	0	0	0	0	0	0	0
117	S	Plus: Provisions for Rate Refunds		0	0	0	0	0	0	0	0
118	S	**EQUALS:**									
119	S	**BASE RATE SALES @ EQUALIZED ROR 7.40%**		1,899,915,237	1,071,330,372	5,019,520	8,889,191	127,057	1,979	1,308,648	64,405,668
120	S										
121	S	**TOTAL COST OF SERVICE INCREASE/DECREASE**		0	0	0	0	0	0	0	0
122	S	**REVENUE INCREASE TO RETAIL REVENUES (%)**		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
101	S	Total Operation and Maintenance Expense	CALCULATED	364,051	5,252,672	59,086,204	42,788,394	9,533,880	7,699,207	35,840
102	S	Depreciation Expense	CALCULATED	20,562	3,103,283	56,193,328	41,376,181	9,137,198	8,528,035	23,691
103	S	Amortization Expense	CALCULATED	1,054	220,339	3,894,065	1,684,932	266,593	205,364	2,124
104	S	Taxes Other Than Income Taxes	CALCULATED	-684	-184,389	-1,945,564	-1,294,601	-233,706	-176,094	-1,529
105	S	Proforma Expense Adjustments	CALCULATED	4,227	779,709	15,228,901	8,104,278	1,695,978	1,515,431	22,643
106	S	Income Taxes	CALCULATED	35,367	3,824,066	68,156,241	48,863,801	10,824,697	10,162,963	29,500
107	S	Provision for Deferred Income Taxes	CALCULATED	9,079	2,180,588	25,159,465	17,579,552	3,389,182	2,745,308	17,594
108	S	Income Taxes Deferred in Prior Years	CALCULATED	0	0	0	0	0	0	0
109	S	Investment Tax Credit Adjustement (Net)	CALCULATED	0	0	0	0	0	0	0
110	S	**TOTAL OPERATING EXPENSES**		433,656	15,176,269	225,772,640	159,102,537	34,613,821	30,680,214	129,863
111	S									
112	S	**EQUALS TOTAL COST OF SERVICE**		512,439	23,171,254	368,717,729	259,879,321	56,903,755	51,580,928	193,788
113	S									
114	S	**LESS:**								
115	S	Other Operating Revenues	CALCULATED	5,710	369,325	5,876,963	4,142,196	906,985	822,144	3,089
116	S	Revenues from Other Sources	CALCULATED	0	0	0	0	0	0	0
117	S	Plus: Provisions for Rate Refunds		0	0	0	0	0	0	0
118	S	**EQUALS:**								
119	S	**BASE RATE SALES @ EQUALIZED ROR 7.40%**		506,728	22,801,929	362,840,766	255,737,125	55,996,770	50,758,783	190,699
120	S									
121	S	**TOTAL COST OF SERVICE INCREASE/DECREASE**		0	0	0	0	0	0	0
122	S	**REVENUE INCREASE TO RETAIL REVENUES (%)**		0.00	0.00	0.00	0.00	0.00	0.00	0.00

PUBLIC SERVICE ELECTRIC & GAS COMPANY
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12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	RBP	**DEVELOPMENT OF RATE BASE**									
2	RBP										
3	RBP	**ELECTRIC PLANT IN SERVICE**									
4	RBP										
5	RBP	PRODUCTION PLANT									
6	RBP	E304-E346 - Production Plant	not_used	0	0	0	0	0	0	0	0
7	RBP	Not Used	not_used	0	0	0	0	0	0	0	0
8	RBP	TOTAL PRODUCTION PLANT		0	0	0	0	0	0	0	0
9	RBP										
10	RBP	TRANSMISSION PLANT									
11	RBP	E350 Land & Land Rights	not_used	0	0	0	0	0	0	0	0
12	RBP	E352 Structures & Improvements	not_used	0	0	0	0	0	0	0	0
13	RBP	E353 Station Equipment	not_used	0	0	0	0	0	0	0	0
14	RBP	E354/E355 Towers and Fixtures	not_used	0	0	0	0	0	0	0	0
15	RBP	E356-E359 Transmission Plant - Others	not_used	0	0	0	0	0	0	0	0
16	RBP	TOTAL TRANSMISSION PLANT		0	0	0	0	0	0	0	0
17	RBP										
18	RBP	DISTRIBUTION PLANT									
19	RBP	E360-E361 Land & Structures									
20	RBP	E360 - Land and Land Rights									
21	RBP	- Headquarters related	DISTPLT	14,080,608	7,606,431	38,672	67,232	343	5	11,019	494,440
22	RBP	- Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0	0
23	RBP	- Direct - HEP	DIR_HEP_03	0	0	0	0	0	0	0	0
24	RBP	- Substation related	E362PLT	37,233,560	16,983,975	54,520	190,989	0	0	11,896	0
25	RBP	E361 - Structures and improvements		0	0	0	0	0	0	0	0
26	RBP	- Headquarters related	DISTPLT	124,204,880	67,096,238	341,129	593,052	3,023	47	97,197	4,361,446
27	RBP	- Substation related	E362PLT	118,051,566	53,848,863	172,858	605,542	0	0	37,717	0
28	RBP	Total Accounts E360-E361		293,570,614	145,535,507	607,179	1,456,815	3,366	53	157,829	4,855,885
29	RBP	E362 - Station Equipment									
30	RBP	Switching Stations	CP_SUBT_05	338,443,408	123,925,080	397,808	1,393,565	0	0	86,801	0
31	RBP	H Class Substations	CP_PRI_05	1,226,974,761	590,135,661	1,894,375	6,636,207	0	0	413,348	0
32	RBP	4 kV Class Substations	CP_PRI_05	0	0	0	0	0	0	0	0
33	RBP	Total Account E362		1,565,418,169	714,060,742	2,292,183	8,029,772	0	0	500,149	0
34	RBP	E364 - Poles Towers & Fixtures									
35	RBP	Streetlight poles - direct to BPL	DIR_BPL_02	8,114,160	0	0	0	0	0	0	8,114,160
36	RBP	Streetlight poles - direct to PSAL	DIR_PSAL_02	1,812,825	0	0	0	0	0	0	0
37	RBP	Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0	0
38	RBP	Subtransmission lines	SUBTRANSLINES	101,446,395	29,308,040	94,081	329,575	0	0	20,528	0
39	RBP	Primary lines	PRIMARYLINES	482,404,572	263,513,493	1,191,442	2,531,024	0	0	462,818	810,202
40	RBP	Secondary lines	SUMPK_SEC_04	433,665,531	250,292,946	1,389,803	2,081,139	0	0	647,459	1,374,806
41	RBP	Total Account E364		1,027,443,483	543,114,479	2,675,325	4,941,739	0	0	1,130,805	10,299,169
42	RBP										
43	RBP										
44	RBP										
45	RBP										
46	RBP										
47	RBP										
48	RBP										
49	RBP	**ELECTRIC PLANT IN SERVICE CONTINUED**									
50	RBP										

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
1	RBP	**DEVELOPMENT OF RATE BASE**								
2	RBP									
3	RBP	**ELECTRIC PLANT IN SERVICE**								
4	RBP									
5	RBP	PRODUCTION PLANT								
6	RBP	E304-E346 - Production Plant	not_used	0	0	0	0	0	0	0
7	RBP	Not Used	not_used	0	0	0	0	0	0	0
8	RBP	TOTAL PRODUCTION PLANT		0	0	0	0	0	0	0
9	RBP									
10	RBP	TRANSMISSION PLANT								
11	RBP	E350 Land & Land Rights	not_used	0	0	0	0	0	0	0
12	RBP	E352 Structures & Improvements	not_used	0	0	0	0	0	0	0
13	RBP	E353 Station Equipment	not_used	0	0	0	0	0	0	0
14	RBP	E354/E355 Towers and Fixtures	not_used	0	0	0	0	0	0	0
15	RBP	E356-E359 Transmission Plant - Others	not_used	0	0	0	0	0	0	0
16	RBP	TOTAL TRANSMISSION PLANT		0	0	0	0	0	0	0
17	RBP									
18	RBP	DISTRIBUTION PLANT								
19	RBP	E360-E361 Land & Structures								
20	RBP	E360 - Land and Land Rights								
21	RBP	- Headquarters related	DISTPLT	1,017	152,132	2,765,379	2,058,144	457,036	427,519	1,240
22	RBP	- Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0
23	RBP	- Direct - HEP	DIR_HEP_03	0	0	0	0	0	0	0
24	RBP	- Substation related	E362PLT	0	0	8,885,414	7,303,859	1,881,413	1,921,495	0
25	RBP	E361 - Structures and improvements		0	0	0	0	0	0	0
26	RBP	- Headquarters related	DISTPLT	8,975	1,341,952	24,393,375	18,154,863	4,031,507	3,771,136	10,941
27	RBP	- Substation related	E362PLT	0	0	28,171,817	23,157,389	5,965,148	6,092,231	0
28	RBP	Total Accounts E360-E361		9,992	1,494,083	64,215,985	50,674,255	12,335,104	12,212,381	12,182
29	RBP	E362 - Station Equipment								
30	RBP	Switching Stations	CP_SUBT_05	0	0	64,833,210	53,293,256	13,727,893	80,785,795	0
31	RBP	H Class Substations	CP_PRI_05	0	0	308,738,062	253,784,389	65,372,719	0	0
32	RBP	4 kV Class Substations	CP_PRI_05	0	0	0	0	0	0	0
33	RBP	Total Account E362		0	0	373,571,272	307,077,645	79,100,612	80,785,795	0
34	RBP	E364 - Poles Towers & Fixtures								
35	RBP	Streetlight poles - direct to BPL	DIR_BPL_02	0	0	0	0	0	0	0
36	RBP	Streetlight poles - direct to PSAL	DIR_PSAL_02	0	1,812,825	0	0	0	0	0
37	RBP	Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0
38	RBP	Subtransmission lines	SUBTRANSLINES	0	0	15,332,928	12,603,751	3,246,620	40,510,872	0
39	RBP	Primary lines	PRIMARYLINES	38,630	398,171	105,415,923	85,965,553	22,077,315	0	0
40	RBP	Secondary lines	SUMPK_SEC_04	65,550	675,644	75,889,522	61,215,998	15,933,226	24,099,439	0
41	RBP	Total Account E364		104,180	2,886,640	196,638,373	159,785,302	41,257,161	64,610,311	0
42	RBP									
43	RBP									
44	RBP									
45	RBP									
46	RBP									
47	RBP									
48	RBP									
49	RBP	**ELECTRIC PLANT IN SERVICE CONTINUED**								
50	RBP									

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				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
51	RBP	DISTRIBUTION PLANT CONTINUED									
52	RBP	E365 - OH Conductors and Devices									
53	RBP	Direct - BPL	DIR_BPL_02	2,226,625	0	0	0	0	0	0	2,226,625
54	RBP	Direct - PSAL	DIR_PSAL_02	6,436,532	0	0	0	0	0	0	0
55	RBP	Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0	0
56	RBP	Subtransmission lines	SUBTRANSLINES	201,889,270	58,326,161	187,231	655,891	0	0	40,853	0
57	RBP	Primary lines	PRIMARYLINES	2,523,188,742	1,378,291,830	6,231,765	13,238,372	0	0	2,420,743	4,237,715
58	RBP	Secondary lines	SUMPK_SEC_04	122,443,422	70,669,035	392,404	587,600	0	0	182,807	388,170
59	RBP	Other	DISTPLT	0	0	0	0	0	0	0	0
60	RBP	Total Account E365		2,856,184,590	1,507,287,026	6,811,401	14,481,863	0	0	2,644,403	6,852,510
61	RBP										
62	RBP	E366 - Underground Conduit									
63	RBP	Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0	0
64	RBP	Direct - HEP	DIR_HEP_03	0	0	0	0	0	0	0	0
65	RBP	Underground Conduits	E367PLT	512,107,003	280,617,273	1,383,575	2,551,877	3	0	584,708	2,012,335
66	RBP	Not Used	not_used								
67	RBP	Total Account E366		512,107,003	280,617,273	1,383,575	2,551,877	3	0	584,708	2,012,335
68	RBP										
69	RBP	E367 - Underground Conductors & Devices									
70	RBP	Direct - BPL	DIR_BPL_02	2,325,498	0	0	0	0	0	0	2,325,498
71	RBP	Direct - PSAL	DIR_PSAL_02	868,520	0	0	0	0	0	0	0
72	RBP	UG BPL Poles in UG areas	DISTPLTXMTR	3,979,461	2,116,850	10,964	19,085	8	0	3,184	144,644
73	RBP	Direct - HEP	DIR_HEP_03	0	0	0	0	0	0	0	0
74	RBP	367.1 - Conventional UG									
75	RBP	Subtransmission lines	SUBTRANSLINES	51,391,650	14,847,137	47,660	166,959	0	0	10,399	0
76	RBP	Primary lines	PRIMARYLINES	354,073,350	193,412,565	874,490	1,857,711	0	0	339,697	594,669
77	RBP	Secondary lines	SUMPK_SEC_04	539,234,440	311,222,744	1,728,128	2,587,759	0	0	805,072	1,709,481
78	RBP	367.2 - BUD									
79	RBP	Subtransmission lines	SUBTRANSLINES	479,311	138,474	445	1,557	0	0	97	0
80	RBP	Primary lines	PRIMARYLINES	448,395,026	244,935,779	1,107,445	2,352,587	0	0	430,189	753,083
81	RBP	Secondary lines	SUMPK_SEC_04	30,436,220	17,566,467	97,541	146,062	0	0	45,441	96,489
82	RBP	Other	E367PLT	0	0	0	0	0	0	0	0
83	RBP	Total Account E367		1,431,183,475	784,240,015	3,866,673	7,131,720	8	0	1,634,080	5,623,864
84	RBP										
85	RBP	E368 - Line Transformers									
86	RBP	Line Transformers	LNTRFRMR_04	1,591,690,631	1,136,331,766	8,618,064	7,219,368	0	0	1,519,865	4,931,400
87	RBP	Not Used	not_used	0	0	0	0	0	0	0	0
88	RBP	Total Account E368		1,591,690,631	1,136,331,766	8,618,064	7,219,368	0	0	1,519,865	4,931,400
89	RBP	E369 - Services									
90	RBP	Basic portion (minimum size)	SERVICESMIN_03	535,269,333	341,702,741	2,001,736	3,344,330	17,930	280	0	0
91	RBP	E369 - Excess portion	SERVICESEXC_04	0	0	0	0	0	0	0	0
92	RBP	Total Account E369		535,269,333	341,702,741	2,001,736	3,344,330	17,930	280	0	0
93	RBP										
94	RBP										
95	RBP										
96	RBP										
97	RBP										
98	RBP										
99	RBP	**ELECTRIC PLANT IN SERVICE CONTINUED**		0	0	0	0	0	0	0	0
100	RBP										

PUBLIC SERVICE ELECTRIC & GAS COMPANY
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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
51	RBP	DISTRIBUTION PLANT CONTINUED								
52	RBP	E365 - OH Conductors and Devices								
53	RBP	Direct - BPL	DIR_BPL_02	0	0	0	0	0	0	0
54	RBP	Direct - PSAL	DIR_PSAL_02	0	6,436,532	0	0	0	0	0
55	RBP	Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0
56	RBP	Subtransmission lines	SUBTRANSLINES	0	0	30,514,180	25,082,824	6,461,124	80,621,006	0
57	RBP	Primary lines	PRIMARYLINES	202,052	2,082,611	551,371,787	449,637,769	115,474,097	0	0
58	RBP	Secondary lines	SUMPK_SEC_04	18,508	190,765	21,427,049	17,284,049	4,498,671	6,804,363	0
59	RBP	Other	DISTPLT	0	0	0	0	0	0	0
60	RBP	Total Account E365		220,559	8,709,908	603,313,016	492,004,642	126,433,892	87,425,369	0
61	RBP									
62	RBP	E366 - Underground Conduit								
63	RBP	Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0
64	RBP	Direct - HEP	DIR_HEP_03	0	0	0	0	0	0	0
65	RBP	Underground Conduits	E367PLT	53,911	881,281	101,503,167	82,463,239	21,271,683	18,783,951	2
66	RBP	Not Used	not_used							
67	RBP	Total Account E366		53,911	881,281	101,503,167	82,463,239	21,271,683	18,783,951	2
68	RBP									
69	RBP	E367 - Underground Conductors & Devices								
70	RBP	Direct - BPL	DIR_BPL_02	0	0	0	0	0	0	0
71	RBP	Direct - PSAL	DIR_PSAL_02	0	868,520	0	0	0	0	0
72	RBP	UG BPL Poles in UG areas	DISTPLTXMTR	298	44,505	783,914	599,188	132,602	124,214	5
73	RBP	Direct - HEP	DIR_HEP_03	0	0	0	0	0	0	0
74	RBP	367.1 - Conventional UG								
75	RBP	Subtransmission lines	SUBTRANSLINES	0	0	7,767,496	6,384,924	1,644,703	20,522,371	0
76	RBP	Primary lines	PRIMARYLINES	28,353	292,248	77,372,752	63,096,648	16,204,218	0	0
77	RBP	Secondary lines	SUMPK_SEC_04	81,507	840,119	94,363,608	76,118,050	19,811,914	29,966,060	0
78	RBP	367.2 - BUD								
79	RBP	Subtransmission lines	SUBTRANSLINES	0	0	72,445	59,550	15,340	191,404	0
80	RBP	Primary lines	PRIMARYLINES	35,907	370,100	97,984,095	79,904,977	20,520,863	0	0
81	RBP	Secondary lines	SUMPK_SEC_04	4,601	47,419	5,326,202	4,296,361	1,118,252	1,691,386	0
82	RBP	Other	E367PLT	0	0	0	0	0	0	0
83	RBP	Total Account E367		150,665	2,462,911	283,670,511	230,459,698	59,447,890	52,495,436	5
84	RBP									
85	RBP	E368 - Line Transformers								
86	RBP	Line Transformers	LNTRFRMR_04	224,770	2,148,246	222,857,213	207,839,938	0	0	0
87	RBP	Not Used	not_used	0	0	0	0	0	0	0
88	RBP	Total Account E368		224,770	2,148,246	222,857,213	207,839,938	0	0	0
89	RBP	E369 - Services								
90	RBP	Basic portion (minimum size)	SERVICESMIN_03	0	0	173,970,914	12,601,784	1,049,662	579,957	0
91	RBP	E369 - Excess portion	SERVICESEXC_04	0	0	0	0	0	0	0
92	RBP	Total Account E369		0	0	173,970,914	12,601,784	1,049,662	579,957	0
93	RBP									
94	RBP									
95	RBP									
96	RBP									
97	RBP									
98	RBP									
99	RBP	**ELECTRIC PLANT IN SERVICE CONTINUED**		0	0	0	0	0	0	0
100	RBP									

PUBLIC SERVICE ELECTRIC & GAS COMPANY
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12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
101	RBP	E370 - Meters		0	0	0	0	0	0	0	0
102	RBP	Load profiling meters	KWHMETERX_04	0	0	0	0	0	0	0	0
103	RBP	Basic portion (minimum size)	METERSMIN_07	339,768,857	283,399,339	913,072	1,525,483	240,822	3,757	103,705	0
104	RBP	Excess portion	METERSEXC_04	25,652,585	0	0	0	0	0	0	0
105	RBP	Total Account E370		365,421,442	283,399,339	913,072	1,525,483	240,822	3,757	103,705	0
106	RBP										
107	RBP	E371 - Installations on Customer Premises	not_used	0	0	0	0	0	0	0	0
108	RBP										
109	RBP	E373 - Street Lighting & Signal Systems									
110	RBP	BPL luminaires & poles	DIR_BPL_02	340,539,607	0	0	0	0	0	0	340,539,607
111	RBP	PSAL luminaires & poles	DIR_PSAL_02	96,860,656	0	0	0	0	0	0	0
112	RBP	UG BPL Poles in UG areas	DISTPLTXMTR	61,626,889	32,782,049	169,794	295,554	127	2	49,305	2,239,999
113	RBP	Total Account E373		499,027,153	32,782,049	169,794	295,554	127	2	49,305	342,779,606
114	RBP										
115	RBP	E374 - Asset Retirement Obligations	E364PLT	96,512,525	51,017,258	251,306	464,200	0	0	106,222	967,449
116	RBP										
117	RBP	Other Distribution and Unallocated Plant									
118	RBP	Not Used	not_used	0	0	0	0	0	0	0	0
119	RBP	Total Other Plant and Unallocated Plant		0	0	0	0	0	0	0	0
120	RBP										
121	RBP	TOTAL DISTRIBUTION PLANT		10,773,828,418	5,820,088,197	29,590,307	51,442,720	262,256	4,091	8,431,071	378,322,216
122	RBP										
123	RBP	GENERAL AND COMMON PLANT									
124	RBP	E390-E398 GENERAL PLANT									
125	RBP	Meter Related	METERPLT	0	0	0	0	0	0	0	0
126	RBP	Customer Service Related	CUSTSVSX	0	0	0	0	0	0	0	0
127	RBP	Substation Related	E362PLT	0	0	0	0	0	0	0	0
128	RBP	Distribution Delivery	DISTPLTXMTR	429,584,593	228,514,914	1,183,591	2,060,226	885	14	343,694	15,614,435
129	RBP	Service & Support Related	UTILWORK_04	0	0	0	0	0	0	0	0
130	RBP	Unassigned	GENPLT	0	0	0	0	0	0	0	0
131	RBP	Total Accounts E390-E398		429,584,593	228,514,914	1,183,591	2,060,226	885	14	343,694	15,614,435
132	RBP										
133	RBP	C389-C399 COMMON PLANT									
134	RBP	Not Used	not_used	0	0	0	0	0	0	0	0
135	RBP	Meter Plant Related	METERPLT	0	0	0	0	0	0	0	0
136	RBP	Meter Reading Related	MRCOST_07	0	0	0	0	0	0	0	0
137	RBP	Not Used	not_used	0	0	0	0	0	0	0	0
138	RBP	Customer Service Related	CUSTSVSX	92,605,476	69,239,577	239,965	404,005	6,821	105	8,885	205,542
139	RBP	Distribution Delivery Related	DISTPLTXMTR	33,738,596	17,947,041	92,957	161,805	69	1	26,993	1,226,322
140	RBP	Service & Support Related	UTILWORK_04	0	0	0	0	0	0	0	0
141	RBP	Unassigned	COMPLT	309,972	213,904	817	1,388	17	0	88	3,513
142	RBP	Not Used	not_used	0	0	0	0	0	0	0	0
143	RBP	Total Accounts C389-C399		126,654,044	87,400,522	333,738	567,199	6,907	107	35,966	1,435,377
144	RBP										
145	RBP	TOTAL GENERAL AND COMMON PLANT		556,238,637	315,915,436	1,517,329	2,627,425	7,792	120	379,660	17,049,812
146	RBP										
147	RBP	**ELECTRIC PLANT IN SERVICE CONTINUED**									
148	RBP										
149	RBP	INTANGIBLE PLANT - E301-E303									
150	RBP	Customer Service Related	CUSTSVSX	40,584,928	30,344,677	105,166	177,058	2,989	46	3,894	90,080

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
101	RBP	E370 - Meters		0	0	0	0	0	0	0
102	RBP	Load profiling meters	KWHMETERX_04	0	0	0	0	0	0	0
103	RBP	Basic portion (minimum size)	METERSMIN_07	0	0	45,701,890	4,023,662	1,050,400	1,869,908	936,819
104	RBP	Excess portion	METERSEXC_04	0	0	19,886,346	3,577,553	1,827,189	361,497	0
105	RBP	Total Account E370		0	0	65,588,236	7,601,215	2,877,589	2,231,405	936,819
106	RBP									
107	RBP	E371 - Installations on Customer Premises	not_used	0	0	0	0	0	0	0
108	RBP									
109	RBP	E373 - Street Lighting & Signal Systems								
110	RBP	BPL luminaires & poles	DIR_BPL_02	0	0	0	0	0	0	0
111	RBP	PSAL luminaires & poles	DIR_PSAL_02	0	96,860,656	0	0	0	0	0
112	RBP	UG BPL Poles in UG areas	DISTPLTXMTR	4,609	689,214	12,139,877	9,279,168	2,053,508	1,923,610	73
113	RBP	Total Account E373		4,609	97,549,871	12,139,877	9,279,168	2,053,508	1,923,610	73
114	RBP									
115	RBP	E374 - Asset Retirement Obligations	E364PLT	9,786	271,155	18,471,153	15,009,373	3,875,476	6,069,146	0
116	RBP									
117	RBP	Other Distribution and Unallocated Plant								
118	RBP	Not Used	not_used	0	0	0	0	0	0	0
119	RBP	Total Other Plant and Unallocated Plant		0	0	0	0	0	0	0
120	RBP									
121	RBP	TOTAL DISTRIBUTION PLANT		778,473	116,404,096	2,115,939,717	1,574,796,259	349,702,577	327,117,359	949,079
122	RBP									
123	RBP	GENERAL AND COMMON PLANT								
124	RBP	E390-E398 GENERAL PLANT								
125	RBP	Meter Related	METERPLT	0	0	0	0	0	0	0
126	RBP	Customer Service Related	CUSTSVSX	0	0	0	0	0	0	0
127	RBP	Substation Related	E362PLT	0	0	0	0	0	0	0
128	RBP	Distribution Delivery	DISTPLTXMTR	32,130	4,804,328	84,623,844	64,682,602	14,314,455	13,408,968	506
129	RBP	Service & Support Related	UTILWORK_04	0	0	0	0	0	0	0
130	RBP	Unassigned	GENPLT	0	0	0	0	0	0	0
131	RBP	Total Accounts E390-E398		32,130	4,804,328	84,623,844	64,682,602	14,314,455	13,408,968	506
132	RBP									
133	RBP	C389-C399 COMMON PLANT								
134	RBP	Not Used	not_used	0	0	0	0	0	0	0
135	RBP	Meter Plant Related	METERPLT	0	0	0	0	0	0	0
136	RBP	Meter Reading Related	MRCOST_07	0	0	0	0	0	0	0
137	RBP	Not Used	not_used	0	0	0	0	0	0	0
138	RBP	Customer Service Related	CUSTSVSX	3,745	952,052	16,257,022	4,778,271	398,336	98,019	13,129
139	RBP	Distribution Delivery Related	DISTPLTXMTR	2,523	377,321	6,646,164	5,080,024	1,124,225	1,053,110	40
140	RBP	Service & Support Related	UTILWORK_04	0	0	0	0	0	0	0
141	RBP	Unassigned	COMPLT	15	3,261	56,191	24,186	3,735	2,824	32
142	RBP	Not Used	not_used	0	0	0	0	0	0	0
143	RBP	Total Accounts C389-C399		6,284	1,332,635	22,959,377	9,882,482	1,526,297	1,153,953	13,202
144	RBP									
145	RBP	TOTAL GENERAL AND COMMON PLANT		38,413	6,136,963	107,583,221	74,565,084	15,840,751	14,562,921	13,708
146	RBP									
147	RBP	**ELECTRIC PLANT IN SERVICE CONTINUED**								
148	RBP									
149	RBP	INTANGIBLE PLANT - E301-E303								
150	RBP	Customer Service Related	CUSTSVSX	1,641	417,243	7,124,741	2,094,107	174,573	42,957	5,754

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
151	RBP	Not Used	not_used	0	0	0	0	0	0	0	0
152	RBP	TOTAL INTANGIBLE PLANT		40,584,928	30,344,677	105,166	177,058	2,989	46	3,894	90,080
153	RBP										
154	RBP	C303 - INTANGIBLE PLANT									
155	RBP	Not Used	not_used	0	0	0	0	0	0	0	0
156	RBP	Meter Reading	MRCOST_07	1,212,800	954,739	3,317	5,542	63	1	75	0
157	RBP	Customer Service Related	CUSTSVSX	84,635,615	63,280,644	219,313	369,235	6,234	96	8,121	187,853
158	RBP	Distribution Related	INTANGPLT	0	0	0	0	0	0	0	0
159	RBP	C390.4 / C111.000 Capital Lease	TOTPLT	0	0	0	0	0	0	0	0
160	RBP	E399 Oth Tangible Plant	GENPLT	0	0	0	0	0	0	0	0
161	RBP	E399.1 Asset Retirement Obligations	GENPLT	490,552	260,946	1,352	2,353	1	0	392	17,830
162	RBP	TOTAL ACCOUNTS C303-C390.4,E399		86,338,967	64,496,329	223,981	377,130	6,298	97	8,588	205,683
163	RBP										
164	RBP	TOTAL INTANGIBLE PLANT		126,923,895	94,841,006	329,148	554,187	9,288	143	12,483	295,763
165	RBP										
166	RBP	**TOTAL ELECTRIC PLANT IN SERVICE**		11,456,990,950	6,230,844,640	31,436,784	54,624,332	279,335	4,355	8,823,214	395,667,792

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12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
151	RBP	Not Used	not_used	0	0	0	0	0	0	0
152	RBP	TOTAL INTANGIBLE PLANT		1,641	417,243	7,124,741	2,094,107	174,573	42,957	5,754
153	RBP									
154	RBP	C303 - INTANGIBLE PLANT								
155	RBP	Not Used	not_used	0	0	0	0	0	0	0
156	RBP	Meter Reading	MRCOST_07	0	0	233,962	13,647	1,137	279	38
157	RBP	Customer Service Related	CUSTSVSX	3,422	870,116	14,857,902	4,367,041	364,055	89,583	12,000
158	RBP	Distribution Related	INTANGPLT	0	0	0	0	0	0	0
159	RBP	C390.4 / C111.000 Capital Lease	TOTPLT	0	0	0	0	0	0	0
160	RBP	E399 Oth Tangible Plant	GENPLT	0	0	0	0	0	0	0
161	RBP	E399.1 Asset Retirement Obligations	GENPLT	37	5,486	96,634	73,862	16,346	15,312	1
162	RBP	TOTAL ACCOUNTS C303-C390.4,E399		3,459	875,602	15,188,498	4,454,551	381,537	105,174	12,038
163	RBP									
164	RBP	TOTAL INTANGIBLE PLANT		5,100	1,292,845	22,313,239	6,548,658	556,111	148,132	17,792
165	RBP									
166	RBP	**TOTAL ELECTRIC PLANT IN SERVICE**		821,986	123,833,904	2,245,836,177	1,655,910,001	366,099,439	341,828,412	980,578

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12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	RBD	**LESS: DEPRECIATION RESERVE & AMORT**									
2	RBD										
3	RBD	E301-E303 - INTANGILE PLANT - RESERVE									
4	RBD	Customer Service Related - Reserve	CUSTSVSX	15,757,979	11,781,979	40,833	68,747	1,161	18	1,512	34,976
5	RBD	Not Used	not_used	0	0	0	0	0	0	0	0
6	RBD	Not used	not_used	0	0	0	0	0	0	0	0
7	RBD	Total Accounts E301-E303 Reserve		15,757,979	11,781,979	40,833	68,747	1,161	18	1,512	34,976
8	RBD										
9	RBD	E304-E346 - PRODUCTION PLANT - RESERVE	not_used	0	0	0	0	0	0	0	0
10	RBD	E350-E359 - TRANSMISSION PLANT - RESERVE	not_used	0	0	0	0	0	0	0	0
11	RBD										
12	RBD	DISTRIBUTION PLANT RESERVE									
13	RBD	E360-E361 Land & Structures - Reserve									
14	RBD	E360 - Land and Land Rights									
15	RBD	- Headquarters Related	DISTPLT	0	0	0	0	0	0	0	0
16	RBD	- Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0	0
17	RBD	- Direct - HEP	DIR_HEP_03	0	0	0	0	0	0	0	0
18	RBD	- Substation Related	E362PLT	667,893	304,658	978	3,426	0	0	213	0
19	RBD	E361 - Structures and improvements									
20	RBD	- Headquarters Related	DISTPLT	40,449,681	21,851,166	111,095	193,139	985	15	31,654	1,420,388
21	RBD	- Substation Related	E362PLT	36,319,499	16,567,029	53,181	186,300	0	0	11,604	0
22	RBD	Total Accounts E360-E361		77,437,073	38,722,852	165,254	382,864	985	15	43,471	1,420,388
23	RBD	E362 Station Equipment - Rsrv	E362PLT	279,293,104	127,398,701	408,958	1,432,627	0	0	89,234	0
24	RBD	E364 Poles Towers and Fixtures Rsrv									
25	RBD	- Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0	0
26	RBD	- All Other	E364PLT	200,061,625	105,754,104	520,934	962,245	0	0	220,188	2,005,432
27	RBD	E365 OH Conductors and Devices - Rsrv									
28	RBD	- Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0	0
29	RBD	- All Other	E365PLT	609,997,837	321,912,606	1,454,717	3,092,904	0	0	564,768	1,463,496
30	RBD	E366 UG Conduit - Rsrv									
31	RBD	- Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0	0
32	RBD	- All Other	E366PLT	258,299,502	141,539,369	697,856	1,287,130	1	0	294,918	1,014,993
33	RBD	E367 UG Conductors and Devices - Rsrv									
34	RBD	- Direct - HTS-HV	DIR_HEP_03	0	0	0	0	0	0	0	0
35	RBD	- All Other	E367PLT	512,800,757	280,997,427	1,385,450	2,555,334	3	0	585,500	2,015,061
36	RBD	E368 Line Transformers - Rsrv	LNTRFRMR_04	378,941,964	270,532,340	2,051,747	1,718,752	0	0	361,842	1,174,044
37	RBD	E369 Services - Rsrv									
38	RBD	Services	E369PLT	240,814,772	153,730,211	900,570	1,504,596	8,066	126	0	0
39	RBD	Not used	not_used	0	0	0	0	0	0	0	0
40	RBD	Total Accounts E369 Rsrv		240,814,772	153,730,211	900,570	1,504,596	8,066	126	0	0
41	RBD	E370 Meters - Rsrv									
42	RBD	Load profile meters	KWHMETERX_04	0	0	0	0	0	0	0	0
43	RBD	All other Meters	METERPLTXPR	136,921,647	106,188,362	342,124	571,591	90,235	1,408	38,858	0
44	RBD	Total Account E370 Rsrv		136,921,647	106,188,362	342,124	571,591	90,235	1,408	38,858	0
45	RBD	E371 - Installations on Cust Premises Rsrv	not_used	0	0	0	0	0	0	0	0
46	RBD	E373 Street Lighting - Rsrv									
47	RBD	Streetlight fixtures	E373PLT	118,939,285	7,813,349	40,469	70,443	30	0	11,752	81,698,884
48	RBD	Not used	not_used	0	0	0	0	0	0	0	0
49	RBD	Total Account E373 Rsrv		118,939,285	7,813,349	40,469	70,443	30	0	11,752	81,698,884
50	RBD										

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
1	RBD	**LESS: DEPRECIATION RESERVE & AMORT**								
2	RBD									
3	RBD	E301-E303 - INTANGILE PLANT - RESERVE								
4	RBD	Customer Service Related - Reserve	CUSTSVSX	637	162,004	2,766,335	813,083	67,782	16,679	2,234
5	RBD	Not Used	not_used	0	0	0	0	0	0	0
6	RBD	Not used	not_used	0	0	0	0	0	0	0
7	RBD	Total Accounts E301-E303 Reserve		637	162,004	2,766,335	813,083	67,782	16,679	2,234
8	RBD									
9	RBD	E304-E346 - PRODUCTION PLANT - RESERVE	not_used	0	0	0	0	0	0	0
10	RBD	E350-E359 - TRANSMISSION PLANT - RESERVE	not_used	0	0	0	0	0	0	0
11	RBD									
12	RBD	DISTRIBUTION PLANT RESERVE								
13	RBD	E360-E361 Land & Structures - Reserve								
14	RBD	E360 - Land and Land Rights								
15	RBD	- Headquarters Related	DISTPLT	0	0	0	0	0	0	0
16	RBD	- Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0
17	RBD	- Direct - HEP	DIR_HEP_03	0	0	0	0	0	0	0
18	RBD	- Substation Related	E362PLT	0	0	159,386	131,016	33,749	34,468	0
19	RBD	E361 - Structures and improvements								
20	RBD	- Headquarters Related	DISTPLT	2,923	437,032	7,944,166	5,912,476	1,312,937	1,228,142	3,563
21	RBD	- Substation Related	E362PLT	0	0	8,667,282	7,124,554	1,835,225	1,874,323	0
22	RBD	Total Accounts E360-E361		2,923	437,032	16,770,835	13,168,047	3,181,911	3,136,933	3,563
23	RBD	E362 Station Equipment - Rsrv	E362PLT	0	0	66,650,485	54,787,066	14,112,686	14,413,347	0
24	RBD	E364 Poles Towers and Fixtures Rsrv								
25	RBD	- Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0
26	RBD	- All Other	E364PLT	20,286	562,080	38,289,009	31,113,057	8,033,507	12,580,783	0
27	RBD	E365 OH Conductors and Devices - Rsrv								
28	RBD	- Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0
29	RBD	- All Other	E365PLT	47,105	1,860,183	128,850,088	105,077,861	27,002,597	18,671,512	0
30	RBD	E366 UG Conduit - Rsrv								
31	RBD	- Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0
32	RBD	- All Other	E366PLT	27,192	444,505	51,196,756	41,593,287	10,729,135	9,474,358	1
33	RBD	E367 UG Conductors and Devices - Rsrv								
34	RBD	- Direct - HTS-HV	DIR_HEP_03	0	0	0	0	0	0	0
35	RBD	- All Other	E367PLT	53,984	882,474	101,640,674	82,574,952	21,300,500	18,809,398	2
36	RBD	E368 Line Transformers - Rsrv	LNTRFRMR_04	53,512	511,444	53,056,761	49,481,522	0	0	0
37	RBD	E369 Services - Rsrv								
38	RBD	Services	E369PLT	0	0	78,268,571	5,669,474	472,237	260,919	0
39	RBD	Not used	not_used	0	0	0	0	0	0	0
40	RBD	Total Accounts E369 Rsrv		0	0	78,268,571	5,669,474	472,237	260,919	0
41	RBD	E370 Meters - Rsrv								
42	RBD	Load profile meters	KWHMETERX_04	0	0	0	0	0	0	0
43	RBD	All other Meters	METERPLTXPR	0	0	24,575,595	2,848,138	1,078,219	836,097	351,021
44	RBD	Total Account E370 Rsrv		0	0	24,575,595	2,848,138	1,078,219	836,097	351,021
45	RBD	E371 - Installations on Cust Premises Rsrv	not_used	0	0	0	0	0	0	0
46	RBD	E373 Street Lighting - Rsrv								
47	RBD	Streetlight fixtures	E373PLT	1,099	23,250,262	2,893,446	2,211,618	489,438	458,478	17
48	RBD	Not used	not_used	0	0	0	0	0	0	0
49	RBD	Total Account E373 Rsrv		1,099	23,250,262	2,893,446	2,211,618	489,438	458,478	17
50	RBD									

PUBLIC SERVICE ELECTRIC & GAS COMPANY
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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
51	RBD	**DEPRECIATION RESERVE & AMORT CONTINUED**									
52	RBD	Other Plant Unallocated - Reserve									
53	RBD	Not Used	not_used	0	0	0	0	0	0	0	0
54	RBD	Not Used	not_used	0	0	0	0	0	0	0	0
55	RBD	Total Other Plant Unallocated - Reserve		0	0	0	0	0	0	0	0
56	RBD										
57	RBD	Not Used	not_used	0	0	0	0	0	0	0	0
58	RBD	Not Used	not_used	0	0	0	0	0	0	0	0
59	RBD	Not Used	not_used	0	0	0	0	0	0	0	0
60	RBD										
61	RBD	TOTAL DISTRIBUTION PLANT RESERVE		2,813,507,566	1,554,589,322	7,968,078	13,578,486	99,321	1,549	2,210,530	90,792,298
62	RBD										
63	RBD	GENERAL AND COMMON PLANT RESERVE									
64	RBD	E390-E398 GENERAL PLANT - RESERVE									
65	RBD	Meter Plant Related	METERPLT	0	0	0	0	0	0	0	0
66	RBD	Customer Service Related	CUSTSVSX	0	0	0	0	0	0	0	0
67	RBD	Substation Related	E362PLT	0	0	0	0	0	0	0	0
68	RBD	Distribution Delivery Related	DISTPLTXMTR	156,424,740	83,209,190	430,981	750,191	322	5	125,149	5,685,688
69	RBD	Service & Support Related	UTILWORK_04	0	0	0	0	0	0	0	0
70	RBD	Unassigned	GENPLT	0	0	0	0	0	0	0	0
71	RBD	Total Accounts E390-E398 Reserve		156,424,740	83,209,190	430,981	750,191	322	5	125,149	5,685,688
72	RBD										
73	RBD	C389-C399 COMMON PLANT RESERVE									
74	RBD	Not Used	not_used	0	0	0	0	0	0	0	0
75	RBD	Meter Plant Related	METERPLT	0	0	0	0	0	0	0	0
76	RBD	Meter Reading Related	MRCOST_07	0	0	0	0	0	0	0	0
77	RBD	Not Used	not_used	0	0	0	0	0	0	0	0
78	RBD	Customer Service Related	CUSTSVSX	46,782,308	34,978,355	121,225	204,095	3,446	53	4,489	103,836
79	RBD	Distribution Delivery Related	DISTPLTXMTR	19,175,874	10,200,490	52,833	91,965	39	1	15,342	697,000
80	RBD	Sales and Service Dept. Related	UTILWORK_04	0	0	0	0	0	0	0	0
81	RBD	Unassigned	COMPLT	0	0	0	0	0	0	0	0
82	RBD	Not Used	not_used	0	0	0	0	0	0	0	0
83	RBD	Total Accounts C389-C399 Reserve		65,958,182	45,178,845	174,059	296,060	3,485	54	19,831	800,836
84	RBD										
85	RBD	C303 - INTANGIBLE PLANT									
86	RBD	Not Used	not_used	0	0	0	0	0	0	0	0
87	RBD	Meter Reading	MRCOST_07	623,486	490,820	1,705	2,849	33	1	39	0
88	RBD	Customer Service Related	CUSTSVSX	46,570,192	34,819,759	120,676	203,169	3,430	53	4,468	103,365
89	RBD	Distribution Related	INTANGPLT	0	0	0	0	0	0	0	0
90	RBD	C390.4 / C111.000 Capital Lease	TOTPLT	0	0	0	0	0	0	0	0
91	RBD	E399 Oth Tangible Plant	GENPLT	0	0	0	0	0	0	0	0
92	RBD	E399.1 Asset Retirement Obligations	GENPLT	490,552	260,946	1,352	2,353	1	0	392	17,830
93	RBD	Total Accounts C303-C390.4,E399		47,684,230	35,571,526	123,732	208,371	3,464	53	4,900	121,195
94	RBD										
95	RBD	**TOTAL DEPRECIATION RESERVE & AMORT.**		3,099,332,698	1,730,330,862	8,737,683	14,901,854	107,752	1,679	2,361,921	97,434,992
96	RBD										
97	RBD	**NET ELECTRIC PLANT IN SERVICE**		8,357,658,252	4,500,513,778	22,699,101	39,722,478	171,583	2,675	6,461,292	298,232,800

PUBLIC SERVICE ELECTRIC & GAS COMPANY
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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
51	RBD	**DEPRECIATION RESERVE & AMORT CONTINUED**								
52	RBD	Other Plant Unallocated - Reserve								
53	RBD	Not Used	not_used	0	0	0	0	0	0	0
54	RBD	Not Used	not_used	0	0	0	0	0	0	0
55	RBD	Total Other Plant Unallocated - Reserve		0	0	0	0	0	0	0
56	RBD									
57	RBD	Not Used	not_used	0	0	0	0	0	0	0
58	RBD	Not Used	not_used	0	0	0	0	0	0	0
59	RBD	Not Used	not_used	0	0	0	0	0	0	0
60	RBD									
61	RBD	TOTAL DISTRIBUTION PLANT RESERVE		206,100	27,947,981	562,192,220	388,525,022	86,400,229	78,641,825	354,604
62	RBD									
63	RBD	GENERAL AND COMMON PLANT RESERVE								
64	RBD	E390-E398 GENERAL PLANT - RESERVE								
65	RBD	Meter Plant Related	METERPLT	0	0	0	0	0	0	0
66	RBD	Customer Service Related	CUSTSVSX	0	0	0	0	0	0	0
67	RBD	Substation Related	E362PLT	0	0	0	0	0	0	0
68	RBD	Distribution Delivery Related	DISTPLTXMTR	11,699	1,749,401	30,814,100	23,552,891	5,212,326	4,882,611	184
69	RBD	Service & Support Related	UTILWORK_04	0	0	0	0	0	0	0
70	RBD	Unassigned	GENPLT	0	0	0	0	0	0	0
71	RBD	Total Accounts E390-E398 Reserve		11,699	1,749,401	30,814,100	23,552,891	5,212,326	4,882,611	184
72	RBD									
73	RBD	C389-C399 COMMON PLANT RESERVE								
74	RBD	Not Used	not_used	0	0	0	0	0	0	0
75	RBD	Meter Plant Related	METERPLT	0	0	0	0	0	0	0
76	RBD	Meter Reading Related	MRCOST_07	0	0	0	0	0	0	0
77	RBD	Not Used	not_used	0	0	0	0	0	0	0
78	RBD	Customer Service Related	CUSTSVSX	1,892	480,956	8,212,700	2,413,881	201,231	49,517	6,633
79	RBD	Distribution Delivery Related	DISTPLTXMTR	1,434	214,456	3,777,454	2,887,314	638,971	598,552	23
80	RBD	Sales and Service Dept. Related	UTILWORK_04	0	0	0	0	0	0	0
81	RBD	Unassigned	COMPLT	0	0	0	0	0	0	0
82	RBD	Not Used	not_used	0	0	0	0	0	0	0
83	RBD	Total Accounts C389-C399 Reserve		3,326	695,413	11,990,155	5,301,194	840,202	648,069	6,655
84	RBD									
85	RBD	C303 - INTANGIBLE PLANT								
86	RBD	Not Used	not_used	0	0	0	0	0	0	0
87	RBD	Meter Reading	MRCOST_07	0	0	120,277	7,016	584	144	19
88	RBD	Customer Service Related	CUSTSVSX	1,883	478,776	8,175,463	2,402,936	200,319	49,292	6,603
89	RBD	Distribution Related	INTANGPLT	0	0	0	0	0	0	0
90	RBD	C390.4 / C111.000 Capital Lease	TOTPLT	0	0	0	0	0	0	0
91	RBD	E399 Oth Tangible Plant	GENPLT	0	0	0	0	0	0	0
92	RBD	E399.1 Asset Retirement Obligations	GENPLT	37	5,486	96,634	73,862	16,346	15,312	1
93	RBD	Total Accounts C303-C390.4,E399		1,920	484,262	8,392,374	2,483,814	217,249	64,748	6,623
94	RBD									
95	RBD	**TOTAL DEPRECIATION RESERVE & AMORT.**		223,683	31,039,060	616,155,185	420,676,004	92,737,788	84,253,932	370,301
96	RBD									
97	RBD	**NET ELECTRIC PLANT IN SERVICE**		598,304	92,794,843	1,629,680,992	1,235,233,997	273,361,651	257,574,480	610,278

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	RBO	**ADDITIONS AND DEDUCTIONS TO RATE BASE**									
2	RBO										
3	RBO	**PLUS: ADDITIONS TO RATE BASE**									
4	RBO										
5	RBO	Working Capital									
6	RBO	Cash (lead/lag)	EXPENDITURES	884,882,332	496,896,476	2,287,746	4,058,268	56,884	886	597,850	34,710,337
7	RBO	Materials and Supplies	EXPENDITURES	297,953,440	167,312,657	770,319	1,366,481	19,154	298	201,305	11,687,502
8	RBO	Prepayments	EXPENDITURES	500,266	280,919	1,293	2,294	32	1	338	19,623
9	RBO	Working Funds	EXPENDITURES								
10	RBO	Total Working Capital		1,183,336,038	664,490,052	3,059,359	5,427,043	76,070	1,185	799,493	46,417,462
11	RBO	Net Plant Adds - Distribution	DISTPLT	1,061,820,806	573,602,113	2,916,290	5,069,967	25,847	403	830,929	37,285,762
12	RBO	Plant Held for Future Use	TOTPLT	489,291	266,099	1,343	2,333	12	0	377	16,898
13	RBO	Capital Stimulas Adjust	DISTPLT	0	0	0	0	0	0	0	0
14	RBO	Net Plant Adds - General & Other	TOTPLTNET	305,589,989	164,557,094	829,971	1,452,415	6,274	98	236,251	10,904,605
15	RBO	CEF-EC Adjustment	ECPRO_07	657,429,985	529,627,120	1,706,383	2,850,880	450,057	7,021	193,808	
16	RBO	CEF-EV Adjustment	TOTREV	42,056,391	23,669,384	110,899	196,393	2,807	44	29,053	1,422,943
17	RBO	TOTAL ADDITIONS TO RATE BASE		3,250,722,500	1,956,211,861	8,624,244	14,999,031	561,067	8,750	2,089,911	96,047,670
18	RBO										
19	RBO										
20	RBO	**PLUS: DEDUCTIONS TO RATE BASE**									
21	RBO										
22	RBO	Customer Advances for Construction	REVREQ	(63,907,492)	(36,036,364)	(168,842)	(299,006)	(4,274)	(67)	(44,019)	(2,166,415)
23	RBO	Unbilled Revenue	TOTREV								
24	RBO	IAP Adjustment	E365PLT	(40,898,861)	(21,583,452)	(97,535)	(207,372)			(37,866)	(98,124)
25	RBO	Deferred Income Taxes and Credits									
26	RBO	ADIT Test/Post year	TOTPLT								
27	RBO	Liberalized Depreciation	TOTPLT	(2,247,763)	(1,222,438)	(6,168)	(10,717)	(55)	(1)	(1,731)	(77,627)
28	RBO	Cost of Removal	TOTPLT	15,629,066	8,499,813	42,885	74,516	381	6	12,036	539,751
29	RBO	3% Investment Tax Credit	DISTPLT								
30	RBO	Computer Software	INTANGPLT								
31	RBO	Capitalized Interest	TOTPLTNET	312,066	168,044	848	1,483	6	0	241	11,136
32	RBO	NJ Corporate Business Tax	TOTPLTNET	6,378,736	3,434,885	17,324	30,317	131	2	4,931	227,617
33	RBO	Defrd Tax & Consolidated Tax Adjustment	TOTPLT	(1,738,024,409)	(945,218,524)	(4,768,957)	(8,286,506)	(42,375)	(661)	(1,338,481)	(60,022,765)
34	RBO	Total Deferred Income Taxes and Credits		(1,717,952,304)	(934,338,220)	(4,714,068)	(8,190,907)	(41,912)	(653)	(1,323,003)	(59,321,888)
35	RBO										
36	RBO	TOTAL DEDUCTIONS TO RATE BASE		(1,822,758,657)	(991,958,036)	(4,980,445)	(8,697,284)	(46,185)	(720)	(1,404,888)	(61,586,427)
37	RBO										
38	RBO										
39	RBO	**TOTAL RATE BASE**		9,785,622,095	5,464,767,603	26,342,900	46,024,225	686,464	10,706	7,146,316	332,694,043

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PUBLIC SERVICE ELECTRIC & GAS COMPANY
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12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
1	RBO	**ADDITIONS AND DEDUCTIONS TO RATE BASE**								
2	RBO									
3	RBO	**PLUS: ADDITIONS TO RATE BASE**								
4	RBO									
5	RBO	Working Capital								
6	RBO	Cash (lead/lag)	EXPENDITURES	358,042	12,847,442	166,284,707	117,675,573	25,974,301	22,932,057	201,764
7	RBO	Materials and Supplies	EXPENDITURES	120,558	4,325,931	55,990,609	39,623,169	8,745,945	7,721,575	67,937
8	RBO	Prepayments	EXPENDITURES	202	7,263	94,009	66,528	14,685	12,965	114
9	RBO	Working Funds	EXPENDITURES							
10	RBO	Total Working Capital		478,803	17,180,636	222,369,324	157,365,269	34,734,931	30,666,597	269,815
11	RBO	Net Plant Adds - Distribution	DISTPLT	76,723	11,472,272	208,537,646	155,204,944	34,465,137	32,239,238	93,537
12	RBO	Plant Held for Future Use	TOTPLT	35	5,289	95,912	70,719	15,635	14,598	42
13	RBO	Capital Stimulus Adjust	DISTPLT	0	0	0	0	0	0	0
14	RBO	Net Plant Adds - General & Other	TOTPLTNET	21,876	3,392,957	59,587,767	45,165,181	9,995,214	9,417,971	22,314
15	RBO	CEF-EC Adjustment	ECPRO_07			122,594,717				
16	RBO	CEF-EV Adjustment	TOTREV	11,195	506,228	8,055,469	5,677,649	1,243,191	1,126,902	4,234
17	RBO	TOTAL ADDITIONS TO RATE BASE		588,632	32,557,382	621,240,837	363,483,761	80,454,108	73,465,305	389,941
18	RBO									
19	RBO									
20	RBO	**PLUS: DEDUCTIONS TO RATE BASE**								
21	RBO									
22	RBO	Customer Advances for Construction	REVREQ	(17,045)	(766,989)	(12,204,883)	(8,602,235)	(1,883,565)	(1,707,374)	(6,415)
23	RBO	Unbilled Revenue	TOTREV							
24	RBO	IAP Adjustment	E365PLT	(3,158)	(124,721)	(8,639,083)	(7,045,213)	(1,810,458)	(1,251,879)	
25	RBO	Deferred Income Taxes and Credits								
26	RBO	ADIT Test/Post year	TOTPLT							
27	RBO	Liberalized Depreciation	TOTPLT	(161)	(24,295)	(440,614)	(324,875)	(71,826)	(67,064)	(192)
28	RBO	Cost of Removal	TOTPLT	1,121	168,928	3,063,660	2,258,911	499,415	466,306	1,338
29	RBO	3% Investment Tax Credit	DISTPLT							
30	RBO	Computer Software	INTANGPLT							
31	RBO	Capitalized Interest	TOTPLTNET	22	3,465	60,850	46,122	10,207	9,618	23
32	RBO	NJ Corporate Business Tax	TOTPLTNET	457	70,823	1,243,806	942,756	208,635	196,586	466
33	RBO	Defrd Tax & Consolidated Tax Adjustment	TOTPLT	(124,695)	(18,785,591)	(340,693,129)	(251,201,386)	(55,537,249)	(51,855,337)	(148,754)
34	RBO	Total Deferred Income Taxes and Credits		(123,256)	(18,566,670)	(336,765,426)	(248,278,471)	(54,890,818)	(51,249,891)	(147,120)
35	RBO									
36	RBO	TOTAL DEDUCTIONS TO RATE BASE		(143,459)	(19,458,380)	(357,609,392)	(263,925,920)	(58,584,840)	(54,209,145)	(153,534)
37	RBO									
38	RBO									
39	RBO	**TOTAL RATE BASE**		1,043,476	105,893,845	1,893,312,437	1,334,791,838	295,230,918	276,830,640	846,685

Updated for 9 and 3

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	REV	**OPERATING REVENUES**									
2	REV										
3	REV	**SALES REVENUES**									
4	REV	BASE RATE SALES @ EQUALIZED ROR 7.40%		1,899,915,237	1,071,330,372	5,019,520	8,889,191	127,057	1,979	1,308,648	64,405,668
5	REV	Not Used	not_used	0	0	0	0	0	0	0	0
6	REV	Not Used	not_used	0	0	0	0	0	0	0	0
7	REV	TOTAL SALES OF ELECTRICITY		1,899,915,237	1,071,330,372	5,019,520	8,889,191	127,057	1,979	1,308,648	64,405,668
8	REV										
9	REV	**OTHER OPERATING REVENUES**									
10	REV	450-Forfeited Discounts	REVLATEP	3,653,078	0	0	0	0	0	6,377	0
11	REV	456-Other Electric Revenues	TOTREV	21,451,361	12,072,850	56,565	100,173	1,432	22	14,819	725,789
12	REV	Not Used	not_used	0	0	0	0	0	0	0	0
13	REV	Not Used	not_used	0	0	0	0	0	0	0	0
14	REV	TOTAL OTHER OPERATING REV		25,104,439	12,072,850	56,565	100,173	1,432	22	21,196	725,789
15	REV										
16	REV	**OTHER REVENUE SOURCES**									
17	REV	Not Used	not_used	0	0	0	0	0	0	0	0
18	REV	Not Used	not_used	0	0	0	0	0	0	0	0
19	REV	TOTAL OTHER REVENUE SOURCES		0	0	0	0	0	0	0	0
20	REV										
21	REV	LESS: E496 Provision for Rate Refunds	TOTREV	0	0	0	0	0	0	0	0
22	REV										
23	REV	**TOTAL OPERATING REVENUES**		1,925,019,676	1,083,403,222	5,076,085	8,989,364	128,489	2,001	1,329,844	65,131,457

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
1	REV	**OPERATING REVENUES**								
2	REV									
3	REV	**SALES REVENUES**								
4	REV	BASE RATE SALES @ EQUALIZED ROR 7.40%		506,728	22,801,929	362,840,766	255,737,125	55,996,770	50,758,783	190,699
5	REV	Not Used	not_used	0	0	0	0	0	0	0
6	REV	Not Used	not_used	0	0	0	0	0	0	0
7	REV	TOTAL SALES OF ELECTRICITY		506,728	22,801,929	362,840,766	255,737,125	55,996,770	50,758,783	190,699
8	REV									
9	REV	**OTHER OPERATING REVENUES**								
10	REV	450-Forfeited Discounts	REVLATEP	0	111,117	1,768,175	1,246,244	272,880	247,355	929
11	REV	456-Other Electric Revenues	TOTREV	5,710	258,208	4,108,788	2,895,952	634,104	574,790	2,159
12	REV	Not Used	not_used	0	0	0	0	0	0	0
13	REV	Not Used	not_used	0	0	0	0	0	0	0
14	REV	TOTAL OTHER OPERATING REV		5,710	369,325	5,876,963	4,142,196	906,985	822,144	3,089
15	REV									
16	REV	**OTHER REVENUE SOURCES**								
17	REV	Not Used	not_used	0	0	0	0	0	0	0
18	REV	Not Used	not_used	0	0	0	0	0	0	0
19	REV	TOTAL OTHER REVENUE SOURCES		0	0	0	0	0	0	0
20	REV									
21	REV	LESS: E496 Provision for Rate Refunds	TOTREV	0	0	0	0	0	0	0
22	REV									
23	REV	**TOTAL OPERATING REVENUES**		512,439	23,171,254	368,717,729	259,879,321	56,903,755	51,580,928	193,788

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	E	**OPERATION & MAINTENANCE EXPENSE**									
2	E	PRODUCTION EXPENSE									
3	E	E500-E557 Production Expenses									
4	E	Not Used	not_used	0	0	0	0	0	0	0	0
5	E	Total Production Expense		0	0	0	0	0	0	0	0
6	E	TOTAL PRODUCTION EXPENSE		0	0	0	0	0	0	0	0
7	E										
8	E	TRANSMISSION EXPENSES									
9	E	E560-E573 Transmission Exp	not_used	0	0	0	0	0	0	0	0
10	E	TOTAL TRANSMISSION EXPENSE		0	0	0	0	0	0	0	0
11	E										
12	E	DISTRIBUTION EXPENSES									
13	E	Operation									
14	E	E580 Operation Supervision & Eng'g	DISTEXPO	0	0	0	0	0	0	0	0
15	E	E581 Load Dispatching	CP_SUBT_05	0	0	0	0	0	0	0	0
16	E	E582 Station Expenses	E362PLT	2,539,578	1,158,421	3,719	13,027	0	0	811	0
17	E	E583 OH Line Expenses	E365PLT	4,195,894	2,214,288	10,006	21,275	0	0	3,885	10,067
18	E	E584 Underground Line Expenses	E367PLT	6,199,909	3,397,340	16,750	30,895	0	0	7,079	24,363
19	E	E585 Street Lighting and System Expenses	E373PLT	173,106	11,372	59	103	0	0	17	118,906
20	E	E586 Meter Expenses									
21	E	- Basic portion (minimum size)	MTROMMIN_07	5,865,310	2,939,512	10,212	17,062	2,798	44	1,160	0
22	E	- Excess portion	METERSEXC_04	0	0	0	0	0	0	0	0
23	E	E587 Customer Installations Expenses									
24	E	-E587 Customer Installation Expenses - Local	CUSTAVG_04	-1,314,125	-1,119,615	-3,890	-6,498	-371	-6	-442	-2,764
25	E	-E587 Customer Installation Expenses - System	CUSTAVG_04	-1,314,125	-1,119,615	-3,890	-6,498	-371	-6	-442	-2,764
26	E	E588 Miscellaneous Distribution Expenses	DISTEXPO	35,897,260	16,430,937	72,401	152,332	4,517	70	26,504	324,609
27	E	E589 Rents	DISTPLT	1,330,133	718,546	3,653	6,351	32	1	1,041	46,708
28	E	Total Distribution Operation		53,572,940	24,631,187	109,021	228,046	6,606	103	39,613	519,124
29	E	Maintenance									
30	E	E590 Maint. Supervision & Eng'g	DISTEXPM	0	0	0	0	0	0	0	0
31	E	E591 Maint of Structures	E360PLT	12,325,542	5,906,557	22,385	62,024	82	1	5,504	118,763
32	E	E592 Maint of Station Equipment	E362PLT	17,215,431	7,852,767	25,208	88,306	0	0	5,500	0
33	E	E593 Maint of Overhead Lines									
34	E	- Direct assigned - BPL poles	DIR_BPL_02	40,988	0	0	0	0	0	0	40,988
35	E	- Direct assigned - PSAL poles	DIR_PSAL_02	118,210	0	0	0	0	0	0	0
36	E	- all other O&M	E365PLT	56,305,216	29,713,808	134,276	285,487	0	0	52,130	135,087
37	E	E594.0 Maint of Underground Lines	E367PLT	20,076,605	11,001,299	54,242	100,044	0	0	22,923	78,891
38	E	Not used		0	0	0	0	0	0	0	0
39	E	E595 Maint of Line Transformers	LNTRFRMR_04	4,205,529	3,002,390	22,770	19,075	0	0	4,016	13,030
40	E	E596 Maint of Street Lighting & Signal Systems									
41	E	- BPL luminaires	DIR_BPL_02	8,123,869	0	0	0	0	0	0	8,123,869
42	E	- BPL-POF luminaires	DIR_BPLPOF_02	340,052	0	0	0	0	0	0	0
43	E	- PSAL luminaires	DIR_PSAL_02	3,594,664	0	0	0	0	0	0	0
44	E	E597 Maint of Meters									
45	E	- Load profiling meters O&M	KWHMETERX_04	0	0	0	0	0	0	0	0
46	E	- Basic portion (minimum size)	MTROMMIN_07	858,670	430,339	1,495	2,498	410	6	170	0
47	E	- Excess portion	METERSEXC_04	0	0	0	0	0	0	0	0
48	E	E598 Other Dist Maint Exp	DISTEXPM	1,231,542	578,834	2,603	5,572	5	0	902	85,071
49	E	Total Distribution Maintenance		124,436,319	58,485,994	262,978	563,006	497	8	91,145	8,595,700
50	E										

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
1	E	**OPERATION & MAINTENANCE EXPENSE**								
2	E	PRODUCTION EXPENSE								
3	E	E500-E557 Production Expenses								
4	E	Not Used	not_used	0	0	0	0	0	0	0
5	E	Total Production Expense		0	0	0	0	0	0	0
6	E	TOTAL PRODUCTION EXPENSE		0	0	0	0	0	0	0
7	E									
8	E	TRANSMISSION EXPENSES								
9	E	E560-E573 Transmission Exp	not_used	0	0	0	0	0	0	0
10	E	TOTAL TRANSMISSION EXPENSE		0	0	0	0	0	0	0
11	E									
12	E	DISTRIBUTION EXPENSES								
13	E	Operation								
14	E	E580 Operation Supervision & Eng'g	DISTEXPO	0	0	0	0	0	0	0
15	E	E581 Load Dispatching	CP_SUBT_05	0	0	0	0	0	0	0
16	E	E582 Station Expenses	E362PLT	0	0	606,045	498,172	128,325	131,059	0
17	E	E583 OH Line Expenses	E365PLT	324	12,795	886,300	722,782	185,738	128,433	0
18	E	E584 Underground Line Expenses	E367PLT	653	10,669	1,228,865	998,355	257,529	227,411	0
19	E	E585 Street Lighting and System Expenses	E373PLT	2	33,839	4,211	3,219	712	667	0
20	E	E586 Meter Expenses								
21	E	- Basic portion (minimum size)	MTROMMIN_07	0	0	405,220	2,249,681	187,387	46,040	6,195
22	E	- Excess portion	METERSEXC_04	0	0	0	0	0	0	0
23	E	E587 Customer Installations Expenses								
24	E	-E587 Customer Installation Expenses - Local	CUSTAVG_04	-50	-13,196	-161,392	-5,335	-444	-109	-15
25	E	-E587 Customer Installation Expenses - System	CUSTAVG_04	-50	-13,196	-161,392	-5,335	-444	-109	-15
26	E	E588 Miscellaneous Distribution Expenses	DISTEXPO	1,928	67,887	6,166,476	9,798,207	1,666,444	1,171,408	13,541
27	E	E589 Rents	DISTPLT	96	14,371	261,233	194,424	43,174	40,386	117
28	E	Total Distribution Operation		2,902	113,170	9,235,567	14,454,170	2,468,421	1,745,186	19,824
29	E	Maintenance								
30	E	E590 Maint. Supervision & Eng'g	DISTEXPM	0	0	0	0	0	0	0
31	E	E591 Maint of Structures	E360PLT	244	36,542	2,798,493	2,248,731	561,690	564,227	298
32	E	E592 Maint of Station Equipment	E362PLT	0	0	4,108,289	3,377,036	869,896	888,429	0
33	E	E593 Maint of Overhead Lines								
34	E	- Direct assigned - BPL poles	DIR_BPL_02	0	0	0	0	0	0	0
35	E	- Direct assigned - PSAL poles	DIR_PSAL_02	0	118,210	0	0	0	0	0
36	E	- all other O&M	E365PLT	4,348	171,702	11,893,373	9,699,103	2,492,447	1,723,455	0
37	E	E594.0 Maint of Underground Lines	E367PLT	2,114	34,550	3,979,323	3,232,883	833,933	736,405	0
38	E	Not used		0	0	0	0	0	0	0
39	E	E595 Maint of Line Transformers	LNTRFRMR_04	594	5,676	588,828	549,150	0	0	0
40	E	E596 Maint of Street Lighting & Signal Systems								
41	E	- BPL luminaires	DIR_BPL_02	0	0	0	0	0	0	0
42	E	- BPL-POF luminaires	DIR_BPLPOF_02	340,052	0	0	0	0	0	0
43	E	- PSAL luminaires	DIR_PSAL_02	0	3,594,664	0	0	0	0	0
44	E	E597 Maint of Meters								
45	E	- Load profiling meters O&M	KWHMETERX_04	0	0	0	0	0	0	0
46	E	- Basic portion (minimum size)	MTROMMIN_07	0	0	59,323	329,349	27,433	6,740	907
47	E	- Excess portion	METERSEXC_04	0	0	0	0	0	0	0
48	E	E598 Other Dist Maint Exp	DISTEXPM	3,472	39,597	234,180	194,283	47,834	39,176	12
49	E	Total Distribution Maintenance		350,824	4,000,941	23,661,810	19,630,534	4,833,233	3,958,432	1,217
50	E									

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
51	E	**OPERATION & MAINTENANCE EXPENSE CONTINUED**									
52	E										
53	E	TOTAL DISTRIBUTION PLANT O&M EXPENSES		178,009,259	83,117,180	371,999	791,052	7,103	111	130,759	9,114,824
54	E										
55	E	TOTAL OPER & MAINT EXP (PROD,TRAN,& DIST)		178,009,259	83,117,180	371,999	791,052	7,103	111	130,759	9,114,824
56	E										
57	E										
58	E	CUSTOMER ACCOUNTS EXPENSES									
59	E	E901 Supervision	CUSTACCTS	0	0	0	0	0	0	0	0
60	E	E902 Meter Reading									
61	E	- Meter O&M	METERPLT	0	0	0	0	0	0	0	0
62	E	- Meter Reading	MRCOST_07	18,646,973	14,679,249	50,997	85,201	972	15	1,158	0
63	E	- Billing	BILLING_06	0	0	0	0	0	0	0	0
64	E	- Remaining	MRCOST_07	-567,391	-446,661	-1,552	-2,593	-30	0	-35	0
65	E	E903 Customer Records and Collection									
66	E	- SONP/RNP	CUSTAVG_06	550,664	469,157	1,630	2,723	155	2	185	1,158
67	E	- Meter O&M	METERPLT	0	0	0	0	0	0	0	0
68	E	- Meter Reading	MRCOST_07	533,054	419,630	1,458	2,436	28	0	33	0
69	E	- Billing	BILLING_06	80,993	58,538	203	340	4	0	5	246
70	E	- Acct Maint related	ACCTMAINT_06	7,745,024	6,451,315	22,412	37,445	2,039	32	2,430	1,840
71	E	- Utility work related	UTILWORK_04	1,062,937	777,147	2,484	5,302	65	1	359	5,313
72	E	- Remaining	BILLING_06	66,341,808	47,948,497	166,577	278,303	3,175	50	3,784	201,196
73	E	Not used	not_used	0	0	0	0	0	0	0	0
74	E	E904 Uncollectible Accounts	not_used	0	0	0	0	0	0	0	0
75	E	E905 Misc Customer Accounts	CUSTACCTS	0	0	0	0	0	0	0	0
76	E	TOTAL CUSTOMER ACCTS EXPENSE		94,394,062	70,356,872	244,210	409,157	6,408	100	7,918	209,752
77	E										
78	E										
79	E	CUSTOMER SERVICE & INFO EXPENSES									
80	E	E907 & 908 - Cust Svs & Info									
81	E	- SONP/RNP	CUSTAVG_06	0	0	0	0	0	0	0	0
82	E	- Acct Maint related	ACCTMAINT_06	2,356,739	1,963,075	6,820	11,394	620	10	739	560
83	E	- Utility work related	UTILWORK_04	847,228	619,436	1,980	4,226	51	0	286	4,234
84	E	- Sales	SALES_06	0	0	0	0	0	0	0	0
85	E	- Billing	BILLING_06	41,297	29,847	104	173	2	0	2	125
86	E	- Remaining	ACCTMAINT_06	0	0	0	0	0	0	0	0
87	E	E909 Info & Instr Advertising	CUSTNUMX_04	0	0	0	0	0	0	0	0
88	E	E910 - Misc Cust Svs & Info									
89	E	- Utility work related	UTILWORK_04	1,163,089	850,371	2,718	5,801	71	1	392	5,813
90	E	- Acct Maint related	ACCTMAINT_06	689,620	574,428	1,996	3,334	182	3	216	164
91	E	- Not used	not_used	0	0	0	0	0	0	0	0
92	E	- Not used	not_used	0	0	0	0	0	0	0	0
93	E	- Not used	not_used	0	0	0	0	0	0	0	0
94	E	- Not used	not_used	0	0	0	0	0	0	0	0
95	E	- Remaining	BILLING_06	220,028	159,025	552	923	11	0	13	667
96	E	TOTAL CUSTOMER SERVICE & INFO EXPENSES		5,318,001	4,196,182	14,170	25,852	936	14	1,649	11,564
97	E										
98	E										
99	E										
100	E	**OPERATION & MAINTENANCE EXPENSE CONTINUED**									

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
51	E	**OPERATION & MAINTENANCE EXPENSE CONTINUED**								
52	E									
53	E	TOTAL DISTRIBUTION PLANT O&M EXPENSES		353,726	4,114,111	32,897,377	34,084,705	7,301,654	5,703,617	21,041
54	E									
55	E	TOTAL OPER & MAINT EXP (PROD,TRAN,& DIST)		353,726	4,114,111	32,897,377	34,084,705	7,301,654	5,703,617	21,041
56	E									
57	E									
58	E	CUSTOMER ACCOUNTS EXPENSES								
59	E	E901 Supervision	CUSTACCTS	0	0	0	0	0	0	0
60	E	E902 Meter Reading								
61	E	- Meter O&M	METERPLT	0	0	0	0	0	0	0
62	E	- Meter Reading	MRCOST_07	0	0	3,597,205	209,825	17,477	4,294	578
63	E	- Billing	BILLING_06	0	0	0	0	0	0	0
64	E	- Remaining	MRCOST_07	0	0	-109,456	-6,385	-532	-131	-18
65	E	E903 Customer Records and Collection								
66	E	- SONP/RNP	CUSTAVG_06	21	5,530	67,629	2,235	186	46	6
67	E	- Meter O&M	METERPLT	0	0	0	0	0	0	0
68	E	- Meter Reading	MRCOST_07	0	0	102,832	5,998	500	123	17
69	E	- Billing	BILLING_06	4	1,173	14,345	5,545	462	113	15
70	E	- Acct Maint related	ACCTMAINT_06	33	8,785	967,013	227,454	18,946	4,655	626
71	E	- Utility work related	UTILWORK_04	99	14,413	238,105	17,580	1,588	445	38
72	E	- Remaining	BILLING_06	3,660	960,714	11,749,958	4,542,099	378,333	92,955	12,508
73	E	Not used	not_used	0	0	0	0	0	0	0
74	E	E904 Uncollectible Accounts	not_used	0	0	0	0	0	0	0
75	E	E905 Misc Customer Accounts	CUSTACCTS	0	0	0	0	0	0	0
76	E	TOTAL CUSTOMER ACCTS EXPENSE		3,818	990,615	16,627,629	5,004,352	416,960	102,501	13,770
77	E									
78	E									
79	E	CUSTOMER SERVICE & INFO EXPENSES								
80	E	E907 & 908 - Cust Svs & Info								
81	E	- SONP/RNP	CUSTAVG_06	0	0	0	0	0	0	0
82	E	- Acct Maint related	ACCTMAINT_06	10	2,673	294,253	69,212	5,765	1,416	191
83	E	- Utility work related	UTILWORK_04	79	11,488	189,785	14,013	1,266	355	30
84	E	- Sales	SALES_06	0	0	0	0	0	0	0
85	E	- Billing	BILLING_06	2	598	7,314	2,827	236	58	8
86	E	- Remaining	ACCTMAINT_06	0	0	0	0	0	0	0
87	E	E909 Info & Instr Advertising	CUSTNUMX_04	0	0	0	0	0	0	0
88	E	E910 - Misc Cust Svs & Info								
89	E	- Utility work related	UTILWORK_04	108	15,771	260,539	19,237	1,737	487	41
90	E	- Acct Maint related	ACCTMAINT_06	3	782	86,103	20,253	1,687	414	56
91	E	- Not used	not_used	0	0	0	0	0	0	0
92	E	- Not used	not_used	0	0	0	0	0	0	0
93	E	- Not used	not_used	0	0	0	0	0	0	0
94	E	- Not used	not_used	0	0	0	0	0	0	0
95	E	- Remaining	BILLING_06	12	3,186	38,970	15,064	1,255	308	41
96	E	TOTAL CUSTOMER SERVICE & INFO EXPENSES		214	34,498	876,964	140,606	11,945	3,040	367
97	E									
98	E									
99	E									
100	E	**OPERATION & MAINTENANCE EXPENSE CONTINUED**								

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
101	E										
102	E	SALES EXPENSES									
103	E	E911-E916 Sales Expenses									
104	E	- Sales	SALES_06	0	0	0	0	0	0	0	0
105	E	- Billing related	BILLING_06	0	0	0	0	0	0	0	0
106	E	- Acct Maint related	ACCTMAINT_06	0	0	0	0	0	0	0	0
107	E	- Utility work related	UTILWORK_04	40,922	29,919	96	204	2	0	14	205
108	E	- Remaining	BILLING_06	0	0	0	0	0	0	0	0
109	E	- Clause	not_used	0	0	0	0	0	0	0	0
110	E	SALES EXPENSES TOTAL (ACCT 916)		40,922	29,919	96	204	2	0	14	205
111	E										
112	E	TOTAL OPER & MAINT EXCL A&G		277,762,244	157,700,154	630,475	1,226,265	14,450	224	140,340	9,336,344
113	E										
114	E	ADMINISTRATIVE & GENERAL EXPENSE									
115	E	E920 A&G Salaries	LABOR	5,694,688	3,554,385	13,737	24,932	522	8	2,409	218,583
116	E	E921 Office Supplies & Exp	LABOR	622,444	388,503	1,502	2,725	57	1	263	23,892
117	E	E923 Outside Services Employed	DISTPLT	68,020,983	36,745,352	186,820	324,786	1,656	26	53,230	2,388,552
118	E	E924 Property Insurance	TOTPLT	1,802,573	980,323	4,946	8,594	44	1	1,388	62,252
119	E	E925 Injuries & Damages	LABOR	14,161,029	8,838,718	34,161	61,998	1,299	20	5,991	543,551
120	E	E926 Employee Pension & Benefits	LABOR	-77,966,713	-48,663,540	-188,078	-341,341	-7,151	-111	-32,984	-2,992,642
121	E	E928 Regulatory Comm Exp	REVREQ	15,042,373	8,482,142	39,742	70,379	1,006	16	10,361	509,925
122	E	E929 Duplicate Charges - credit	REVLPLS	-3,363,888	0	0	0	0	0	0	0
123	E	E930.1 General Advertising Expenses	CUSTAVG_04	2,277,517	1,940,410	6,741	11,263	642	10	766	4,789
124	E	E930.2 Misc General Expenses	DISTPLT	2,932,568	1,584,191	8,054	14,002	71	1	2,295	102,977
125	E	E931 Rents	DISTPLT	4,471,819	2,415,704	12,282	21,352	109	2	3,499	157,028
126	E	E932 Maint of General Plant	COMGENPLT	0	0	0	0	0	0	0	0
127	E	E935 Other A&G Maint	COMGENPLT	0	0	0	0	0	0	0	0
128	E	Not Used	not_used	0	0	0	0	0	0	0	0
129	E	TOTAL A&G EXPENSE		33,695,393	16,266,189	119,905	198,689	-1,744	-27	47,218	1,018,906
130	E										
131	E	**TOTAL OPERATION & MAINTENANCE EXPENSES**		311,457,637	173,966,343	750,380	1,424,953	12,706	197	187,558	10,355,250

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
101	E									
102	E	SALES EXPENSES								
103	E	E911-E916 Sales Expenses								
104	E	- Sales	SALES_06	0	0	0	0	0	0	0
105	E	- Billing related	BILLING_06	0	0	0	0	0	0	0
106	E	- Acct Maint related	ACCTMAINT_06	0	0	0	0	0	0	0
107	E	- Utility work related	UTILWORK_04	4	555	9,167	677	61	17	1
108	E	- Remaining	BILLING_06	0	0	0	0	0	0	0
109	E	- Clause	not_used	0	0	0	0	0	0	0
110	E	SALES EXPENSES TOTAL (ACCT 916)		4	555	9,167	677	61	17	1
111	E									
112	E	TOTAL OPER & MAINT EXCL A&G		357,761	5,139,779	50,411,138	39,230,340	7,730,620	5,809,175	35,179
113	E									
114	E	ADMINISTRATIVE & GENERAL EXPENSE								
115	E	E920 A&G Salaries	LABOR	336	91,620	955,313	633,715	113,585	84,783	760
116	E	E921 Office Supplies & Exp	LABOR	37	10,014	104,418	69,267	12,415	9,267	83
117	E	E923 Outside Services Employed	DISTPLT	4,915	734,922	13,359,067	9,942,537	2,207,861	2,065,268	5,992
118	E	E924 Property Insurance	TOTPLT	129	19,483	353,346	260,531	57,600	53,781	154
119	E	E925 Injuries & Damages	LABOR	835	227,832	2,375,586	1,575,865	282,453	210,831	1,890
120	E	E926 Employee Pension & Benefits	LABOR	-4,595	-1,254,378	-13,079,319	-8,676,278	-1,555,108	-1,160,779	-10,407
121	E	E928 Regulatory Comm Exp	REVREQ	4,012	180,532	2,872,752	2,024,771	443,348	401,877	1,510
122	E	E929 Duplicate Charges - credit	REVLPLS	0	0	0	-3,363,888	0	0	0
123	E	E930.1 General Advertising Expenses	CUSTAVG_04	87	22,870	279,709	9,245	770	189	25
124	E	E930.2 Misc General Expenses	DISTPLT	212	31,684	575,945	428,650	95,187	89,039	258
125	E	E931 Rents	DISTPLT	323	48,315	878,249	653,640	145,149	135,774	394
126	E	E932 Maint of General Plant	COMGENPLT	0	0	0	0	0	0	0
127	E	E935 Other A&G Maint	COMGENPLT	0	0	0	0	0	0	0
128	E	Not Used	not_used	0	0	0	0	0	0	0
129	E	TOTAL A&G EXPENSE		6,290	112,894	8,675,067	3,558,055	1,803,260	1,890,032	660
130	E									
131	E	**TOTAL OPERATION & MAINTENANCE EXPENSES**		364,051	5,252,672	59,086,204	42,788,394	9,533,880	7,699,207	35,840

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	DE	**DEPRECIATION AND AMORTIZATION EXPENSES**									
2	DE										
3	DE	E403 DEPRECIATION EXPENSE									
4	DE	Production Plant	not_used	0	0	0	0	0	0	0	0
5	DE	Transmission Plant	not_used	0	0	0	0	0	0	0	0
6	DE	Distribution Plant	DISTPLT	257,769,144	139,248,473	707,963	1,230,792	6,275	98	201,718	9,051,545
7	DE	General Plant	GENPLT	19,786,964	10,525,555	54,517	94,895	41	1	15,831	719,212
8	DE	Common Plant	COMPLT	9,215,747	6,359,537	24,284	41,271	503	8	2,617	104,443
9	DE	Other Plant & Misc	DISTPLT	0	0	0	0	0	0	0	0
10	DE	TOTAL DEPRECIATION EXPENSE		286,771,855	156,133,565	786,764	1,366,959	6,818	106	220,165	9,875,199
11	DE										
12	DE	E404.3 AMORT OF OTHER LIMITED TERM PLANT									
13	DE	not used	not_used	0	0	0	0	0	0	0	0
14	DE	Distribution Delivery Related	DISTPLTXMTR	6,072,872	3,230,427	16,732	29,125	13	0	4,859	220,735
15	DE	Meter Reading	MRCOST_07	492,670	387,839	1,347	2,251	26	0	31	0
16	DE	Customer Service related	CUSTSVSX	14,826,022	11,085,171	38,418	64,681	1,092	17	1,423	32,907
17	DE	not used	not_used	0	0	0	0	0	0	0	0
18	DE	not used	not_used	0	0	0	0	0	0	0	0
19	DE	TOTAL AMORT OF OTHER LIMITED TERM PLT		21,391,564	14,703,437	56,497	96,056	1,130	17	6,312	253,642
20	DE										
21	DE	E407 AMORT OF PROPERTY LOSSES									
22	DE	Regulatory assets	KWHMETER_04	0	0	0	0	0	0	0	0
23	DE	Securitization amortization	not_used	0	0	0	0	0	0	0	0
24	DE	not used	not_used	0	0	0	0	0	0	0	0
25	DE	TOTAL AMORT OF PROPERTY LOSSES		0	0	0	0	0	0	0	0
26	DE										
27	DE	TOTAL AMORTIZATION EXPENSE		21,391,564	14,703,437	56,497	96,056	1,130	17	6,312	253,642
28	DE										
29	DE	**TOTAL DEPRECIATION AND AMORTIZATION EXPENSES**		308,163,419	170,837,002	843,261	1,463,015	7,948	124	226,477	10,128,842

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
1	DE	**DEPRECIATION AND AMORTIZATION EXPENSES**								
2	DE									
3	DE	E403 DEPRECIATION EXPENSE								
4	DE	Production Plant	not_used	0	0	0	0	0	0	0
5	DE	Transmission Plant	not_used	0	0	0	0	0	0	0
6	DE	Distribution Plant	DISTPLT	18,625	2,785,025	50,624,898	37,677,775	8,366,806	7,826,444	22,707
7	DE	General Plant	GENPLT	1,480	221,291	3,897,833	2,979,325	659,334	617,626	23
8	DE	Common Plant	COMPLT	457	96,967	1,670,597	719,080	111,058	83,965	961
9	DE	Other Plant & Misc	DISTPLT	0	0	0	0	0	0	0
10	DE	TOTAL DEPRECIATION EXPENSE		20,562	3,103,283	56,193,328	41,376,181	9,137,198	8,528,035	23,691
11	DE									
12	DE	E404.3 AMORT OF OTHER LIMITED TERM PLANT								
13	DE	not used	not_used	0	0	0	0	0	0	0
14	DE	Distribution Delivery Related	DISTPLTXMTR	454	67,917	1,196,295	914,393	202,358	189,557	7
15	DE	Meter Reading	MRCOST_07	0	0	95,041	5,544	462	113	15
16	DE	Customer Service related	CUSTSVSX	600	152,422	2,602,729	764,995	63,773	15,693	2,102
17	DE	not used	not_used	0	0	0	0	0	0	0
18	DE	not used	not_used	0	0	0	0	0	0	0
19	DE	TOTAL AMORT OF OTHER LIMITED TERM PLT		1,054	220,339	3,894,065	1,684,932	266,593	205,364	2,124
20	DE									
21	DE	E407 AMORT OF PROPERTY LOSSES								
22	DE	Regulatory assets	KWHMETER_04	0	0	0	0	0	0	0
23	DE	Securitization amortization	not_used	0	0	0	0	0	0	0
24	DE	not used	not_used	0	0	0	0	0	0	0
25	DE	TOTAL AMORT OF PROPERTY LOSSES		0	0	0	0	0	0	0
26	DE									
27	DE	TOTAL AMORTIZATION EXPENSE		1,054	220,339	3,894,065	1,684,932	266,593	205,364	2,124
28	DE									
29	DE	**TOTAL DEPRECIATION AND AMORTIZATION EXPENSES**		21,616	3,323,622	60,087,393	43,061,113	9,403,791	8,733,399	25,816

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	EO	**OTHER OPERATING EXPENSES**									
2	EO	**E408 TAXES OTHER THAN INCOME TAXES**									
3	EO	TEFA	TEFA_04	0	0	0	0	0	0	0	0
4	EO	Real Estate Taxes	TOTPLT	0	0	0	0	0	0	0	0
5	EO	Miscellaneous State and Municipal Tax	TOTPLT	-275,485	-149,822	-756	-1,313	-7	0	-212	-9,514
6	EO	State Unemploy Insur (SUI) Tax	LABOR	0	0	0	0	0	0	0	0
7	EO	FICA & UnempTax	LABOR	-11,275,732	-7,037,837	-27,200	-49,366	-1,034	-16	-4,770	-432,803
8	EO	Other Taxes	TOTPLT	0	0	0	0	0	0	0	0
9	EO	not used	not_used	0	0	0	0	0	0	0	0
10	EO	**TOTAL TAXES OTHER THAN INCOME**		-11,551,217	-7,187,659	-27,956	-50,679	-1,041	-16	-4,982	-442,317
11	EO	**PROFORMA EXPENSE ADJUSTMENTS**									
12	EO	Amortization of CEF-EC Program Regulatory Assets	ECPRO_07	20,893,898	16,832,173	54,231	90,604	14,303	223	6,159	0
13	EO	Amortization of CEF-EV Program Regulatory Assets	TOTPLTNET	3,943,445	2,123,505	10,710	18,743	81	1	3,049	140,717
14	EO	BGS Administrative Expense Adjustment	A_GEXP	671,374	390,393	1,852	3,247	33	1	482	24,120
15	EO	CIP Revenue Accrual Adjustment	not_used	0	0	0	0	0	0	0	0
16	EO	Deferred Compensation & Severance Expense	LABOR	-785,085	-490,017	-1,894	-3,437	-72	-1	-332	-30,134
17	EO	Gas Bad Debt Adjustment		0	0	0	0	0	0	0	0
18	EO	TAC Revenue Accrual Adjustment	not_used	0	0	0	0	0	0	0	0
19	EO	Tax Bad Debt Adjustment	not_used	0	0	0	0	0	0	0	0
20	EO	TSG-NF Gas Margin Reset		0	0	0	0	0	0	0	0
21	EO	Wage Increases (Rate Year)	LABOR	7,691,360	4,800,623	18,554	33,673	705	11	3,254	295,222
22	EO	Payroll Taxes (Rate Year)	LABOR	541,904	338,234	1,307	2,372	50	1	229	20,800
23	EO	Interest Syncronization	TOTPLTNET	-459,649	-247,516	-1,248	-2,185	-9	0	-355	-16,402
24	EO	- add'l tax effects on rev req	TOTPLTNET	-179,729	-96,782	-488	-854	-4	0	-139	-6,413
25	EO	Pension & Fringe Benefit (Rate Year)	LABOR	11,745,951	7,331,328	28,335	51,424	1,077	17	4,969	450,852
26	EO	COLI Interest Expense Recovery	LABOR	2,434,135	1,519,285	5,872	10,657	223	3	1,030	93,431
27	EO	- add'l tax effects on rev req	LABOR	951,781	594,062	2,296	4,167	87	1	403	36,533
28	EO	ASB Margin	TOTPLT	0	0	0	0	0	0	0	0
29	EO	BPU / Rate Counsel Assessment	KWHMETER_04	377,877	126,702	865	1,806	5	0	110	2,623
30	EO	Adj #6 - Weather Normalization	not_used	0	0	0	0	0	0	0	0
31	EO	Gains / Losses Normalization	TOTPLT	-44,137	-24,004	-121	-210	-1	0	-34	-1,524
32	EO	- add'l tax effects on rev req	TOTPLT	-17,258	-9,386	-47	-82	0	0	-13	-596
33	EO	Other Regulatory Asset / Liability Amortizations	TOTPLT	0	0	0	0	0	0	0	0
34	EO	Adj #15 - Excess COR Refund Recovery	TOTPLT	0	0	0	0	0	0	0	0
35	EO	Real Estate Tax Increases (Rate Year)	TOTPLT	700,231	380,818	1,921	3,339	17	0	539	24,183
36	EO	Test Year Amortization Adjustments	TOTPLT	-17,276,070	-9,395,531	-47,404	-82,368	-421	-7	-13,305	-596,630
37	EO	Insurance Premium Increases (Rate Year)	TOTPLT	481,185	261,691	1,320	2,294	12	0	371	16,618
38	EO	Rate Case Expenses	TOTPLT	166,097	90,331	456	792	4	0	128	5,736
39	EO	Depreciation Rate Change	DEPREXP	50,211,393	27,337,703	137,756	239,343	1,194	19	38,549	1,729,066
40	EO	Adj #14 Post Rate Case Storm Cost Normalization	TOTPLT	0	0	0	0	0	0	0	0
41	EO	Adj #13 - Storm Cost Amortization	TOTPLTNET	0	0	0	0	0	0	0	0
42	EO	Adj #20 - Vacation Accrual	LABOR	0	0	0	0	0	0	0	0
43	EO	Energy Strong II / IAP Revenue Adjustment	TOTPLT	0	0	0	0	0	0	0	0
44	EO	Recovery of Credit Card Fees	CUSTSVSX	0	0	0	0	0	0	0	0
45	EO	Test Year Corrections	TOTPLT								
46	EO	TOTAL PROFORMA EXPENSE ADJUSTMENTS		82,048,703	51,852,648	214,230	373,247	24,420	380	45,086	2,187,525
47	EO										
48	EO	**TOTAL OTHER OPERATING EXPENSES**		70,497,486	44,664,989	186,274	322,568	23,379	364	40,104	1,745,208
49	EO	TOTAL OPERATING REVENUES		1,925,019,676	1,083,403,222	5,076,085	8,989,364	128,489	2,001	1,329,844	65,131,457
50	EO	LESS:									

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
1	EO	**OTHER OPERATING EXPENSES**								
2	EO	**E408 TAXES OTHER THAN INCOME TAXES**								
3	EO	TEFA	TEFA_04	0	0	0	0	0	0	0
4	EO	Real Estate Taxes	TOTPLT	0	0	0	0	0	0	0
5	EO	Miscellaneous State and Municipal Tax	TOTPLT	-20	-2,978	-54,001	-39,817	-8,803	-8,219	-24
6	EO	State Unemploy Insur (SUI) Tax	LABOR	0	0	0	0	0	0	0
7	EO	FICA & UnempTax	LABOR	-665	-181,411	-1,891,562	-1,254,784	-224,903	-167,875	-1,505
8	EO	Other Taxes	TOTPLT	0	0	0	0	0	0	0
9	EO	not used	not_used	0	0	0	0	0	0	0
10	EO	**TOTAL TAXES OTHER THAN INCOME**		-684	-184,389	-1,945,564	-1,294,601	-233,706	-176,094	-1,529
11	EO	**PROFORMA EXPENSE ADJUSTMENTS**								
12	EO	Amortization of CEF-EC Program Regulatory Assets	ECPRO_07	0	0	3,896,204	0	0	0	0
13	EO	Amortization of CEF-EV Program Regulatory Assets	TOTPLTNET	282	43,784	768,942	582,828	128,982	121,533	288
14	EO	BGS Administrative Expense Adjustment	A_GEXP	65	8,221	130,799	73,560	20,192	18,343	67
15	EO	CIP Revenue Accrual Adjustment	not_used	0	0	0	0	0	0	0
16	EO	Deferred Compensation & Severance Expense	LABOR	-46	-12,631	-131,702	-87,366	-15,659	-11,688	-105
17	EO	Gas Bad Debt Adjustment		0	0	0	0	0	0	0
18	EO	TAC Revenue Accrual Adjustment	not_used	0	0	0	0	0	0	0
19	EO	Tax Bad Debt Adjustment	not_used	0	0	0	0	0	0	0
20	EO	TSG-NF Gas Margin Reset		0	0	0	0	0	0	0
21	EO	Wage Increases (Rate Year)	LABOR	453	123,744	1,290,265	855,909	153,410	114,510	1,027
22	EO	Payroll Taxes (Rate Year)	LABOR	32	8,718	90,907	60,304	10,809	8,068	72
23	EO	Interest Syncronization	TOTPLTNET	-33	-5,103	-89,628	-67,935	-15,034	-14,166	-34
24	EO	- add'l tax effects on rev req	TOTPLTNET	-13	-1,996	-35,046	-26,563	-5,879	-5,539	-13
25	EO	Pension & Fringe Benefit (Rate Year)	LABOR	692	188,976	1,970,444	1,307,111	234,282	174,875	1,568
26	EO	COLI Interest Expense Recovery	LABOR	143	39,162	408,339	270,875	48,551	36,240	325
27	EO	- add'l tax effects on rev req	LABOR	56	15,313	159,666	105,916	18,984	14,170	127
28	EO	ASB Margin	TOTPLT	0	0	0	0	0	0	0
29	EO	BPU / Rate Counsel Assessment	KWHMETER_04	142	1,273	68,069	98,038	28,788	43,231	6,226
30	EO	Adj #6 - Weather Normalization	not_used	0	0	0	0	0	0	0
31	EO	Gains / Losses Normalization	TOTPLT	-3	-477	-8,652	-6,379	-1,410	-1,317	-4
32	EO	- add'l tax effects on rev req	TOTPLT	-1	-187	-3,383	-2,494	-551	-515	-1
33	EO	Other Regulatory Asset / Liability Amortizations	TOTPLT	0	0	0	0	0	0	0
34	EO	Adj #15 - Excess COR Refund Recovery	TOTPLT	0	0	0	0	0	0	0
35	EO	Real Estate Tax Increases (Rate Year)	TOTPLT	50	7,569	137,261	101,206	22,375	20,892	60
36	EO	Test Year Amortization Adjustments	TOTPLT	-1,239	-186,730	-3,386,511	-2,496,957	-552,044	-515,445	-1,479
37	EO	Insurance Premium Increases (Rate Year)	TOTPLT	35	5,201	94,323	69,547	15,376	14,357	41
38	EO	Rate Case Expenses	TOTPLT	12	1,795	32,559	24,006	5,308	4,956	14
39	EO	Depreciation Rate Change	DEPREXP	3,600	543,359	9,838,990	7,244,629	1,599,848	1,493,189	4,148
40	EO	Adj #14 Post Rate Case Storm Cost Normalization	TOTPLT	0	0	0	0	0	0	0
41	EO	Adj #13 - Storm Cost Amortization	TOTPLTNET	0	0	0	0	0	0	0
42	EO	Adj #20 - Vacation Accrual	LABOR	0	0	0	0	0	0	0
43	EO	Energy Strong II / IAP Revenue Adjustment	TOTPLT	0	0	0	0	0	0	0
44	EO	Recovery of Credit Card Fees	CUSTSVSX	0	0	0	0	0	0	0
45	EO	Test Year Corrections	TOTPLT							
46	EO	TOTAL PROFORMA EXPENSE ADJUSTMENTS		4,227	779,709	15,228,901	8,104,278	1,695,978	1,515,431	22,643
47	EO									
48	EO	**TOTAL OTHER OPERATING EXPENSES**		3,542	595,320	13,283,337	6,809,678	1,462,271	1,339,337	21,114
49	EO	TOTAL OPERATING REVENUES		512,439	23,171,254	368,717,729	259,879,321	56,903,755	51,580,928	193,788
50	EO	LESS:								

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
51	EO	OPERATION & MAINTAINENCE EXPENSE		311,457,637	173,966,343	750,380	1,424,953	12,706	197	187,558	10,355,250
52	EO	DEPRECIATION & AMORTIZATION EXPENSE		308,163,419	170,837,002	843,261	1,463,015	7,948	124	226,477	10,128,842
53	EO	OTHER OPERATING EXPENSES		70,497,486	44,664,989	186,274	322,568	23,379	364	40,104	1,745,208
54	EO	NET OPERATING INCOME BEFORE TAXES		1,234,901,135	693,934,889	3,296,170	5,778,827	84,455	1,316	875,705	42,902,157
55	EO	LESS:									
56	EO	E427 - E432 INTEREST CHARGES	TOTPLTNET	(137,585,275)	(74,088,268)	(373,677)	(653,919)	(2,825)	(44)	(106,367)	(4,909,562)
57	EO	**TOTAL OPERATING INCOME BEFORE TAXES**		1,372,486,410	768,023,157	3,669,846	6,432,745	87,280	1,360	982,072	47,811,720
58	EO	Adjustment Reclassification Minus	ADJEXP_04	-17,563	-10,963	-42	-77	0	0	-7	-674
59	EO	Adjustment Reclassification Plus	ADJ_Plus_04	17,563	0	0	0	7,136	111	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
51	EO	OPERATION & MAINTAINENCE EXPENSE		364,051	5,252,672	59,086,204	42,788,394	9,533,880	7,699,207	35,840
52	EO	DEPRECIATION & AMORTIZATION EXPENSE		21,616	3,323,622	60,087,393	43,061,113	9,403,791	8,733,399	25,816
53	EO	OTHER OPERATING EXPENSES		3,542	595,320	13,283,337	6,809,678	1,462,271	1,339,337	21,114
54	EO	NET OPERATING INCOME BEFORE TAXES		123,229	13,999,640	236,260,795	167,220,136	36,503,813	33,808,985	111,019
55	EO	LESS:								
56	EO	E427 - E432 INTEREST CHARGES	TOTPLTNET	(9,849)	(1,527,605)	(26,828,102)	(20,334,644)	(4,500,129)	(4,240,237)	(10,047)
57	EO	**TOTAL OPERATING INCOME BEFORE TAXES**		133,078	15,527,245	263,088,897	187,554,780	41,003,942	38,049,222	121,065
58	EO	Adjustment Reclassification Minus	ADJEXP_04	-1	-283	-2,947	-1,955	-350	-262	0
59	EO	Adjustment Reclassification Plus	ADJ_Plus_04	0	0	0	0	0	0	10,316

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	TI	**[TI] DEVELOPMENT OF INCOME TAXES**									
2	TI										
3	TI	**[TI] TAX ADJUSTMENTS - FEDERAL**									
4	TI	[TI][Fed Tax Adj.] Additional Expenses on Rental Property	TOTPLT	-108,083	-58,781	-297	-515	-3	0	-83	-3,733
5	TI	[TI][Fed Tax Adj.] Additional Rental Income - NJ Properties	TOTPLT	16,349	8,891	45	78	0	0	13	565
6	TI	[TI][Fed Tax Adj.] Amort of Def Gain on Sale of Services Asse	not_used	0	0	0	0	0	0	0	0
7	TI	[TI][Fed Tax Adj.] Amort of Deferred Gain on Sale of Generati	not_used	0	0	0	0	0	0	0	0
8	TI	[TI][Fed Tax Adj.] Amortization of Reacquisition of Pref Stock	TOTPLT	11,771	6,402	32	56	0	0	9	407
9	TI	[TI][Fed Tax Adj.] CECL Reserve	not_used	0	0	0	0	0	0	0	0
10	TI	[TI][Fed Tax Adj.] CEF- EC AMI	TOTPLT	-20,866,765	-11,348,318	-57,256	-99,488	-509	-8	-16,070	-720,635
11	TI	[TI][Fed Tax Adj.] CEF- EV Deferral	TOTPLT	-1,855,840	-1,009,292	-5,092	-8,848	-45	-1	-1,429	-64,092
12	TI	[TI][Fed Tax Adj.] Clause - Demographic Studies	not_used	0	0	0	0	0	0	0	0
13	TI	[TI][Fed Tax Adj.] Clause - Navigant Studies	not_used	0	0	0	0	0	0	0	0
14	TI	[TI][Fed Tax Adj.] Clause - RAC (Environmental Clean Up)	not_used	0	0	0	0	0	0	0	0
15	TI	[TI][Fed Tax Adj.] Clause - Societal Benefits Clause (AAP)	not_used	0	0	0	0	0	0	0	0
16	TI	[TI][Fed Tax Adj.] Company Owned Life Insurance - Book	LABOR	-1,117,127	-697,264	-2,695	-4,891	-102	-2	-473	-42,879
17	TI	[TI][Fed Tax Adj.] Company Owned Life Insurance - Tax	LABOR	-58,279	-36,375	-141	-255	-5	0	-25	-2,237
18	TI	[TI][Fed Tax Adj.] COVID Deferrals	not_used	0	0	0	0	0	0	0	0
19	TI	[TI][Fed Tax Adj.] Current SHARE -- FT	DEPREXP	-11,513,122	-6,268,345	-31,586	-54,880	-274	-4	-8,839	-396,463
20	TI	[TI][Fed Tax Adj.] Customer Advances	TOTPLTNET	4,645,423	2,501,513	12,617	22,079	95	1	3,591	165,766
21	TI	[TI][Fed Tax Adj.] Customer Connection Fees (Contributions ir	TOTPLTNET	6,684,538	3,599,556	18,155	31,770	137	2	5,168	238,530
22	TI	[TI][Fed Tax Adj.] Deduction for Retention Payments (c)	LABOR	-5,352	-3,340	-13	-23	0	0	-2	-205
23	TI	[TI][Fed Tax Adj.] Deferred Employer ER FICA	LABOR	-7,086,760	-4,423,257	-17,095	-31,026	-650	-10	-2,998	-272,015
24	TI	[TI][Fed Tax Adj.] Diesel Fuel Tax Credit	TOTPLT	82	44	0	0	0	0	0	3
25	TI	[TI][Fed Tax Adj.] Entertainment (100%)	LABOR	38,419	23,980	93	168	4	0	16	1,475
26	TI	[TI][Fed Tax Adj.] FAS 5 (ASC40) Reserve - Sales Tax	not_used	0	0	0	0	0	0	0	0
27	TI	[TI][Fed Tax Adj.] Fed Amort of Deferred Gain on Sale of Gen	not_used	0	0	0	0	0	0	0	0
28	TI	[TI][Fed Tax Adj.] Injuries & Damages - FT	TOTPLT	1,298,774	706,334	3,564	6,192	32	0	1,000	44,853
29	TI	[TI][Fed Tax Adj.] Line Pack Adjustment	not_used	0	0	0	0	0	0	0	0
30	TI	[TI][Fed Tax Adj.] Plant Related	DEPREXP	-33,454,683	-18,214,476	-91,784	-159,469	-795	-12	-25,684	-1,152,037
31	TI	[TI][Fed Tax Adj.] Previously Deducted Amort - Reacquired Bo	not_used	0	0	0	0	0	0	0	0
32	TI	[TI][Fed Tax Adj.] Qualified Transportation Fringe	LABOR	162,269	101,281	391	710	15	0	69	6,228
33	TI	[TI][Fed Tax Adj.] R & D Credits CF	not_used	0	0	0	0	0	0	0	0
34	TI	[TI][Fed Tax Adj.] R&D Expenditure	TOTPLT	-5,622	-3,058	-15	-27	0	0	-4	-194
35	TI	[TI][Fed Tax Adj.] Rabbi Trust	not_used	0	0	0	0	0	0	0	0
36	TI	[TI][Fed Tax Adj.] RE - Lease Liability	TOTPLT	-236,259	-128,489	-648	-1,126	-6	0	-182	-8,159
37	TI	[TI][Fed Tax Adj.] RE - ROU Lease Asset	TOTPLT	319,172	173,581	876	1,522	8	0	246	11,023
38	TI	[TI][Fed Tax Adj.] Reversal of Book Income from Partnerships	TOTPLT	42,165	22,931	116	201	1	0	32	1,456
39	TI	[TI][Fed Tax Adj.] Severance Pay (nc)	LABOR	154,681	96,545	373	677	14	0	65	5,937
40	TI	[TI][Fed Tax Adj.] State NOL CF (c)	DEPREXP	17,908,279	9,750,202	49,132	85,364	426	7	13,749	616,685
41	TI	[TI][Fed Tax Adj.] Tax Net Bad Debt Writeoffs - FT	TOTPLT	-460,907	-250,663	-1,265	-2,197	-11	0	-355	-15,917
42	TI	[TI][Fed Tax Adj.] Unicap book/tax inventory FS	not_used	0	0	0	0	0	0	0	0
43	TI	[TI][Fed Tax Adj.] Unrealized G/L on Equity Securities	TOTPLT	125,367	68,181	344	598	3	0	97	4,330
44	TI	[TI][Fed Tax Adj.] Stock-Based Compensation - Reverse Book	TOTPLTNET	-328,125	-176,692	-891	-1,560	-7	0	-254	-11,709
45	TI	[TI][Fed Tax Adj.] GainState LILOAudit Refunds not yet receiv	TOTPLTNET	0	0	0	0	0	0	0	0
46	TI	[TI][Fed Tax Adj.] Repair Allowance	TOTPLT	0	0	0	0	0	0	0	0
47	TI	[TI][Fed Tax Adj.] Uncollectible Accounts	REVREQ	0	0	0	0	0	0	0	0
48	TI	[TI][Fed Tax Adj.] Injuries and Damages ;	TOTPLT	0	0	0	0	0	0	0	0
49	TI	[TI][Fed Tax Adj.] Diesel Fuel Credit	not_used	0	0	0	0	0	0	0	0
50	TI	[TI][Fed Tax Adj.] Partnership Income/Loss (nc)	TOTPLT	-42,165	-22,931	-116	-201	-1	0	-32	-1,456

Updated for 9 and 3

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
1	TI	**[TI] DEVELOPMENT OF INCOME TAXES**								
2	TI									
3	TI	**[TI] TAX ADJUSTMENTS - FEDERAL**								
4	TI	[TI][Fed Tax Adj.] Additional Expenses on Rental Property	TOTPLT	-8	-1,168	-21,187	-15,622	-3,454	-3,225	-9
5	TI	[TI][Fed Tax Adj.] Additional Rental Income - NJ Properties	TOTPLT	1	177	3,205	2,363	522	488	1
6	TI	[TI][Fed Tax Adj.] Amort of Def Gain on Sale of Services Asse	not_used	0	0	0	0	0	0	0
7	TI	[TI][Fed Tax Adj.] Amort of Deferred Gain on Sale of Generati	not_used	0	0	0	0	0	0	0
8	TI	[TI][Fed Tax Adj.] Amortization of Reacquisition of Pref Stock	TOTPLT	1	127	2,307	1,701	376	351	1
9	TI	[TI][Fed Tax Adj.] CECL Reserve	not_used	0	0	0	0	0	0	0
10	TI	[TI][Fed Tax Adj.] CEF- EC AMI	TOTPLT	-1,497	-225,540	-4,090,370	-3,015,930	-666,782	-622,576	-1,786
11	TI	[TI][Fed Tax Adj.] CEF- EV Deferral	TOTPLT	-133	-20,059	-363,788	-268,230	-59,302	-55,370	-159
12	TI	[TI][Fed Tax Adj.] Clause - Demographic Studies	not_used	0	0	0	0	0	0	0
13	TI	[TI][Fed Tax Adj.] Clause - Navigant Studies	not_used	0	0	0	0	0	0	0
14	TI	[TI][Fed Tax Adj.] Clause - RAC (Environmental Clean Up)	not_used	0	0	0	0	0	0	0
15	TI	[TI][Fed Tax Adj.] Clause - Societal Benefits Clause (AAP)	not_used	0	0	0	0	0	0	0
16	TI	[TI][Fed Tax Adj.] Company Owned Life Insurance - Book	LABOR	-66	-17,973	-187,404	-124,316	-22,282	-16,632	-149
17	TI	[TI][Fed Tax Adj.] Company Owned Life Insurance - Tax	LABOR	-3	-938	-9,777	-6,485	-1,162	-868	-8
18	TI	[TI][Fed Tax Adj.] COVID Deferrals	not_used	0	0	0	0	0	0	0
19	TI	[TI][Fed Tax Adj.] Current SHARE -- FT	DEPREXP	-826	-124,588	-2,256,012	-1,661,143	-366,834	-342,378	-951
20	TI	[TI][Fed Tax Adj.] Customer Advances	TOTPLTNET	333	51,578	905,823	686,578	151,942	143,167	339
21	TI	[TI][Fed Tax Adj.] Customer Connection Fees (Contributions i	TOTPLTNET	479	74,218	1,303,435	987,952	218,637	206,011	488
22	TI	[TI][Fed Tax Adj.] Deduction for Retention Payments (c)	LABOR	0	-86	-898	-596	-107	-80	-1
23	TI	[TI][Fed Tax Adj.] Deferred Employer ER FICA	LABOR	-418	-114,016	-1,188,841	-788,628	-141,351	-105,509	-946
24	TI	[TI][Fed Tax Adj.] Diesel Fuel Tax Credit	TOTPLT	0	1	16	12	3	2	0
25	TI	[TI][Fed Tax Adj.] Entertainment (100%)	LABOR	2	618	6,445	4,275	766	572	5
26	TI	[TI][Fed Tax Adj.] FAS 5 (ASC40) Reserve - Sales Tax	not_used	0	0	0	0	0	0	0
27	TI	[TI][Fed Tax Adj.] Fed Amort of Deferred Gain on Sale of Gen	not_used	0	0	0	0	0	0	0
28	TI	[TI][Fed Tax Adj.] Injuries & Damages - FT	TOTPLT	93	14,038	254,590	187,715	41,501	38,750	111
29	TI	[TI][Fed Tax Adj.] Line Pack Adjustment	not_used	0	0	0	0	0	0	0
30	TI	[TI][Fed Tax Adj.] Plant Related	DEPREXP	-2,399	-362,028	-6,555,490	-4,826,928	-1,065,942	-994,877	-2,764
31	TI	[TI][Fed Tax Adj.] Previously Deducted Amort - Reacquired Bo	not_used	0	0	0	0	0	0	0
32	TI	[TI][Fed Tax Adj.] Qualified Transportation Fringe	LABOR	10	2,611	27,221	18,058	3,237	2,416	22
33	TI	[TI][Fed Tax Adj.] R & D Credits CF	not_used	0	0	0	0	0	0	0
34	TI	[TI][Fed Tax Adj.] R&D Expenditure	TOTPLT	0	-61	-1,102	-813	-180	-168	0
35	TI	[TI][Fed Tax Adj.] Rabbi Trust	not_used	0	0	0	0	0	0	0
36	TI	[TI][Fed Tax Adj.] RE - Lease Liability	TOTPLT	-17	-2,554	-46,312	-34,147	-7,549	-7,049	-20
37	TI	[TI][Fed Tax Adj.] RE - ROU Lease Asset	TOTPLT	23	3,450	62,565	46,131	10,199	9,523	27
38	TI	[TI][Fed Tax Adj.] Reversal of Book Income from Partnerships	TOTPLT	3	456	8,265	6,094	1,347	1,258	4
39	TI	[TI][Fed Tax Adj.] Severance Pay (nc)	LABOR	9	2,489	25,949	17,213	3,085	2,303	21
40	TI	[TI][Fed Tax Adj.] State NOL CF (c)	DEPREXP	1,284	193,793	3,509,151	2,583,853	570,598	532,557	1,479
41	TI	[TI][Fed Tax Adj.] Tax Net Bad Debt Writeoffs - FT	TOTPLT	-33	-4,982	-90,348	-66,616	-14,728	-13,752	-39
42	TI	[TI][Fed Tax Adj.] Unicap book/tax inventory FS	not_used	0	0	0	0	0	0	0
43	TI	[TI][Fed Tax Adj.] Unrealized G/L on Equity Securities	TOTPLT	9	1,355	24,575	18,120	4,006	3,740	11
44	TI	[TI][Fed Tax Adj.] Stock-Based Compensation - Reverse Book	TOTPLTNET	-23	-3,643	-63,982	-48,496	-10,732	-10,112	-24
45	TI	[TI][Fed Tax Adj.] GainState LILOAudit Refunds not yet receiv	TOTPLTNET	0	0	0	0	0	0	0
46	TI	[TI][Fed Tax Adj.] Repair Allowance	TOTPLT	0	0	0	0	0	0	0
47	TI	[TI][Fed Tax Adj.] Uncollectible Accounts	REVREQ	0	0	0	0	0	0	0
48	TI	[TI][Fed Tax Adj.] Injuries and Damages ;	TOTPLT	0	0	0	0	0	0	0
49	TI	[TI][Fed Tax Adj.] Diesel Fuel Credit	not_used	0	0	0	0	0	0	0
50	TI	[TI][Fed Tax Adj.] Partnership Income/Loss (nc)	TOTPLT	-3	-456	-8,265	-6,094	-1,347	-1,258	-4

PUBLIC SERVICE ELECTRIC & GAS COMPANY
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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
51	TI	[TI][Fed Tax Adj.] Meals and Entertainment (50%)	LABOR	-417,376	-260,509	-1,007	-1,827	-38	-1	-177	-16,020
52	TI	[TI][Fed Tax Adj.] Company owned life insurance	LABOR	0	0	0	0	0	0	0	0
53	TI	[TI][Fed Tax Adj.] ESOP/401(k) Cash Dividends	TOTPLTNET	-1,032,350	-555,910	-2,804	-4,907	-21	0	-798	-36,838
54	TI	[TI][Fed Tax Adj.] Medicare Subsidy	LABOR	0	0	0	0	0	0	0	0
55	TI	[TI][Fed Tax Adj.] Dividends Received Deduction-2	TOTPLTNET	0	0	0	0	0	0	0	0
56	TI	[TI][Fed Tax Adj.] W-2 Earnings Exceeding $1.000.000	LABOR	1,841,683	1,149,501	4,443	8,063	169	3	779	70,690
57	TI	[TI][Fed Tax Adj.] Allowable Depreciation	DEPREXP	0	0	0	0	0	0	0	0
58	TI	[TI][Fed Tax Adj.] Book Depreciation	DEPREXP	0	0	0	0	0	0	0	0
59	TI	[TI][Fed Tax Adj.] Previously Ded Amort-Reacq Bonds	not_used	0	0	0	0	0	0	0	0
60	TI	[TI][Fed Tax Adj.] Amortization of Computer Software	INTANGPLT	0	0	0	0	0	0	0	0
61	TI	[TI][Fed Tax Adj.] Amort Def Gain - Sale of Gen Asset	not_used	0	0	0	0	0	0	0	0
62	TI	[TI][Fed Tax Adj.] Gain on Sale of Services Corp Asset	not_used	0	0	0	0	0	0	0	0
63	TI	[TI][Fed Tax Adj.] AFUDC / IDC - Debt	TOTPLT	-1,076,666	-585,541	-2,954	-5,133	-26	0	-829	-37,183
64	TI	[TI][Fed Tax Adj.] Capitalized Interest - Section 263A	TOTPLT	3,363,340	1,829,141	9,229	16,036	82	1	2,590	116,153
65	TI	[TI][Fed Tax Adj.] Cost of removal	TOTPLT	0	0	0	0	0	0	0	0
66	TI	[TI][Fed Tax Adj.] Utility Commodity Costs	not_used	0	0	0	0	0	0	0	0
67	TI	[TI][Fed Tax Adj.] RAC-Environmental Cleanup Costs	not_used	0	0	0	0	0	0	0	0
68	TI	[TI][Fed Tax Adj.] SBC-Societal Benefits Clause	not_used	0	0	0	0	0	0	0	0
69	TI	[TI][Fed Tax Adj.] Def Comp - Off/Dir/NOC (c)	LABOR	11,058	6,902	27	48	1	0	5	424
70	TI	[TI][Fed Tax Adj.] Deduction of Securitizartion	not_used	0	0	0	0	0	0	0	0
71	TI	[TI][Fed Tax Adj.] Additional Vacation Pay Adj (c)	LABOR	-344,695	-215,144	-832	-1,509	-32	0	-146	-13,231
72	TI	[TI][Fed Tax Adj.] Third Party Claims	TOTPLT	87,346	47,503	240	416	2	0	67	3,016
73	TI	[TI][Fed Tax Adj.] Deduction for New Network Meter Equipme	TOTPLT	0	0	0	0	0	0	0	0
74	TI	[TI][Fed Tax Adj.] Gain/loss bond reacq	not_used	0	0	0	0	0	0	0	0
75	TI	[TI][Fed Tax Adj.] Amortization of Call Option Sale	LABOR	0	0	0	0	0	0	0	0
76	TI	[TI][Fed Tax Adj.] Defer Dividend Equivalents/Restricted Stocl	LABOR	0	0	0	0	0	0	0	0
77	TI	[TI][Fed Tax Adj.] Repair Allow Deferral Carrying Charges	TOTPLT	0	0	0	0	0	0	0	0
78	TI	[TI][Fed Tax Adj.] CIAC Tax Gross Up	TOTPLTNET	905,779	487,753	2,460	4,305	19	0	700	32,322
79	TI	[TI][Fed Tax Adj.] FIN48 Services Allocation	TOTPLT	0	0	0	0	0	0	0	0
80	TI	[TI][Fed Tax Adj.] Pension	LABOR	-3,671,962	-2,291,884	-8,858	-16,076	-337	-5	-1,553	-140,943
81	TI	[TI][Fed Tax Adj.] OPEB	LABOR	-105,080,197	-65,586,635	-253,484	-460,045	-9,637	-150	-44,455	-4,033,355
82	TI	[TI][Fed Tax Adj.] Deferred Return on CIP ll	TOTPLT	66,348	36,083	182	316	2	0	51	2,291
83	TI	[TI][Fed Tax Adj.] Deferred Depreciation on CIP ll	TOTPLT	52,458	28,529	144	250	1	0	40	1,812
84	TI	[TI][Fed Tax Adj.] FIN48 Reg Asset Reversal	LABOR	0	0	0	0	0	0	0	0
85	TI	[TI][Fed Tax Adj.] Assessment by Board of Public Utilities of th	TOTPLTNET	91,151	49,084	248	433	2	0	70	3,253
86	TI	[TI][Fed Tax Adj.] Misc Adj - Permanent	TOTPLTNET	0	0	0	0	0	0	0	0
87	TI	[TI][Fed Tax Adj.] Casualty Loss Deferred O&M	TOTPLTNET	1,120,547	603,403	3,043	5,326	23	0	866	39,985
88	TI	[TI][Fed Tax Adj.] Performance Incentive Plan Adj (c)	TOTPLTNET	-1,045,327	-562,898	-2,839	-4,968	-21	0	-808	-37,301
89	TI										
90	TI										
91	TI	[TI][Fed Tax Adj.] LCAPP	TOTPLTNET	0	0	0	0	0	0	0	0
92	TI	[TI][Fed Tax Adj.] Clause - Deferred Fuel	not_used	0	0	0	0	0	0	0	0
93	TI	[TI][Fed Tax Adj.] Penalties	not_used	0	0	0	0	0	0	0	0
94	TI	[TI][Fed Tax Adj.] Restricted Stock - Permanent	TOTPLTNET	-82,615	-44,488	-224	-393	-2	0	-64	-2,948
95	TI	[TI][Fed Tax Adj.] Environmental Accrual	TOTPLTNET	0	0	0	0	0	0	0	0
96	TI	[TI][Fed Tax Adj.] Legal Reserves (nc)	TOTPLTNET	401,853	216,394	1,091	1,910	8	0	311	14,340
97	TI	[TI][Fed Tax Adj.] Material & Supplies Reserve (c)	TOTPLT	107,143	58,270	294	511	3	0	83	3,700
98	TI	[TI][Fed Tax Adj.] Lobbying Expenses	LABOR	0	0	0	0	0	0	0	0
99	TI	[TI][Fed Tax Adj.] Bankruptcies and Accum Provision for Rent	TOTPLTNET	62,834	33,836	171	299	1	0	49	2,242
100	TI	[TI][Fed Tax Adj.] Real Estate Taxes (nc)	TOTPLTNET	1,046,714	563,645	2,843	4,975	21	0	809	37,351

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
51	TI	[TI][Fed Tax Adj.] Meals and Entertainment (50%)	LABOR	-25	-6,715	-70,017	-46,446	-8,325	-6,214	-56
52	TI	[TI][Fed Tax Adj.] Company owned life insurance	LABOR	0	0	0	0	0	0	0
53	TI	[TI][Fed Tax Adj.] ESOP/401(k) Cash Dividends	TOTPLTNET	-74	-11,462	-201,301	-152,578	-33,766	-31,816	-75
54	TI	[TI][Fed Tax Adj.] Medicare Subsidy	LABOR	0	0	0	0	0	0	0
55	TI	[TI][Fed Tax Adj.] Dividends Received Deduction-2	TOTPLTNET	0	0	0	0	0	0	0
56	TI	[TI][Fed Tax Adj.] W-2 Earnings Exceeding $1.000.000	LABOR	109	29,630	308,952	204,946	36,734	27,419	246
57	TI	[TI][Fed Tax Adj.] Allowable Depreciation	DEPREXP	0	0	0	0	0	0	0
58	TI	[TI][Fed Tax Adj.] Book Depreciation	DEPREXP	0	0	0	0	0	0	0
59	TI	[TI][Fed Tax Adj.] Previously Ded Amort-Reacq Bonds	not_used	0	0	0	0	0	0	0
60	TI	[TI][Fed Tax Adj.] Amortization of Computer Software	INTANGPLT	0	0	0	0	0	0	0
61	TI	[TI][Fed Tax Adj.] Amort Def Gain - Sale of Gen Asset	not_used	0	0	0	0	0	0	0
62	TI	[TI][Fed Tax Adj.] Gain on Sale of Services Corp Asset	not_used	0	0	0	0	0	0	0
63	TI	[TI][Fed Tax Adj.] AFUDC / IDC - Debt	TOTPLT	-77	-11,637	-211,052	-155,613	-34,404	-32,123	-92
64	TI	[TI][Fed Tax Adj.] Capitalized Interest - Section 263A	TOTPLT	241	36,353	659,293	486,113	107,473	100,348	288
65	TI	[TI][Fed Tax Adj.] Cost of removal	TOTPLT	0	0	0	0	0	0	0
66	TI	[TI][Fed Tax Adj.] Utility Commodity Costs	not_used	0	0	0	0	0	0	0
67	TI	[TI][Fed Tax Adj.] RAC-Environmental Cleanup Costs	not_used	0	0	0	0	0	0	0
68	TI	[TI][Fed Tax Adj.] SBC-Societal Benefits Clause	not_used	0	0	0	0	0	0	0
69	TI	[TI][Fed Tax Adj.] Def Comp - Off/Dir/NOC (c)	LABOR	1	178	1,855	1,231	221	165	1
70	TI	[TI][Fed Tax Adj.] Deduction of Securitizartion	not_used	0	0	0	0	0	0	0
71	TI	[TI][Fed Tax Adj.] Additional Vacation Pay Adj (c)	LABOR	-20	-5,546	-57,824	-38,358	-6,875	-5,132	-46
72	TI	[TI][Fed Tax Adj.] Third Party Claims	TOTPLT	6	944	17,122	12,624	2,791	2,606	7
73	TI	[TI][Fed Tax Adj.] Deduction for New Network Meter Equipme	TOTPLT	0	0	0	0	0	0	0
74	TI	[TI][Fed Tax Adj.] Gain/loss bond reacq	not_used	0	0	0	0	0	0	0
75	TI	[TI][Fed Tax Adj.] Amortization of Call Option Sale	LABOR	0	0	0	0	0	0	0
76	TI	[TI][Fed Tax Adj.] Defer Dividend Equivalents/Restricted Stocl	LABOR	0	0	0	0	0	0	0
77	TI	[TI][Fed Tax Adj.] Repair Allow Deferral Carrying Charges	TOTPLT	0	0	0	0	0	0	0
78	TI	[TI][Fed Tax Adj.] CIAC Tax Gross Up	TOTPLTNET	65	10,057	176,620	133,871	29,626	27,915	66
79	TI	[TI][Fed Tax Adj.] FIN48 Services Allocation	TOTPLT	0	0	0	0	0	0	0
80	TI	[TI][Fed Tax Adj.] Pension	LABOR	-216	-59,077	-615,991	-408,623	-73,240	-54,669	-490
81	TI	[TI][Fed Tax Adj.] OPEB	LABOR	-6,194	-1,690,597	-17,627,746	-11,693,516	-2,095,908	-1,564,448	-14,026
82	TI	[TI][Fed Tax Adj.] Deferred Return on CIP II	TOTPLT	5	717	13,006	9,590	2,120	1,980	6
83	TI	[TI][Fed Tax Adj.] Deferred Depreciation on CIP II	TOTPLT	4	567	10,283	7,582	1,676	1,565	4
84	TI	[TI][Fed Tax Adj.] FIN48 Reg Asset Reversal	LABOR	0	0	0	0	0	0	0
85	TI	[TI][Fed Tax Adj.] Assessment by Board of Public Utilities of th	TOTPLTNET	7	1,012	17,774	13,472	2,981	2,809	7
86	TI	[TI][Fed Tax Adj.] Misc Adj - Permanent	TOTPLTNET	0	0	0	0	0	0	0
87	TI	[TI][Fed Tax Adj.] Casualty Loss Deferred O&M	TOTPLTNET	80	12,441	218,498	165,613	36,651	34,534	82
88	TI	[TI][Fed Tax Adj.] Performance Incentive Plan Adj (c)	TOTPLTNET	-75	-11,606	-203,831	-154,496	-34,190	-32,216	-76
89	TI									
90	TI									
91	TI	[TI][Fed Tax Adj.] LCAPP	TOTPLTNET	0	0	0	0	0	0	0
92	TI	[TI][Fed Tax Adj.] Clause - Deferred Fuel	not_used	0	0	0	0	0	0	0
93	TI	[TI][Fed Tax Adj.] Penalties	not_used	0	0	0	0	0	0	0
94	TI	[TI][Fed Tax Adj.] Restricted Stock - Permanent	TOTPLTNET	-6	-917	-16,109	-12,210	-2,702	-2,546	-6
95	TI	[TI][Fed Tax Adj.] Environmental Accrual	TOTPLTNET	0	0	0	0	0	0	0
96	TI	[TI][Fed Tax Adj.] Legal Reserves (nc)	TOTPLTNET	29	4,462	78,358	59,393	13,144	12,385	29
97	TI	[TI][Fed Tax Adj.] Material & Supplies Reserve (c)	TOTPLT	8	1,158	21,003	15,486	3,424	3,197	9
98	TI	[TI][Fed Tax Adj.] Lobbying Expenses	LABOR	0	0	0	0	0	0	0
99	TI	[TI][Fed Tax Adj.] Bankruptcies and Accum Provision for Rent	TOTPLTNET	4	698	12,252	9,287	2,055	1,936	5
100	TI	[TI][Fed Tax Adj.] Real Estate Taxes (nc)	TOTPLTNET	75	11,622	204,101	154,701	34,236	32,259	76

PUBLIC SERVICE ELECTRIC & GAS COMPANY
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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
101	TI	[TI][Fed Tax Adj.] Credits & Adjustments	TOTPLTNET	0	0	0	0	0	0	0	0
102	TI	**[TI][Fed Tax Adj.] Miscellaneous**	TOTPLT								
103	TI	**[TI] TOTAL TAX ADJUSTMENTS - FEDERAL**		-149,324,736	-90,574,806	-371,745	-667,061	-11,454	-178	-74,785	-5,584,714
104	TI										
105	TI	**[TI] TAX ADJUSTMENTS - STATE**									
106	TI	[TI] TEFA	TEFA_04	0	0	0	0	0	0	0	0
107	TI	[TI] Federal Depreciation Reversal	DEPREXP	72,042,765	39,223,841	197,651	343,407	1,713	27	55,310	2,480,845
108	TI	[TI] State Tax Depreciation	DEPREXP	36,681,624	19,971,391	100,637	174,851	872	14	28,162	1,263,159
109	TI	[Electric] Not Used_42	not_used	0	0	0	0	0	0	0	0
110	TI	**[TI] TOTAL TAX ADJUSTMENTS - STATE**		108,724,389	59,195,232	298,287	518,258	2,585	40	83,472	3,744,004
111	TI										
112	TI	**[TI] TAXABLE NET INCOME - STATE**		1,331,886,063	736,643,582	3,596,389	6,283,942	78,410	1,223	990,759	45,971,009
113	TI	[TI] State Tax Liability		119,869,746	66,297,922	323,675	565,555	7,057	110	89,168	4,137,391
114	TI	[TI] Prior Year Adjustment	TOTPLTNET	0	0	0	0	0	0	0	0
115	TI	**[TI] TOTAL STATE INCOME TAX LIABILITY**		119,869,746	66,297,922	323,675	565,555	7,057	110	89,168	4,137,391
116	TI										
117	TI	**[TI] TAXABLE NET INCOME - FEDERAL**		1,103,291,929	611,150,428	2,974,426	5,200,129	68,769	1,072	818,119	38,089,614
118	TI	[TI] Federal Tax Liability		231,691,305	128,341,590	624,630	1,092,027	14,441	225	171,805	7,998,819
119	TI	[Electric] Not Used_43	not_used	0	0	0	0	0	0	0	0
120	TI	[Electric] Not Used_44	not_used	0	0	0	0	0	0	0	0
121	TI	**[TI] TOTAL FEDERAL INCOME TAX LIABILITY**		231,691,305	128,341,590	624,630	1,092,027	14,441	225	171,805	7,998,819
122	TI										
123	TI	**[TI] TOTAL INCOME TAX EXPENSE**		351,561,051	194,639,512	948,305	1,657,582	21,498	335	260,973	12,136,210
124	TI										
125	TI										
126	TI										
127	TI										
128	TI	**[TI] TAX RATES**									
129	TI	[TI] FEDERAL TAX RATE - CURRENT		21.000%							
130	TI	[TI] NEW JERSEY CORP BUSINESS TAX RATE		9.000%							
131	TI	[TI] CUSTOMER ACCT UNCOLLECTIBLE RATE		0.0							
132	TI	[TI] EFFECTIVE TAX RATE		28.110%							
133	TI	[TI] COMPOSITE RATE		28.110%							
134	TI	[TI] 1 - EFFECTIVE TAX RATE		71.89000%							
135	TI										
136	TI	**[TI] DEVELOPMENT OF OPERATING INCOME ADJUSTED**									
137	TI	[TI] 410 + 411 - Additional Rental Income - NJ Properties	TOTPLT	-16,349	-8,891	-45	-78	0	0	-13	-565
138	TI	[TI] 410 + 411 - Amort of Def Gain on Sale of Services Assets	not_used	0	0	0	0	0	0	0	0
139	TI	[TI] 410 + 411 - Amort of Deferred Gain on Sale of Generation	not_used	0	0	0	0	0	0	0	0
140	TI	[TI] 410 + 411 - Bankruptcies and Accum Provision for Rent R	TOTPLT	53,745	29,229	147	256	1	0	41	1,856
141	TI	[TI] 410 + 411 - Casualty Loss Deferred O&M	TOTPLTNET	-1,120,547	-603,403	-3,043	-5,326	-23	0	-866	-39,985
142	TI	[TI] 410 + 411 - CECL Reserve	not_used	0	0	0	0	0	0	0	0
143	TI	[TI] 410 + 411 - CEF- EC AMI	TOTPLT	20,866,765	11,348,318	57,256	99,488	509	8	16,070	720,635
144	TI	[TI] 410 + 411 - CEF- EV Deferral	TOTPLT	1,855,840	1,009,292	5,092	8,848	45	1	1,429	64,092
145	TI	[TI] 410 + 411 - Clause - Demographic Studies	not_used	0	0	0	0	0	0	0	0
146	TI	[TI] 410 + 411 - Clause - Navigant Studies	not_used	0	0	0	0	0	0	0	0
147	TI	[TI] 410 + 411 - Clause - RAC (Environmental Clean Up)	not_used	0	0	0	0	0	0	0	0
148	TI	[TI] 410 + 411 - Clause - Societal Benefits Clause (AAP)	not_used	0	0	0	0	0	0	0	0
149	TI	[TI] 410 + 411 - COVID Deferrals	not_used	0	0	0	0	0	0	0	0
150	TI	[TI] 410 + 411 - Current SHARE -- FT	DEPREXP	2,912,070	1,585,483	7,989	13,881	69	1	2,236	100,279

Updated for 9 and 3

PUBLIC SERVICE ELECTRIC & GAS COMPANY
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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
101	TI	[TI][Fed Tax Adj.] Credits & Adjustments	TOTPLTNET	0	0	0	0	0	0	0
102	TI	**[TI][Fed Tax Adj.] Miscellaneous**	TOTPLT							
103	TI	**[TI] TOTAL TAX ADJUSTMENTS - FEDERAL**		-9,234	-2,220,901	-26,014,982	-17,691,912	-3,371,811	-2,712,761	-18,391
104	TI									
105	TI	**[TI] TAX ADJUSTMENTS - STATE**								
106	TI	[TI] TEFA	TEFA_04	0	0	0	0	0	0	0
107	TI	[TI] Federal Depreciation Reversal	DEPREXP	5,166	779,606	14,116,876	10,394,515	2,295,445	2,142,411	5,952
108	TI	[TI] State Tax Depreciation	DEPREXP	2,630	396,948	7,187,813	5,292,519	1,168,759	1,090,840	3,030
109	TI	[Electric] Not Used_42	not_used	0	0	0	0	0	0	0
110	TI	**[TI] TOTAL TAX ADJUSTMENTS - STATE**		7,796	1,176,554	21,304,689	15,687,035	3,464,204	3,233,251	8,982
111	TI									
112	TI	**[TI] TAXABLE NET INCOME - STATE**		131,640	14,482,898	258,378,604	185,549,903	41,096,335	38,569,712	111,656
113	TI	[TI] State Tax Liability		11,848	1,303,461	23,254,074	16,699,491	3,698,670	3,471,274	10,049
114	TI	[TI] Prior Year Adjustment	TOTPLTNET	0	0	0	0	0	0	0
115	TI	**[TI] TOTAL STATE INCOME TAX LIABILITY**		11,848	1,303,461	23,254,074	16,699,491	3,698,670	3,471,274	10,049
116	TI									
117	TI	**[TI] TAXABLE NET INCOME - FEDERAL**		111,996	12,002,884	213,819,841	153,163,378	33,933,460	31,865,187	92,625
118	TI	[TI] Federal Tax Liability		23,519	2,520,606	44,902,167	32,164,309	7,126,027	6,691,689	19,451
119	TI	[Electric] Not Used_43	not_used	0	0	0	0	0	0	0
120	TI	[Electric] Not Used_44	not_used	0	0	0	0	0	0	0
121	TI	**[TI] TOTAL FEDERAL INCOME TAX LIABILITY**		23,519	2,520,606	44,902,167	32,164,309	7,126,027	6,691,689	19,451
122	TI									
123	TI	**[TI] TOTAL INCOME TAX EXPENSE**		35,367	3,824,066	68,156,241	48,863,801	10,824,697	10,162,963	29,500
124	TI									
125	TI									
126	TI									
127	TI									
128	TI	**[TI] TAX RATES**								
129	TI	[TI] FEDERAL TAX RATE - CURRENT								
130	TI	[TI] NEW JERSEY CORP BUSINESS TAX RATE								
131	TI	[TI] CUSTOMER ACCT UNCOLLECTIBLE RATE								
132	TI	[TI] EFFECTIVE TAX RATE								
133	TI	[TI] COMPOSITE RATE								
134	TI	[TI] 1 - EFFECTIVE TAX RATE								
135	TI									
136	TI	**[TI] DEVELOPMENT OF OPERATING INCOME ADJUSTED**								
137	TI	[TI] 410 + 411 - Additional Rental Income - NJ Properties	TOTPLT	-1	-177	-3,205	-2,363	-522	-488	-1
138	TI	[TI] 410 + 411 - Amort of Def Gain on Sale of Services Assets	not_used	0	0	0	0	0	0	0
139	TI	[TI] 410 + 411 - Amort of Deferred Gain on Sale of Generation	not_used	0	0	0	0	0	0	0
140	TI	[TI] 410 + 411 - Bankruptcies and Accum Provision for Rent R	TOTPLT	4	581	10,535	7,768	1,717	1,604	5
141	TI	[TI] 410 + 411 - Casualty Loss Deferred O&M	TOTPLTNET	-80	-12,441	-218,498	-165,613	-36,651	-34,534	-82
142	TI	[TI] 410 + 411 - CECL Reserve	not_used	0	0	0	0	0	0	0
143	TI	[TI] 410 + 411 - CEF- EC AMI	TOTPLT	1,497	225,540	4,090,370	3,015,930	666,782	622,576	1,786
144	TI	[TI] 410 + 411 - CEF- EV Deferral	TOTPLT	133	20,059	363,788	268,230	59,302	55,370	159
145	TI	[TI] 410 + 411 - Clause - Demographic Studies	not_used	0	0	0	0	0	0	0
146	TI	[TI] 410 + 411 - Clause - Navigant Studies	not_used	0	0	0	0	0	0	0
147	TI	[TI] 410 + 411 - Clause - RAC (Environmental Clean Up)	not_used	0	0	0	0	0	0	0
148	TI	[TI] 410 + 411 - Clause - Societal Benefits Clause (AAP)	not_used	0	0	0	0	0	0	0
149	TI	[TI] 410 + 411 - COVID Deferrals	not_used	0	0	0	0	0	0	0
150	TI	[TI] 410 + 411 - Current SHARE -- FT	DEPREXP	209	31,513	570,624	420,161	92,785	86,599	241

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2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
151	TI	[TI] 410 + 411 - Customer Advances	TOTPLTNET	-4,645,423	-2,501,513	-12,617	-22,079	-95	-1	-3,591	-165,766
152	TI	[TI] 410 + 411 - Deduction for Retention Payments (c)	LABOR	5,352	3,340	13	23	0	0	2	205
153	TI	[TI] 410 + 411 - Deferred Employer ER FICA	LABOR	7,086,760	4,423,257	17,095	31,026	650	10	2,998	272,015
154	TI	[TI] 410 + 411 - FAS 5 (ASC40) Reserve - Sales Tax	not_used	0	0	0	0	0	0	0	0
155	TI	[TI] 410 + 411 - Fed Amort of Deferred Gain on Sale of Gener	not_used	0	0	0	0	0	0	0	0
156	TI	[TI] 410 + 411 - Injuries & Damages - FT	TOTPLT	-328,505	-178,656	-901	-1,566	-8	0	-253	-11,345
157	TI	[TI] 410 + 411 - Line Pack Adjustment	not_used	0	0	0	0	0	0	0	0
158	TI	[TI] 410 + 411 - Medicare Subsidy	not_used	0	0	0	0	0	0	0	0
159	TI	[TI] 410 + 411 - Partnership Income/Loss (nc)	TOTPLT	42,165	22,931	116	201	1	0	32	1,456
160	TI	[TI] 410 + 411 - Plant Related	DEPREXP	37,305,084	20,310,835	102,347	177,823	887	14	28,640	1,284,628
161	TI	[TI] 410 + 411 - Previously Deducted Amort - Reacquired Bon	not_used	0	0	0	0	0	0	0	0
162	TI	[TI] 410 + 411 - R & D Credits CF	TOTPLT	-15,263	-8,301	-42	-73	0	0	-12	-527
163	TI	[TI] 410 + 411 - RE - Lease Liability	TOTPLT	236,259	128,489	648	1,126	6	0	182	8,159
164	TI	[TI] 410 + 411 - RE - ROU Lease Asset	TOTPLT	-319,172	-173,581	-876	-1,522	-8	0	-246	-11,023
165	TI	[TI] 410 + 411 - Real Estate Taxes (nc)	TOTPLT	-1,046,714	-569,252	-2,872	-4,990	-26	0	-806	-36,148
166	TI	[TI] 410 + 411 - Reversal of Book Income from Partnerships	TOTPLT	-42,165	-22,931	-116	-201	-1	0	-32	-1,456
167	TI	[TI] 410 + 411 - Severance Pay (nc)	LABOR	-154,681	-96,545	-373	-677	-14	0	-65	-5,937
168	TI	[TI] 410 + 411 - State NOL CF (c)	DEPREXP	-17,908,279	-9,750,202	-49,132	-85,364	-426	-7	-13,749	-616,685
169	TI	[TI] 410 + 411 - Unrealized G/L on Equity Securities	TOTPLT	-125,367	-68,181	-344	-598	-3	0	-97	-4,330
170	TI	**[TI] E410 + E411- PROVISION FOR DEFERRED INCOME T/**									
171	TI	[TI] E410 + E411 - Legal Reserves (c)	TOTPLTNET	0	0	0	0	0	0	0	0
172	TI	[TI] E410 + E411 - Tax Depreciation	DEPREXP	0	0	0	0	0	0	0	0
173	TI	[TI] 410 + 411 - Previously Ded Amort-Reacq Bonds	not_used	0	0	0	0	0	0	0	0
174	TI	[TI] E410 + E411 - Amortization of Power Gain	not_used	0	0	0	0	0	0	0	0
175	TI	[TI] E410 + E411 - Amort Def Gain - Sale of Gen Asset	not_used	0	0	0	0	0	0	0	0
176	TI	[TI] 410 + 411 - Gain on Sale of Services Corp Asset	not_used	0	0	0	0	0	0	0	0
177	TI	[TI] 410 + 411 - AFUDC / IDC - Debt	TOTPLT	1,076,666	585,541	2,954	5,133	26	0	829	37,183
178	TI	[TI] 410 + 411 - Capitalized Interest - Section 263A	TOTPLT	-3,363,340	-1,829,141	-9,229	-16,036	-82	-1	-2,590	-116,153
179	TI	[TI] 410 + 411 - Cost of removal	TOTPLT	0	0	0	0	0	0	0	0
180	TI	[TI] E410 + E411 - Utility Commodity Costs	not_used	0	0	0	0	0	0	0	0
181	TI	[TI] E410 + E411 - RAC-Environmental Cleanup Costs	not_used	0	0	0	0	0	0	0	0
182	TI	[TI] E410 + E411 - SBC-Societal Benefits Clause	not_used	0	0	0	0	0	0	0	0
183	TI	[TI] 410 + 411 - Def Comp - Off/Dir/NOC (c)	LABOR	-11,058	-6,902	-27	-48	-1	0	-5	-424
184	TI	[TI] 410 + 411 - Deduction of Securitizartion	not_used	0	0	0	0	0	0	0	0
185	TI	[TI] 410 + 411 - Additional Vacation Pay Adj (c)	LABOR	344,695	215,144	832	1,509	32	0	146	13,231
186	TI	[TI] 410 + 411 - Third Party Claims	TOTPLT	-87,346	-47,503	-240	-416	-2	0	-67	-3,016
187	TI	[TI] E410 + E411 - Bankruptcies & Acc Prov-Rent Receivable	LABOR	0	0	0	0	0	0	0	0
188	TI	[TI] E410 + E411 - Deduction for New Network Meter Equipm	TOTPLT	0	0	0	0	0	0	0	0
189	TI	[TI] 410 + 411 - Gain/loss bond reacq	not_used	0	0	0	0	0	0	0	0
190	TI	[TI] 410 + 411 - Amortization of Call Option Sale	LABOR	0	0	0	0	0	0	0	0
191	TI	[TI] 410 + 411 - Defer Dividend Equivalents/Restricted Stock-T	LABOR	0	0	0	0	0	0	0	0
192	TI	[TI] E410 + E411 - Repair Allow Deferral Carrying Charges	TOTPLT	0	0	0	0	0	0	0	0
193	TI	[TI] 410 + 411 - CIAC Tax Gross Up	TOTPLTNET	-905,779	-487,753	-2,460	-4,305	-19	0	-700	-32,322
194	TI	[TI] E410 + E411 - FIN48 Services Allocation	TOTPLT	0	0	0	0	0	0	0	0
195	TI	[TI] 410 + 411 - Pension	LABOR	3,671,962	2,291,884	8,858	16,076	337	5	1,553	140,943
196	TI	[TI] 410 + 411 - OPEB	LABOR	105,080,197	65,586,635	253,484	460,045	9,637	150	44,455	4,033,355
197	TI	[TI] 410 + 411 - Fin Def-Energy Competition Act Ct	TOTPLT	0	0	0	0	0	0	0	0
198	TI	[TI] E410 + E411 - Conditional Asset Retire Obligations	TOTPLTNET	0	0	0	0	0	0	0	0
199	TI	[TI] 410 + 411 - Rabbi Trust	LABOR	0	0	0	0	0	0	0	0
200	TI	[TI] E410 + E411 - FIN48 Reg Asset Reversal	LABOR	0	0	0	0	0	0	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
151	TI	[TI] 410 + 411 - Customer Advances	TOTPLTNET	-333	-51,578	-905,823	-686,578	-151,942	-143,167	-339
152	TI	[TI] 410 + 411 - Deduction for Retention Payments (c)	LABOR	0	86	898	596	107	80	1
153	TI	[TI] 410 + 411 - Deferred Employer ER FICA	LABOR	418	114,016	1,188,841	788,628	141,351	105,509	946
154	TI	[TI] 410 + 411 - FAS 5 (ASC40) Reserve - Sales Tax	not_used	0	0	0	0	0	0	0
155	TI	[TI] 410 + 411 - Fed Amort of Deferred Gain on Sale of Gener	not_used	0	0	0	0	0	0	0
156	TI	[TI] 410 + 411 - Injuries & Damages - FT	TOTPLT	-24	-3,551	-64,395	-47,480	-10,497	-9,801	-28
157	TI	[TI] 410 + 411 - Line Pack Adjustment	not_used	0	0	0	0	0	0	0
158	TI	[TI] 410 + 411 - Medicare Subsidy	not_used	0	0	0	0	0	0	0
159	TI	[TI] 410 + 411 - Partnership Income/Loss (nc)	TOTPLT	3	456	8,265	6,094	1,347	1,258	4
160	TI	[TI] 410 + 411 - Plant Related	DEPREXP	2,675	403,694	7,309,981	5,382,473	1,188,624	1,109,380	3,082
161	TI	[TI] 410 + 411 - Previously Deducted Amort - Reacquired Bon	not_used	0	0	0	0	0	0	0
162	TI	[TI] 410 + 411 - R & D Credits CF	TOTPLT	-1	-165	-2,992	-2,206	-488	-455	-1
163	TI	[TI] 410 + 411 - RE - Lease Liability	TOTPLT	17	2,554	46,312	34,147	7,549	7,049	20
164	TI	[TI] 410 + 411 - RE - ROU Lease Asset	TOTPLT	-23	-3,450	-62,565	-46,131	-10,199	-9,523	-27
165	TI	[TI] 410 + 411 - Real Estate Taxes (nc)	TOTPLT	-75	-11,314	-205,180	-151,284	-33,447	-31,230	-90
166	TI	[TI] 410 + 411 - Reversal of Book Income from Partnerships	TOTPLT	-3	-456	-8,265	-6,094	-1,347	-1,258	-4
167	TI	[TI] 410 + 411 - Severance Pay (nc)	LABOR	-9	-2,489	-25,949	-17,213	-3,085	-2,303	-21
168	TI	[TI] 410 + 411 - State NOL CF (c)	DEPREXP	-1,284	-193,793	-3,509,151	-2,583,853	-570,598	-532,557	-1,479
169	TI	[TI] 410 + 411 - Unrealized G/L on Equity Securities	TOTPLT	-9	-1,355	-24,575	-18,120	-4,006	-3,740	-11
170	TI	**[TI] E410 + E411- PROVISION FOR DEFERRED INCOME T/**								
171	TI	[TI] E410 + E411 - Legal Reserves (c)	TOTPLTNET	0	0	0	0	0	0	0
172	TI	[TI] E410 + E411 - Tax Depreciation	DEPREXP	0	0	0	0	0	0	0
173	TI	[TI] 410 + 411 - Previously Ded Amort-Reacq Bonds	not_used	0	0	0	0	0	0	0
174	TI	[TI] E410 + E411 - Amortization of Power Gain	not_used	0	0	0	0	0	0	0
175	TI	[TI] E410 + E411 - Amort Def Gain - Sale of Gen Asset	not_used	0	0	0	0	0	0	0
176	TI	[TI] 410 + 411 - Gain on Sale of Services Corp Asset	not_used	0	0	0	0	0	0	0
177	TI	[TI] 410 + 411 - AFUDC / IDC - Debt	TOTPLT	77	11,637	211,052	155,613	34,404	32,123	92
178	TI	[TI] 410 + 411 - Capitalized Interest - Section 263A	TOTPLT	-241	-36,353	-659,293	-486,113	-107,473	-100,348	-288
179	TI	[TI] 410 + 411 - Cost of removal	TOTPLT	0	0	0	0	0	0	0
180	TI	[TI] E410 + E411 - Utility Commodity Costs	not_used	0	0	0	0	0	0	0
181	TI	[TI] E410 + E411 - RAC-Environmental Cleanup Costs	not_used	0	0	0	0	0	0	0
182	TI	[TI] E410 + E411 - SBC-Societal Benefits Clause	not_used	0	0	0	0	0	0	0
183	TI	[TI] 410 + 411 - Def Comp - Off/Dir/NOC (c)	LABOR	-1	-178	-1,855	-1,231	-221	-165	-1
184	TI	[TI] 410 + 411 - Deduction of Securitizartion	not_used	0	0	0	0	0	0	0
185	TI	[TI] 410 + 411 - Additional Vacation Pay Adj (c)	LABOR	20	5,546	57,824	38,358	6,875	5,132	46
186	TI	[TI] 410 + 411 - Third Party Claims	TOTPLT	-6	-944	-17,122	-12,624	-2,791	-2,606	-7
187	TI	[TI] E410 + E411 - Bankruptcies & Acc Prov-Rent Receivable	LABOR	0	0	0	0	0	0	0
188	TI	[TI] E410 + E411 - Deduction for New Network Meter Equipm	TOTPLT	0	0	0	0	0	0	0
189	TI	[TI] 410 + 411 - Gain/loss bond reacq	not_used	0	0	0	0	0	0	0
190	TI	[TI] 410 + 411 - Amortization of Call Option Sale	LABOR	0	0	0	0	0	0	0
191	TI	[TI] 410 + 411 - Defer Dividend Equivalents/Restricted Stock-T	LABOR	0	0	0	0	0	0	0
192	TI	[TI] E410 + E411 - Repair Allow Deferral Carrying Charges	TOTPLT	0	0	0	0	0	0	0
193	TI	[TI] 410 + 411 - CIAC Tax Gross Up	TOTPLTNET	-65	-10,057	-176,620	-133,871	-29,626	-27,915	-66
194	TI	[TI] E410 + E411 - FIN48 Services Allocation	TOTPLT	0	0	0	0	0	0	0
195	TI	[TI] 410 + 411 - Pension	LABOR	216	59,077	615,991	408,623	73,240	54,669	490
196	TI	[TI] 410 + 411 - OPEB	LABOR	6,194	1,690,597	17,627,746	11,693,516	2,095,908	1,564,448	14,026
197	TI	[TI] 410 + 411 - Fin Def-Energy Competition Act Ct	TOTPLT	0	0	0	0	0	0	0
198	TI	[TI] E410 + E411 - Conditional Asset Retire Obligations	TOTPLTNET	0	0	0	0	0	0	0
199	TI	[TI] 410 + 411 - Rabbi Trust	LABOR	0	0	0	0	0	0	0
200	TI	[TI] E410 + E411 - FIN48 Reg Asset Reversal	LABOR	0	0	0	0	0	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
201	TI	[TI] 410 + 411 - Additional Expenses on Rental Property	TOTPLT	108,083	58,781	297	515	3	0	83	3,733
202	TI	[TI] 410 + 411 - Performance Incentive Plan Adj (c)	LABOR	1,045,327	652,449	2,522	4,576	96	1	442	40,123
203	TI	[TI] 410 + 411 - Deferred NJ Corp Bus Tax(Net of FIT)	TOTPLTNET	0	0	0	0	0	0	0	0
204	TI	[TI] 410 + 411 - Misc	TOTPLT	0	0	0	0	0	0	0	0
205	TI	[TI] 410 + 411 - Construction Period Interest	TOTPLTNET	0	0	0	0	0	0	0	0
206	TI	[TI] E410 + E411 - Clause - Deferred Return on CIP II	TOTPLT	-66,348	-36,083	-182	-316	-2	0	-51	-2,291
207	TI	[TI] E410 + E411 - Clause - Deferred Depreciation on CIP II	TOTPLT	-52,458	-28,529	-144	-250	-1	0	-40	-1,812
208	TI	[TI] 410 + 411 - Customer Connection Fees (Contributions in /	CUSTACCTS	-6,684,538	-4,982,339	-17,294	-28,975	-454	-7	-561	-14,854
209	TI	[TI] E410 + E411 - Decommissioning Costs	KWHMETER_04	0	0	0	0	0	0	0	0
210	TI	[TI] 410 + 411 - Investment Tax Credit	TOTPLT	0	0	0	0	0	0	0	0
211	TI	[TI] 410 + 411 - Assessment by Board of Public Utilities of the	TOTPLTNET	-91,151	-49,084	-248	-433	-2	0	-70	-3,253
212	TI	[TI] E410 + E411 - Casualty Loss Deferred O&M & Ins Procee	TOTPLTNET	0	0	0	0	0	0	0	0
213	TI	[TI] E410 + E411 - GainState LILOAudit Refunds not yet recei	TOTPLTNET	0	0	0	0	0	0	0	0
214	TI	[TI] E410 + E411 - LCAPP	TOTPLTNET	0	0	0	0	0	0	0	0
215	TI	[TI] E410 + E411 - Audit Adjustment	not_used	0	0	0	0	0	0	0	0
216	TI	[TI] 410 + 411 - Stock-Based Compensation - Reverse Book -	TOTPLTNET	328,125	176,692	891	1,560	7	0	254	11,709
217	TI	[TI] 410 + 411 - Clause - Deferred Fuel	not_used	0	0	0	0	0	0	0	0
218	TI	[TI] 410 + 411 - Legal Reserves (nc)	TOTPLTNET	-401,853	-216,394	-1,091	-1,910	-8	0	-311	-14,340
219	TI										
220	TI										
221	TI	**[TI] DEVELOPMENT OF OPERATING INCOME ADJ CONTI**									
222	TI	**[TI] E410 + E411- PROVISION FOR DEFER INC TAX CONT**									
223	TI	[TI] E410 + E411 - Material & Supplies Reserve (c)	TOTPLTNET	-107,143	-57,696	-291	-509	-2	0	-83	-3,823
224	TI	[TI] E410 + E411 - Medicare Subsidy	TOTPLTNET								
225	TI	**[TI] TOTAL DEFERRED INCOME TAX**		144,525,616	86,705,422	358,976	646,416	11,129	173	75,185	5,647,547
226	TI										
227	TI	**[TI] TOTAL INC TAXES DEF IN PRIOR YEAR**	not_used	0	0	0	0	0	0	0	0
228	TI	**[TI] TOTAL INVEST TAX CRED ADJ (NET)**	not_used	0	0	0	0	0	0	0	0
229	TI	**[TI] TOTAL PRO FORMA OP INC ADJUSTMENTS**	not_used	0	0	0	0	0	0	0	0
230	TI										
231	TI	**[TI] OPERATING INCOME ADJUSTED**		738,814,468	412,589,954	1,988,889	3,474,829	51,828	808	539,547	25,118,400

PUBLIC SERVICE ELECTRIC & GAS COMPANY
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12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
201	TI	[TI] 410 + 411 - Additional Expenses on Rental Property	TOTPLT	8	1,168	21,187	15,622	3,454	3,225	9
202	TI	[TI] 410 + 411 - Performance Incentive Plan Adj (c)	LABOR	62	16,818	175,359	116,326	20,850	15,563	140
203	TI	[TI] 410 + 411 - Deferred NJ Corp Bus Tax(Net of FIT)	TOTPLTNET	0	0	0	0	0	0	0
204	TI	[TI] 410 + 411 - Misc	TOTPLT	0	0	0	0	0	0	0
205	TI	[TI] 410 + 411 - Construction Period Interest	TOTPLTNET	0	0	0	0	0	0	0
206	TI	[TI] E410 + E411 - Clause - Deferred Return on CIP II	TOTPLT	-5	-717	-13,006	-9,590	-2,120	-1,980	-6
207	TI	[TI] E410 + E411 - Clause - Deferred Depreciation on CIP II	TOTPLT	-4	-567	-10,283	-7,582	-1,676	-1,565	-4
208	TI	[TI] 410 + 411 - Customer Connection Fees (Contributions in /	CUSTACCTS	-270	-70,151	-1,177,490	-354,384	-29,527	-7,259	-975
209	TI	[TI] E410 + E411 - Decommissioning Costs	KWHMETER_04	0	0	0	0	0	0	0
210	TI	[TI] 410 + 411 - Investment Tax Credit	TOTPLT	0	0	0	0	0	0	0
211	TI	[TI] 410 + 411 - Assessment by Board of Public Utilities of the	TOTPLTNET	-7	-1,012	-17,774	-13,472	-2,981	-2,809	-7
212	TI	[TI] E410 + E411 - Casualty Loss Deferred O&M & Ins Procee	TOTPLTNET	0	0	0	0	0	0	0
213	TI	[TI] E410 + E411 - GainState LILOAudit Refunds not yet recei	TOTPLTNET	0	0	0	0	0	0	0
214	TI	[TI] E410 + E411 - LCAPP	TOTPLTNET	0	0	0	0	0	0	0
215	TI	[TI] E410 + E411 - Audit Adjustment	not_used	0	0	0	0	0	0	0
216	TI	[TI] 410 + 411 - Stock-Based Compensation - Reverse Book -	TOTPLTNET	23	3,643	63,982	48,496	10,732	10,112	24
217	TI	[TI] 410 + 411 - Clause - Deferred Fuel	not_used	0	0	0	0	0	0	0
218	TI	[TI] 410 + 411 - Legal Reserves (nc)	TOTPLTNET	-29	-4,462	-78,358	-59,393	-13,144	-12,385	-29
219	TI									
220	TI									
221	TI	**[TI] DEVELOPMENT OF OPERATING INCOME ADJ CONTI**								
222	TI	**[TI] E410 + E411- PROVISION FOR DEFER INC TAX CONT**								
223	TI	[TI] E410 + E411 - Material & Supplies Reserve (c)	TOTPLTNET	-8	-1,190	-20,892	-15,835	-3,504	-3,302	-8
224	TI	[TI] E410 + E411 - Medicare Subsidy	TOTPLTNET							
225	TI	**[TI] TOTAL DEFERRED INCOME TAX**		9,079	2,180,588	25,159,465	17,579,552	3,389,182	2,745,308	17,594
226	TI									
227	TI	**[TI] TOTAL INC TAXES DEF IN PRIOR YEAR**	not_used	0	0	0	0	0	0	0
228	TI	**[TI] TOTAL INVEST TAX CRED ADJ (NET)**	not_used	0	0	0	0	0	0	0
229	TI	**[TI] TOTAL PRO FORMA OP INC ADJUSTMENTS**	not_used	0	0	0	0	0	0	0
230	TI									
231	TI	**[TI] OPERATING INCOME ADJUSTED**		78,782	7,994,985	142,945,089	100,776,784	22,289,934	20,900,713	63,925

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				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	LR	**DEVELOPMENT OF LABOR ALLOCATION FACTOR**									
2	LR										
3	LR	**PRODUCTION LABOR EXPENSE**	not_used	0	0	0	0	0	0	0	0
4	LR										
5	LR	**TRANSMISSION LABOR EXPENSE**	not_used	0	0	0	0	0	0	0	0
6	LR										
7	LR	**DISTRIBUTION LABOR EXPENSE**									
8	LR	Operation									
9	LR	582-Station Equipment	E367PLT	280,636	153,779	758	1,398	0	0	320	1,103
10	LR	583-Overhead Lines	E367PLT	941,919	516,139	2,545	4,694	0	0	1,075	3,701
11	LR	584-Underground Lines	E367PLT	4,591,058	2,515,744	12,404	22,878	0	0	5,242	18,041
12	LR	586-Metering	MTROMMIN_07	4,311,826	2,160,954	7,507	12,543	2,057	32	853	
13	LR	587-Customer Installations	CUSTAVG_04	17,308,754	14,746,796	51,232	85,593	4,883	76	5,819	36,399
14	LR	588-Miscellaneous	DISTEXPO	16,169,609	7,401,173	32,612	68,617	2,035	32	11,939	146,217
15	LR	Total Operation		43,603,802	27,494,585	107,058	195,722	8,974	140	25,248	205,461
16	LR	Maintenance									
17	LR	590-Supervision & Engineering	DISTEXPM	0	0	0	0	0	0	0	0
18	LR	591-Structures	E361PLT	2,559,859	1,277,994	5,431	12,665	32	0	1,426	46,086
19	LR	592-Station Equipment	E362PLT	8,699,368	3,968,190	12,738	44,623			2,779	
20	LR	593-Overhead Lines	E365PLT	11,294,340	5,960,333	26,935	57,266			10,457	27,097
21	LR	594-Underground Lines	E367PLT	11,333,758	6,210,515	30,621	56,477	0	0	12,941	44,536
22	LR	595-Line Transformers	LNTRFRMR_04	2,457,581	1,754,504	13,306	11,147			2,347	7,614
23	LR	596-Street Lighting and Signal Systems	E373PLT	7,842,365	515,180	2,668	4,645	2	0	775	5,386,887
24	LR	597-Meters	MTROMMIN_07	700,642	351,140	1,220	2,038	334	5	139	
25	LR	598-Other Distribution Maintenance	DISTEXPM	529,302	248,776	1,119	2,395	2	0	388	36,563
26	LR	Total Maintenance		45,417,214	20,286,632	94,038	191,256	370	6	31,250	5,548,783
27	LR	TOTAL DISTRIBUTION LABOR EXPENSE		89,021,016	47,781,217	201,096	386,979	9,345	146	56,498	5,754,244
28	LR										
29	LR	**E901-E903,E905 CUST ACCOUNTS EXPENSE**	CUSTACCTS	58,697,026	43,749,989	151,857	254,426	3,985	62	4,924	130,430
30	LR	**E907-E910, xDSM CUST SERV & INFO EXP**	CUSTS_I	5,539,923	4,371,290	14,761	26,931	976	14	1,718	12,046
31	LR	**E911-E916 SALES EXPENSE**	SALESEXP								
32	LR	**ADMIN & GENERAL EXP ACCOUNTS xE926**	A_GEXP	5,748,870	3,342,876	15,856	27,803	278	4	4,129	206,533
33	LR	**Employee Pension/Benefits Acct E926**	LABOR								
34	LR										
35	LR	**TOTAL OPERATION & MAINT LABOR EXPENSE**		159,006,836	99,245,373	383,571	696,138	14,583	226	67,269	6,103,253

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
1	LR	**DEVELOPMENT OF LABOR ALLOCATION FACTOR**								
2	LR									
3	LR	**PRODUCTION LABOR EXPENSE**	not_used	0	0	0	0	0	0	0
4	LR									
5	LR	**TRANSMISSION LABOR EXPENSE**	not_used	0	0	0	0	0	0	0
6	LR									
7	LR	**DISTRIBUTION LABOR EXPENSE**								
8	LR	Operation								
9	LR	582-Station Equipment	E367PLT	30	483	55,624	45,190	11,657	10,294	0
10	LR	583-Overhead Lines	E367PLT	99	1,621	186,695	151,675	39,125	34,549	0
11	LR	584-Underground Lines	E367PLT	483	7,901	909,980	739,286	190,701	168,399	0
12	LR	586-Metering	MTROMMIN_07			297,894	1,653,831	137,755	33,846	4,554
13	LR	587-Customer Installations	CUSTAVG_04	662	173,807	2,125,740	70,264	5,853	1,438	193
14	LR	588-Miscellaneous	DISTEXPO	868	30,579	2,777,636	4,413,517	750,635	527,651	6,099
15	LR	Total Operation		2,142	214,391	6,353,567	7,073,763	1,135,727	776,176	10,847
16	LR	Maintenance								
17	LR	590-Supervision & Engineering	DISTEXPM	0	0	0	0	0	0	0
18	LR	591-Structures	E361PLT	95	14,180	555,442	436,535	105,632	104,224	116
19	LR	592-Station Equipment	E362PLT			2,076,017	1,706,497	439,579	448,944	
20	LR	593-Overhead Lines	E365PLT	872	34,442	2,385,708	1,945,556	499,963	345,710	
21	LR	594-Underground Lines	E367PLT	1,193	19,504	2,246,430	1,825,045	470,777	415,719	0
22	LR	595-Line Transformers	LNTRFRMR_04	347	3,317	344,093	320,906			
23	LR	596-Street Lighting and Signal Systems	E373PLT	72	1,533,026	190,782	145,825	32,272	30,230	1
24	LR	597-Meters	MTROMMIN_07			48,406	268,736	22,384	5,500	740
25	LR	598-Other Distribution Maintenance	DISTEXPM	1,492	17,018	100,648	83,500	20,559	16,838	5
26	LR	Total Maintenance		4,072	1,621,488	7,947,525	6,732,602	1,591,166	1,367,165	862
27	LR	TOTAL DISTRIBUTION LABOR EXPENSE		6,214	1,835,878	14,301,092	13,806,364	2,726,892	2,143,341	11,709
28	LR									
29	LR	**E901-E903,E905 CUST ACCOUNTS EXPENSE**	CUSTACCTS	2,374	615,994	10,339,553	3,111,855	259,278	63,738	8,563
30	LR	**E907-E910, xDSM CUST SERV & INFO EXP**	CUSTS_I	223	35,938	913,560	146,473	12,444	3,166	382
31	LR	**E911-E916 SALES EXPENSE**	SALESEXP							
32	LR	**ADMIN & GENERAL EXP ACCOUNTS xE926**	A_GEXP	560	70,393	1,120,014	629,879	172,904	157,070	570
33	LR	**Employee Pension/Benefits Acct E926**	LABOR							
34	LR									
35	LR	**TOTAL OPERATION & MAINT LABOR EXPENSE**		9,372	2,558,203	26,674,219	17,694,571	3,171,518	2,367,315	21,224

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	CA	**DEVELOPMENT OF CAPITAL ADDITIONS ALLOCATION F**									
2	CA										
3	CA	**INTANGIBLE PLANT**	INTANGPLT	49,607,381	37,090,615	128,546	216,420	3,654	56	4,760	110,106
4	CA										
5	CA	**PRODUCTION PLANT**	not_used	0	0	0	0	0	0	0	0
6	CA										
7	CA	**TRANSMISSION PLANT**									
8	CA	E352 Structure & Improvements	not_used	0	0	0	0	0	0	0	0
9	CA	E353 Station Equipment	not_used	0	0	0	0	0	0	0	0
10	CA	E354/355 Towers and Fixtures	not_used	0	0	0	0	0	0	0	0
11	CA	E356 OH Cond and Devices	not_used	0	0	0	0	0	0	0	0
12	CA	E357 UG Conduits	not_used	0	0	0	0	0	0	0	0
13	CA	E358 Underground Cond. and Devices	not_used	0	0	0	0	0	0	0	0
14	CA	E359 Roads and Trails	not_used	0	0	0	0	0	0	0	0
15	CA	Other Tangible Plant Unallocated	not_used	0	0	0	0	0	0	0	0
16	CA	TOTAL TRANSMISSION PLANT		0	0	0	0	0	0	0	0
17	CA										
18	CA	**DISTRIBUTION PLANT**									
19	CA	E360 Land and Land Rights	E360PLT	3,481,598	1,668,426	6,323	17,520	23	0	1,555	33,547
20	CA	E361 Structures and Improvements	E361PLT	1,433,350	715,592	3,041	7,092	18	0	798	25,805
21	CA	E362 Station Equipment	E362PLT	72,557,752	33,096,998	106,244	372,183	0	0	23,182	0
22	CA	E364 Poles Towers and Fixtures	E364PLT	86,501,520	45,725,365	225,238	416,050	0	0	95,204	867,098
23	CA	E365 OH Conductors and Dev.	E365PLT	235,018,380	124,025,652	560,469	1,191,626	0	0	217,592	563,852
24	CA	E366 Underground Conduits	E367PLT	3,221,386	1,765,210	8,703	16,052	0	0	3,678	12,658
25	CA	E367 Underground Cond. and Dev.	E367PLT	32,807,746	17,977,532	88,638	163,484	0	0	37,459	128,919
26	CA	E368 Line Transformers	LNTRFRMR_04	92,859,144	66,293,533	502,777	421,178	0	0	88,669	287,698
27	CA	E369 Services	E369PLT	11,962,969	7,636,864	44,738	74,744	401	6	0	0
28	CA	E370 Meters	METERPLT	73,420,491	56,940,607	183,454	306,500	48,386	755	20,836	0
29	CA	E371 Installation on Customer Premise	not_used	0	0	0	0	0	0	0	0
30	CA	E373 Street Lighting	E373PLT	39,887,684	2,620,298	13,572	23,624	10	0	3,941	27,398,679
31	CA	E374 Asset Retirement Obligations	TOTPLT								
32	CA	TOTAL DISTRIBUTION PLANT		653,152,020	358,466,077	1,743,198	3,010,053	48,838	762	492,914	29,318,255
33	CA										
34	CA	**TOTAL CAPITAL ADDITIONS**		702,759,401	395,556,693	1,871,744	3,226,472	52,492	818	497,674	29,428,361

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
1	CA	**DEVELOPMENT OF CAPITAL ADDITIONS ALLOCATION F**								
2	CA									
3	CA	**INTANGIBLE PLANT**	INTANGPLT	2,006	510,000	8,708,646	2,559,649	213,383	52,507	7,033
4	CA									
5	CA	**PRODUCTION PLANT**	not_used	0	0	0	0	0	0	0
6	CA									
7	CA	**TRANSMISSION PLANT**								
8	CA	E352 Structure & Improvements	not_used	0	0	0	0	0	0	0
9	CA	E353 Station Equipment	not_used	0	0	0	0	0	0	0
10	CA	E354/355 Towers and Fixtures	not_used	0	0	0	0	0	0	0
11	CA	E356 OH Cond and Devices	not_used	0	0	0	0	0	0	0
12	CA	E357 UG Conduits	not_used	0	0	0	0	0	0	0
13	CA	E358 Underground Cond. and Devices	not_used	0	0	0	0	0	0	0
14	CA	E359 Roads and Trails	not_used	0	0	0	0	0	0	0
15	CA	Other Tangible Plant Unallocated	not_used	0	0	0	0	0	0	0
16	CA	TOTAL TRANSMISSION PLANT		0	0	0	0	0	0	0
17	CA									
18	CA	**DISTRIBUTION PLANT**								
19	CA	E360 Land and Land Rights	E360PLT	69	10,322	790,491	635,199	158,661	159,377	84
20	CA	E361 Structures and Improvements	E361PLT	53	7,940	311,011	244,431	59,147	58,358	65
21	CA	E362 Station Equipment	E362PLT	0	0	17,315,176	14,233,170	3,666,345	3,744,454	0
22	CA	E364 Poles Towers and Fixtures	E364PLT	8,771	243,029	16,555,186	13,452,488	3,473,483	5,439,608	0
23	CA	E365 OH Conductors and Dev.	E365PLT	18,149	716,686	49,643,027	40,484,125	10,403,490	7,193,712	0
24	CA	E366 Underground Conduits	E367PLT	339	5,544	638,501	518,731	133,809	118,160	0
25	CA	E367 Underground Cond. and Dev.	E367PLT	3,454	56,459	6,502,723	5,282,945	1,362,754	1,203,380	0
26	CA	E368 Line Transformers	LNTRFRMR_04	13,113	125,329	13,001,478	12,125,371	0	0	0
27	CA	E369 Services	E369PLT	0	0	3,888,152	281,643	23,459	12,962	0
28	CA	E370 Meters	METERPLT	0	0	13,177,991	1,527,236	578,165	448,334	188,226
29	CA	E371 Installation on Customer Premise	not_used	0	0	0	0	0	0	0
30	CA	E373 Street Lighting	E373PLT	368	7,797,248	970,351	741,692	164,139	153,756	6
31	CA	E374 Asset Retirement Obligations	TOTPLT							
32	CA	TOTAL DISTRIBUTION PLANT		44,316	8,962,556	122,794,087	89,527,032	20,023,451	18,532,100	188,380
33	CA									
34	CA	**TOTAL CAPITAL ADDITIONS**		46,322	9,472,556	131,502,733	92,086,681	20,236,834	18,584,607	195,414

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	AF	**ALLOCATION FACTOR TABLE**									
2	AF	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**									
3	AF										
4	AF	**ALLOCATION FACTORS PART A**									
5	AF										
6	AF	Number of Customers x Aux &SL rates - local	CUSTNUMX_04	2,318,149	2,000,647	6,950	11,612	0	0	0	0
7	AF										
8	AF										
9	AF	CP @ 26 kV lines - switching station load -systems	CP_SUBT_05	2,437,470	892,509	2,865	10,036	0	0	625	0
10	AF	CP @ primary lines - systems	CP_PRI_05	8,789,384	4,227,413	13,570	47,538	0	0	2,961	0
11	AF	Sum Cust Peaks @ 26 kV lines - local	SUMPK_SUBT_04	0	0	0	0	0	0	0	0
12	AF	Sum Cust Peaks @ primary lines - local	SUMPK_PRI_04	19,689,051	12,040,483	66,857	100,114	0	0	31,146	66,136
13	AF	Sum Cust Peaks @ secondary lines - local	SUMPK_SEC_04	20,498,179	11,830,661	65,692	98,370	0	0	30,604	64,983
14	AF										
15	AF										
16	AF	**BILLING DETERMINANTS**									
17	AF										
18	AF	Number of Customers		2,348,219	2,000,647	6,950	11,612	662	10	789	4,938
19	AF	Delivered kWh @ Meter - annual (w/n net)		40,231,265,119	13,286,613,062	93,109,748	189,891,666	581,366	7,149	11,877,324	283,298,553
20	AF	Delivered Kw @ Meter - annual		0	0	0	0	0	0	0	0
21	AF										
22	AF										
23	AF	**ALLOCATION FACTORS PART B**									
24	AF										
25	AF	Delivery kWh @ meter	KWHMETER_04	40,816,033,564	13,685,554,460	93,469,833	195,107,964	584,797	7,149	11,887,502	283,298,553
26	AF	Delivery kWh @ meter x non-profiled rates	KWHMETERX_04	21,338,981,079	13,685,554,460	93,469,833	195,107,964	584,797	7,149	11,887,502	0
27	AF										
28	AF										
29	AF	**ALLOCATION FACTORS PART C**									
30	AF										
31	AF	Draft EC Proforma	ECPRO_07	472,721,631	380,825,641	1,226,966	2,049,910	323,611	5,048	139,357	0
32	AF	E587 Customer Installation Expenses Local	CUSINT_04	112	100	1	1	1	1	1	1
33	AF	E587 Customer Installation Expenses System	CUSINT_05	112	100	1	1	1	1	1	1
34	AF	E369 minimum Service investment- access	SERVICESMIN_03	1,445,778,695	922,949,463	5,406,749	9,033,137	48,429	755	0	0
35	AF	E369 excess Service investment- local delivery	SERVICESEXC_04	0	0	0	0	0	0	0	0
36	AF	Avg Customer Bills - local	CUSTAVG_04	2,348,219	2,000,647	6,950	11,612	662	10	789	4,938
37	AF	Avg Customer Bills - cust svs	CUSTAVG_06	2,348,219	2,000,647	6,950	11,612	662	10	789	4,938
38	AF	E370 minimum meter investment - measurement	METERSMIN_07	456,573,728	380,825,641	1,226,966	2,049,910	323,611	5,048	139,357	0
39	AF	E368 Line Transfomers - local	LNTRFRMR_04	559,887,636	399,712,164	3,031,461	2,539,460	0	0	534,622	1,734,652
40	AF	Billing Function costs - cust svs	BILLING_06	130,951	94,645	329	549	6	0	7	397
41	AF	E370 excess meter investment - local delivery	METERSEXC_04	34,490,851	0	0	0	0	0	0	0
42	AF										
43	AF	Account Maint - cust svs	ACCTMAINT_06	80,564,013	67,106,800	233,135	389,502	21,207	331	25,273	19,139
44	AF	Meter Reading Costs - measurement	MRCOST_07	20,538,511	16,168,305	56,170	93,844	1,071	17	1,276	0
45	AF	Sales	SALES_06	0	0	0	0	0	0	0	0
46	AF	Other Utility work by Cust Ops - local	UTILWORK_04	3,334,747	2,438,140	7,794	16,634	202	2	1,125	16,667
47	AF										
48	AF	Choice - local	CHOICE_04	0	0	0	0	0	0	0	0
49	AF										
50	AF	Direct - PSAL - streetlighting	DIR_PSAL_02	1	0	0	0	0	0	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
1	AF	**ALLOCATION FACTOR TABLE**								
2	AF	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**								
3	AF									
4	AF	**ALLOCATION FACTORS PART A**								
5	AF									
6	AF	Number of Customers x Aux &SL rates - local	CUSTNUMX_04	0	0	288,392	9,532	794	195	26
7	AF									
8	AF									
9	AF	CP @ 26 kV lines - switching station load -systems	CP_SUBT_05	0	0	466,929	383,818	98,868	581,819	0
10	AF	CP @ primary lines - systems	CP_PRI_05	0	0	2,211,633	1,817,974	468,295	0	0
11	AF	Sum Cust Peaks @ 26 kV lines - local	SUMPK_SUBT_04	0	0	0	0	0	0	0
12	AF	Sum Cust Peaks @ primary lines - local	SUMPK_PRI_04	3,153	32,502	3,650,708	2,944,830	753,120	0	0
13	AF	Sum Cust Peaks @ secondary lines - local	SUMPK_SEC_04	3,098	31,936	3,587,089	2,893,512	753,120	1,139,114	0
14	AF									
15	AF									
16	AF	**BILLING DETERMINANTS**								
17	AF									
18	AF	Number of Customers		90	23,580	288,392	9,532	794	195	26
19	AF	Delivered kWh @ Meter - annual (w/n net)		15,313,401	137,520,699	7,289,563,210	10,497,945,935	3,083,571,353	4,669,504,753	672,466,899
20	AF	Delivered Kw @ Meter - annual		0	0	0	0	0	0	0
21	AF									
22	AF									
23	AF	**ALLOCATION FACTORS PART B**								
24	AF									
25	AF	Delivery kWh @ meter	KWHMETER_04	15,313,401	137,520,699	7,352,369,374	10,589,422,620	3,109,525,559	4,669,504,753	672,466,899
26	AF	Delivery kWh @ meter x non-profiled rates	KWHMETERX_04	0	0	7,352,369,374	0	0	0	0
27	AF									
28	AF									
29	AF	**ALLOCATION FACTORS PART C**								
30	AF									
31	AF	Draft EC Proforma	ECPRO_07	0	0	88,151,097	0	0	0	0
32	AF	E587 Customer Installation Expenses Local	CUSINT_04	1	1	1	1	1	0	1
33	AF	E587 Customer Installation Expenses System	CUSINT_05	1	1	1	1	1	0	1
34	AF	E369 minimum Service investment- access	SERVICESMIN_03	0	0	469,900,712	34,037,800	2,835,169	1,566,481	0
35	AF	E369 excess Service investment- local delivery	SERVICESEXC_04	0	0	0	0	0	0	0
36	AF	Avg Customer Bills - local	CUSTAVG_04	90	23,580	288,392	9,532	794	195	26
37	AF	Avg Customer Bills - cust svs	CUSTAVG_06	90	23,580	288,392	9,532	794	195	26
38	AF	E370 minimum meter investment - measurement	METERSMIN_07	0	0	61,413,169	5,406,906	1,411,504	2,512,740	1,258,876
39	AF	E368 Line Transformers - local	LNTRFRMR_04	79,064	755,659	78,391,489	73,109,064	0	0	0
40	AF	Billing Function costs - cust svs	BILLING_06	7	1,896	23,193	8,966	747	183	25
41	AF	E370 excess meter investment - local delivery	METERSEXC_04	0	0	26,737,929	4,810,153	2,456,723	486,046	0
42	AF									
43	AF	Account Maint - cust svs	ACCTMAINT_06	348	91,387	10,058,899	2,365,984	197,074	48,420	6,515
44	AF	Meter Reading Costs - measurement	MRCOST_07	0	0	3,962,103	231,110	19,250	4,730	636
45	AF	Sales	SALES_06	0	0	0	0	0	0	0
46	AF	Other Utility work by Cust Ops - local	UTILWORK_04	310	45,217	747,005	55,155	4,982	1,398	118
47	AF									
48	AF	Choice - local	CHOICE_04	0	0	0	0	0	0	0
49	AF									
50	AF	Direct - PSAL - streetlighting	DIR_PSAL_02	0	1	0	0	0	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
51	AF	Direct - BPL - streetlighting	DIR_BPL_02	1	0	0	0	0	0	0	1
52	AF	Direct - BPL-POF - streetlighting	DIR_BPLPOF_02	1	0	0	0	0	0	0	0
53	AF	Direct - HTS-HV - access	DIR_HTSHV_03	1	0	0	0	0	0	0	0
54	AF	Direct - HEP - access	DIR_HEP_03	0	0	0	0	0	0	0	0
55	**AF**	**ALLOCATION FACTOR TABLE CONTINUED**									
56	**AF**	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**									
57	AF	Direct - HTS-Sub - systems	DIR_HTSS_05	0	0	0	0	0	0	0	0
58	AF										
59	AF	Direct - HTS-Sub - local	DIR_HTSS_04	1	0	0	0	0	0	0	0
60	AF	Meter O&M - minimum - measurement	MTROMMIN_07	6,387,137	3,201,035	11,121	18,579	3,047	48	1,263	0
61	AF	Meter O&M - excess - measurement	MTROMEXC_07	0	0	0	0	0	0	0	0
62	AF	WN TEFA Responsibility	TEFA_04	0	0	0	0	0	0	0	0
63	AF	E370 excess meter investment - dummy	METERSEXC_08	0	0	0	0	0	0	0	0
64	AF	Meter O&M - excess - dummy	MTROMEXC_08	0	0	0	0	0	0	0	0
65	AF	E369 excess Service investment- dummy	SERVICESEXC_08	0	0	0	0	0	0	0	0
66	AF	E368 Line Transfomers - dummy	LNTRFRMR_08	0	0	0	0	0	0	0	0
67	AF	CP @ 26 kV lines - switching station load - dummy	CP@SUBT_08	0	0	0	0	0	0	0	0
68	AF	CP @ primary lines - dummy	CP@PRI_08	0	0	0	0	0	0	0	0
69	AF	Sum Cust Peaks @ secondary lines - local	SUMPK@SEC_08	0	0	0	0	0	0	0	0
70	AF										
71	AF										
72	AF	Dummy allocator for unused lines	not_used	0	0	0	0	0	0	0	0
73	AF										
74	AF										
75	AF	**Plant Related**									
76	AF	Distribution Plant Total	DISTPLT	10,773,828,418	5,820,088,197	29,590,307	51,442,720	262,256	4,091	8,431,071	378,322,216
77	AF	Distribution Plant x meters	DISTPLTXMTR	10,408,406,976	5,536,688,858	28,677,235	49,917,236	21,434	334	8,327,366	378,322,216
78	AF	Acct E360 - Land & Land Rights	E360PLT	51,314,168	24,590,406	93,192	258,220	343	5	22,915	494,440
79	AF	Acct E361 - Structures & Improvments	E361PLT	242,256,447	120,945,102	513,987	1,198,594	3,023	47	134,914	4,361,446
80	AF	Acct E362 - Station Equipment	E362PLT	1,565,418,169	714,060,742	2,292,183	8,029,772	0	0	500,149	0
81	AF	Acct E364 - Poles & Towers	E364PLT	1,027,443,483	543,114,479	2,675,325	4,941,739	0	0	1,130,805	10,299,169
82	AF	Acct E365 - OH Conductors & Devices x HTSHV	E365PLT	2,856,184,590	1,507,287,026	6,811,401	14,481,863	0	0	2,644,403	6,852,510
83	AF	Acct E366 - UG Conduit	E366PLT	512,107,003	280,617,273	1,383,575	2,551,877	3	0	584,708	2,012,335
84	AF	Acct E367 - UG Conductors & Devices x HEP	E367PLT	1,431,183,475	784,240,015	3,866,673	7,131,720	8	0	1,634,080	5,623,864
85	AF	Acct E369 Services	E369PLT	535,269,333	341,702,741	2,001,736	3,344,330	17,930	280	0	0
86	AF	Acct E370 Meters	METERPLT	365,421,442	283,399,339	913,072	1,525,483	240,822	3,757	103,705	0
87	AF										
88	AF	Acct E370 Meters x load profile meters	METERPLTXPR	365,421,442	283,399,339	913,072	1,525,483	240,822	3,757	103,705	0
89	AF	Acct E373 - Streetlights	E373PLT	499,027,153	32,782,049	169,794	295,554	127	2	49,305	342,779,606
90	AF	Subtrans Lines - HTS-S/Switching Station load	SUBTRANSLINES	1.0000	0.2889	0.0009	0.0032			0.0002	
91	AF	Primary Lines - 50 Sys CP/50 Loc Sum Cust Pks	PRIMARYLINES	1.0000	0.5462	0.0025	0.0052			0.0010	0.0017
92	AF										
93	AF	Acct E301-E303 Intangible Plt	INTANGPLT	40,584,928	30,344,677	105,166	177,058	2,989	46	3,894	90,080
94	AF	Acct E399.10-23 Oth Tangible Plt	TANGPLT	86,338,967	64,496,329	223,981	377,130	6,298	97	8,588	205,683
95	AF	E391-E398 General Plant	GENPLT	429,584,593	228,514,914	1,183,591	2,060,226	885	14	343,694	15,614,435
96	AF	Common Plant	COMPLT	126,654,044	87,400,522	333,738	567,199	6,907	107	35,966	1,435,377
97	AF	Accts C389-C399, E389-E399 Com & Gen Plt	COMGENPLT	556,238,637	315,915,436	1,517,329	2,627,425	7,792	120	379,660	17,049,812
98	AF										
99	AF	Total Plant	TOTPLT	11,456,990,950	6,230,844,640	31,436,784	54,624,332	279,335	4,355	8,823,214	395,667,792
100	AF										

PUBLIC SERVICE ELECTRIC & GAS COMPANY
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12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
51	AF	Direct - BPL - streetlighting	DIR_BPL_02	0	0	0	0	0	0	0
52	AF	Direct - BPL-POF - streetlighting	DIR_BPLPOF_02	1	0	0	0	0	0	0
53	AF	Direct - HTS-HV - access	DIR_HTSHV_03	0	0	0	0	0	0	1
54	AF	Direct - HEP - access	DIR_HEP_03	0	0	0	0	0	0	0
55	**AF**	**ALLOCATION FACTOR TABLE CONTINUED**								
56	**AF**	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**								
57	AF	Direct - HTS-Sub - systems	DIR_HTSS_05	0	0	0	0	0	0	0
58	AF									
59	AF	Direct - HTS-Sub - local	DIR_HTSS_04	0	0	0	0	0	1	0
60	AF	Meter O&M - minimum - measurement	MTROMMIN_07	0	0	441,272	2,449,831	204,058	50,136	6,746
61	AF	Meter O&M - excess - measurement	MTROMEXC_07	0	0	0	0	0	0	0
62	AF	WN TEFA Responsibility	TEFA_04	0	0	0	0	0	0	0
63	AF	E370 excess meter investment - dummy	METERSEXC_08	0	0	0	0	0	0	0
64	AF	Meter O&M - excess - dummy	MTROMEXC_08	0	0	0	0	0	0	0
65	AF	E369 excess Service investment- dummy	SERVICESEXC_08	0	0	0	0	0	0	0
66	AF	E368 Line Transfomers - dummy	LNTRFRMR_08	0	0	0	0	0	0	0
67	AF	CP @ 26 kV lines - switching station load - dummy	CP@SUBT_08	0	0	0	0	0	0	0
68	AF	CP @ primary lines - dummy	CP@PRI_08	0	0	0	0	0	0	0
69	AF	Sum Cust Peaks @ secondary lines - local	SUMPK@SEC_08	0	0	0	0	0	0	0
70	AF									
71	AF									
72	AF	Dummy allocator for unused lines	not_used	0	0	0	0	0	0	0
73	AF									
74	AF									
75	AF	**Plant Related**								
76	AF	Distribution Plant Total	DISTPLT	778,473	116,404,096	2,115,939,717	1,574,796,259	349,702,577	327,117,359	949,079
77	AF	Distribution Plant x meters	DISTPLTXMTR	778,473	116,404,096	2,050,351,482	1,567,195,044	346,824,988	324,885,954	12,261
78	AF	Acct E360 - Land & Land Rights	E360PLT	1,017	152,132	11,650,793	9,362,003	2,338,448	2,349,013	1,240
79	AF	Acct E361 - Structures & Improvments	E361PLT	8,975	1,341,952	52,565,192	41,312,252	9,996,655	9,863,367	10,941
80	AF	Acct E362 - Station Equipment	E362PLT	0	0	373,571,272	307,077,645	79,100,612	80,785,795	0
81	AF	Acct E364 - Poles & Towers	E364PLT	104,180	2,886,640	196,638,373	159,785,302	41,257,161	64,610,311	0
82	AF	Acct E365 - OH Conductors & Devices x HTSHV	E365PLT	220,559	8,709,908	603,313,016	492,004,642	126,433,892	87,425,369	0
83	AF	Acct E366 - UG Conduit	E366PLT	53,911	881,281	101,503,167	82,463,239	21,271,683	18,783,951	2
84	AF	Acct E367 - UG Conductors & Devices x HEP	E367PLT	150,665	2,462,911	283,670,511	230,459,698	59,447,890	52,495,436	5
85	AF	Acct E369 Services	E369PLT	0	0	173,970,914	12,601,784	1,049,662	579,957	0
86	AF	Acct E370 Meters	METERPLT	0	0	65,588,236	7,601,215	2,877,589	2,231,405	936,819
87	AF									
88	AF	Acct E370 Meters x load profile meters	METERPLTXPR	0	0	65,588,236	7,601,215	2,877,589	2,231,405	936,819
89	AF	Acct E373 - Streetlights	E373PLT	4,609	97,549,871	12,139,877	9,279,168	2,053,508	1,923,610	73
90	AF	Subtrans Lines - HTS-S/Switching Station load	SUBTRANSLINES			0.1511	0.1242	0.0320	0.3993	
91	AF	Primary Lines - 50 Sys CP/50 Loc Sum Cust Pks	PRIMARYLINES	0.0001	0.0008	0.2185	0.1782	0.0458		
92	AF									
93	AF	Acct E301-E303 Intangible Plt	INTANGPLT	1,641	417,243	7,124,741	2,094,107	174,573	42,957	5,754
94	AF	Acct E399.10-23 Oth Tangible Plt	TANGPLT	3,459	875,602	15,188,498	4,454,551	381,537	105,174	12,038
95	AF	E391-E398 General Plant	GENPLT	32,130	4,804,328	84,623,844	64,682,602	14,314,455	13,408,968	506
96	AF	Common Plant	COMPLT	6,284	1,332,635	22,959,377	9,882,482	1,526,297	1,153,953	13,202
97	AF	Accts C389-C399, E389-E399 Com & Gen Plt	COMGENPLT	38,413	6,136,963	107,583,221	74,565,084	15,840,751	14,562,921	13,708
98	AF									
99	AF	Total Plant	TOTPLT	821,986	123,833,904	2,245,836,177	1,655,910,001	366,099,439	341,828,412	980,578
100	AF									

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
101	AF	Total Distribution Plant Reserve	TOTDRESERVE	3,099,332,698	1,730,330,862	8,737,683	14,901,854	107,752	1,679	2,361,921	97,434,992
102	AF	Total Net Plant	TOTPLTNET	8,357,658,252	4,500,513,778	22,699,101	39,722,478	171,583	2,675	6,461,292	298,232,800
103	AF										
104	AF										
105	AF	**Revenue Related**									
106	AF	Total Operating Revenue	TOTREV	1,925,019,676	1,083,403,222	5,076,085	8,989,364	128,489	2,001	1,329,844	65,131,457
107	**AF**	**ALLOCATION PROPORTIONS TABLE CONTINUED**									
108	**AF**	**INTERNALLY DEVELOPED ALLOCATION FACTORS**									
109	AF										
110	AF	**Expense Related**									
111	AF	Distr Oper Exp	DISTEXPO	52,242,807	23,912,641	105,368	221,695	6,574	103	38,573	472,417
112	AF	Distr Maint Exp	DISTEXPM	123,204,777	57,907,160	260,376	557,434	492	8	90,243	8,510,628
113	AF	Cust Serv & Info Expense	CUSTS_I	5,318,001	4,196,182	14,170	25,852	936	14	1,649	11,564
114	AF	Acct E901-E903,E905 Cust Acct Exp Excl 904	CACCTEXP	94,394,062	70,356,872	244,210	409,157	6,408	100	7,918	209,752
115	AF	Accts E901-E910 Excl 904 - Cust Accts,Serv & Info	CUSTSVSX	99,712,063	74,553,054	258,380	435,009	7,344	113	9,567	221,316
116	AF	Sales Expense	SALESEXP	40,922	29,919	96	204	2	0	14	205
117	AF	Total O&M Expense Excl 904-Uncollectibles	TOTOMXAG	311,457,637	173,966,343	750,380	1,424,953	12,706	197	187,558	10,355,250
118	AF	Tot Admin & Genl Exp xPension/Ben	A_GEXP	111,662,106	64,929,729	307,984	540,030	5,407	84	80,203	4,011,548
119	AF	Accts E901-E905 Cust Accts Exp Excl 904-Uncol	CUSTACCTS	94,394,062	70,356,872	244,210	409,157	6,408	100	7,918	209,752
120	AF	O&M + Capital Additions	EXPENDITURES	1,014,217,038	569,523,035	2,622,124	4,651,426	65,198	1,015	685,232	39,783,611
121	AF										
122	AF	Depreciation Expense (total)	DEPREXP	286,771,855	156,133,565	786,764	1,366,959	6,818	106	220,165	9,875,199
123	AF										
124	AF	NJ State Income Tax (CBT)	STATEINCTAX	119,869,746	66,297,922	323,675	565,555	7,057	110	89,168	4,137,391
125	AF	NJ State Deferred Income Tax	DFSTATEINCTAX	2,766,183	1,804,131	6,398	11,771	318	5	853	108,621
126	AF										
127	AF	**Labor Expense Related**									
128	AF	Total Distribution Exp (Oper) Labor	TLABDO	43,603,802	27,494,585	107,058	195,722	8,974	140	25,248	205,461
129	AF	Total Distribution Exp (Maint) Labor	TLABDM	45,417,214	20,286,632	94,038	191,256	370	6	31,250	5,548,783
130	AF	Total Labor	LABOR	159,006,836	99,245,373	383,571	696,138	14,583	226	67,269	6,103,253
131	AF										
132	AF	**REVENUES AND BILLING DETERMINANTS**									
133	AF										
134	AF	Base Rate Sales Revenue	SALESREV	1,899,915,237	1,071,330,372	5,019,520	8,889,191	127,057	1,979	1,308,648	64,405,668
135	AF										
136	AF	Residential Service	REVRS	1,071,330,372	1,071,330,372	0	0	0	0	0	0
137	AF	Residential Heating Service	REVRHS	5,019,520	0	5,019,520	0	0	0	0	0
138	AF	Residential Load Management Service	REVRLM	8,889,191	0	0	8,889,191	0	0	0	0
139	AF	Water Heating Service	REVWH	127,057	0	0	0	127,057	0	0	0
140	AF	Water Heating Storage Service	REVWHS	1,979	0	0	0	0	1,979	0	0
141	AF	Building Heating Service	REVHS	1,308,648	0	0	0	0	0	1,308,648	0
142	AF	Body Police Lighting Service	REVBLP	64,405,668	0	0	0	0	0	0	64,405,668
143	AF	Body Police Lighting Service from Publicly Owned	REVBLPPOF	506,728	0	0	0	0	0	0	0
144	AF	Private Street and Area Lighting Service	REVPAL	22,801,929	0	0	0	0	0	0	0
145	AF	General Power and Lighting Service	REVGLP	362,840,766	0	0	0	0	0	0	0
146	AF	Large Power and Lighting Service - Secondary	REVLPLS	255,737,125	0	0	0	0	0	0	0
147	AF	Large Power and Lighting Service - Primary	REVLPLP	55,996,770	0	0	0	0	0	0	0
148	AF	High Tension Service - Subtransmission	REVHTSS	50,758,783	0	0	0	0	0	0	0
149	AF	High Tension Service - High Voltage	REVHTSHV	190,699	0	0	0	0	0	0	0
150	AF	HEP	REVHEP	0	0	0	0	0	0	0	0

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				(9)	(10)	(11)	(12)	(13)	(14)	(15)
101	AF	Total Distribution Plant Reserve	TOTDRESERVE	223,683	31,039,060	616,155,185	420,676,004	92,737,788	84,253,932	370,301
102	AF	Total Net Plant	TOTPLTNET	598,304	92,794,843	1,629,680,992	1,235,233,997	273,361,651	257,574,480	610,278
103	AF									
104	AF									
105	AF	**Revenue Related**								
106	AF	Total Operating Revenue	TOTREV	512,439	23,171,254	368,717,729	259,879,321	56,903,755	51,580,928	193,788
107	**AF**	**ALLOCATION PROPORTIONS TABLE CONTINUED**								
108	**AF**	**INTERNALLY DEVELOPED ALLOCATION FACTORS**								
109	AF									
110	AF	**Expense Related**								
111	AF	Distr Oper Exp	DISTEXPO	2,805	98,798	8,974,334	14,259,747	2,425,247	1,704,800	19,707
112	AF	Distr Maint Exp	DISTEXPM	347,352	3,961,344	23,427,630	19,436,252	4,785,399	3,919,255	1,205
113	AF	Cust Serv & Info Expense	CUSTS_I	214	34,498	876,964	140,606	11,945	3,040	367
114	AF	Acct E901-E903,E905 Cust Acct Exp Excl 904	CACCTEXP	3,818	990,615	16,627,629	5,004,352	416,960	102,501	13,770
115	AF	Accts E901-E910 Excl 904 - Cust Accts,Serv & Info	CUSTSVSX	4,032	1,025,113	17,504,593	5,144,958	428,905	105,541	14,137
116	AF	Sales Expense	SALESEXP	4	555	9,167	677	61	17	1
117	AF	Total O&M Expense Excl 904-Uncollectibles	TOTOMXAG	364,051	5,252,672	59,086,204	42,788,394	9,533,880	7,699,207	35,840
118	AF	Tot Admin & Genl Exp xPension/Ben	A_GEXP	10,885	1,367,272	21,754,386	12,234,333	3,358,368	3,050,811	11,067
119	AF	Accts E901-E905 Cust Accts Exp Excl 904-Uncol	CUSTACCTS	3,818	990,615	16,627,629	5,004,352	416,960	102,501	13,770
120	AF	O&M + Capital Additions	EXPENDITURES	410,373	14,725,229	190,588,937	134,875,075	29,770,714	26,283,814	231,253
121	AF									
122	AF	Depreciation Expense (total)	DEPREXP	20,562	3,103,283	56,193,328	41,376,181	9,137,198	8,528,035	23,691
123	AF									
124	AF	NJ State Income Tax (CBT)	STATEINCTAX	11,848	1,303,461	23,254,074	16,699,491	3,698,670	3,471,274	10,049
125	AF	NJ State Deferred Income Tax	DFSTATEINCTAX	152	49,020	439,370	274,752	43,614	26,753	424
126	AF									
127	AF	**Labor Expense Related**								
128	AF	Total Distribution Exp (Oper) Labor	TLABDO	2,142	214,391	6,353,567	7,073,763	1,135,727	776,176	10,847
129	AF	Total Distribution Exp (Maint) Labor	TLABDM	4,072	1,621,488	7,947,525	6,732,602	1,591,166	1,367,165	862
130	AF	Total Labor	LABOR	9,372	2,558,203	26,674,219	17,694,571	3,171,518	2,367,315	21,224
131	AF									
132	AF	**REVENUES AND BILLING DETERMINANTS**								
133	AF									
134	AF	Base Rate Sales Revenue	SALESREV	506,728	22,801,929	362,840,766	255,737,125	55,996,770	50,758,783	190,699
135	AF									
136	AF	Residential Service	REVRS	0	0	0	0	0	0	0
137	AF	Residential Heating Service	REVRHS	0	0	0	0	0	0	0
138	AF	Residential Load Management Service	REVRLM	0	0	0	0	0	0	0
139	AF	Water Heating Service	REVWH	0	0	0	0	0	0	0
140	AF	Water Heating Storage Service	REVWHS	0	0	0	0	0	0	0
141	AF	Building Heating Service	REVHS	0	0	0	0	0	0	0
142	AF	Body Police Lighting Service	REVBLP	0	0	0	0	0	0	0
143	AF	Body Police Lighting Service from Publicly Owned	REVBLPPOF	506,728	0	0	0	0	0	0
144	AF	Private Street and Area Lighting Service	REVPAL	0	22,801,929	0	0	0	0	0
145	AF	General Power and Lighting Service	REVGLP	0	0	362,840,766	0	0	0	0
146	AF	Large Power and Lighting Service - Secondary	REVLPLS	0	0	0	255,737,125	0	0	0
147	AF	Large Power and Lighting Service - Primary	REVLPLP	0	0	0	0	55,996,770	0	0
148	AF	High Tension Service - Subtransmission	REVHTSS	0	0	0	0	0	50,758,783	0
149	AF	High Tension Service - High Voltage	REVHTSHV	0	0	0	0	0	0	190,699
150	AF	HEP	REVHEP	0	0	0	0	0	0	0

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12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
151	AF										
152	AF										
153	AF	Total Rev Req @ desired ROR	REVREQ	1,899,915,237	1,071,330,372	5,019,520	8,889,191	127,057	1,979	1,308,648	64,405,668
154	AF										
155	AF										
156	AF	**PRESENT REVENUES FROM SALES INPUT**									
157	AF										
158	AF	Total Sales of Electricity Revenues		0	0	0	0	0	0	0	0
159	AF	Sales of Electricity Revenues - Rates		1,254,696,745	597,284,000	4,407,000	7,778,000	52,355	161	740,000	56,059,000
160	AF	Sales of Electricity Revenues - Other		0	0	0	0	0	0	0	0
161	AF										
162	AF	**RATE OF RETURN**									
163	AF	Rate of Return (Equalized)	CALCULATED	7.55%	7.55%	7.55%	7.55%	7.55%	7.55%	7.55%	7.55%
164	AF	Expense Reclassification Plus-local	ADJ_Plus_04	17,563	0	0	0	7,136	111	0	0
165	AF	Expense Reclassification-local	ADJEXP_04	-17,563	-10,963	-42	-77	0	0	-7	-674

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
151	AF									
152	AF									
153	AF	Total Rev Req @ desired ROR	REVREQ	506,728	22,801,929	362,840,766	255,737,125	55,996,770	50,758,783	190,699
154	AF									
155	AF									
156	AF	**PRESENT REVENUES FROM SALES INPUT**								
157	AF									
158	AF	Total Sales of Electricity Revenues		0	0	0	0	0	0	0
159	AF	Sales of Electricity Revenues - Rates		322,229	27,815,000	264,859,000	223,909,000	38,961,000	30,175,000	2,335,000
160	AF	Sales of Electricity Revenues - Other		0	0	0	0	0	0	0
161	AF									
162	AF	**RATE OF RETURN**								
163	AF	Rate of Return (Equalized)	CALCULATED	7.55%	7.55%	7.55%	7.55%	7.55%	7.55%	7.55%
164	AF	Expense Reclassification Plus-local	ADJ_Plus_04	0	0	0	0	0	0	10,316
165	AF	Expense Reclassification-local	ADJEXP_04	-1	-283	-2,947	-1,955	-350	-262	0

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	AP	**ALLOCATION PROPORTIONS TABLE**									
2	AP	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**									
3	AP										
4	AP	**ALLOCATION FACTORS PART A**									
5	AP										
6	AP	Number of Customers x Aux &SL rates - local	CUSTNUMX_04	1.000000	0.863036	0.002998	0.005009	0.000000	0.000000	0.000000	0.000000
7	AP										
8	AP										
9	AP	CP @ 26 kV lines - switching station load -systems	CP_SUBT_05	1.000000	0.366162	0.001175	0.004118	0.000000	0.000000	0.000256	0.000000
10	AP	CP @ primary lines - systems	CP_PRI_05	1.000000	0.480968	0.001544	0.005409	0.000000	0.000000	0.000337	0.000000
11	AP	Sum Cust Peaks @ 26 kV lines - local	SUMPK_SUBT_04	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
12	AP	Sum Cust Peaks @ primary lines - local	SUMPK_PRI_04	1.000000	0.611532	0.003396	0.005085	0.000000	0.000000	0.001582	0.003359
13	AP	Sum Cust Peaks @ secondary lines - local	SUMPK_SEC_04	1.000000	0.577157	0.003205	0.004799	0.000000	0.000000	0.001493	0.003170
14	AP										
15	AP	**BILLING DETERMINANTS**									
16	AP										
17	AP	Number of Customers									
18	AP	Delivered kWh @ Meter - annual (w/n net)									
19	AP	Delivered Kw @ Meter - annual									
20	AP										
21	AP	**ALLOCATION FACTORS PART B**									
22	AP										
23	AP	Delivery kWh @ meter	KWHMETER_04	1.000000	0.335298	0.002290	0.004780	0.000014	0.000000	0.000291	0.006941
24	AP	Delivery kWh @ meter x non-profiled rates	KWHMETERX_04	1.000000	0.641341	0.004380	0.009143	0.000027	0.000000	0.000557	0.000000
25	AP										
26	AP										
27	AP	**ALLOCATION FACTORS PART C**									
28	AP										
29	AP	Draft EC Proforma	ECPRO_07	1.000000	0.805602	0.002596	0.004336	0.000685	0.000011	0.000295	0.000000
30	AP	E587 Customer Installation Expenses Local	CUSINT_04	1.000000	0.892857	0.008929	0.008929	0.008929	0.008929	0.008929	0.008929
31	AP	E587 Customer Installation Expenses System	CUSINT_05	1.000000	0.892857	0.008929	0.008929	0.008929	0.008929	0.008929	0.008929
32	AP	E369 minimum Service investment- access	SERVICESMIN_03	1.000000	0.638375	0.003740	0.006248	0.000033	0.000001	0.000000	0.000000
33	AP	E369 excess Service investment- local delivery	SERVICESEXC_04	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
34	AP	Avg Customer Bills - local	CUSTAVG_04	1.000000	0.851985	0.002960	0.004945	0.000282	0.000004	0.000336	0.002103
35	AP	Avg Customer Bills - cust svs	CUSTAVG_06	1.000000	0.851985	0.002960	0.004945	0.000282	0.000004	0.000336	0.002103
36	AP	E370 minimum meter investment - measurement	METERSMIN_07	1.000000	0.834095	0.002687	0.004490	0.000709	0.000011	0.000305	0.000000
37	AP	E368 Line Transfomers - local	LNTRFRMR_04	1.000000	0.713915	0.005414	0.004536	0.000000	0.000000	0.000955	0.003098
38	AP	Billing Function costs - cust svs	BILLING_06	1.000000	0.722749	0.002511	0.004195	0.000048	0.000001	0.000057	0.003033
39	AP	E370 excess meter investment - local delivery	METERSEXC_04	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
40	AP										
41	AP	Account Maint - cust svs	ACCTMAINT_06	1.000000	0.832962	0.002894	0.004835	0.000263	0.000004	0.000314	0.000238
42	AP	Meter Reading Costs - measurement	MRCOST_07	1.000000	0.787219	0.002735	0.004569	0.000052	0.000001	0.000062	0.000000
43	AP										
44	AP	Sales	SALES_06	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
45	AP	Other Utility work by Cust Ops - local	UTILWORK_04	1.000000	0.731132	0.002337	0.004988	0.000061	0.000001	0.000337	0.004998
46	AP	Choice - local	CHOICE_04	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
47	AP										
48	AP	Direct - PSAL - streetlighting	DIR_PSAL_02	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
49	AP	Direct - BPL - streetlighting	DIR_BPL_02	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000
50	AP	Direct - BPL-POF - streetlighting	DIR_BPLPOF_02	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
1	AP	**ALLOCATION PROPORTIONS TABLE**								
2	AP	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**								
3	AP									
4	AP	**ALLOCATION FACTORS PART A**								
5	AP									
6	AP	Number of Customers x Aux &SL rates - local	CUSTNUMX_04	0.000000	0.000000	0.124406	0.004112	0.000343	0.000084	0.000011
7	AP									
8	AP									
9	AP	CP @ 26 kV lines - switching station load -systems	CP_SUBT_05	0.000000	0.000000	0.191563	0.157466	0.040562	0.238698	0.000000
10	AP	CP @ primary lines - systems	CP_PRI_05	0.000000	0.000000	0.251625	0.206837	0.053280	0.000000	0.000000
11	AP	Sum Cust Peaks @ 26 kV lines - local	SUMPK_SUBT_04	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
12	AP	Sum Cust Peaks @ primary lines - local	SUMPK_PRI_04	0.000160	0.001651	0.185418	0.149567	0.038251	0.000000	0.000000
13	AP	Sum Cust Peaks @ secondary lines - local	SUMPK_SEC_04	0.000151	0.001558	0.174996	0.141159	0.036741	0.055571	0.000000
14	AP									
15	AP	**BILLING DETERMINANTS**								
16	AP									
17	AP	Number of Customers								
18	AP	Delivered kWh @ Meter - annual (w/n net)								
19	AP	Delivered Kw @ Meter - annual								
20	AP									
21	AP	**ALLOCATION FACTORS PART B**								
22	AP									
23	AP	Delivery kWh @ meter	KWHMETER_04	0.000375	0.003369	0.180134	0.259443	0.076184	0.114404	0.016476
24	AP	Delivery kWh @ meter x non-profiled rates	KWHMETERX_04	0.000000	0.000000	0.344551	0.000000	0.000000	0.000000	0.000000
25	AP									
26	AP									
27	AP	**ALLOCATION FACTORS PART C**								
28	AP									
29	AP	Draft EC Proforma	ECPRO_07	0.000000	0.000000	0.186476	0.000000	0.000000	0.000000	0.000000
30	AP	E587 Customer Installation Expenses Local	CUSINT_04	0.008929	0.008929	0.008929	0.008929	0.008929	0.000000	0.008929
31	AP	E587 Customer Installation Expenses System	CUSINT_05	0.008929	0.008929	0.008929	0.008929	0.008929	0.000000	0.008929
32	AP	E369 minimum Service investment- access	SERVICESMIN_03	0.000000	0.000000	0.325016	0.023543	0.001961	0.001083	0.000000
33	AP	E369 excess Service investment- local delivery	SERVICESEXC_04	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
34	AP	Avg Customer Bills - local	CUSTAVG_04	0.000038	0.010042	0.122813	0.004059	0.000338	0.000083	0.000011
35	AP	Avg Customer Bills - cust svs	CUSTAVG_06	0.000038	0.010042	0.122813	0.004059	0.000338	0.000083	0.000011
36	AP	E370 minimum meter investment - measurement	METERSMIN_07	0.000000	0.000000	0.134509	0.011842	0.003092	0.005503	0.002757
37	AP	E368 Line Transfomers - local	LNTRFRMR_04	0.000141	0.001350	0.140013	0.130578	0.000000	0.000000	0.000000
38	AP	Billing Function costs - cust svs	BILLING_06	0.000055	0.014481	0.177112	0.068465	0.005703	0.001401	0.000189
39	AP	E370 excess meter investment - local delivery	METERSEXC_04	0.000000	0.000000	0.775218	0.139462	0.071228	0.014092	0.000000
40	AP									
41	AP	Account Maint - cust svs	ACCTMAINT_06	0.000004	0.001134	0.124856	0.029368	0.002446	0.000601	0.000081
42	AP	Meter Reading Costs - measurement	MRCOST_07	0.000000	0.000000	0.192911	0.011253	0.000937	0.000230	0.000031
43	AP									
44	AP	Sales	SALES_06	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
45	AP	Other Utility work by Cust Ops - local	UTILWORK_04	0.000093	0.013559	0.224006	0.016539	0.001494	0.000419	0.000035
46	AP	Choice - local	CHOICE_04	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
47	AP									
48	AP	Direct - PSAL - streetlighting	DIR_PSAL_02	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
49	AP	Direct - BPL - streetlighting	DIR_BPL_02	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
50	AP	Direct - BPL-POF - streetlighting	DIR_BPLPOF_02	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
51	AP	Direct - HTS-HV - access	DIR_HTSHV_03	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
52	AP	Direct - HEP - access	DIR_HEP_03	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
53	AP	Direct - HTS-Sub - systems	DIR_HTSS_05	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
54	AP										
55	**AP**	**ALLOCATION FACTOR TABLE CONTINUED**									
56	**AP**	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**									
57	AP										
58	AP	Direct - HTS-Sub - local	DIR_HTSS_04	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
59	AP	Meter O&M - minimum - measurement	MTROMMIN_07	1.000000	0.501169	0.001741	0.002909	0.000477	0.000007	0.000198	0.000000
60	AP	Meter O&M - excess - measurement	MTROMEXC_07	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
61	AP	WN TEFA Responsibility	TEFA_04	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
62	AP	E370 excess meter investment - dummy	METERSEXC_08	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
63	AP	Meter O&M - excess - dummy	MTROMEXC_08	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
64	AP	E369 excess Service investment- dummy	SERVICESEXC_08	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
65	AP	E368 Line Transfomers - dummy	LNTRFRMR_08	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
66	AP	CP @ 26 kV lines - switching station load - dummy	CP@SUBT_08	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
67	AP	CP @ primary lines - dummy	CP@PRI_08	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
68	AP	Sum Cust Peaks @ secondary lines - local	SUMPK@SEC_08	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
69	AP										
70	AP										
71	AP	Dummy allocator for unused lines	not_used	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
72	AP										
73	AP	**Plant Related**									
74	AP	Distribution Plant Total	DISTPLT	1.000000	0.540206	0.002746	0.004775	0.000024	0.000000	0.000783	0.035115
75	AP	Distribution Plant x meters	DISTPLTXMTR	1.000000	0.531944	0.002755	0.004796	0.000002	0.000000	0.000800	0.036348
76	AP	Acct E360 - Land & Land Rights	E360PLT	1.000000	0.479213	0.001816	0.005032	0.000007	0.000000	0.000447	0.009636
77	AP	Acct E361 - Structures & Improvments	E361PLT	1.000000	0.499244	0.002122	0.004948	0.000012	0.000000	0.000557	0.018003
78	AP	Acct E362 - Station Equipment	E362PLT	1.000000	0.456147	0.001464	0.005129	0.000000	0.000000	0.000319	0.000000
79	AP	Acct E364 - Poles & Towers	E364PLT	1.000000	0.528608	0.002604	0.004810	0.000000	0.000000	0.001101	0.010024
80	AP	Acct E365 - OH Conductors & Devices x HTSHV	E365PLT	1.000000	0.527727	0.002385	0.005070	0.000000	0.000000	0.000926	0.002399
81	AP	Acct E366 - UG Conduit	E366PLT	1.000000	0.547966	0.002702	0.004983	0.000000	0.000000	0.001142	0.003930
82	AP	Acct E367 - UG Conductors & Devices x HEP	E367PLT	1.000000	0.547966	0.002702	0.004983	0.000000	0.000000	0.001142	0.003930
83	AP	Acct E369 Services	E369PLT	1.000000	0.638375	0.003740	0.006248	0.000033	0.000001	0.000000	0.000000
84	AP	Acct E370 Meters	METERPLT	1.000000	0.775541	0.002499	0.004175	0.000659	0.000010	0.000284	0.000000
85	AP	Acct E370 Meters x load profile meters	METERPLTXPR	1.000000	0.775541	0.002499	0.004175	0.000659	0.000010	0.000284	0.000000
86	AP	Acct E373 - Streetlights	E373PLT	1.000000	0.065692	0.000340	0.000592	0.000000	0.000000	0.000099	0.686896
87	AP	Subtrans Lines - HTS-S/Switching Station load	SUBTRANSLINES	1.000000	0.288902	0.000927	0.003249	0.000000	0.000000	0.000202	0.000000
88	AP	Primary Lines - 50 Sys CP/50 Loc Sum Cust Pks	PRIMARYLINES	1.000000	0.546250	0.002470	0.005247	0.000000	0.000000	0.000959	0.001680
89	AP										
90	AP	Acct E301-E303 Intangible Plt	INTANGPLT	1.000000	0.747683	0.002591	0.004363	0.000074	0.000001	0.000096	0.002220
91	AP										
92	AP	Acct E399.10-23 Oth Tangible Plt	TANGPLT	1.000000	0.747013	0.002594	0.004368	0.000073	0.000001	0.000099	0.002382
93	AP	E391-E398 General Plant	GENPLT	1.000000	0.531944	0.002755	0.004796	0.000002	0.000000	0.000800	0.036348
94	AP	Common Plant	COMPLT	1.000000	0.690073	0.002635	0.004478	0.000055	0.000001	0.000284	0.011333
95	AP	Accts C389-C399, E389-E399 Com & Gen Plt	COMGENPLT	1.000000	0.567949	0.002728	0.004724	0.000014	0.000000	0.000683	0.030652
96	AP										
97	AP	Total Plant	TOTPLT	1.000000	0.543847	0.002744	0.004768	0.000024	0.000000	0.000770	0.034535
98	AP										
99	AP	Total Distribution Plant Reserve	TOTDRESERVE	1.000000	0.558291	0.002819	0.004808	0.000035	0.000001	0.000762	0.031437
100	AP	Total Net Plant	TOTPLTNET	1.000000	0.538490	0.002716	0.004753	0.000021	0.000000	0.000773	0.035684

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
51	AP	Direct - HTS-HV - access	DIR_HTSHV_03	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000
52	AP	Direct - HEP - access	DIR_HEP_03	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
53	AP	Direct - HTS-Sub - systems	DIR_HTSS_05	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
54	AP									
55	**AP**	**ALLOCATION FACTOR TABLE CONTINUED**								
56	**AP**	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**								
57	AP									
58	AP	Direct - HTS-Sub - local	DIR_HTSS_04	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000
59	AP	Meter O&M - minimum - measurement	MTROMMIN_07	0.000000	0.000000	0.069088	0.383557	0.031948	0.007850	0.001056
60	AP	Meter O&M - excess - measurement	MTROMEXC_07	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
61	AP	WN TEFA Responsibility	TEFA_04	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
62	AP	E370 excess meter investment - dummy	METERSEXC_08	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
63	AP	Meter O&M - excess - dummy	MTROMEXC_08	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
64	AP	E369 excess Service investment- dummy	SERVICESEXC_08	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
65	AP	E368 Line Transfomers - dummy	LNTRFRMR_08	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
66	AP	CP @ 26 kV lines - switching station load - dummy	CP@SUBT_08	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
67	AP	CP @ primary lines - dummy	CP@PRI_08	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
68	AP	Sum Cust Peaks @ secondary lines - local	SUMPK@SEC_08	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
69	AP									
70	AP									
71	AP	Dummy allocator for unused lines	not_used	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
72	AP									
73	AP	**Plant Related**								
74	AP	Distribution Plant Total	DISTPLT	0.000072	0.010804	0.196396	0.146169	0.032459	0.030362	0.000088
75	AP	Distribution Plant x meters	DISTPLTXMTR	0.000075	0.011184	0.196990	0.150570	0.033322	0.031214	0.000001
76	AP	Acct E360 - Land & Land Rights	E360PLT	0.000020	0.002965	0.227048	0.182445	0.045571	0.045777	0.000024
77	AP	Acct E361 - Structures & Improvments	E361PLT	0.000037	0.005539	0.216982	0.170531	0.041265	0.040715	0.000045
78	AP	Acct E362 - Station Equipment	E362PLT	0.000000	0.000000	0.238640	0.196163	0.050530	0.051607	0.000000
79	AP	Acct E364 - Poles & Towers	E364PLT	0.000101	0.002810	0.191386	0.155517	0.040155	0.062885	0.000000
80	AP	Acct E365 - OH Conductors & Devices x HTSHV	E365PLT	0.000077	0.003049	0.211230	0.172259	0.044267	0.030609	0.000000
81	AP	Acct E366 - UG Conduit	E366PLT	0.000105	0.001721	0.198207	0.161027	0.041538	0.036680	0.000000
82	AP	Acct E367 - UG Conductors & Devices x HEP	E367PLT	0.000105	0.001721	0.198207	0.161027	0.041538	0.036680	0.000000
83	AP	Acct E369 Services	E369PLT	0.000000	0.000000	0.325016	0.023543	0.001961	0.001083	0.000000
84	AP	Acct E370 Meters	METERPLT	0.000000	0.000000	0.179487	0.020801	0.007875	0.006106	0.002564
85	AP	Acct E370 Meters x load profile meters	METERPLTXPR	0.000000	0.000000	0.179487	0.020801	0.007875	0.006106	0.002564
86	AP	Acct E373 - Streetlights	E373PLT	0.000009	0.195480	0.024327	0.018595	0.004115	0.003855	0.000000
87	AP	Subtrans Lines - HTS-S/Switching Station load	SUBTRANSLINES	0.000000	0.000000	0.151143	0.124241	0.032003	0.399333	0.000000
88	AP	Primary Lines - 50 Sys CP/50 Loc Sum Cust Pks	PRIMARYLINES	0.000080	0.000825	0.218522	0.178202	0.045765	0.000000	0.000000
89	AP									
90	AP	Acct E301-E303 Intangible Plt	INTANGPLT	0.000040	0.010281	0.175551	0.051598	0.004301	0.001058	0.000142
91	AP									
92	AP	Acct E399.10-23 Oth Tangible Plt	TANGPLT	0.000040	0.010141	0.175917	0.051594	0.004419	0.001218	0.000139
93	AP	E391-E398 General Plant	GENPLT	0.000075	0.011184	0.196990	0.150570	0.033322	0.031214	0.000001
94	AP	Common Plant	COMPLT	0.000050	0.010522	0.181276	0.078027	0.012051	0.009111	0.000104
95	AP	Accts C389-C399, E389-E399 Com & Gen Plt	COMGENPLT	0.000069	0.011033	0.193412	0.134052	0.028478	0.026181	0.000025
96	AP									
97	AP	Total Plant	TOTPLT	0.000072	0.010809	0.196023	0.144533	0.031954	0.029836	0.000086
98	AP									
99	AP	Total Distribution Plant Reserve	TOTDRESERVE	0.000072	0.010015	0.198803	0.135731	0.029922	0.027185	0.000119
100	AP	Total Net Plant	TOTPLTNET	0.000072	0.011103	0.194993	0.147797	0.032708	0.030819	0.000073

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
101	AP										
102	AP										
103	AP	**Revenue Related**									
104	AP	Total Operating Revenue	TOTREV	1.000000	0.562801	0.002637	0.004670	0.000067	0.000001	0.000691	0.033834
105	AP										
106	AP										
107	**AP**	**ALLOCATION FACTOR TABLE CONTINUED**									
108	**AP**	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**									
109	AP										
110	AP	**Expense Related**									
111	AP	Distr Oper Exp	DISTEXPO	1.000000	0.457721	0.002017	0.004244	0.000126	0.000002	0.000738	0.009043
112	AP	Distr Maint Exp	DISTEXPM	1.000000	0.470007	0.002113	0.004524	0.000004	0.000000	0.000732	0.069077
113	AP	Cust Serv & Info Expense	CUSTS_I	1.000000	0.789053	0.002665	0.004861	0.000176	0.000003	0.000310	0.002174
114	AP	Acct E901-E903,E905 Cust Acct Exp Excl 904	CACCTEXP	1.000000	0.745353	0.002587	0.004335	0.000068	0.000001	0.000084	0.002222
115	AP	Accts E901-E910 Excl 904 - Cust Accts,Serv & Info	CUSTSVSX	1.000000	0.747683	0.002591	0.004363	0.000074	0.000001	0.000096	0.002220
116	AP	Sales Expense	SALESEXP	1.000000	0.731132	0.002337	0.004988	0.000061	0.000001	0.000337	0.004998
117	AP	Total O&M Expense Excl 904-Uncollectibles	TOTOMXAG	1.000000	0.558555	0.002409	0.004575	0.000041	0.000001	0.000602	0.033248
118	AP	Tot Admin & Genl Exp xPension/Ben	A_GEXP	1.000000	0.581484	0.002758	0.004836	0.000048	0.000001	0.000718	0.035926
119	AP	Accts E901-E905 Cust Accts Exp Excl 904-Uncol	CUSTACCTS	1.000000	0.745353	0.002587	0.004335	0.000068	0.000001	0.000084	0.002222
120	AP	O&M + Capital Additions	EXPENDITURES	1.000000	0.561540	0.002585	0.004586	0.000064	0.000001	0.000676	0.039226
121	AP										
122	AP	Depreciation Expense (total)	DEPREXP	1.000000	0.544452	0.002744	0.004767	0.000024	0.000000	0.000768	0.034436
123	AP										
124	AP	NJ State Income Tax (CBT)	STATEINCTAX	1.000000	0.553083	0.002700	0.004718	0.000059	0.000001	0.000744	0.034516
125	AP	NJ State Deferred Income Tax	DFSTATEINCTAX	1.000000	0.652210	0.002313	0.004255	0.000115	0.000002	0.000308	0.039268
126	AP										
127	AP	**Labor Expense Related**									
128	AP	Total Distribution Exp (Oper) Labor	TLABDO	1.000000	0.630555	0.002455	0.004489	0.000206	0.000003	0.000579	0.004712
129	AP	Total Distribution Exp (Maint) Labor	TLABDM	1.000000	0.446673	0.002071	0.004211	0.000008	0.000000	0.000688	0.122174
130	AP	Total Labor	LABOR	1.000000	0.624158	0.002412	0.004378	0.000092	0.000001	0.000423	0.038384
131	AP										
132	AP	**REVENUES AND BILLING DETERMINANTS**									
133	AP										
134	AP	Base Rate Sales Revenue	SALESREV	1.000000	0.563883	0.002642	0.004679	0.000067	0.000001	0.000689	0.033899
135	AP										
136	AP	Residential Service	REVRS	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
137	AP	Residential Heating Service	REVRHS	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
138	AP	Residential Load Management Service	REVRLM	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000
139	AP	Water Heating Service	REVWH	1.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000
140	AP	Water Heating Storage Service	REVWHS	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000
141	AP	Building Heating Service	REVHS	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000
142	AP	Body Police Lighting Service	REVBLP	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000
143	AP	Body Police Lighting Service from Publicly Owned	REVBLPPOF	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
144	AP	Private Street and Area Lighting Service	REVPAL	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
145	AP										
146	AP	General Power and Lighting Service	REVGLP	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
147	AP	Large Power and Lighting Service - Secondary	REVLPLS	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
148	AP	Large Power and Lighting Service - Primary	REVLPLP	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
149	AP	High Tension Service - Subtransmission	REVHTSS	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
150	AP	High Tension Service - High Voltage	REVHTSHV	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
101	AP									
102	AP									
103	AP	**Revenue Related**								
104	AP	Total Operating Revenue	TOTREV	0.000266	0.012037	0.191540	0.135001	0.029560	0.026795	0.000101
105	AP									
106	AP									
107	**AP**	**ALLOCATION FACTOR TABLE CONTINUED**								
108	**AP**	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**								
109	AP									
110	AP	**Expense Related**								
111	AP	Distr Oper Exp	DISTEXPO	0.000054	0.001891	0.171781	0.272951	0.046423	0.032632	0.000377
112	AP	Distr Maint Exp	DISTEXPM	0.002819	0.032153	0.190152	0.157756	0.038841	0.031811	0.000010
113	AP	Cust Serv & Info Expense	CUSTS_I	0.000040	0.006487	0.164905	0.026440	0.002246	0.000572	0.000069
114	AP	Acct E901-E903,E905 Cust Acct Exp Excl 904	CACCTEXP	0.000040	0.010494	0.176151	0.053016	0.004417	0.001086	0.000146
115	AP	Accts E901-E910 Excl 904 - Cust Accts,Serv & Info	CUSTSVSX	0.000040	0.010281	0.175551	0.051598	0.004301	0.001058	0.000142
116	AP	Sales Expense	SALESEXP	0.000093	0.013559	0.224006	0.016539	0.001494	0.000419	0.000035
117	AP	Total O&M Expense Excl 904-Uncollectibles	TOTOMXAG	0.001169	0.016865	0.189709	0.137381	0.030611	0.024720	0.000115
118	AP	Tot Admin & Genl Exp xPension/Ben	A_GEXP	0.000097	0.012245	0.194823	0.109566	0.030076	0.027322	0.000099
119	AP	Accts E901-E905 Cust Accts Exp Excl 904-Uncol	CUSTACCTS	0.000040	0.010494	0.176151	0.053016	0.004417	0.001086	0.000146
120	AP	O&M + Capital Additions	EXPENDITURES	0.000405	0.014519	0.187917	0.132984	0.029353	0.025915	0.000228
121	AP									
122	AP	Depreciation Expense (total)	DEPREXP	0.000072	0.010821	0.195951	0.144283	0.031862	0.029738	0.000083
123	AP									
124	AP	NJ State Income Tax (CBT)	STATEINCTAX	0.000099	0.010874	0.193995	0.139314	0.030856	0.028959	0.000084
125	AP	NJ State Deferred Income Tax	DFSTATEINCTAX	0.000055	0.017721	0.158836	0.099325	0.015767	0.009672	0.000153
126	AP									
127	AP	**Labor Expense Related**								
128	AP	Total Distribution Exp (Oper) Labor	TLABDO	0.000049	0.004917	0.145711	0.162228	0.026047	0.017801	0.000249
129	AP	Total Distribution Exp (Maint) Labor	TLABDM	0.000090	0.035702	0.174989	0.148239	0.035034	0.030102	0.000019
130	AP	Total Labor	LABOR	0.000059	0.016089	0.167755	0.111282	0.019946	0.014888	0.000133
131	AP									
132	AP	**REVENUES AND BILLING DETERMINANTS**								
133	AP									
134	AP	Base Rate Sales Revenue	SALESREV	0.000267	0.012002	0.190977	0.134604	0.029473	0.026716	0.000100
135	AP									
136	AP	Residential Service	REVRS	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
137	AP	Residential Heating Service	REVRHS	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
138	AP	Residential Load Management Service	REVRLM	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
139	AP	Water Heating Service	REVWH	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
140	AP	Water Heating Storage Service	REVWHS	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
141	AP	Building Heating Service	REVHS	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
142	AP	Body Police Lighting Service	REVBLP	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
143	AP	Body Police Lighting Service from Publicly Owned	REVBLPPOF	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
144	AP	Private Street and Area Lighting Service	REVPAL	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
145	AP									
146	AP	General Power and Lighting Service	REVGLP	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000
147	AP	Large Power and Lighting Service - Secondary	REVLPLS	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000
148	AP	Large Power and Lighting Service - Primary	REVLPLP	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000
149	AP	High Tension Service - Subtransmission	REVHTSS	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000
150	AP	High Tension Service - High Voltage	REVHTSHV	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
151	AP	HEP	REVHEP	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
152	AP										
153	AP	Total Rev Req @ desired ROR	REVREQ	1.000000	0.563883	0.002642	0.004679	0.000067	0.000001	0.000689	0.033899
154	AP										
155	AP	**PRESENT REVENUES FROM SALES INPUT**									
156	AP										
157	AP	Total Sales of Electricity Revenues		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
158	AP	Sales of Electricity Revenues - Rates		1.000000	0.476039	0.003512	0.006199	0.000042	0.000000	0.000590	0.044679
159	AP	Sales of Electricity Revenues - Other		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
160	AP	Expense Reclassification Plus-local	ADJ_Plus_04	1.000000	0.000000	0.000000	0.000000	0.406337	0.006306	0.000000	0.000000
161	AP	Expense Reclassification-local	ADJEXP_04	1.000000	0.624242	0.002413	0.004379	0.000000	0.000000	0.000423	0.038400

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
151	AP	HEP	REVHEP	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
152	AP									
153	AP	Total Rev Req @ desired ROR	REVREQ	0.000267	0.012002	0.190977	0.134604	0.029473	0.026716	0.000100
154	AP									
155	AP	**PRESENT REVENUES FROM SALES INPUT**								
156	AP									
157	AP	Total Sales of Electricity Revenues		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
158	AP	Sales of Electricity Revenues - Rates		0.000257	0.022169	0.211094	0.178457	0.031052	0.024050	0.001861
159	AP	Sales of Electricity Revenues - Other		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
160	AP	Expense Reclassification Plus-local	ADJ_Plus_04	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.587357
161	AP	Expense Reclassification-local	ADJEXP_04	0.000059	0.016095	0.167800	0.111337	0.019957	0.014895	0.000000

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	ADA	**ALLOCATED DIRECT ASSIGNMENTS**									
2	ADA	**DIRECT ASSIGN TO CLASSES W/SALES REV FUNCTIONS**									
3	ADA										
4	ADA	**Net Write-Offs**									
5	ADA	Residential Service	REVRS	0	0	0	0	0	0	0	0
6	ADA	Residential Heating Service	REVRHS	0	0	0	0	0	0	0	0
7	ADA	Residential Load Management Service	REVRLM	0	0	0	0	0	0	0	0
8	ADA	Water Heating Service	REVWH	0	0	0	0	0	0	0	0
9	ADA	Water Heating Storage Service	REVWHS	0	0	0	0	0	0	0	0
10	ADA	Building Heating Service	REVHS	0	0	0	0	0	0	0	0
11	ADA	Body Police Lighting Service	REVBLP	0	0	0	0	0	0	0	0
12	ADA	Body Police Lighting Service from Publicly Owned	REVBLPPOF	0	0	0	0	0	0	0	0
13	ADA	Private Street and Area Lighting Service	REVPAL	0	0	0	0	0	0	0	0
14	ADA	General Power and Lighting Service	REVGLP	0	0	0	0	0	0	0	0
15	ADA	Large Power and Lighting Service - Secondary	REVLPLS	0	0	0	0	0	0	0	0
16	ADA	Large Power and Lighting Service - Primary	REVLPLP	0	0	0	0	0	0	0	0
17	ADA	High Tension Service - Subtransmission	REVHTSS	0	0	0	0	0	0	0	0
18	ADA	High Tension Service - High Voltage	REVHTSHV	0	0	0	0	0	0	0	0
19	ADA	HEP	REVHEP	0	0	0	0	0	0	0	0
20	ADA										
21	ADA	Total Write-Offs	EXP_904	0	0	0	0	0	0	0	0
22	ADA										
23	ADA	Total Write-Offs	EXP_904	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
24	ADA										
25	ADA	Additional Net Write-Offs at Claimed Rate	EXP_904	0	0	0	0	0	0	0	0
26	ADA										
27	ADA										
28	ADA	**Rev to Customers w/Late Payment fees**									
29	ADA	Residential Service	REVRS	0	0	0	0	0	0	0	0
30	ADA	Residential Heating Service	REVRHS	0	0	0	0	0	0	0	0
31	ADA	Residential Load Management Service	REVRLM	0	0	0	0	0	0	0	0
32	ADA	Water Heating Service	REVWH	0	0	0	0	0	0	0	0
33	ADA	Water Heating Storage Service	REVWHS	0	0	0	0	0	0	0	0
34	ADA	Building Heating Service	REVHS	1,308,648	0	0	0	0	0	1,308,648	0
35	ADA	Body Police Lighting Service	REVBLP	0	0	0	0	0	0	0	0
36	ADA	Body Police Lighting Service from Publicly Owned	REVBLPPOF	0	0	0	0	0	0	0	0
37	ADA	Private Street and Area Lighting Service	REVPAL	22,801,929	0	0	0	0	0	0	0
38	ADA	General Power and Lighting Service	REVGLP	362,840,766	0	0	0	0	0	0	0
39	ADA	Large Power and Lighting Service - Secondary	REVLPLS	255,737,125	0	0	0	0	0	0	0
40	ADA	Large Power and Lighting Service - Primary	REVLPLP	55,996,770	0	0	0	0	0	0	0
41	ADA	High Tension Service - Subtransmission	REVHTSS	50,758,783	0	0	0	0	0	0	0
42	ADA	High Tension Service - High Voltage	REVHTSHV	190,699	0	0	0	0	0	0	0
43	ADA	HEP	REVHEP	0	0	0	0	0	0	0	0
44	ADA										
45	ADA	Total Late Payment Fees	REVLATEP	749,634,721	0	0	0	0	0	1,308,648	0
46	ADA	Total Late Payment Fees	REVLATEP	1.000000						0.001746	
47	ADA										
48	ADA	**ALLOCATED DIRECT ASSIGNMENTS**									
49	ADA	DIRECT ASSIGN TO CLASSES W/SALES REV FUNCTIONS									
50	ADA										

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
1	ADA	**ALLOCATED DIRECT ASSIGNMENTS**								
2	ADA	**DIRECT ASSIGN TO CLASSES W/SALES REV FUNCTIONS**								
3	ADA									
4	ADA	**Net Write-Offs**								
5	ADA	Residential Service	REVRS	0	0	0	0	0	0	0
6	ADA	Residential Heating Service	REVRHS	0	0	0	0	0	0	0
7	ADA	Residential Load Management Service	REVRLM	0	0	0	0	0	0	0
8	ADA	Water Heating Service	REVWH	0	0	0	0	0	0	0
9	ADA	Water Heating Storage Service	REVWHS	0	0	0	0	0	0	0
10	ADA	Building Heating Service	REVHS	0	0	0	0	0	0	0
11	ADA	Body Police Lighting Service	REVBLP	0	0	0	0	0	0	0
12	ADA	Body Police Lighting Service from Publicly Owned	REVBLPPOF	0	0	0	0	0	0	0
13	ADA	Private Street and Area Lighting Service	REVPAL	0	0	0	0	0	0	0
14	ADA	General Power and Lighting Service	REVGLP	0	0	0	0	0	0	0
15	ADA	Large Power and Lighting Service - Secondary	REVLPLS	0	0	0	0	0	0	0
16	ADA	Large Power and Lighting Service - Primary	REVLPLP	0	0	0	0	0	0	0
17	ADA	High Tension Service - Subtransmission	REVHTSS	0	0	0	0	0	0	0
18	ADA	High Tension Service - High Voltage	REVHTSHV	0	0	0	0	0	0	0
19	ADA	HEP	REVHEP	0	0	0	0	0	0	0
20	ADA									
21	ADA	Total Write-Offs	EXP_904	0	0	0	0	0	0	0
22	ADA									
23	ADA	Total Write-Offs	EXP_904	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
24	ADA									
25	ADA	Additional Net Write-Offs at Claimed Rate	EXP_904	0	0	0	0	0	0	0
26	ADA									
27	ADA									
28	ADA	**Rev to Customers w/Late Payment fees**								
29	ADA	Residential Service	REVRS	0	0	0	0	0	0	0
30	ADA	Residential Heating Service	REVRHS	0	0	0	0	0	0	0
31	ADA	Residential Load Management Service	REVRLM	0	0	0	0	0	0	0
32	ADA	Water Heating Service	REVWH	0	0	0	0	0	0	0
33	ADA	Water Heating Storage Service	REVWHS	0	0	0	0	0	0	0
34	ADA	Building Heating Service	REVHS	0	0	0	0	0	0	0
35	ADA	Body Police Lighting Service	REVBLP	0	0	0	0	0	0	0
36	ADA	Body Police Lighting Service from Publicly Owned	REVBLPPOF	0	0	0	0	0	0	0
37	ADA	Private Street and Area Lighting Service	REVPAL	0	22,801,929	0	0	0	0	0
38	ADA	General Power and Lighting Service	REVGLP	0	0	362,840,766	0	0	0	0
39	ADA	Large Power and Lighting Service - Secondary	REVLPLS	0	0	0	255,737,125	0	0	0
40	ADA	Large Power and Lighting Service - Primary	REVLPLP	0	0	0	0	55,996,770	0	0
41	ADA	High Tension Service - Subtransmission	REVHTSS	0	0	0	0	0	50,758,783	0
42	ADA	High Tension Service - High Voltage	REVHTSHV	0	0	0	0	0	0	190,699
43	ADA	HEP	REVHEP	0	0	0	0	0	0	0
44	ADA									
45	ADA	Total Late Payment Fees	REVLATEP	0	22,801,929	362,840,766	255,737,125	55,996,770	50,758,783	190,699
46	ADA	Total Late Payment Fees	REVLATEP		0.030417	0.484023	0.341149	0.074699	0.067711	0.000254
47	ADA									
48	ADA	**ALLOCATED DIRECT ASSIGNMENTS**								
49	ADA	DIRECT ASSIGN TO CLASSES W/SALES REV FUNCTIONS								
50	ADA									

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
51	ADA	**AVAILABLE**									
52	ADA	Residential Service	REVRS	0	0	0	0	0	0	0	0
53	ADA	Residential Heating Service	REVRHS	0	0	0	0	0	0	0	0
54	ADA	Residential Load Management Service	REVRLM	0	0	0	0	0	0	0	0
55	ADA	Water Heating Service	REVWH	0	0	0	0	0	0	0	0
56	ADA	Water Heating Storage Service	REVWHS	0	0	0	0	0	0	0	0
57	ADA	Building Heating Service	REVHS	0	0	0	0	0	0	0	0
58	ADA	Body Police Lighting Service	REVBLP	0	0	0	0	0	0	0	0
59	ADA	Body Police Lighting Service from Publicly Owned	REVBLPPOF	0	0	0	0	0	0	0	0
60	ADA	Private Street and Area Lighting Service	REVPAL	0	0	0	0	0	0	0	0
61	ADA	General Power and Lighting Service	REVGLP	0	0	0	0	0	0	0	0
62	ADA	Large Power and Lighting Service - Secondary	REVLPLS	0	0	0	0	0	0	0	0
63	ADA	Large Power and Lighting Service - Primary	REVLPLP	0	0	0	0	0	0	0	0
64	ADA	High Tension Service - Subtransmission	REVHTSS	0	0	0	0	0	0	0	0
65	ADA	High Tension Service - High Voltage	REVHTSHV	0	0	0	0	0	0	0	0
66	ADA	HEP	REVHEP	0	0	0	0	0	0	0	0
67	ADA										
68	ADA	Total Available	REVAVAIL	0	0	0	0	0	0	0	0
69	ADA	Total Available	REVAVAIL	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
51	ADA	**AVAILABLE**								
52	ADA	Residential Service	REVRS	0	0	0	0	0	0	0
53	ADA	Residential Heating Service	REVRHS	0	0	0	0	0	0	0
54	ADA	Residential Load Management Service	REVRLM	0	0	0	0	0	0	0
55	ADA	Water Heating Service	REVWH	0	0	0	0	0	0	0
56	ADA	Water Heating Storage Service	REVWHS	0	0	0	0	0	0	0
57	ADA	Building Heating Service	REVHS	0	0	0	0	0	0	0
58	ADA	Body Police Lighting Service	REVBLP	0	0	0	0	0	0	0
59	ADA	Body Police Lighting Service from Publicly Owned	REVBLPPOF	0	0	0	0	0	0	0
60	ADA	Private Street and Area Lighting Service	REVPAL	0	0	0	0	0	0	0
61	ADA	General Power and Lighting Service	REVGLP	0	0	0	0	0	0	0
62	ADA	Large Power and Lighting Service - Secondary	REVLPLS	0	0	0	0	0	0	0
63	ADA	Large Power and Lighting Service - Primary	REVLPLP	0	0	0	0	0	0	0
64	ADA	High Tension Service - Subtransmission	REVHTSS	0	0	0	0	0	0	0
65	ADA	High Tension Service - High Voltage	REVHTSHV	0	0	0	0	0	0	0
66	ADA	HEP	REVHEP	0	0	0	0	0	0	0
67	ADA									
68	ADA	Total Available	REVAVAIL	0	0	0	0	0	0	0
69	ADA	Total Available	REVAVAIL	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	RRW	**REVENUE REQUIREMENTS**									
2	RRW										
3	RRW	PRESENT RATES									
4	RRW	--									
5	RRW	RATE BASE		9,785,622,095	5,464,767,603	26,342,900	46,024,225	686,464	10,706	7,146,316	332,694,043
6	RRW	NET OPER INC (PRESENT RATES)		738,814,468	412,589,954	1,988,889	3,474,829	51,828	808	539,547	25,118,400
7	RRW	RATE OF RETURN (PRES RATES)		7.55%	7.55%	7.55%	7.55%	7.55%	7.55%	7.55%	7.55%
8	RRW	RELATIVE RATE OF RETURN		1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
9	RRW	SALES REVENUE (PRE RATES)		1,899,915,237	1,071,330,372	5,019,520	8,889,191	127,057	1,979	1,308,648	64,405,668
10	RRW	REVENUE PRES RATES $/KWH		$0.0465	$0.0783	$0.0537	$0.0456	$0.2173	$0.2768	$0.1101	$0.2273
11	RRW	REVENUE REQUIRED - $/MO/CUST		$67.42	$44.62	$60.18	$63.79	$15.98	$15.96	$138.15	$1,086.87
12	RRW	SALES REV REQUIRED $/KW		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	RRW										
14	RRW	CLAIMED RATE OF RETURN									
15	RRW	--									
16	RRW	CLAIMED RATE OF RETURN		7.55%	7.55%	7.55%	7.55%	7.55%	7.55%	7.55%	7.55%
17	RRW	RETURN REQ FOR CLAIMED ROR		738,814,468	412,589,954	1,988,889	3,474,829	51,828	808	539,547	25,118,400
18	RRW	SALES REVENUE REQ CLAIMED ROR		1,899,915,237	1,071,330,372	5,019,520	8,889,191	127,057	1,979	1,308,648	64,405,668
19	RRW	REVENUE DEFICIENCY SALES REV		0							
20	RRW	PERCENT INCREASE REQUIRED		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
21	RRW	ANNUAL BOOKED KWH SALES		40,816,033,564	13,685,554,460	93,469,833	195,107,964	584,797	7,149	11,887,502	283,298,553
22	RRW	SALES REV REQUIRED $/KWH		$0.0465	$0.0783	$0.0537	$0.0456	$0.2173	$0.2768	$0.1101	$0.2273
23	RRW	REVENUE DEFICIENCY $/KWH									

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
1	RRW	**REVENUE REQUIREMENTS**								
2	RRW									
3	RRW	PRESENT RATES								
4	RRW	--								
5	RRW	RATE BASE		1,043,476	105,893,845	1,893,312,437	1,334,791,838	295,230,918	276,830,640	846,685
6	RRW	NET OPER INC (PRESENT RATES)		78,782	7,994,985	142,945,089	100,776,784	22,289,934	20,900,713	63,925
7	RRW	RATE OF RETURN (PRES RATES)		7.55%	7.55%	7.55%	7.55%	7.55%	7.55%	7.55%
8	RRW	RELATIVE RATE OF RETURN		1.00	1.00	1.00	1.00	1.00	1.00	1.00
9	RRW	SALES REVENUE (PRE RATES)		506,728	22,801,929	362,840,766	255,737,125	55,996,770	50,758,783	190,699
10	RRW	REVENUE PRES RATES $/KWH		$0.0331	$0.1658	$0.0494	$0.0242	$0.0180	$0.0109	$0.0003
11	RRW	REVENUE REQUIRED - $/MO/CUST		$470.06	$80.58	$104.85	$2,235.68	$5,877.07	$21,682.52	$605.39
12	RRW	SALES REV REQUIRED $/KW		0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	RRW									
14	RRW	CLAIMED RATE OF RETURN								
15	RRW	--								
16	RRW	CLAIMED RATE OF RETURN		7.55%	7.55%	7.55%	7.55%	7.55%	7.55%	7.55%
17	RRW	RETURN REQ FOR CLAIMED ROR		78,782	7,994,985	142,945,089	100,776,784	22,289,934	20,900,713	63,925
18	RRW	SALES REVENUE REQ CLAIMED ROR		506,728	22,801,929	362,840,766	255,737,125	55,996,770	50,758,783	190,699
19	RRW	REVENUE DEFICIENCY SALES REV				0			(0)	
20	RRW	PERCENT INCREASE REQUIRED		0.0	0.0	0.0	0.0	0.0	0.0	0.0
21	RRW	ANNUAL BOOKED KWH SALES		15,313,401	137,520,699	7,352,369,374	10,589,422,620	3,109,525,559	4,669,504,753	672,466,899
22	RRW	SALES REV REQUIRED $/KWH		$0.0331	$0.1658	$0.0494	$0.0242	$0.0180	$0.0109	$0.0003
23	RRW	REVENUE DEFICIENCY $/KWH								

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery	System Delivery	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	S	**SUMMARY OF RESULTS**								
2	S	**DEVELOPMENT OF RETURN**								
3	S									
4	S	**RATE BASE**								
5	S	Plant in Service								
6	S	Production Plant E310-E346	CALCULATED	0	0	0	0	0	0	0
7	S	Transmission Plant E350-E359	CALCULATED	0	0	0	0	0	0	0
8	S	Distribution Plant								
9	S	Land & Structures E360-E361	CALCULATED	293,570,614	6,036,776	7,005,382	67,252,735	208,857,606	0	4,418,116
10	S	Station Equipment E362	CALCULATED	1,565,418,169	0	0	0	1,565,418,169	0	0
11	S	Poles, Towers, and Fixtures E364	CALCULATED	1,027,443,483	9,926,985	0	696,273,007	321,243,491	0	0
12	S	OH Conductors and Devices E365	CALCULATED	2,856,184,590	8,663,157	0	1,426,636,429	1,420,885,005	0	0
13	S	UG Conductors E366	CALCULATED	512,107,003	1,207,229	74,667	352,039,379	158,785,119	0	608
14	S	UG Conduits and Devices E367	CALCULATED	1,431,183,475	3,373,838	208,673	983,843,101	443,756,163	0	1,700
15	S	Line Transformers E368	CALCULATED	1,591,690,631	0	0	1,591,690,631	0	0	0
16	S	Services E369	CALCULATED	535,269,333	0	535,269,333	0	0	0	0
17	S	Meters E370	CALCULATED	365,421,442	0	0	25,652,585	0	0	339,768,857
18	S	Street Lighting E373	CALCULATED	499,027,153	440,185,003	3,231,553	30,871,513	24,712,756	0	26,329
19	S	Asset Retirement Obligations E374	CALCULATED	96,512,525	932,488	0	65,404,148	30,175,889	0	0
20	S	Other Distribution and Unallocated Plant	CALCULATED	0	0	0	0	0	0	0
21	S	Total Distribution Plant	CALCULATED	10,773,828,418	470,325,475	545,789,607	5,239,663,528	4,173,834,198	0	344,215,610
22	S	General Plant E389-E399	CALCULATED	429,584,593	19,411,672	22,526,291	215,197,078	172,266,022	0	183,530
23	S	Common Plant C389-C399	CALCULATED	126,654,044	1,528,289	1,773,504	19,803,776	13,562,574	72,642,949	17,342,952
24	S	Intangible Plant E301-E303, E399, C303-C390	CALCULATED	126,923,895	22,167	25,723	4,105,197	196,714	97,986,938	24,587,156
25	S	Total Plant in Service	CALCULATED	11,456,990,950	491,287,602	570,115,126	5,478,769,579	4,359,859,508	170,629,886	386,329,248
26	S									
27	S	Less: Reserve for Depreciation and Amorization	CALCULATED	3,099,332,698	120,238,498	252,980,311	1,477,503,032	1,013,555,312	85,380,573	149,674,973
28	S	Plus: Rate Base Additions								
29	S	Working Capital	CALCULATED	1,183,336,038	60,119,630	19,586,535	460,789,429	396,438,821	116,225,940	130,175,683
30	S	Plant Held for Future Use	CALCULATED	489,291	20,981	24,348	233,981	186,196	7,287	16,499
31	S	Capital Stimulus	CALCULATED	0	0	0	0	0	0	0
32	S	Other Rate Base Additions		2,066,897,171	61,732,398	66,667,584	679,841,513	548,404,998	5,997,927	704,252,751
33	S	Plus: Rate Base Deductions								
34	S	Customer Advances	CALCULATED	-63,907,492	-2,755,689	-1,947,348	-26,050,395	-22,316,828	-4,380,763	-6,456,469
35	S	Unbilled Revenue	CALCULATED	0	0	0	0	0	0	0
36	S	Deferred Income Taxes and Credits	CALCULATED	-1,717,952,304	-73,657,430	-85,566,652	-821,526,577	-653,619,207	-25,617,001	-57,965,436
37	S									
38	S									
39	S	Other Rate Base Deductions		-40,898,861	-124,051	0	-20,428,583	-20,346,226	0	0
40	S	TOTAL RATE BASE		9,785,622,095	416,384,944	315,899,282	4,274,125,914	3,595,051,949	177,482,704	1,006,677,303
41	S									
42	S									
43	S									
44	S									

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery	System Delivery	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)	(7)
45	S	**SUMMARY OF RESULTS**								
46	S	**DEVELOPMENT OF RETURN**	CALCULATED							
47	S									
48	S	**RATE BASE**	CALCULATED	9,785,622,095	416,384,944	315,899,282	4,274,125,914	3,595,051,949	177,482,704	1,006,677,303
49	S									
50	S	**OPERATING REVENUES**								
51	S	Rate Revenues from Customers	CALCULATED	1,899,915,237	81,924,279	57,892,994	774,456,024	663,460,281	130,236,339	191,945,320
52	S	Other Operating Revenues	CALCULATED	25,104,439	1,021,512	752,328	10,123,194	9,205,172	1,627,635	2,374,598
53	S	Revenues from Other Sources	CALCULATED	0	0	0	0	0	0	0
54	S	Less: Provisions for Rate Refunds	CALCULATED	0	0	0	0	0	0	0
55	S	TOTAL OPERATING REVENUES		1,925,019,676	82,945,791	58,645,322	784,579,218	672,665,453	131,863,973	194,319,919
56	S									
57	S	**OPERATING EXPENSES**								
58	S	Operation and Maintenance Expense								
59	S	Production Expense	CALCULATED	0	0	0	0	0	0	0
60	S	Transmission Expense	CALCULATED	0	0	0	0	0	0	0
61	S	Distribution Expense	CALCULATED	178,009,259	13,342,811	249,859	60,854,576	83,796,643	0	19,765,369
62	S	Customer Accounts Expense	CALCULATED	94,394,062	0	0	1,062,937	0	74,718,489	18,612,636
63	S	Customer Service & Information Expense	CALCULATED	5,318,001	0	0	2,010,317	0	3,307,684	0
64	S	Sales Expense	CALCULATED	40,922	0	0	40,922	0	0	0
65	S	Administrative and General Expense	CALCULATED	33,695,393	1,292,992	4,225,276	27,357,187	22,438,447	-17,229,425	-4,389,083
66	S	Total Operation and Maintenance Expense	CALCULATED	311,457,637	14,635,803	4,475,135	91,325,939	106,235,090	60,796,748	33,988,922
67	S	Depreciation Expense	CALCULATED	286,771,855	12,258,086	14,224,907	136,714,639	108,782,584	5,285,730	9,505,909
68	S	Amortization Expense	CALCULATED	21,391,564	274,415	318,445	3,499,115	2,435,258	11,601,583	3,262,747
69	S	Taxes Other Than Income Taxes	CALCULATED	-11,551,217	-546,406	-38,448	-3,506,452	-2,264,538	-3,570,372	-1,625,003
70	S	Proforma Expense Adjustments	CALCULATED	82,048,703	2,707,852	1,896,332	25,313,646	18,834,587	7,907,300	25,388,986
71	S	State Income Taxes	CALCULATED	119,869,746	5,172,083	4,167,598	53,842,629	45,024,559	1,443,600	10,219,276
72	S	Federal Income Taxes	CALCULATED	231,691,305	10,006,096	7,716,645	103,440,942	86,941,125	2,644,406	20,942,090
73	S	Provision for Deferred Income Taxes	CALCULATED	144,525,616	7,000,797	2,034,312	51,252,253	35,250,364	32,355,035	16,632,855
74	S	Income Taxes Deferred in Prior Years	CALCULATED	0	0	0	0	0	0	0
75	S	Investment Tax Credit Adjustement (Net)	CALCULATED	0	0	0	0	0	0	0
76	S	TOTAL OPERATING EXPENSES		1,186,205,208	51,508,728	34,794,927	461,882,711	401,239,030	118,464,029	118,315,782
77	S									
78	S	**OPERATING INCOME (RETURN)**		738,814,468	31,437,063	23,850,396	322,696,506	271,426,422	13,399,944	76,004,136
79	S	Plus Operating Income Adjustment	CALCULATED	0	0	0	0	0	0	0
80	S	TOTAL NET OPERATING INCOME		738,814,468	31,437,063	23,850,396	322,696,506	271,426,422	13,399,944	76,004,136
81	S									
82	S	**RATE OF RETURN ON RATE BASE (PRESENT)**		7.55%	7.55%	7.55%	7.55%	7.55%	7.55%	7.55%
83	S	**INDEX RATE OF RETURN (PRESENT)**		1.00	1.00	1.00	1.00	1.00	1.00	1.00
84	S									
85	S	**EQUALIZED RETURN AT PROPOSED ROR**								
86	S									
87	S	**DEVELOPMENT OF RETURN (EQUALIZED RATE LEVELS)**								
88	S									

PUBLIC SERVICE ELECTRIC & GAS COMPANY
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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery	System Delivery	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)	(7)
89	S	**RATE BASE**	CALCULATED	9,785,622,095	416,384,944	315,899,282	4,274,125,914	3,595,051,949	177,482,704	1,006,677,303
90	S									
91	S	**RATE OF RETURN**		7.55%	7.55%	7.55%	7.55%	7.55%	7.55%	7.55%
92	S									
93	S	**RETURN (RATE BASE * 7.40% ROR)**		738,814,468	31,437,063	23,850,396	322,696,506	271,426,422	13,399,944	76,004,136
94	S									
95	S	**PLUS:**	CALCULATED							
96	S	**OPERATING EXPENSES**								
97	S	Total Operation and Maintenance Expense	CALCULATED	311,457,637	14,635,803	4,475,135	91,325,939	106,235,090	60,796,748	33,988,922
98	S	Depreciation Expense	CALCULATED	286,771,855	12,258,086	14,224,907	136,714,639	108,782,584	5,285,730	9,505,909
99	S	Amortization Expense	CALCULATED	21,391,564	274,415	318,445	3,499,115	2,435,258	11,601,583	3,262,747
100	S	Taxes Other Than Income Taxes	CALCULATED	-11,551,217	-546,406	-38,448	-3,506,452	-2,264,538	-3,570,372	-1,625,003
101	S	Proforma Expense Adjustments	CALCULATED	82,048,703	2,707,852	1,896,332	25,313,646	18,834,587	7,907,300	25,388,986
102	S	Income Taxes	CALCULATED	351,561,051	15,178,180	11,884,244	157,283,571	131,965,684	4,088,006	31,161,366
103	S	Provision for Deferred Income Taxes	CALCULATED	144,525,616	7,000,797	2,034,312	51,252,253	35,250,364	32,355,035	16,632,855
104	S	Income Taxes Deferred in Prior Years	CALCULATED	0	0	0	0	0	0	0
105	S	Investment Tax Credit Adjustement (Net)	CALCULATED	0	0	0	0	0	0	0
106	S	**TOTAL OPERATING EXPENSES**		1,186,205,208	51,508,728	34,794,927	461,882,711	401,239,030	118,464,029	118,315,782
107	S									
108	S	**EQUALS TOTAL COST OF SERVICE**		1,925,019,676	82,945,791	58,645,322	784,579,218	672,665,453	131,863,973	194,319,919
109	S									
110	S	**LESS:**								
111	S	Other Operating Revenues	CALCULATED	25,104,439	1,021,512	752,328	10,123,194	9,205,172	1,627,635	2,374,598
112	S	Revenues from Other Sources	CALCULATED	0	0	0	0	0	0	0
113	S	Plus: Provisions for Rate Refunds		0	0	0	0	0	0	0
114	S	**EQUALS:**								
115	S	**BASE RATE SALES @ EQUALIZED ROR 7.40%**		1,899,915,237	81,924,279	57,892,994	774,456,024	663,460,281	130,236,339	191,945,320
116	S									
117	S	**TOTAL COST OF SERVICE INCREASE/DECREASE**		0	0	0	0	0	0	0
118	S	**REVENUE INCREASE TO RETAIL REVENUES (%)**		0.00	0.00	0.00	0.00	0.00	0.00	0.00
119	S									
120	S									
121	S									
122	S									
123	S									
124	S									
125	S									
126	S									

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery	System Delivery	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	RBP	**DEVELOPMENT OF RATE BASE**								
2	RBP									
3	RBP	**ELECTRIC PLANT IN SERVICE**								
4	RBP									
5	RBP	PRODUCTION PLANT								
6	RBP	E304-E346 - Production Plant	not_used	0	0	0	0	0	0	0
7	RBP	Not Used	not_used	0	0	0	0	0	0	0
8	RBP	TOTAL PRODUCTION PLANT		0	0	0	0	0	0	0
9	RBP									
10	RBP	TRANSMISSION PLANT								
11	RBP	E350 Land & Land Rights	not_used	0	0	0	0	0	0	0
12	RBP	E352 Structures & Improvements	not_used	0	0	0	0	0	0	0
13	RBP	E353 Station Equipment	not_used	0	0	0	0	0	0	0
14	RBP	E354/E355 Towers and Fixtures	not_used	0	0	0	0	0	0	0
15	RBP	E356-E359 Transmission Plant - Others	not_used	0	0	0	0	0	0	0
16	RBP	TOTAL TRANSMISSION PLANT		0	0	0	0	0	0	0
17	RBP									
18	RBP	DISTRIBUTION PLANT								
19	RBP	E360-E361 Land & Structures								
20	RBP	E360 - Land and Land Rights								
21	RBP	- Headquarters related	DISTPLT	14,080,608	614,681	713,307	6,847,858	5,454,897	0	449,865
22	RBP	- Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0
23	RBP	- Direct - HEP	DIR_HEP_03	0	0	0	0	0	0	0
24	RBP	- Substation related	E362PLT	37,233,560	0	0	0	37,233,560	0	0
25	RBP	E361 - Structures and improvements		0	0	0	0	0	0	0
26	RBP	- Headquarters related	DISTPLT	124,204,880	5,422,095	6,292,075	60,404,877	48,117,582	0	3,968,251
27	RBP	- Substation related	E362PLT	118,051,566	0	0	0	118,051,566	0	0
28	RBP	Total Accounts E360-E361		293,570,614	6,036,776	7,005,382	67,252,735	208,857,606	0	4,418,116
29	RBP	E362 - Station Equipment								
30	RBP	Switching Stations	CP_SUBT_05	338,443,408	0	0	0	338,443,408	0	0
31	RBP	H Class Substations	CP_PRI_05	1,226,974,761	0	0	0	1,226,974,761	0	0
32	RBP	4 kV Class Substations	CP_PRI_05	0	0	0	0	0	0	0
33	RBP	Total Account E362		1,565,418,169	0	0	0	1,565,418,169	0	0
34	RBP	E364 - Poles Towers & Fixtures								
35	RBP	Streetlight poles - direct to BPL	DIR_BPL_02	8,114,160	8,114,160	0	0	0	0	0
36	RBP	Streetlight poles - direct to PSAL	DIR_PSAL_02	1,812,825	1,812,825	0	0	0	0	0
37	RBP	Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0
38	RBP	Subtransmission lines	SUBTRANSLINES	101,446,395	0	0	21,405,189	80,041,206	0	0
39	RBP	Primary lines	PRIMARYLINES	482,404,572	0	0	241,202,286	241,202,286	0	0
40	RBP	Secondary lines	SUMPK_SEC_04	433,665,531	0	0	433,665,531	0	0	0
41	RBP	Total Account E364		1,027,443,483	9,926,985	0	696,273,007	321,243,491	0	0
42	RBP									
43	RBP									
44	RBP	**ELECTRIC PLANT IN SERVICE CONTINUED**								

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				(1)	(2)	(3)	(4)	(5)	(6)	(7)
45	RBP									
46	RBP	DISTRIBUTION PLANT CONTINUED								
47	RBP	E365 - OH Conductors and Devices								
48	RBP	Direct - BPL	DIR_BPL_02	2,226,625	2,226,625	0	0	0	0	0
49	RBP	Direct - PSAL	DIR_PSAL_02	6,436,532	6,436,532	0	0	0	0	0
50	RBP	Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0
51	RBP	Subtransmission lines	SUBTRANSLINES	201,889,270	0	0	42,598,636	159,290,634	0	0
52	RBP	Primary lines	PRIMARYLINES	2,523,188,742	0	0	1,261,594,371	1,261,594,371	0	0
53	RBP	Secondary lines	SUMPK_SEC_04	122,443,422	0	0	122,443,422	0	0	0
54	RBP	Other	DISTPLT	0	0	0	0	0	0	0
55	RBP	Total Account E365		2,856,184,590	8,663,157	0	1,426,636,429	1,420,885,005	0	0
56	RBP									
57	RBP	E366 - Underground Conduit								
58	RBP	Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0
59	RBP	Direct - HEP	DIR_HEP_03	0	0	0	0	0	0	0
60	RBP	Underground Conduits	E367PLT	512,107,003	1,207,229	74,667	352,039,379	158,785,119	0	608
61	RBP	Not Used	not_used							
62	RBP	Total Account E366		512,107,003	1,207,229	74,667	352,039,379	158,785,119	0	608
63	RBP									
64	RBP	E367 - Underground Conductors & Devices								
65	RBP	Direct - BPL	DIR_BPL_02	2,325,498	2,325,498	0	0	0	0	0
66	RBP	Direct - PSAL	DIR_PSAL_02	868,520	868,520	0	0	0	0	0
67	RBP	UG BPL Poles in UG areas	DISTPLTXMTR	3,979,461	179,820	208,673	1,993,480	1,595,788	0	1,700
68	RBP	Direct - HEP	DIR_HEP_03	0	0	0	0	0	0	0
69	RBP	367.1 - Conventional UG								
70	RBP	Subtransmission lines	SUBTRANSLINES	51,391,650	0	0	10,843,638	40,548,011	0	0
71	RBP	Primary lines	PRIMARYLINES	354,073,350	0	0	177,036,675	177,036,675	0	0
72	RBP	Secondary lines	SUMPK_SEC_04	539,234,440	0	0	539,234,440	0	0	0
73	RBP	367.2 - BUD								
74	RBP	Subtransmission lines	SUBTRANSLINES	479,311	0	0	101,135	378,176	0	0
75	RBP	Primary lines	PRIMARYLINES	448,395,026	0	0	224,197,513	224,197,513	0	0
76	RBP	Secondary lines	SUMPK_SEC_04	30,436,220	0	0	30,436,220	0	0	0
77	RBP	Other	E367PLT	0	0	0	0	0	0	0
78	RBP	Total Account E367		1,431,183,475	3,373,838	208,673	983,843,101	443,756,163	0	1,700
79	RBP									
80	RBP	E368 - Line Transformers								
81	RBP	Line Transformers	LNTRFRMR_04	1,591,690,631	0	0	1,591,690,631	0	0	0
82	RBP	Not Used	not_used	0	0	0	0	0	0	0
83	RBP	Total Account E368		1,591,690,631	0	0	1,591,690,631	0	0	0
84	RBP	E369 - Services								
85	RBP	Basic portion (minimum size)	SERVICESMIN_03	535,269,333	0	535,269,333	0	0	0	0
86	RBP	E369 - Excess portion	SERVICESEXC_04	0	0	0	0	0	0	0
87	RBP	Total Account E369		535,269,333	0	535,269,333	0	0	0	0
88	RBP	**ELECTRIC PLANT IN SERVICE CONTINUED**		0	0	0	0	0	0	0

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				(1)	(2)	(3)	(4)	(5)	(6)	(7)
89	RBP									
90	RBP	E370 - Meters		0	0	0	0	0	0	0
91	RBP	Load profiling meters	KWHMETERX_04	0	0	0	0	0	0	0
92	RBP	Basic portion (minimum size)	METERSMIN_07	339,768,857	0	0	0	0	0	339,768,857
93	RBP	Excess portion	METERSEXC_04	25,652,585	0	0	25,652,585	0	0	0
94	RBP	Total Account E370		365,421,442	0	0	25,652,585	0	0	339,768,857
95	RBP									
96	RBP	E371 - Installations on Customer Premises	not_used	0	0	0	0	0	0	0
97	RBP									
98	RBP	E373 - Street Lighting & Signal Systems								
99	RBP	BPL luminaires & poles	DIR_BPL_02	340,539,607	340,539,607	0	0	0	0	0
100	RBP	PSAL luminaires & poles	DIR_PSAL_02	96,860,656	96,860,656	0	0	0	0	0
101	RBP	UG BPL Poles in UG areas	DISTPLTXMTR	61,626,889	2,784,739	3,231,553	30,871,513	24,712,756	0	26,329
102	RBP	Total Account E373		499,027,153	440,185,003	3,231,553	30,871,513	24,712,756	0	26,329
103	RBP									
104	RBP	E374 - Asset Retirement Obligations	E364PLT	96,512,525	932,488	0	65,404,148	30,175,889	0	0
105	RBP									
106	RBP	Other Distribution and Unallocated Plant								
107	RBP	Not Used	not_used	0	0	0	0	0	0	0
108	RBP	Total Other Plant and Unallocated Plant		0	0	0	0	0	0	0
109	RBP									
110	RBP	TOTAL DISTRIBUTION PLANT		10,773,828,418	470,325,475	545,789,607	5,239,663,528	4,173,834,198	0	344,215,610
111	RBP									
112	RBP	GENERAL AND COMMON PLANT								
113	RBP	E390-E398 GENERAL PLANT								
114	RBP	Meter Related	METERPLT	0	0	0	0	0	0	0
115	RBP	Customer Service Related	CUSTSVSX	0	0	0	0	0	0	0
116	RBP	Substation Related	E362PLT	0	0	0	0	0	0	0
117	RBP	Distribution Delivery	DISTPLTXMTR	429,584,593	19,411,672	22,526,291	215,197,078	172,266,022	0	183,530
118	RBP	Service & Support Related	UTILWORK_04	0	0	0	0	0	0	0
119	RBP	Unassigned	GENPLT	0	0	0	0	0	0	0
120	RBP	Total Accounts E390-E398		429,584,593	19,411,672	22,526,291	215,197,078	172,266,022	0	183,530
121	RBP									
122	RBP	C389-C399 COMMON PLANT								
123	RBP	Not Used	not_used	0	0	0	0	0	0	0
124	RBP	Meter Plant Related	METERPLT	0	0	0	0	0	0	0
125	RBP	Meter Reading Related	MRCOST_07	0	0	0	0	0	0	0
126	RBP	Not Used	not_used	0	0	0	0	0	0	0
127	RBP	Customer Service Related	CUSTSVSX	92,605,476	0	0	2,854,220	0	72,465,163	17,286,093
128	RBP	Distribution Delivery Related	DISTPLTXMTR	33,738,596	1,524,549	1,769,164	16,901,089	13,529,381		14,414
129	RBP	Service & Support Related	UTILWORK_04	0	0	0	0	0	0	0
130	RBP	Unassigned	COMPLT	309,972	3,740	4,340	48,468	33,193	177,786	42,445
131	RBP	Not Used	not_used	0	0	0	0	0	0	0
132	RBP	Total Accounts C389-C399		126,654,044	1,528,289	1,773,504	19,803,776	13,562,574	72,642,949	17,342,952

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				(1)	(2)	(3)	(4)	(5)	(6)	(7)
133	RBP									
134	RBP	TOTAL GENERAL AND COMMON PLANT		556,238,637	20,939,960	24,299,795	235,000,854	185,828,596	72,642,949	17,526,482
135	RBP	**ELECTRIC PLANT IN SERVICE CONTINUED**								
136	RBP									
137	RBP	INTANGIBLE PLANT - E301-E303								
138	RBP	Customer Service Related	CUSTSVSX	40,584,928	0	0	1,250,880	0	31,758,310	7,575,738
139	RBP	Not Used	not_used	0	0	0	0	0	0	0
140	RBP	TOTAL INTANGIBLE PLANT		40,584,928	0	0	1,250,880	0	31,758,310	7,575,738
141	RBP									
142	RBP	C303 - INTANGIBLE PLANT								
143	RBP	Not Used	not_used	0	0	0	0	0	0	0
144	RBP	Meter Reading	MRCOST_07	1,212,800	0	0	0	0	0	1,212,800
145	RBP	Customer Service Related	CUSTSVSX	84,635,615	0	0	2,608,579	0	66,228,628	15,798,408
146	RBP	Distribution Related	INTANGPLT	0	0	0	0	0	0	0
147	RBP	C390.4 / C111.000 Capital Lease	TOTPLT	0	0	0	0	0	0	0
148	RBP	E399 Oth Tangible Plant	GENPLT	0	0	0	0	0	0	0
149	RBP	E399.1 Asset Retirement Obligations	GENPLT	490,552	22,167	25,723	245,738	196,714		210
150	RBP	TOTAL ACCOUNTS C303-C390.4,E399		86,338,967	22,167	25,723	2,854,317	196,714	66,228,628	17,011,418
151	RBP									
152	RBP	TOTAL INTANGIBLE PLANT		126,923,895	22,167	25,723	4,105,197	196,714	97,986,938	24,587,156
153	RBP									
154	RBP	**TOTAL ELECTRIC PLANT IN SERVICE**		11,456,990,950	491,287,602	570,115,126	5,478,769,579	4,359,859,508	170,629,886	386,329,248
155	RBP									
156	RBP									
157	RBP									
158	RBP									
159	RBP									

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				(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	RBD	**LESS: DEPRECIATION RESERVE & AMORT**								
2	RBD									
3	RBD	E301-E303 - INTANGILE PLANT - RESERVE								
4	RBD	Customer Service Related - Reserve	CUSTSVSX	15,757,979	0	0	485,681	0	12,330,853	2,941,445
5	RBD	Not Used	not_used	0	0	0	0	0	0	0
6	RBD	Not used	not_used	0	0	0	0	0	0	0
7	RBD	Total Accounts E301-E303 Reserve		15,757,979	0	0	485,681	0	12,330,853	2,941,445
8	RBD									
9	RBD	E304-E346 - PRODUCTION PLANT - RESERVE	not_used	0	0	0	0	0	0	0
10	RBD	E350-E359 - TRANSMISSION PLANT - RESERVE	not_used	0	0	0	0	0	0	0
11	RBD									
12	RBD	DISTRIBUTION PLANT RESERVE								
13	RBD	E360-E361 Land & Structures - Reserve								
14	RBD	E360 - Land and Land Rights								
15	RBD	- Headquarters Related	DISTPLT	0	0	0	0	0	0	0
16	RBD	- Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0
17	RBD	- Direct - HEP	DIR_HEP_03	0	0	0	0	0	0	0
18	RBD	- Substation Related	E362PLT	667,893	0	0	0	667,893	0	0
19	RBD	E361 - Structures and improvements								
20	RBD	- Headquarters Related	DISTPLT	40,449,681	1,765,808	2,049,134	19,671,997	15,670,406	0	1,292,336
21	RBD	- Substation Related	E362PLT	36,319,499	0	0	0	36,319,499	0	0
22	RBD	Total Accounts E360-E361		77,437,073	1,765,808	2,049,134	19,671,997	52,657,798	0	1,292,336
23	RBD	E362 Station Equipment - Rsrv	E362PLT	279,293,104	0	0	0	279,293,104	0	0
24	RBD	E364 Poles Towers and Fixtures Rsrv								
25	RBD	- Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0
26	RBD	- All Other	E364PLT	200,061,625	1,932,962	0	135,576,809	62,551,854	0	0
27	RBD	E365 OH Conductors and Devices - Rsrv								
28	RBD	- Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0
29	RBD	- All Other	E365PLT	609,997,837	1,850,198	0	304,687,988	303,459,651	0	0
30	RBD	E366 UG Conduit - Rsrv								
31	RBD	- Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0
32	RBD	- All Other	E366PLT	258,299,502	608,909	37,661	177,563,665	80,088,960	0	307
33	RBD	E367 UG Conductors and Devices - Rsrv								
34	RBD	- Direct - HTS-HV	DIR_HEP_03	0	0	0	0	0	0	0
35	RBD	- All Other	E367PLT	512,800,757	1,208,864	74,768	352,516,289	159,000,226	0	609
36	RBD	E368 Line Transformers - Rsrv	LNTRFRMR_04	378,941,964	0	0	378,941,964	0	0	0
37	RBD	E369 Services - Rsrv								
38	RBD	Services	E369PLT	240,814,772	0	240,814,772	0	0	0	0
39	RBD	Not used	not_used	0	0	0	0	0	0	0
40	RBD	Total Accounts E369 Rsrv		240,814,772	0	240,814,772	0	0	0	0
41	RBD	E370 Meters - Rsrv								
42	RBD	Load profile meters	KWHMETERX_04	0	0	0	0	0	0	0
43	RBD	All other Meters	METERPLTXPR	136,921,647	0	0	9,611,900	0	0	127,309,748
44	RBD	Total Account E370 Rsrv		136,921,647	0	0	9,611,900	0	0	127,309,748

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery	System Delivery	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)	(7)
45	RBD	E371 - Installations on Cust Premises Rsrv	not_used	0	0	0	0	0	0	0
46	RBD	E373 Street Lighting - Rsrv								
47	RBD	Streetlight fixtures	E373PLT	118,939,285	104,914,711	770,216	7,357,988	5,890,095	0	6,275
48	RBD	Not used	not_used	0	0	0	0	0	0	0
49	RBD	Total Account E373 Rsrv		118,939,285	104,914,711	770,216	7,357,988	5,890,095	0	6,275
50	RBD									
51	RBD									
52	RBD									
53	**RBD**	**DEPRECIATION RESERVE & AMORT CONTINUED**								
54	RBD									
55	RBD									
56	RBD									
57	RBD	Other Plant Unallocated - Reserve								
58	RBD	Not Used	not_used	0	0	0	0	0	0	0
59	RBD	Not Used	not_used	0	0	0	0	0	0	0
60	RBD	Total Other Plant Unallocated - Reserve		0	0	0	0	0	0	0
61	RBD									
62	RBD	Not Used	not_used	0	0	0	0	0	0	0
63	RBD	Not Used	not_used	0	0	0	0	0	0	0
64	RBD	Not Used	not_used	0	0	0	0	0	0	0
65	RBD									
66	RBD	TOTAL DISTRIBUTION PLANT RESERVE		2,813,507,566	112,281,453	243,746,551	1,385,928,599	942,941,689		128,609,275
67	RBD									
68	RBD	GENERAL AND COMMON PLANT RESERVE								
69	RBD	E390-E398 GENERAL PLANT - RESERVE								
70	RBD	Meter Plant Related	METERPLT	0	0	0	0	0	0	0
71	RBD	Customer Service Related	CUSTSVSX	0	0	0	0	0	0	0
72	RBD	Substation Related	E362PLT	0	0	0	0	0	0	0
73	RBD	Distribution Delivery Related	DISTPLTXMTR	156,424,740	7,068,377	8,202,504	78,359,763	62,727,268	0	66,829
74	RBD	Service & Support Related	UTILWORK_04	0	0	0	0	0	0	0
75	RBD	Unassigned	GENPLT	0	0	0	0	0	0	0
76	RBD	Total Accounts E390-E398 Reserve		156,424,740	7,068,377	8,202,504	78,359,763	62,727,268	0	66,829
77	RBD									
78	RBD	C389-C399 COMMON PLANT RESERVE								
79	RBD	Not Used	not_used	0	0	0	0	0	0	0
80	RBD	Meter Plant Related	METERPLT	0	0	0	0	0	0	0
81	RBD	Meter Reading Related	MRCOST_07	0	0	0	0	0	0	0
82	RBD	Not Used	not_used	0	0	0	0	0	0	0
83	RBD	Customer Service Related	CUSTSVSX	46,782,308	0	0	1,441,891	0	36,607,852	8,732,565
84	RBD	Distribution Delivery Related	DISTPLTXMTR	19,175,874	866,502	1,005,533	9,606,006	7,689,642	0	8,192
85	RBD	Sales and Service Dept. Related	UTILWORK_04	0	0	0	0	0	0	0
86	RBD	Unassigned	COMPLT	0	0	0	0	0	0	0
87	RBD	Not Used	not_used	0	0	0	0	0	0	0
88	RBD	Total Accounts C389-C399 Reserve		65,958,182	866,502	1,005,533	11,047,897	7,689,642	36,607,852	8,740,757

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery	System Delivery	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)	(7)
89	RBD									
90	RBD	C303 - INTANGIBLE PLANT								
91	RBD	Not Used	not_used	0	0	0	0	0	0	0
92	RBD	Meter Reading	MRCOST_07	623,486	0	0	0	0	0	623,486
93	RBD	Customer Service Related	CUSTSVSX	46,570,192	0	0	1,435,353	0	36,441,868	8,692,971
94	RBD	Distribution Related	INTANGPLT	0	0	0	0	0	0	0
95	RBD	C390.4 / C111.000 Capital Lease	TOTPLT	0	0	0	0	0	0	0
96	RBD	E399 Oth Tangible Plant	GENPLT	0	0	0	0	0	0	0
97	RBD	E399.1 Asset Retirement Obligations	GENPLT	490,552	22,167	25,723	245,738	196,714	0	210
98	RBD	Total Accounts C303-C390.4,E399		47,684,230	22,167	25,723	1,681,092	196,714	36,441,868	9,316,666
99	RBD									
100	RBD	**TOTAL DEPRECIATION RESERVE & AMORT.**		3,099,332,698	120,238,498	252,980,311	1,477,503,032	1,013,555,312	85,380,573	149,674,973
101	RBD									
102	RBD	**NET ELECTRIC PLANT IN SERVICE**		8,357,658,252	371,049,105	317,134,815	4,001,266,547	3,346,304,196	85,249,313	236,654,276

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery	System Delivery	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	RBO	**ADDITIONS AND DEDUCTIONS TO RATE BASE**								
2	RBO									
3	RBO	**PLUS: ADDITIONS TO RATE BASE**								
4	RBO									
5	RBO	Working Capital								
6	RBO	Cash (lead/lag)	EXPENDITURES	884,882,332	44,956,628	14,646,540	344,571,965	296,451,470	86,912,151	97,343,577
7	RBO	Materials and Supplies	EXPENDITURES	297,953,440	15,137,586	4,931,714	116,022,660	99,819,752	29,264,653	32,777,074
8	RBO	Prepayments	EXPENDITURES	500,266	25,416	8,280	194,803	167,598	49,136	55,033
9	RBO	Working Funds	EXPENDITURES							
10	RBO	Total Working Capital		1,183,336,038	60,119,630	19,586,535	460,789,429	396,438,821	116,225,940	130,175,683
11	RBO	Net Plant Adds - Distribution	DISTPLT	1,061,820,806	46,353,196	53,790,606	516,398,028	411,354,610		33,924,366
12	RBO	Plant Held for Future Use	TOTPLT	489,291	20,981	24,348	233,981	186,196	7,287	16,499
13	RBO	Capital Stimulas Adjust	DISTPLT							
14	RBO	Net Plant Adds - General & Other	TOTPLTNET	305,589,989	13,567,065	11,595,739	146,302,584	122,354,496	3,117,062	8,653,043
15	RBO	CEF-EC Adjustment	ECPRO_07	657,429,985						657,429,985
16	RBO	CEF-EV Adjustment	TOTREV	42,056,391	1,812,138	1,281,239	17,140,900	14,695,892	2,880,866	4,245,356
17	RBO	TOTAL ADDITIONS TO RATE BASE		3,250,722,500	121,873,010	86,278,467	1,140,864,922	945,030,015	122,231,154	834,444,933
18	RBO									
19	RBO									
20	RBO	**PLUS: DEDUCTIONS TO RATE BASE**								
21	RBO									
22	RBO	Customer Advances for Construction	REVREQ	(63,907,492)	(2,755,689)	(1,947,348)	(26,050,395)	(22,316,828)	(4,380,763)	(6,456,469)
23	RBO	Unbilled Revenue	TOTREV							
24	RBO	IAP Adjustment	E365PLT	(40,898,861)	(124,051)		(20,428,583)	(20,346,226)		
25	RBO	Deferred Income Taxes and Credits								
26	RBO	ADIT Test/Post year	TOTPLT							
27	RBO	Liberalized Depreciation	TOTPLT	(2,247,763)	(96,386)	(111,852)	(1,074,887)	(855,367)	(33,476)	(75,794)
28	RBO	Cost of Removal	TOTPLT	15,629,066	670,190	777,723	7,473,869	5,947,507	232,765	527,011
29	RBO	3% Investment Tax Credit	DISTPLT							
30	RBO	Computer Software	INTANGPLT							
31	RBO	Capitalized Interest	TOTPLTNET	312,066	13,855	11,841	149,403	124,947	3,183	8,836
32	RBO	NJ Corporate Business Tax	TOTPLTNET	6,378,736	283,192	242,044	3,053,849	2,553,968	65,064	180,619
33	RBO	Defrd Tax & Consolidated Tax Adjustment	TOTPLT	(1,738,024,409)	(74,528,281)	(86,486,409)	(831,128,810)	(661,390,262)	(25,884,537)	(58,606,109)
34	RBO	Total Deferred Income Taxes and Credits		(1,717,952,304)	(73,657,430)	(85,566,652)	(821,526,577)	(653,619,207)	(25,617,001)	(57,965,436)
35	RBO									
36	RBO	TOTAL DEDUCTIONS TO RATE BASE		(1,822,758,657)	(76,537,170)	(87,514,000)	(868,005,555)	(696,282,262)	(29,997,764)	(64,421,906)
37	RBO									
38	RBO									
39	RBO	**TOTAL RATE BASE**		9,785,622,095	416,384,944	315,899,282	4,274,125,914	3,595,051,949	177,482,704	1,006,677,303

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery	System Delivery	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	REV	**OPERATING REVENUES**								
2	REV									
3	REV	**SALES REVENUES**								
4	REV	BASE RATE SALES @ EQUALIZED ROR 7.40%		1,899,915,237	81,924,279	57,892,994	774,456,024	663,460,281	130,236,339	191,945,320
5	REV	Not Used	not_used	0	0	0	0	0	0	0
6	REV	Not Used	not_used	0	0	0	0	0	0	0
7	REV	TOTAL SALES OF ELECTRICITY		1,899,915,237	81,924,279	57,892,994	774,456,024	663,460,281	130,236,339	191,945,320
8	REV									
9	REV	**OTHER OPERATING REVENUES**								
10	REV	450-Forfeited Discounts	REVLATEP	3,653,078	97,210	98,817	1,380,275	1,709,358	158,215	209,204
11	REV	456-Other Electric Revenues	TOTREV	21,451,361	924,302	653,511	8,742,920	7,495,814	1,469,420	2,165,394
12	REV	Not Used	not_used	0	0	0	0	0	0	0
13	REV	Not Used	not_used	0	0	0	0	0	0	0
14	REV	TOTAL OTHER OPERATING REV		25,104,439	1,021,512	752,328	10,123,194	9,205,172	1,627,635	2,374,598
15	REV									
16	REV	**OTHER REVENUE SOURCES**								
17	REV	Not Used	not_used	0	0	0	0	0	0	0
18	REV	Not Used	not_used	0	0	0	0	0	0	0
19	REV	TOTAL OTHER REVENUE SOURCES		0	0	0	0	0	0	0
20	REV									
21	REV	LESS: E496 Provision for Rate Refunds	TOTREV	0	0	0	0	0	0	0
22	REV									
23	REV	**TOTAL OPERATING REVENUES**		1,925,019,676	82,945,791	58,645,322	784,579,218	672,665,453	131,863,973	194,319,919

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery	System Delivery	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	E	**OPERATION & MAINTENANCE EXPENSE**								
2	E	PRODUCTION EXPENSE								
3	E	E500-E557 Production Expenses								
4	E	Not Used	not_used	0	0	0	0	0	0	0
5	E	Total Production Expense		0	0	0	0	0	0	0
6	E	TOTAL PRODUCTION EXPENSE		0	0	0	0	0	0	0
7	E									
8	E	TRANSMISSION EXPENSES								
9	E	E560-E573 Transmission Exp	not_used	0	0	0	0	0	0	0
10	E	TOTAL TRANSMISSION EXPENSE		0	0	0	0	0	0	0
11	E									
12	E	DISTRIBUTION EXPENSES								
13	E	Operation								
14	E	E580 Operation Supervision & Eng'g	DISTEXPO	0	0	0	0	0	0	0
15	E	E581 Load Dispatching	CP_SUBT_05	0	0	0	0	0	0	0
16	E	E582 Station Expenses	E362PLT	2,539,578	0	0	0	2,539,578	0	0
17	E	E583 OH Line Expenses	E365PLT	4,195,894	12,727	0	2,095,808	2,087,359	0	0
18	E	E584 Underground Line Expenses	E367PLT	6,199,909	14,616	904	4,262,024	1,922,359	0	7
19	E	E585 Street Lighting and System Expenses	E373PLT	173,106	152,694	1,121	10,709	8,573		9
20	E	E586 Meter Expenses								
21	E	- Basic portion (minimum size)	MTROMMIN_07	5,865,310	0	0	0	0	0	5,865,310
22	E	- Excess portion	METERSEXC_04	0	0	0	0	0	0	0
23	E	E587 Customer Installations Expenses		0	0	0	0	0	0	0
24	E	-E587 Customer Installation Expenses - System	CUSTAVG_04	-1,314,125	0	0	-1,314,125	0	0	0
25	E	-E587 Customer Installation Expenses - Local	CUSTAVG_04	-1,314,125	0	0	-1,314,125	0	0	0
26	E	E588 Miscellaneous Distribution Expenses	DISTEXPO	35,897,260	395,387	4,447	8,214,237	14,402,057	0	12,881,132
27	E	E589 Rents	DISTPLT	1,330,133	58,066	67,383	646,887	515,300	0	42,497
28	E	Total Distribution Operation		53,572,940	633,490	73,855	12,601,414	21,475,225	0	18,788,955
29	E	Maintenance								
30	E	E590 Maint. Supervision & Eng'g	DISTEXPM	0	0	0	0	0	0	0
31	E	E591 Maint of Structures	E360PLT	12,325,542	147,645	171,335	1,644,839	10,253,667	0	108,056
32	E	E592 Maint of Station Equipment	E362PLT	17,215,431	0	0	0	17,215,431	0	0
33	E	E593 Maint of Overhead Lines								
34	E	- Direct assigned - BPL poles	DIR_BPL_02	40,988	40,988	0	0	0	0	0
35	E	- Direct assigned - PSAL poles	DIR_PSAL_02	118,210	118,210	0	0	0	0	0
36	E	- all other O&M	E365PLT	56,305,216	170,781	0	28,123,908	28,010,528	0	0
37	E	E594.0 Maint of Underground Lines	E367PLT	20,076,605	47,328	2,927	13,801,326	6,225,000	0	24
38	E	Not used		0	0	0	0	0	0	0
39	E	E595 Maint of Line Transformers	LNTRFRMR_04	4,205,529	0	0	4,205,529	0	0	0
40	E	E596 Maint of Street Lighting & Signal Systems								
41	E	- BPL luminaires	DIR_BPL_02	8,123,869	8,123,869	0	0	0	0	0
42	E	- BPL-POF luminaires	DIR_BPLPOF_02	340,052	340,052	0	0	0	0	0
43	E	- PSAL luminaires	DIR_PSAL_02	3,594,664	3,594,664	0	0	0	0	0
44	E	E597 Maint of Meters								

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				(1)	(2)	(3)	(4)	(5)	(6)	(7)
45	E	- Load profiling meters O&M	KWHMETERX_04	0	0	0	0	0	0	0
46	E	- Basic portion (minimum size)	MTROMMIN_07	858,670	0	0	0	0	0	858,670
47	E	- Excess portion	METERSEXC_04	0	0	0	0	0	0	0
48	E	E598 Other Dist Maint Exp	DISTEXPM	1,231,542	125,784	1,742	477,560	616,793	0	9,664
49	**E**	**OPERATION & MAINTENANCE EXPENSE CONTINUED**								
50	E									
51	E	Total Distribution Maintenance		124,436,319	12,709,321	176,004	48,253,162	62,321,418	0	976,414
52	E	TOTAL DISTRIBUTION PLANT O&M EXPENSES		178,009,259	13,342,811	249,859	60,854,576	83,796,643		19,765,369
53	E									
54	E									
55	E	TOTAL OPER & MAINT EXP (PROD,TRAN,& DIST)		178,009,259	13,342,811	249,859	60,854,576	83,796,643		19,765,369
56	E									
57	E									
58	E	CUSTOMER ACCOUNTS EXPENSES								
59	E	E901 Supervision	CUSTACCTS	0	0	0	0	0	0	0
60	E	E902 Meter Reading								
61	E	- Meter O&M	METERPLT	0	0	0	0	0	0	0
62	E	- Meter Reading	MRCOST_07	18,646,973	0	0	0	0	0	18,646,973
63	E	- Billing	BILLING_06	0	0	0	0	0	0	0
64	E	- Remaining	MRCOST_07	-567,391	0	0	0	0	0	-567,391
65	E	E903 Customer Records and Collection								
66	E	- SONP/RNP	CUSTAVG_06	550,664	0	0	0	0	550,664	0
67	E	- Meter O&M	METERPLT	0	0	0	0	0	0	0
68	E	- Meter Reading	MRCOST_07	533,054	0	0	0	0	0	533,054
69	E	- Billing	BILLING_06	80,993	0	0	0	0	80,993	0
70	E	- Acct Maint related	ACCTMAINT_06	7,745,024	0	0	0	0	7,745,024	0
71	E	- Utility work related	UTILWORK_04	1,062,937	0	0	1,062,937	0	0	0
72	E	- Remaining	BILLING_06	66,341,808	0	0	0	0	66,341,808	0
73	E	Not used	not_used	0	0	0	0	0	0	0
74	E	E904 Uncollectible Accounts	not_used	0	0	0	0	0	0	0
75	E	E905 Misc Customer Accounts	CUSTACCTS	0	0	0	0	0	0	0
76	E	TOTAL CUSTOMER ACCTS EXPENSE		94,394,062	0	0	1,062,937	0	74,718,489	18,612,636
77	E									
78	E									
79	E	CUSTOMER SERVICE & INFO EXPENSES								
80	E	E907 & 908 - Cust Svs & Info								
81	E	- SONP/RNP	CUSTAVG_06	0	0	0	0	0	0	0
82	E	- Acct Maint related	ACCTMAINT_06	2,356,739	0	0	0	0	2,356,739	0
83	E	- Utility work related	UTILWORK_04	847,228	0	0	847,228	0	0	0
84	E	- Sales	SALES_06	0	0	0	0	0	0	0
85	E	- Billing	BILLING_06	41,297	0	0	0	0	41,297	0
86	E	- Remaining	ACCTMAINT_06	0	0	0	0	0	0	0
87	E	E909 Info & Instr Advertising	CUSTNUMX_04	0	0	0	0	0	0	0
88	E	E910 - Misc Cust Svs & Info								

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				(1)	(2)	(3)	(4)	(5)	(6)	(7)
89	E	- Utility work related	UTILWORK_04	1,163,089	0	0	1,163,089	0	0	0
90	E	- Acct Maint related	ACCTMAINT_06	689,620	0	0	0	0	689,620	0
91	E	- Not used	not_used	0	0	0	0	0	0	0
92	E	- Not used	not_used	0	0	0	0	0	0	0
93	E	- Not used	not_used	0	0	0	0	0	0	0
94	E	- Not used	not_used	0	0	0	0	0	0	0
95	E	- Remaining	BILLING_06	220,028					220,028	
96	**E**	**OPERATION & MAINTENANCE EXPENSE CONTINUED**								
97	E									
98	E	TOTAL CUSTOMER SERVICE & INFO EXPENSES		5,318,001	0	0	2,010,317	0	3,307,684	0
99	E									
100	E	SALES EXPENSES								
101	E	E911-E916 Sales Expenses								
102	E	- Sales	SALES_06	0	0	0	0	0	0	0
103	E	- Billing related	BILLING_06	0	0	0	0	0	0	0
104	E	- Acct Maint related	ACCTMAINT_06	0	0	0	0	0	0	0
105	E	- Utility work related	UTILWORK_04	40,922	0	0	40,922	0	0	0
106	E	- Remaining	BILLING_06	0	0	0	0	0	0	0
107	E	- Clause	not_used							
108	E	SALES EXPENSES TOTAL (ACCT 916)		40,922	0	0	40,922	0	0	0
109	E									
110	E	TOTAL OPER & MAINT EXCL A&G		277,762,244	13,342,811	249,859	63,968,752	83,796,643	78,026,173	38,378,005
111	E									
112	E	ADMINISTRATIVE & GENERAL EXPENSE								
113	E	E920 A&G Salaries	LABOR	5,694,688	269,990	12,494	1,704,363	1,090,735	1,801,106	815,999
114	E	E921 Office Supplies & Exp	LABOR	622,444	29,511	1,366	186,291	119,220	196,865	89,191
115	E	E923 Outside Services Employed	DISTPLT	68,020,983	2,969,418	3,445,864	33,080,819	26,351,664	0	2,173,219
116	E	E924 Property Insurance	TOTPLT	1,802,573	77,296	89,698	861,996	685,954	26,846	60,783
117	E	E925 Injuries & Damages	LABOR	14,161,029	671,387	31,070	4,238,255	2,712,341	4,478,825	2,029,151
118	E	E926 Employee Pension & Benefits	LABOR	-77,966,713	-3,696,471	-171,062	-23,334,659	-14,933,401	-24,659,176	-11,171,945
119	E	E928 Regulatory Comm Exp	REVREQ	15,042,373	648,627	458,362	6,131,672	5,252,875	1,031,132	1,519,706
120	E	E929 Duplicate Charges - credit	REVLPLS	-3,363,888	0	-17,613	-1,390,062	-1,709,438	-105,025	-141,751
121	E	E930.1 General Advertising Expenses	CUSTAVG_04	2,277,517	0	0	2,277,517	0	0	0
122	E	E930.2 Misc General Expenses	DISTPLT	2,932,568	128,020	148,560	1,426,203	1,136,091	0	93,693
123	E	E931 Rents	DISTPLT	4,471,819	195,215	226,537	2,174,791	1,732,405	0	142,871
124	E	E932 Maint of General Plant	COMGENPLT	0	0	0	0	0	0	0
125	E	E935 Other A&G Maint	COMGENPLT	0	0	0	0	0	0	0
126	E	Not Used	not_used	0	0	0	0	0	0	0
127	E	TOTAL A&G EXPENSE		33,695,393	1,292,992	4,225,276	27,357,187	22,438,447	-17,229,425	-4,389,083
128	E									
129	E	**TOTAL OPERATION & MAINTENANCE EXPENSES**		311,457,637	14,635,803	4,475,135	91,325,939	106,235,090	60,796,748	33,988,922

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery	System Delivery	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	DE	**DEPRECIATION AND AMORTIZATION EXPENSES**								
2	DE									
3	DE	E403 DEPRECIATION EXPENSE								
4	DE	Production Plant	not_used	0	0	0	0	0	0	0
5	DE	Transmission Plant	not_used	0	0	0	0	0	0	0
6	DE	Distribution Plant	DISTPLT	257,769,144	11,252,768	13,058,285	125,361,527	99,861,036	0	8,235,528
7	DE	General Plant	GENPLT	19,786,964	894,115	1,037,577	9,912,127	7,934,692	0	8,454
8	DE	Common Plant	COMPLT	9,215,747	111,203	129,046	1,440,985	986,856	5,285,730	1,261,928
9	DE	Other Plant & Misc	DISTPLT	0	0	0	0	0	0	0
10	DE	TOTAL DEPRECIATION EXPENSE		286,771,855	12,258,086	14,224,907	136,714,639	108,782,584	5,285,730	9,505,909
11	DE									
12	DE	E404.3 AMORT OF OTHER LIMITED TERM PLANT								
13	DE	not used	not_used	0	0	0	0	0	0	0
14	DE	Distribution Delivery Related	DISTPLTXMTR	6,072,872	274,415	318,445	3,042,158	2,435,258	0	2,594
15	DE	Meter Reading	MRCOST_07	492,670	0	0	0	0	0	492,670
16	DE	Customer Service related	CUSTSVSX	14,826,022	0	0	456,957	0	11,601,583	2,767,482
17	DE	not used	not_used	0	0	0	0	0	0	0
18	DE	not used	not_used	0	0	0	0	0	0	0
19	DE	TOTAL AMORT OF OTHER LIMITED TERM PLT		21,391,564	274,415	318,445	3,499,115	2,435,258	11,601,583	3,262,747
20	DE									
21	DE	E407 AMORT OF PROPERTY LOSSES								
22	DE	Regulatory assets	KWHMETER_04	0	0	0	0	0	0	0
23	DE	Securitization amortization	not_used	0	0	0	0	0	0	0
24	DE	not used	not_used	0	0	0	0	0	0	0
25	DE	TOTAL AMORT OF PROPERTY LOSSES		0	0	0	0	0	0	0
26	DE									
27	DE	TOTAL AMORTIZATION EXPENSE		21,391,564	274,415	318,445	3,499,115	2,435,258	11,601,583	3,262,747
28	DE									
29	DE	**TOTAL DEPRECIATION AND AMORTIZATION EXPENSES**		308,163,419	12,532,502	14,543,353	140,213,754	111,217,842	16,887,313	12,768,656

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery	System Delivery	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	EO	**OTHER OPERATING EXPENSES**								
2	EO	**E408 TAXES OTHER THAN INCOME TAXES**								
3	EO	TEFA	TEFA_04	0	0	0	0	0	0	0
4	EO	Real Estate Taxes	TOTPLT	0	0	0	0	0	0	0
5	EO	Miscellaneous State and Municipal Tax	TOTPLT	-275,485	-11,813	-13,709	-131,738	-104,833	-4,103	-9,289
6	EO	State Unemploy Insur (SUI) Tax	LABOR	0	0	0	0	0	0	0
7	EO	FICA & UnempTax	LABOR	-11,275,732	-534,592	-24,739	-3,374,714	-2,159,704	-3,566,269	-1,615,713
8	EO	Other Taxes	TOTPLT	0	0	0	0	0	0	0
9	EO	not used	not_used	0	0	0	0	0	0	0
10	EO	**TOTAL TAXES OTHER THAN INCOME**		-11,551,217	-546,406	-38,448	-3,506,452	-2,264,538	-3,570,372	-1,625,003
11	EO	**PROFORMA EXPENSE ADJUSTMENTS**								
12	EO	Amortization of CEF-EC Program Regulatory Assets	ECPRO_07	20,893,898	0	0	0	0	0	20,893,898
13	EO	Amortization of CEF-EV Program Regulatory Assets	TOTPLTNET	3,943,445	175,074	149,636	1,887,942	1,578,907	40,224	111,662
14	EO	BGS Administrative Expense Adjustment	A_GEXP	671,374	29,999	26,433	304,787	224,700	44,672	40,782
15	EO	CIP Revenue Accrual Adjustment	not_used	0	0	0	0	0	0	0
16	EO	Deferred Compensation & Severance Expense	LABOR	-785,085	-37,222	-1,723	-234,968	-150,372	-248,305	-112,496
17	EO	Gas Bad Debt Adjustment		0	0	0	0	0	0	0
18	EO	TAC Revenue Accrual Adjustment	not_used	0	0	0	0	0	0	0
19	EO	Tax Bad Debt Adjustment	not_used	0	0	0	0	0	0	0
20	EO	TSG-NF Gas Margin Reset		0	0	0	0	0	0	0
21	EO	Wage Increases (Rate Year)	LABOR	7,691,360	364,654	16,875	2,301,947	1,473,169	2,432,610	1,102,104
22	EO	Payroll Taxes (Rate Year)	LABOR	541,904	25,692	1,189	162,186	103,794	171,392	77,650
23	EO	Interest Syncronization	TOTPLTNET	-459,649	-20,407	-17,442	-220,059	-184,038	-4,688	-13,015
24	EO	- add'l tax effects on rev req	TOTPLTNET	-179,729	-7,979	-6,820	-86,046	-71,961	-1,833	-5,089
25	EO	Pension & Fringe Benefit (Rate Year)	LABOR	11,745,951	556,886	25,771	3,515,446	2,249,768	3,714,989	1,683,092
26	EO	COLI Interest Expense Recovery	LABOR	2,434,135	115,405	5,341	728,512	466,224	769,864	348,790
27	EO	- add'l tax effects on rev req	LABOR	951,781	45,125	2,088	284,859	182,300	301,028	136,382
28	EO	ASB Margin	TOTPLT	0	0	0	0	0	0	0
29	EO	BPU / Rate Counsel Assessment	KWHMETER_04	377,877	0	0	377,877	0	0	0
30	EO	Adj #6 - Weather Normalization	not_used	0	0	0	0	0	0	0
31	EO	Gains / Losses Normalization	TOTPLT	-44,137	-1,893	-2,196	-21,107	-16,796	-657	-1,488
32	EO	- add'l tax effects on rev req	TOTPLT	-17,258	-740	-859	-8,253	-6,567	-257	-582
33	EO	Other Regulatory Asset / Liability Amortizations	TOTPLT	0	0	0	0	0	0	0
34	EO	Adj #15 - Excess COR Refund Recovery	TOTPLT	0	0	0	0	0	0	0
35	EO	Real Estate Tax Increases (Rate Year)	TOTPLT	700,231	30,027	34,844	334,853	266,467	10,429	23,612
36	EO	Test Year Amortization Adjustments	TOTPLT	-17,276,070	-740,816	-859,680	-8,261,472	-6,574,260	-257,294	-582,548
37	EO	Insurance Premium Increases (Rate Year)	TOTPLT	481,185	20,634	23,944	230,104	183,111	7,166	16,226
38	EO	Rate Case Expenses	TOTPLT	166,097	7,122	8,265	79,428	63,207	2,474	5,601
39	EO	Depreciation Rate Change	DEPREXP	50,211,393	2,146,290	2,490,664	23,937,609	19,046,936	925,488	1,664,407
40	EO	Adj #14 Post Rate Case Storm Cost Normalization	TOTPLT	0	0	0	0	0	0	0
41	EO	Adj #13 - Storm Cost Amortization	TOTPLTNET	0	0	0	0	0	0	0
42	EO	Adj #20 - Vacation Accrual	LABOR	0	0	0	0	0	0	0
43	EO	Energy Strong II / IAP Revenue Adjustment	TOTPLT	0	0	0	0	0	0	0
44	EO	Recovery of Credit Card Fees	CUSTSVSX	0	0	0	0	0	0	0

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				(1)	(2)	(3)	(4)	(5)	(6)	(7)
45	EO	Test Year Corrections	TOTPLT							
46	EO	TOTAL PROFORMA EXPENSE ADJUSTMENTS		82,048,703	2,707,852	1,896,332	25,313,646	18,834,587	7,907,300	25,388,986
47	EO									
48	EO	**TOTAL OTHER OPERATING EXPENSES**		70,497,486	2,161,447	1,857,884	21,807,195	16,570,050	4,336,928	23,763,983
49	EO	TOTAL OPERATING REVENUES		1,925,019,676	82,945,791	58,645,322	784,579,218	672,665,453	131,863,973	194,319,919
50	EO	LESS:								
51	EO	OPERATION & MAINTAINENCE EXPENSE		311,457,637	14,635,803	4,475,135	91,325,939	106,235,090	60,796,748	33,988,922
52	EO	DEPRECIATION & AMORTIZATION EXPENSE		308,163,419	12,532,502	14,543,353	140,213,754	111,217,842	16,887,313	12,768,656
53	EO	OTHER OPERATING EXPENSES		70,497,486	2,161,447	1,857,884	21,807,195	16,570,050	4,336,928	23,763,983
54	EO	NET OPERATING INCOME BEFORE TAXES		1,234,901,135	53,616,039	37,768,951	531,232,331	438,642,470	49,842,985	123,798,358
55	EO	LESS:								
56	EO	E427 - E432 INTEREST CHARGES	TOTPLTNET	(137,585,275)	(6,108,277)	(5,220,730)	(65,869,570)	(55,087,462)	(1,403,390)	(3,895,845)
57	EO	**TOTAL OPERATING INCOME BEFORE TAXES**		1,372,486,410	59,724,317	42,989,681	597,101,901	493,729,933	51,246,375	127,694,203
58	EO	Adjustment Reclassification Minus	ADJEXP_04	-17,563	0	0	-17,563	0	0	0
59	EO	Adjustment Reclassification Plus	ADJ_Plus_04	17,563	0	0	17,563	0	0	0

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				(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	TI	**DEVELOPMENT OF INCOME TAXES**								
2	TI									
3	TI	**TAX ADJUSTMENTS - FEDERAL**								
4	TI	Additional Expenses on Rental Property	TOTPLT	-108,083	-4,635	-5,378	-51,686	-41,130	-1,610	-3,645
5	TI	Additional Rental Income - NJ Properties	TOTPLT	16,349	701	814	7,818	6,221	243	551
6	TI	Amort of Def Gain on Sale of Services Assets	not_used	0	0	0	0	0	0	0
7	TI	Amort of Deferred Gain on Sale of Generation Assets	not_used	0	0	0	0	0	0	0
8	TI	Amortization of Reacquisition of Pref Stock	TOTPLT	11,771	505	586	5,629	4,479	175	397
9	TI	CECL Reserve	not_used	0	0	0	0	0	0	0
10	TI	CEF- EC AMI	TOTPLT	-20,866,765	-894,788	-1,038,358	-9,978,554	-7,940,668	-310,770	-703,626
11	TI	CEF- EV Deferral	TOTPLT	-1,855,840	-79,580	-92,349	-887,469	-706,224	-27,639	-62,579
12	TI	Clause - Demographic Studies	not_used	0	0	0	0	0	0	0
13	TI	Clause - Navigant Studies	not_used	0	0	0	0	0	0	0
14	TI	Clause - RAC (Environmental Clean Up)	not_used	0	0	0	0	0	0	0
15	TI	Clause - Societal Benefits Clause (AAP)	not_used	0	0	0	0	0	0	0
16	TI	Company Owned Life Insurance - Book	LABOR	-1,117,127	-52,964	-2,451	-334,345	-213,970	-353,323	-160,074
17	TI	Company Owned Life Insurance - Tax	LABOR	-58,279	-2,763	-128	-17,442	-11,163	-18,432	-8,351
18	TI	COVID Deferrals	not_used	0	0	0	0	0	0	0
19	TI	Current SHARE -- FT	DEPREXP	-11,513,122	-492,129	-571,092	-5,488,727	-4,367,329	-212,208	-381,637
20	TI	Customer Advances	TOTPLTNET	4,645,423	206,240	176,273	2,224,017	1,859,971	47,384	131,539
21	TI	Customer Connection Fees (Contributions in Aid of Constructi	TOTPLTNET	6,684,538	296,769	253,648	3,200,253	2,676,407	68,183	189,278
22	TI	Deduction for Retention Payments (c)	LABOR	-5,352	-254	-12	-1,602	-1,025	-1,693	-767
23	TI	Deferred Employer ER FICA	LABOR	-7,086,760	-335,990	-15,549	-2,120,996	-1,357,367	-2,241,388	-1,015,470
24	TI	Diesel Fuel Tax Credit	TOTPLT	82	4	4	39	31	1	3
25	TI	Entertainment (100%)	LABOR	38,419	1,821	84	11,498	7,359	12,151	5,505
26	TI	FAS 5 (ASC40) Reserve - Sales Tax	not_used	0	0	0	0	0	0	0
27	TI	Fed Amort of Deferred Gain on Sale of Generation Assets	not_used	0	0	0	0	0	0	0
28	TI	Injuries & Damages - FT	TOTPLT	1,298,774	55,693	64,629	621,078	494,237	19,343	43,795
29	TI	Line Pack Adjustment	not_used	0	0	0	0	0	0	0
30	TI	Plant Related	DEPREXP	-33,454,683	-1,430,023	-1,659,472	-15,949,072	-12,690,530	-616,631	-1,108,955
31	TI	Previously Deducted Amort - Reacquired Bonds	not_used	0	0	0	0	0	0	0
32	TI	Qualified Transportation Fringe	LABOR	162,269	7,693	356	48,565	31,080	51,322	23,252
33	TI	R & D Credits CF	not_used	0	0	0	0	0	0	0
34	TI	R&D Expenditure	TOTPLT	-5,622	-241	-280	-2,688	-2,139	-84	-190
35	TI	Rabbi Trust	not_used	0	0	0	0	0	0	0
36	TI	RE - Lease Liability	TOTPLT	-236,259	-10,131	-11,757	-112,980	-89,906	-3,519	-7,967
37	TI	RE - ROU Lease Asset	TOTPLT	319,172	13,686	15,882	152,629	121,458	4,753	10,762
38	TI	Reversal of Book Income from Partnerships	TOTPLT	42,165	1,808	2,098	20,163	16,046	628	1,422
39	TI	Severance Pay (nc)	LABOR	154,681	7,334	339	46,295	29,627	48,922	22,164
40	TI	State NOL CF (c)	DEPREXP	17,908,279	765,491	888,315	8,537,532	6,793,236	330,082	593,623
41	TI	Tax Net Bad Debt Writeoffs - FT	TOTPLT	-460,907	-19,764	-22,935	-220,407	-175,394	-6,864	-15,542
42	TI	Unicap book/tax inventory FS	not_used	0	0	0	0	0	0	0
43	TI	Unrealized G/L on Equity Securities	TOTPLT	125,367	5,376	6,238	59,951	47,707	1,867	4,227
44	TI	Stock Based Compensation	TOTPLTNET	-328,125	-14,568	-12,451	-157,091	-131,377	-3,347	-9,291

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				(1)	(2)	(3)	(4)	(5)	(6)	(7)
45	TI	GainState LILOAudit Refunds not yet received	TOTPLTNET	0	0	0	0	0	0	0
46	TI	Repair Allowance	TOTPLT	0	0	0	0	0	0	0
47	TI	Uncollectible Accounts	REVREQ	0	0	0	0	0	0	0
48	TI	Injuries and Damages ;	TOTPLT	0	0	0	0	0	0	0
49	TI	Diesel Fuel Credit	not_used	0	0	0	0	0	0	0
50	TI	Partnership income/loss per K-1	TOTPLT	-42,165	-1,808	-2,098	-20,163	-16,046	-628	-1,422
51	TI	Meals & entertainment	LABOR	-417,376	-19,788	-916	-124,917	-79,942	-132,007	-59,806
52	TI	Company owned life insurance	LABOR	0	0	0	0	0	0	0
53	TI	ESOP/401(k) Cash Dividends	TOTPLTNET	-1,032,350	-45,833	-39,173	-494,242	-413,340	-10,530	-29,232
54	TI	Medicare Subsidy	LABOR	0	0	0	0	0	0	0
55	TI	Dividends Received Deduction	TOTPLTNET	0	0	0	0	0	0	0
56	TI	W-2 Earnings Exceeding $1,000,000	LABOR	1,841,683	87,316	4,041	551,197	352,748	582,484	263,897
57	TI	Allowable Depreciation	DEPREXP	0	0	0	0	0	0	0
58	TI	Book Depreciation	DEPREXP	0	0	0	0	0	0	0
59	TI	Previously Ded Amort-Reacq Bonds	not_used	0	0	0	0	0	0	0
60	TI	Amortization of Computer Software	INTANGPLT	0	0	0	0	0	0	0
61	TI	Amort Def Gain - Sale of Gen Asset	not_used	0	0	0	0	0	0	0
62	TI	Gain on Sale of Services Corp Asset	not_used	0	0	0	0	0	0	0
63	TI	AFUDC / IDC	TOTPLT	-1,076,666	-46,169	-53,576	-514,865	-409,716	-16,035	-36,305
64	TI	Capitalized interest-Section 263A	TOTPLT	3,363,340	144,223	167,364	1,608,360	1,279,890	50,090	113,412
65	TI	Cost of removal	TOTPLT	0	0	0	0	0	0	0
66	TI	Utility Commodity Costs	not_used	0	0	0	0	0	0	0
67	TI	RAC-Environmental Cleanup Costs	not_used	0	0	0	0	0	0	0
68	TI	SBC-Societal Benefits Clause	not_used	0	0	0	0	0	0	0
69	TI	Deferred Comp - officers	LABOR	11,058	524	24	3,309	2,118	3,497	1,584
70	TI	Deduction of Securitizartion	not_used	0	0	0	0	0	0	0
71	TI	Accrued vacation pay adjustment	LABOR	-344,695	-16,342	-756	-103,164	-66,021	-109,019	-49,392
72	TI	3rd Party Claims	TOTPLT	87,346	3,745	4,346	41,769	33,239	1,301	2,945
73	TI	Deduction for New Network Meter Equipment	TOTPLT	0	0	0	0	0	0	0
74	TI	Gain/loss bond reacq	not_used	0	0	0	0	0	0	0
75	TI	Amortization of Call Option Sale	LABOR	0	0	0	0	0	0	0
76	TI	Defer Dividend Equivalents/Restricted Stock-Temp.	LABOR	0	0	0	0	0	0	0
77	TI	Repair Allow Deferral Carrying Charges	TOTPLT	0	0	0	0	0	0	0
78	TI	Contribution in Aid of Construct	TOTPLTNET	905,779	40,213	34,370	433,646	362,663	9,239	25,648
79	TI	FIN48 Services Allocation	TOTPLT	0	0	0	0	0	0	0
80	TI	Pension Accrual Adjustment	LABOR	-3,671,962	-174,091	-8,056	-1,098,982	-703,312	-1,161,362	-526,160
81	TI	Unallowable OPEB Amortization	LABOR	-105,080,197	-4,981,945	-230,550	-31,449,454	-20,126,598	-33,234,581	-15,057,069
82	TI	Deferred Return on CIP ll	TOTPLT	66,348	2,845	3,302	31,728	25,248	988	2,237
83	TI	Deferred Depreciation on CIP ll	TOTPLT	52,458	2,249	2,610	25,086	19,963	781	1,769
84	TI	FIN48 Reg Asset Reversal	LABOR	0	0	0	0	0	0	0
85	TI	Assessment by Board of Public Utilities of the State of NJ	TOTPLTNET	91,151	4,047	3,459	43,639	36,496	930	2,581
86	TI	Misc Adj - Permanent	TOTPLTNET	0	0	0	0	0	0	0
87	TI	Casualty Loss Deferred O&M & Ins Proceeds	TOTPLTNET	1,120,547	49,748	42,520	536,467	448,653	11,430	31,729
88	TI	Performance Incentive Plan Adjustment	TOTPLTNET	-1,045,327	-46,409	-39,665	-500,455	-418,536	-10,662	-29,599

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery	System Delivery	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)	(7)
89	TI									
90	TI									
91	TI									
92	TI	**DEVELOPMENT OF INCOME TAXES CONTINUED**								
93	TI	**TAX ADJUSTMENTS - FEDERAL CONTINUED**								
94	TI	LCAPP	TOTPLTNET	0	0	0	0	0	0	0
95	TI	Clause - Deferred Fuel	not_used	0	0	0	0	0	0	0
96	TI	Penalties	not_used	0	0	0	0	0	0	0
97	TI	Restricted Stock - Permanent	TOTPLTNET	-82,615	-3,668	-3,135	-39,553	-33,078	-843	-2,339
98	TI	Environmental Accrual	TOTPLTNET	0	0	0	0	0	0	0
99	TI	Legal Reserves (c & nc)	TOTPLTNET	401,853	17,841	15,248	192,389	160,897	4,099	11,379
100	TI	Material Supplies & Reserves	TOTPLT	107,143	4,594	5,332	51,236	40,773	1,596	3,613
101	TI	Lobbying Expenses	LABOR	0	0	0	0	0	0	0
102	TI	Bankrupticies & Acc. Prov. For Rents Receivable	TOTPLTNET	62,834	2,790	2,384	30,082	25,158	641	1,779
103	TI	Real Estate Taxes	TOTPLTNET	1,046,714	46,470	39,718	501,119	419,092	10,677	29,639
104	TI	Credits & Adjustments	TOTPLTNET	0	0	0	0	0	0	0
105	TI	**Miscellaneous**	TOTPLT							
106	TI	**TOTAL TAX ADJUSTMENTS - FEDERAL**		-149,324,736	-6,904,156	-2,076,153	-50,683,358	-34,700,017	-37,210,366	-17,750,687
107	TI									
108	TI	**TAX ADJUSTMENTS - STATE**								
109	TI	TEFA	TEFA_04	0	0	0	0	0	0	0
110	TI	Federal Depreciation Reversal	DEPREXP	72,042,765	3,079,474	3,573,578	34,345,423	27,328,338	1,327,880	2,388,072
111	TI	State Tax Depreciation	DEPREXP	36,681,624	1,567,959	1,819,539	17,487,473	13,914,622	676,109	1,215,922
112	TI	not used	not_used	0	0	0	0	0	0	0
113	TI	**TOTAL TAX ADJUSTMENTS - STATE**		108,724,389	4,647,433	5,393,118	51,832,895	41,242,959	2,003,989	3,603,994
114	TI									
115	TI	**TAXABLE NET INCOME - STATE**		1,331,886,063	57,467,594	46,306,646	598,251,439	500,272,875	16,039,998	113,547,511
116	TI	State Tax Liability		119,869,746	5,172,083	4,167,598	53,842,629	45,024,559	1,443,600	10,219,276
117	TI	Prior Year Adjustment	TOTPLTNET	0	0	0	0	0	0	0
118	TI	**TOTAL STATE INCOME TAX LIABILITY**		119,869,746	5,172,083	4,167,598	53,842,629	45,024,559	1,443,600	10,219,276
119	TI									
120	TI	**TAXABLE NET INCOME - FEDERAL**		1,103,291,929	47,648,077	36,745,931	492,575,914	414,005,357	12,592,409	99,724,240
121	TI	Federal Tax Liability		231,691,305	10,006,096	7,716,645	103,440,942	86,941,125	2,644,406	20,942,090
122	TI	not used	not_used	0	0	0	0	0	0	0
123	TI	not used	not_used	0	0	0	0	0	0	0
124	TI	**TOTAL FEDERAL INCOME TAX LIABILITY**		231,691,305	10,006,096	7,716,645	103,440,942	86,941,125	2,644,406	20,942,090
125	TI									
126	TI	**TOTAL INCOME TAX EXPENSE**		351,561,051	15,178,180	11,884,244	157,283,571	131,965,684	4,088,006	31,161,366
127	TI									
128	TI									
129	TI									
130	TI									
131	TI	**TAX RATES**								
132	TI	FEDERAL TAX RATE - CURRENT		21.000%						

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				(1)	(2)	(3)	(4)	(5)	(6)	(7)
133	TI	NEW JERSEY CORP BUSINESS TAX RATE		9.000%						
134	TI	CUSTOMER ACCT UNCOLLECTIBLE RATE		0.000						
135	TI	EFFECTIVE TAX RATE		28.110%						
136	TI	COMPOSITE RATE		28.110%						
137	TI	1 - EFFECTIVE TAX RATE		71.89000%						
138	TI									
139	TI									
140	TI									
141	TI									
142	TI									
143	TI									
144	TI	**DEVELOPMENT OF OPERATING INCOME ADJUSTED**								
145	TI	Additional Rental Income - NJ Properties	TOTPLT	-16,349	-701	-814	-7,818	-6,221	-243	-551
146	TI	Amort of Def Gain on Sale of Services Assets	not_used	0	0	0	0	0	0	0
147	TI	Amort of Deferred Gain on Sale of Generation Assets	not_used	0	0	0	0	0	0	0
148	TI	Bankruptcies and Accum Provision for Rent Receivable	TOTPLT	53,745	2,305	2,674	25,701	20,452	800	1,812
149	TI	Casualty Loss Deferred O&M	TOTPLTNET	-1,120,547	-49,748	-42,520	-536,467	-448,653	-11,430	-31,729
150	TI	CECL Reserve	not_used	0	0	0	0	0	0	0
151	TI	CEF- EC AMI	TOTPLT	20,866,765	894,788	1,038,358	9,978,554	7,940,668	310,770	703,626
152	TI	CEF- EV Deferral	TOTPLT	1,855,840	79,580	92,349	887,469	706,224	27,639	62,579
153	TI	Clause - Demographic Studies	not_used	0	0	0	0	0	0	0
154	TI	Clause - Navigant Studies	not_used	0	0	0	0	0	0	0
155	TI	Clause - RAC (Environmental Clean Up)	not_used	0	0	0	0	0	0	0
156	TI	Clause - Societal Benefits Clause (AAP)	not_used	0	0	0	0	0	0	0
157	TI	COVID Deferrals	not_used	0	0	0	0	0	0	0
158	TI	Current SHARE -- FT	DEPREXP	2,912,070	124,477	144,449	1,388,291	1,104,650	53,675	96,529
159	TI	Customer Advances	TOTPLTNET	-4,645,423	-206,240	-176,273	-2,224,017	-1,859,971	-47,384	-131,539
160	TI	Deduction for Retention Payments (c)	LABOR	5,352	254	12	1,602	1,025	1,693	767
161	TI	Deferred Employer ER FICA	LABOR	7,086,760	335,990	15,549	2,120,996	1,357,367	2,241,388	1,015,470
162	TI	FAS 5 (ASC40) Reserve - Sales Tax	not_used	0	0	0	0	0	0	0
163	TI	Fed Amort of Deferred Gain on Sale of Generation Assets	not_used	0	0	0	0	0	0	0
164	TI	Injuries & Damages - FT	TOTPLT	-328,505	-14,087	-16,347	-157,092	-125,010	-4,892	-11,077
165	TI	Line Pack Adjustment	not_used	0	0	0	0	0	0	0
166	TI	Medicare Subsidy	not_used	0	0	0	0	0	0	0
167	TI	Partnership Income/Loss (nc)	TOTPLT	42,165	1,808	2,098	20,163	16,046	628	1,422
168	TI	Plant Related	DEPREXP	37,305,084	1,594,609	1,850,465	17,784,699	14,151,122	687,601	1,236,588
169	TI	Previously Deducted Amort - Reacquired Bonds	not_used	0	0	0	0	0	0	0
170	TI	R & D Credits CF	TOTPLT	-15,263	-654	-759	-7,299	-5,808	-227	-515
171	TI	RE - Lease Liability	TOTPLT	236,259	10,131	11,757	112,980	89,906	3,519	7,967
172	TI	RE - ROU Lease Asset	TOTPLT	-319,172	-13,686	-15,882	-152,629	-121,458	-4,753	-10,762
173	TI	Real Estate Taxes (nc)	TOTPLT	-1,046,714	-44,884	-52,086	-500,542	-398,318	-15,589	-35,295
174	TI	Reversal of Book Income from Partnerships	TOTPLT	-42,165	-1,808	-2,098	-20,163	-16,046	-628	-1,422
175	TI	Severance Pay (nc)	LABOR	-154,681	-7,334	-339	-46,295	-29,627	-48,922	-22,164
176	TI	State NOL CF (c)	DEPREXP	-17,908,279	-765,491	-888,315	-8,537,532	-6,793,236	-330,082	-593,623

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				(1)	(2)	(3)	(4)	(5)	(6)	(7)
177	TI	Unrealized G/L on Equity Securities	TOTPLT	-125,367	-5,376	-6,238	-59,951	-47,707	-1,867	-4,227
178	TI	**E410 + E411- PROVISION FOR DEFERRED INCOME TAX**								
179	TI	Legal Reserves (c)	TOTPLTNET	0	0	0	0	0	0	0
180	TI	Tax Depreciation	DEPREXP	0	0	0	0	0	0	0
181	TI	Previously Ded Amort-Reacq Bonds	not_used	0	0	0	0	0	0	0
182	TI	Amortization of Power Gain	not_used	0	0	0	0	0	0	0
183	TI	Amort Def Gain - Sale of Gen Asset	not_used	0	0	0	0	0	0	0
184	TI	Gain on Sale of Services Corp Asset	not_used	0	0	0	0	0	0	0
185	TI	AFUDC / IDC	TOTPLT	1,076,666	46,169	53,576	514,865	409,716	16,035	36,305
186	TI	Capitalized interest-Section 263A	TOTPLT	-3,363,340	-144,223	-167,364	-1,608,360	-1,279,890	-50,090	-113,412
187	TI	Cost of removal	TOTPLT	0	0	0	0	0	0	0
188	TI	Utility Commodity Costs	not_used	0	0	0	0	0	0	0
189	TI	RAC-Environmental Cleanup Costs	not_used	0	0	0	0	0	0	0
190	TI	SBC-Societal Benefits Clause	not_used	0	0	0	0	0	0	0
191	TI	Deferred Comp - officers	LABOR	-11,058	-524	-24	-3,309	-2,118	-3,497	-1,584
192	TI	Deduction of Securitizartion	not_used	0	0	0	0	0	0	0
193	TI	Accrued vacation pay adjustment	LABOR	344,695	16,342	756	103,164	66,021	109,019	49,392
194	TI	3rd Party Claims	TOTPLT	-87,346	-3,745	-4,346	-41,769	-33,239	-1,301	-2,945
195	TI	Bankruptcies & Acc Prov-Rent Receivable	LABOR	0	0	0	0	0	0	0
196	TI	Deduction for New Network Meter Equipment	TOTPLT	0	0	0	0	0	0	0
197	TI	Gain/loss bond reacq	not_used	0	0	0	0	0	0	0
198	TI	Amortization of Call Option Sale	LABOR	0	0	0	0	0	0	0
199	TI	Defer Dividend Equivalents/Restricted Stock-Temp.	LABOR	0	0	0	0	0	0	0
200	TI	Repair Allow Deferral Carrying Charges	TOTPLT	0	0	0	0	0	0	0
201	TI	Contribution in Aid of Construct	TOTPLTNET	-905,779	-40,213	-34,370	-433,646	-362,663	-9,239	-25,648
202	TI	FIN48 Services Allocation	TOTPLT	0	0	0	0	0	0	0
203	TI	Pension Accrual Adjustment	LABOR	3,671,962	174,091	8,056	1,098,982	703,312	1,161,362	526,160
204	TI	Unallowable OPEB Amortization	LABOR	105,080,197	4,981,945	230,550	31,449,454	20,126,598	33,234,581	15,057,069
205	TI	Fin Def-Energy Competition Act Ct	TOTPLT	0	0	0	0	0	0	0
206	TI	Conditional Asset Retire Obligations	TOTPLTNET	0	0	0	0	0	0	0
207	TI	Rabbi Trust Unrealized Losses	LABOR	0	0	0	0	0	0	0
208	TI	FIN48 Reg Asset Reversal	LABOR	0	0	0	0	0	0	0
209	TI	Additional Real Estate Taxes	TOTPLT	108,083	4,635	5,378	51,686	41,130	1,610	3,645
210	TI	PIP Adjustment	LABOR	1,045,327	49,560	2,293	312,856	200,217	330,614	149,786
211	TI	Deferred NJ Corp Bus Tax(Net of FIT)	TOTPLTNET	0	0	0	0	0	0	0
212	TI	Misc	TOTPLT	0	0	0	0	0	0	0
213	TI	Construction Period Interest	TOTPLTNET	0	0	0	0	0	0	0
214	TI	Deferred Return on CIP ll	TOTPLT	-66,348	-2,845	-3,302	-31,728	-25,248	-988	-2,237
215	TI	Deferred Depreciation on CIP ll	TOTPLT	-52,458	-2,249	-2,610	-25,086	-19,963	-781	-1,769
216	TI	Customer Connections Fees	CUSTACCTS	-6,684,538	0	0	-75,272	0	-5,291,208	-1,318,058
217	TI	Decommissioning Costs	KWHMETER_04	0	0	0	0	0	0	0
218	TI	Investment Tax Credit	TOTPLT	0	0	0	0	0	0	0
219	TI	Assessment by Board of Public Utilities of the State of NJ	TOTPLTNET	-91,151	-4,047	-3,459	-43,639	-36,496	-930	-2,581
220	TI	Casualty Loss Deferred O&M & Ins Proceeds	TOTPLTNET	0	0	0	0	0	0	0

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				(1)	(2)	(3)	(4)	(5)	(6)	(7)
221	TI	GainState LILOAudit Refunds not yet received	TOTPLTNET	0	0	0	0	0	0	0
222	TI	LCAPP	TOTPLTNET	0	0	0	0	0	0	0
223	TI	Audit Adjustment	not_used	0	0	0	0	0	0	0
224	TI	Stock Based Compensation	TOTPLTNET	328,125	14,568	12,451	157,091	131,377	3,347	9,291
225	TI	Clause - Deferred Fuel	not_used	0	0	0	0	0	0	0
226	TI	Legal Reserves (nc)	TOTPLTNET	-401,853	-17,841	-15,248	-192,389	-160,897	-4,099	-11,379
227	TI									
228	TI									
229	TI	**DEVELOPMENT OF OPERATING INCOME ADJ CONTINUE**								
230	TI	**E410 + E411- PROVISION FOR DEFER INC TAX CONTINUE**								
231	TI	Material Supplies & Reserves	TOTPLTNET	-107,143	-4,757	-4,066	-51,295	-42,899	-1,093	-3,034
232	TI	Medicare Subsidy	TOTPLTNET							
233	TI	**TOTAL DEFERRED INCOME TAX**		144,525,616	7,000,797	2,034,312	51,252,253	35,250,364	32,355,035	16,632,855
234	TI									
235	TI	**TOTAL INC TAXES DEF IN PRIOR YEAR**	not_used	0	0	0	0	0	0	0
236	TI	**TOTAL INVEST TAX CRED ADJ (NET)**	not_used	0	0	0	0	0	0	0
237	TI	**TOTAL PRO FORMA OP INC ADJUSTMENTS**	not_used	0	0	0	0	0	0	0
238	TI									
239	TI	**OPERATING INCOME ADJUSTED**		738,814,468	31,437,063	23,850,396	322,696,506	271,426,422	13,399,944	76,004,136

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				(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	LR	**DEVELOPMENT OF LABOR ALLOCATION FACTOR**								
2	LR									
3	LR	**PRODUCTION LABOR EXPENSE**	not_used	0	0	0	0	0	0	0
4	LR									
5	LR	**TRANSMISSION LABOR EXPENSE**	not_used	0	0	0	0	0	0	0
6	LR									
7	LR	**DISTRIBUTION LABOR EXPENSE**								
8	LR	Operation								
9	LR	582-Station Equipment	E367PLT	280,636	662	41	192,918	87,015	0	0
10	LR	583-Overhead Lines	E367PLT	941,919	2,220	137	647,506	292,054	0	1
11	LR	584-Underground Lines	E367PLT	4,591,058	10,823	669	3,156,046	1,423,514	0	5
12	LR	586-Metering	MTROMMIN_07	4,311,826	0	0	0	0	0	4,311,826
13	LR	587-Customer Installations	CUSTAVG_04	17,308,754	0	0	17,308,754	0	0	0
14	LR	588-Miscellaneous	DISTEXPO	16,169,609	178,099	2,003	3,700,032	6,487,282	0	5,802,194
15	LR	Total Operation		43,603,802	191,804	2,851	25,005,256	8,289,864	0	10,114,027
16	LR	Maintenance								
17	LR	590-Supervision & Engineering	DISTEXPM	0	0	0	0	0	0	0
18	LR	591-Structures	E361PLT	2,559,859	57,294	66,487	638,282	1,755,865	0	41,931
19	LR	592-Station Equipment	E362PLT	8,699,368	0	0	0	8,699,368	0	0
20	LR	593-Overhead Lines	E365PLT	11,294,340	34,257	0	5,641,413	5,618,670	0	0
21	LR	594-Underground Lines	E367PLT	11,333,758	26,718	1,653	7,791,202	3,514,172	0	13
22	LR	595-Line Transformers	LNTRFRMR_04	2,457,581	0	0	2,457,581	0	0	0
23	LR	596-Street Lighting and Signal Systems	E373PLT	7,842,365	6,917,642	50,785	485,155	388,369	0	414
24	LR	597-Meters	MTROMMIN_07	700,642	0	0	0	0	0	700,642
25	LR	598-Other Distribution Maintenance	DISTEXPM	529,302	54,060	749	205,249	265,090	0	4,153
26	LR	Total Maintenance		45,417,214	7,089,971	119,673	17,218,882	20,241,533		747,154
27	LR	TOTAL DISTRIBUTION LABOR EXPENSE		89,021,016	7,281,775	122,523	42,224,138	28,531,397	0	10,861,181
28	LR									
29	LR	**E901-E903,E905 CUST ACCOUNTS EXPENSE**	CUSTACCTS	58,697,026	0	0	660,966	0	46,462,172	11,573,889
30	LR	**E907-E910, xDSM CUST SERV & INFO EXP**	CUSTS_I	5,539,923	0	0	2,094,208	0	3,445,715	0
31	LR	**E911-E916 SALES EXPENSE**	SALESEXP	0	0	0	0	0	0	0
32	LR	**ADMIN & GENERAL EXP ACCOUNTS xE926**	A_GEXP	5,748,870	256,880	226,343	2,609,845	1,924,072	382,517	349,212
33	LR	**Employee Pension/Benefits Acct E926**	LABOR	0	0	0	0	0	0	0
34	LR									
35	LR	**TOTAL OPERATION & MAINT LABOR EXPENSE**		159,006,836	7,538,655	348,867	47,589,158	30,455,469	50,290,404	22,784,283

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				(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	CA	**DEVELOPMENT OF CAPITAL ADDITIONS ALLOCATION F/**								
2	CA									
3	CA	**INTANGIBLE PLANT**	INTANGPLT	49,607,381	0	0	1,528,963	0	38,818,514	9,259,904
4	CA									
5	CA	**PRODUCTION PLANT**	not_used	0	0	0	0	0	0	0
6	CA									
7	CA	**TRANSMISSION PLANT**								
8	CA	E352 Structure & Improvements	not_used	0	0	0	0	0	0	0
9	CA	E353 Station Equipment	not_used	0	0	0	0	0	0	0
10	CA	E354/355 Towers and Fixtures	not_used	0	0	0	0	0	0	0
11	CA	E356 OH Cond and Devices	not_used	0	0	0	0	0	0	0
12	CA	E357 UG Conduits	not_used	0	0	0	0	0	0	0
13	CA	E358 Underground Cond. and Devices	not_used	0	0	0	0	0	0	0
14	CA	E359 Roads and Trails	not_used	0	0	0	0	0	0	0
15	CA	Other Tangible Plant Unallocated	not_used	0	0	0	0	0	0	0
16	CA	TOTAL TRANSMISSION PLANT		0	0	0	0	0	0	0
17	CA									
18	CA	**DISTRIBUTION PLANT**								
19	CA	E360 Land and Land Rights	E360PLT	3,481,598	41,705	48,397	464,618	2,896,355	0	30,523
20	CA	E361 Structures and Improvements	E361PLT	1,433,350	32,081	37,228	357,395	983,167	0	23,479
21	CA	E362 Station Equipment	E362PLT	72,557,752	0	0	0	72,557,752	0	0
22	CA	E364 Poles Towers and Fixtures	E364PLT	86,501,520	835,763	0	58,619,938	27,045,819	0	0
23	CA	E365 OH Conductors and Dev.	E365PLT	235,018,380	712,839	0	117,389,395	116,916,145	0	0
24	CA	E366 Underground Conduits	E367PLT	3,221,386	7,594	470	2,214,488	998,831	0	4
25	CA	E367 Underground Cond. and Dev.	E367PLT	32,807,746	77,340	4,784	22,553,135	10,172,448	0	39
26	CA	E368 Line Transformers	LNTRFRMR_04	92,859,144	0	0	92,859,144	0	0	0
27	CA	E369 Services	E369PLT	11,962,969	0	11,962,969	0	0	0	0
28	CA	E370 Meters	METERPLT	73,420,491	0	0	5,154,118	0	0	68,266,373
29	CA	E371 Installation on Customer Premise	not_used	0	0	0	0	0	0	0
30	CA	E373 Street Lighting	E373PLT	39,887,684	35,184,379	258,301	2,467,588	1,975,313	0	2,104
31	CA	E374 Asset Retirement Obligations	TOTPLT							
32	CA	TOTAL DISTRIBUTION PLANT		653,152,020	36,891,701	12,312,148	302,079,820	233,545,829	0	68,322,521
33	CA									
34	CA	**TOTAL CAPITAL ADDITIONS**		702,759,401	36,891,701	12,312,148	303,608,783	233,545,829	38,818,514	77,582,425

PUBLIC SERVICE ELECTRIC & GAS COMPANY
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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery	System Delivery	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	AF	**ALLOCATION FACTOR TABLE**								
2	AF	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**								
3	AF									
4	AF	**ALLOCATION FACTORS PART A**								
5	AF									
6	AF	Number of Customers x Aux &SL rates - local	CUSTNUMX_04	2,318,149	0	0	2,318,149	0	0	0
7	AF									
8	AF									
9	AF	CP @ 26 kV lines - switching station load -systems	CP_SUBT_05	2,437,470	0	0	0	2,437,470	0	0
10	AF	CP @ primary lines - systems	CP_PRI_05	8,789,384	0	0	0	8,789,384	0	0
11	AF	Sum Cust Peaks @ 26 kV lines - local	SUMPK_SUBT_04	0	0	0	0	0	0	0
12	AF	Sum Cust Peaks @ primary lines - local	SUMPK_PRI_04	19,689,051	0	0	19,689,051	0	0	0
13	AF	Sum Cust Peaks @ secondary lines - local	SUMPK_SEC_04	20,498,179	0	0	20,498,179	0	0	0
14	AF									
15	AF									
16	AF	**BILLING DETERMINANTS**								
17	AF									
18	AF	Number of Customers		2,348,219	2,348,219	2,348,219	2,348,219	2,348,219	2,348,219	2,348,219
19	AF	Delivered kWh @ Meter - annual (w/n net)		40,231,265,119	40,231,265,119	40,231,265,119	40,231,265,119	40,231,265,119	40,231,265,119	40,231,265,119
20	AF	Delivered Kw @ Meter - annual		0	0	0	0	0	0	0
21	AF									
22	AF									
23	AF	**ALLOCATION FACTORS PART B**								
24	AF									
25	AF	Delivery kWh @ meter	KWHMETER_04	40,816,033,564	0	0	40,816,033,564	0	0	0
26	AF	Delivery kWh @ meter x non-profiled rates	KWHMETERX_04	21,338,981,079	0	0	21,338,981,079	0	0	0
27	AF									
28	AF									
29	AF	**ALLOCATION FACTORS PART C**								
30	AF									
31	AF	E587 Customer Installation Expenses Local	CUSINT_04	112	0	0	112	0	0	0
32	AF	E587 Customer Installation Expenses System	CUSINT_05	112	0	0	0	112	0	0
33	AF	Draft EC Proforma	ECPRO_07	472,721,631	0	0	0	0	0	472,721,631
34	AF	Expense Reclassification-local	ADJEXP_04	-17,563	0	0	-17,563	0	0	0
35	AF	Expense Reclassification Plus-local	ADJ_Plus_04	17,563	0	0	17,563	0	0	0
36	AF	E369 minimum Service investment- access	SERVICESMIN_03	1,445,778,695	0	1,445,778,695	0	0	0	0
37	AF	E369 excess Service investment- local delivery	SERVICESEXC_04	0	0	0	0	0	0	0
38	AF	Avg Customer Bills - local	CUSTAVG_04	2,348,219	0	0	2,348,219	0	0	0
39	AF	Avg Customer Bills - cust svs	CUSTAVG_06	2,348,219	0	0	0	0	2,348,219	0
40	AF	E370 minimum meter investment - measurement	METERSMIN_07	456,573,728	0	0	0	0	0	456,573,728
41	AF	E368 Line Transfomers - local	LNTRFRMR_04	559,887,636	0	0	559,887,636	0	0	0
42	AF	Billing Function costs - cust svs	BILLING_06	130,951	0	0	0	0	130,951	0
43	AF	E370 excess meter investment - local delivery	METERSEXC_04	34,490,851	0	0	34,490,851	0	0	0
44	AF									

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery	System Delivery	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)	(7)
45	AF	Account Maint - cust svs	ACCTMAINT_06	80,564,013	0	0	0	0	80,564,013	0
46	AF	Meter Reading Costs - measurement	MRCOST_07	20,538,511	0	0	0	0	0	20,538,511
47	AF	Sales	SALES_06	0	0	0	0	0	0	0
48	AF	Other Utility work by Cust Ops - local	UTILWORK_04	3,334,747	0	0	3,334,747	0	0	0
49	AF									
50	AF	Choice - local	CHOICE_04	0	0	0	0	0	0	0
51	AF									
52	**AF**	**ALLOCATION FACTOR TABLE CONTINUED**								
53	**AF**	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**								
54	AF	Direct - PSAL - streetlighting	DIR_PSAL_02	1	1	0	0	0	0	0
55	AF	Direct - BPL - streetlighting	DIR_BPL_02	1	1	0	0	0	0	0
56	AF	Direct - BPL-POF - streetlighting	DIR_BPLPOF_02	1	1	0	0	0	0	0
57	AF	Direct - HTS-HV - access	DIR_HTSHV_03	1	0	1	0	0	0	0
58	AF	Direct - HEP - access	DIR_HEP_03	0	0	0	0	0	0	0
59	AF									
60	AF	Direct - HTS-Sub - systems	DIR_HTSS_05	0	0	0	0	0	0	0
61	AF									
62	AF	Direct - HTS-Sub - local	DIR_HTSS_04	1	0	0	1	0	0	0
63	AF	Meter O&M - minimum - measurement	MTROMMIN_07	6,387,137	0	0	0	0	0	6,387,137
64	AF	Meter O&M - excess - measurement	MTROMEXC_07	0	0	0	0	0	0	0
65	AF	WN TEFA Responsibility	TEFA_04	0	0	0	0	0	0	0
66	AF	E370 excess meter investment - dummy	METERSEXC_08	0	0	0	0	0	0	0
67	AF	Meter O&M - excess - dummy	MTROMEXC_08	0	0	0	0	0	0	0
68	AF	E369 excess Service investment- dummy	SERVICESEXC_08	0	0	0	0	0	0	0
69	AF	E368 Line Transfomers - dummy	LNTRFRMR_08	0	0	0	0	0	0	0
70	AF	CP @ 26 kV lines - switching station load - dummy	CP@SUBT_08	0	0	0	0	0	0	0
71	AF	CP @ primary lines - dummy	CP@PRI_08	0	0	0	0	0	0	0
72	AF	Sum Cust Peaks @ secondary lines - local	SUMPK@SEC_08	0	0	0	0	0	0	0
73	AF									
74	AF									
75	AF	Dummy allocator for unused lines	not_used	0	0	0	0	0	0	0
76	AF									
77	AF									
78	AF	**Plant Related**								
79	AF	Distribution Plant Total	DISTPLT	10,773,828,418	470,325,475	545,789,607	5,239,663,528	4,173,834,198	0	344,215,610
80	AF	Distribution Plant x meters	DISTPLTXMTR	10,408,406,976	470,325,475	545,789,607	5,214,010,943	4,173,834,198	0	4,446,753
81	AF	Acct E360 - Land & Land Rights	E360PLT	51,314,168	614,681	713,307	6,847,858	42,688,457	0	449,865
82	AF	Acct E361 - Structures & Improvments	E361PLT	242,256,447	5,422,095	6,292,075	60,404,877	166,169,149	0	3,968,251
83	AF	Acct E362 - Station Equipment	E362PLT	1,565,418,169	0	0	0	1,565,418,169	0	0
84	AF	Acct E364 - Poles & Towers	E364PLT	1,027,443,483	9,926,985	0	696,273,007	321,243,491	0	0
85	AF	Acct E365 - OH Conductors & Devices x HTSHV	E365PLT	2,856,184,590	8,663,157	0	1,426,636,429	1,420,885,005	0	0
86	AF	Acct E366 - UG Conduit	E366PLT	512,107,003	1,207,229	74,667	352,039,379	158,785,119	0	608
87	AF	Acct E367 - UG Conductors & Devices x HEP	E367PLT	1,431,183,475	3,373,838	208,673	983,843,101	443,756,163	0	1,700
88	AF	Acct E369 Services	E369PLT	535,269,333	0	535,269,333	0	0	0	0

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				(1)	(2)	(3)	(4)	(5)	(6)	(7)
89	AF	Acct E370 Meters	METERPLT	365,421,442	0	0	25,652,585	0	0	339,768,857
90	AF									
91	AF	Acct E370 Meters x load profile meters	METERPLTXPR	365,421,442	0	0	25,652,585	0	0	339,768,857
92	AF	Acct E373 - Streetlights	E373PLT	499,027,153	440,185,003	3,231,553	30,871,513	24,712,756	0	26,329
93	AF	Subtrans Lines - HTS-S/Switching Station load	SUBTRANSLINES	1.0000			0.2110	0.7890		
94	AF	Primary Lines - 50 Sys CP/50 Loc Sum Cust Pks	PRIMARYLINES	1.0000			0.5000	0.5000		
95	AF									
96	AF	Acct E301-E303 Intangible Plt	INTANGPLT	40,584,928	0	0	1,250,880	0	31,758,310	7,575,738
97	AF	Acct E399.10-23 Oth Tangible Plt	TANGPLT	86,338,967	22,167	25,723	2,854,317	196,714	66,228,628	17,011,418
98	AF	E391-E398 General Plant	GENPLT	429,584,593	19,411,672	22,526,291	215,197,078	172,266,022	0	183,530
99	**AF**	**ALLOCATION FACTOR TABLE CONTINUED**								
100	**AF**	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**								
101	AF									
102	AF	Common Plant	COMPLT	126,654,044	1,528,289	1,773,504	19,803,776	13,562,574	72,642,949	17,342,952
103	AF	Accts C389-C399, E389-E399 Com & Gen Plt	COMGENPLT	556,238,637	20,939,960	24,299,795	235,000,854	185,828,596	72,642,949	17,526,482
104	AF									
105	AF	Total Plant	TOTPLT	11,456,990,950	491,287,602	570,115,126	5,478,769,579	4,359,859,508	170,629,886	386,329,248
106	AF									
107	AF	Total Distribution Plant Reserve	TOTDRESERVE	3,099,332,698	120,238,498	252,980,311	1,477,503,032	1,013,555,312	85,380,573	149,674,973
108	AF	Total Net Plant	TOTPLTNET	8,357,658,252	371,049,105	317,134,815	4,001,266,547	3,346,304,196	85,249,313	236,654,276
109	AF									
110	AF									
111	AF	**Revenue Related**								
112	AF	Total Operating Revenue	TOTREV	1,925,019,676	82,945,791	58,645,322	784,579,218	672,665,453	131,863,973	194,319,919
113	AF									
114	AF	**Expense Related**								
115	AF	Distr Oper Exp	DISTEXPO	52,242,807	575,424	6,472	11,954,527	20,959,925	0	18,746,459
116	AF	Distr Maint Exp	DISTEXPM	123,204,777	12,583,538	174,262	47,775,602	61,704,625	0	966,750
117	AF	Cust Serv & Info Expense	CUSTS_I	5,318,001	0	0	2,010,317	0	3,307,684	0
118	AF	Acct E901-E903,E905 Cust Acct Exp Excl 904	CACCTEXP	94,394,062	0	0	1,062,937	0	74,718,489	18,612,636
119	AF	Accts E901-E910 Excl 904 - Cust Accts,Serv & Info	CUSTSVSX	99,712,063	0	0	3,073,254	0	78,026,173	18,612,636
120	AF	Sales Expense	SALESEXP	40,922	0	0	40,922	0	0	0
121	AF	Total O&M Expense Excl 904-Uncollectibles	TOTOMXAG	311,457,637	14,635,803	4,475,135	91,325,939	106,235,090	60,796,748	33,988,922
122	AF	Tot Admin & Genl Exp xPension/Ben	A_GEXP	111,662,106	4,989,463	4,396,338	50,691,845	37,371,848	7,429,750	6,782,862
123	AF	Accts E901-E905 Cust Accts Exp Excl 904-Uncol	CUSTACCTS	94,394,062	0	0	1,062,937	0	74,718,489	18,612,636
124	AF	O&M + Capital Additions	EXPENDITURES	1,014,217,038	51,527,505	16,787,283	394,934,722	339,780,919	99,615,261	111,571,347
125	AF									
126	AF	Depreciation Expense (total)	DEPREXP	286,771,855	12,258,086	14,224,907	136,714,639	108,782,584	5,285,730	9,505,909
127	AF									
128	AF	NJ State Income Tax (CBT)	STATEINCTAX	119,869,746	5,172,083	4,167,598	53,842,629	45,024,559	1,443,600	10,219,276
129	AF	NJ State Deferred Income Tax	DFSTATEINCTAX	2,766,183	133,878	-26,314	665,336	340,649	1,152,123	500,512
130	AF									
131	AF	**Labor Expense Related**								
132	AF	Total Distribution Exp (Oper) Labor	TLABDO	43,603,802	191,804	2,851	25,005,256	8,289,864	0	10,114,027

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				(1)	(2)	(3)	(4)	(5)	(6)	(7)
133	AF	Total Distribution Exp (Maint) Labor	TLABDM	45,417,214	7,089,971	119,673	17,218,882	20,241,533	0	747,154
134	AF	Total Labor	LABOR	159,006,836	7,538,655	348,867	47,589,158	30,455,469	50,290,404	22,784,283
135	AF									
136	AF	**REVENUES AND BILLING DETERMINANTS**								
137	AF									
138	AF	Base Rate Sales Revenue	SALESREV	1,899,915,237	81,924,279	57,892,994	774,456,024	663,460,281	130,236,339	191,945,320
139	AF									
140	AF	Residential Service	REVRS	1,071,330,372	0	37,033,775	481,937,668	308,233,692	96,514,663	147,610,575
141	AF	Residential Heating Service	REVRHS	5,019,520	0	216,948	2,992,663	989,451	335,300	485,158
142	AF	Residential Load Management Service	REVRLM	8,889,191	0	362,459	3,689,825	3,466,156	560,191	810,560
143	AF	Water Heating Service	REVWH	127,057	0	1,943	7,238	0	10,499	107,377
144	AF	Water Heating Storage Service	REVWHS	1,979	0	30	110	0	164	1,675
145	AF	Building Heating Service	REVHS	1,308,648	0	0	1,034,300	214,843	12,450	47,055
146	**AF**	**ALLOCATION FACTOR TABLE CONTINUED**								
147	**AF**	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**								
148	AF									
149	AF	Body Police Lighting Service	REVBLP	64,405,668	61,591,337	0	2,471,767	0	342,564	0
150	AF	Body Police Lighting Service from Publicly Owned	REVBLPPOF	506,728	384,832	0	115,664	0	6,232	0
151	AF	Private Street and Area Lighting Service	REVPAL	22,801,929	19,948,110	0	1,226,049	0	1,627,771	0
152	AF	General Power and Lighting Service	REVGLP	362,840,766	0	18,763,041	131,137,463	160,470,606	21,978,891	30,490,765
153	AF	Large Power and Lighting Service - Secondary	REVLPLS	255,737,125	0	1,339,041	105,678,423	129,958,748	7,984,411	10,776,502
154	AF	Large Power and Lighting Service - Primary	REVLPLP	55,996,770	0	113,208	20,225,124	33,978,317	675,033	1,005,088
155	AF	High Tension Service - Subtransmission	REVHTSS	50,758,783	0	62,549	23,923,133	26,148,467	165,854	458,780
156	AF	High Tension Service - High Voltage	REVHTSHV	190,699	0	0	16,597	0	22,317	151,785
157	AF	HEP	REVHEP	0	0	0	0	0	0	0
158	AF									
159	AF									
160	AF	Total Rev Req @ desired ROR	REVREQ	1,899,915,237	81,924,279	57,892,994	774,456,024	663,460,281	130,236,339	191,945,320
161	AF									
162	AF									
163	AF	**PRESENT REVENUES FROM SALES INPUT**								
164	AF									
165	AF	Total Sales of Electricity Revenues		0	0	0	0	0	0	0
166	AF	Sales of Electricity Revenues - Rates		1,254,696,745	1,254,696,745	1,254,696,745	1,254,696,745	1,254,696,745	1,254,696,745	1,254,696,745
167	AF	Sales of Electricity Revenues - Other		0	0	0	0	0	0	0
168	AF									
169	AF	**RATE OF RETURN**								
170	AF	Rate of Return (Equalized)	CALCULATED	7.55%	7.55%	7.55%	7.55%	7.55%	7.55%	7.55%

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				(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	AP	**ALLOCATION PROPORTIONS TABLE**								
2	AP	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**								
3	AP									
4	AP	**ALLOCATION FACTORS PART A**								
5	AP									
6	AP	Number of Customers x Aux &SL rates - local	CUSTNUMX_04	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000
7	AP									
8	AP									
9	AP	CP @ 26 kV lines - switching station load -systems	CP_SUBT_05	1.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000
10	AP	CP @ primary lines - systems	CP_PRI_05	1.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000
11	AP	Sum Cust Peaks @ 26 kV lines - local	SUMPK_SUBT_04	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
12	AP	Sum Cust Peaks @ primary lines - local	SUMPK_PRI_04	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000
13	AP	Sum Cust Peaks @ secondary lines - local	SUMPK_SEC_04	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000
14	AP									
15	AP	**BILLING DETERMINANTS**								
16	AP									
17	AP	Number of Customers								
18	AP	Delivered kWh @ Meter - annual (w/n net)								
19	AP	Delivered Kw @ Meter - annual								
20	AP									
21	AP	**ALLOCATION FACTORS PART B**								
22	AP									
23	AP	Delivery kWh @ meter	KWHMETER_04	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000
24	AP	Delivery kWh @ meter x non-profiled rates	KWHMETERX_04	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000
25	AP									
26	AP									
27	AP	**ALLOCATION FACTORS PART C**								
28	AP									
29	AP	Draft EC Proforma	ECPRO_07	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000
30	AP	E587 Customer Installation Expenses Local	CUSINT_04	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000
31	AP	E587 Customer Installation Expenses System	CUSINT_05	1.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000
32	AP	E369 minimum Service investment- access	SERVICESMIN_03	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000
33	AP	E369 excess Service investment- local delivery	SERVICESEXC_04	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
34	AP	Avg Customer Bills - local	CUSTAVG_04	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000
35	AP	Avg Customer Bills - cust svs	CUSTAVG_06	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000
36	AP	E370 minimum meter investment - measurement	METERSMIN_07	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000
37	AP	E368 Line Transfomers - local	LNTRFRMR_04	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000
38	AP	Billing Function costs - cust svs	BILLING_06	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000
39	AP	E370 excess meter investment - local delivery	METERSEXC_04	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000
40	AP									
41	AP	Account Maint - cust svs	ACCTMAINT_06	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000
42	AP	Meter Reading Costs - measurement	MRCOST_07	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000
43	AP									
44	AP	Sales	SALES_06	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000

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				(1)	(2)	(3)	(4)	(5)	(6)	(7)
45	AP	Other Utility work by Cust Ops - local	UTILWORK_04	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000
46	AP	Choice - local	CHOICE_04	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
47	AP									
48	AP									
49	AP									
50	**AP**	**ALLOCATION FACTOR TABLE CONTINUED**								
51	**AP**	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**								
52	AP	Direct - PSAL - streetlighting	DIR_PSAL_02	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
53	AP	Direct - BPL - streetlighting	DIR_BPL_02	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
54	AP	Direct - BPL-POF - streetlighting	DIR_BPLPOF_02	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
55	AP	Direct - HTS-HV - access	DIR_HTSHV_03	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000
56	AP	Direct - HEP - access	DIR_HEP_03	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
57	AP	Direct - HTS-Sub - systems	DIR_HTSS_05	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
58	AP									
59	AP	Direct - HTS-Sub - local	DIR_HTSS_04	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000
60	AP	Meter O&M - minimum - measurement	MTROMMIN_07	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000
61	AP	Meter O&M - excess - measurement	MTROMEXC_07	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
62	AP	WN TEFA Responsibility	TEFA_04	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
63	AP	E370 excess meter investment - dummy	METERSEXC_08	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
64	AP	Meter O&M - excess - dummy	MTROMEXC_08	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
65	AP	E369 excess Service investment- dummy	SERVICESEXC_08	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
66	AP	E368 Line Transfomers - dummy	LNTRFRMR_08	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
67	AP	CP @ 26 kV lines - switching station load - dummy	CP@SUBT_08	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
68	AP	CP @ primary lines - dummy	CP@PRI_08	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
69	AP	Sum Cust Peaks @ secondary lines - local	SUMPK@SEC_08	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
70	AP									
71	AP									
72	AP	Dummy allocator for unused lines	not_used	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
73	AP									
74	AP	**Plant Related**								
75	AP	Distribution Plant Total	DISTPLT	1.000000	0.043654	0.050659	0.486333	0.387405	0.000000	0.031949
76	AP	Distribution Plant x meters	DISTPLTXMTR	1.000000	0.045187	0.052437	0.500942	0.401006	0.000000	0.000427
77	AP	Acct E360 - Land & Land Rights	E360PLT	1.000000	0.011979	0.013901	0.133450	0.831904	0.000000	0.008767
78	AP	Acct E361 - Structures & Improvments	E361PLT	1.000000	0.022382	0.025973	0.249343	0.685923	0.000000	0.016380
79	AP	Acct E362 - Station Equipment	E362PLT	1.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000
80	AP	Acct E364 - Poles & Towers	E364PLT	1.000000	0.009662	0.000000	0.677675	0.312663	0.000000	0.000000
81	AP	Acct E365 - OH Conductors & Devices x HTSHV	E365PLT	1.000000	0.003033	0.000000	0.499490	0.497477	0.000000	0.000000
82	AP	Acct E366 - UG Conduit	E366PLT	1.000000	0.002357	0.000146	0.687433	0.310062	0.000000	0.000001
83	AP	Acct E367 - UG Conductors & Devices x HEP	E367PLT	1.000000	0.002357	0.000146	0.687433	0.310062	0.000000	0.000001
84	AP	Acct E369 Services	E369PLT	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000
85	AP	Acct E370 Meters	METERPLT	1.000000	0.000000	0.000000	0.070200	0.000000	0.000000	0.929800
86	AP	Acct E370 Meters x load profile meters	METERPLTXPR	1.000000	0.000000	0.000000	0.070200	0.000000	0.000000	0.929800
87	AP	Acct E373 - Streetlights	E373PLT	1.000000	0.882086	0.006476	0.061863	0.049522	0.000000	0.000053
88	AP	Subtrans Lines - HTS-S/Switching Station load	SUBTRANSLINES	1.000000	0.000000	0.000000	0.211000	0.789000	0.000000	0.000000

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				(1)	(2)	(3)	(4)	(5)	(6)	(7)
89	AP	Primary Lines - 50 Sys CP/50 Loc Sum Cust Pks	PRIMARYLINES	1.000000	0.000000	0.000000	0.500000	0.500000	0.000000	0.000000
90	AP									
91	AP	Acct E301-E303 Intangible Plt	INTANGPLT	1.000000	0.000000	0.000000	0.030821	0.000000	0.782515	0.186664
92	AP									
93	AP	Acct E399.10-23 Oth Tangible Plt	TANGPLT	1.000000	0.000257	0.000298	0.033059	0.002278	0.767077	0.197031
94	AP	E391-E398 General Plant	GENPLT	1.000000	0.045187	0.052437	0.500942	0.401006	0.000000	0.000427
95	AP	Common Plant	COMPLT	1.000000	0.012067	0.014003	0.156361	0.107084	0.573554	0.136932
96	AP	Accts C389-C399, E389-E399 Com & Gen Plt	COMGENPLT	1.000000	0.037646	0.043686	0.422482	0.334081	0.130597	0.031509
97	**AP**	**ALLOCATION FACTOR TABLE CONTINUED**								
98	**AP**	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**								
99	AP									
100	AP	Total Plant	TOTPLT	1.000000	0.042881	0.049761	0.478203	0.380541	0.014893	0.033720
101	AP									
102	AP	Total Distribution Plant Reserve	TOTDRESERVE	1.000000	0.038795	0.081624	0.476716	0.327024	0.027548	0.048293
103	AP	Total Net Plant	TOTPLTNET	1.000000	0.044396	0.037945	0.478755	0.400388	0.010200	0.028316
104	AP									
105	AP									
106	AP	**Revenue Related**								
107	AP	Total Operating Revenue	TOTREV	1.000000	0.043088	0.030465	0.407569	0.349433	0.068500	0.100944
108	AP									
109	AP	**Expense Related**								
110	AP	Distr Oper Exp	DISTEXPO	1.000000	0.011014	0.000124	0.228826	0.401202	0.000000	0.358833
111	AP	Distr Maint Exp	DISTEXPM	1.000000	0.102135	0.001414	0.387774	0.500830	0.000000	0.007847
112	AP	Cust Serv & Info Expense	CUSTS_I	1.000000	0.000000	0.000000	0.378021	0.000000	0.621979	0.000000
113	AP	Acct E901-E903,E905 Cust Acct Exp Excl 904	CACCTEXP	1.000000	0.000000	0.000000	0.011261	0.000000	0.791559	0.197180
114	AP	Accts E901-E910 Excl 904 - Cust Accts,Serv & Info	CUSTSVSX	1.000000	0.000000	0.000000	0.030821	0.000000	0.782515	0.186664
115	AP	Sales Expense	SALESEXP	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000
116	AP	Total O&M Expense Excl 904-Uncollectibles	TOTOMXAG	1.000000	0.046991	0.014368	0.293221	0.341090	0.195201	0.109129
117	AP	Tot Admin & Genl Exp xPension/Ben	A_GEXP	1.000000	0.044684	0.039372	0.453975	0.334687	0.066538	0.060745
118	AP	Accts E901-E905 Cust Accts Exp Excl 904-Uncol	CUSTACCTS	1.000000	0.000000	0.000000	0.011261	0.000000	0.791559	0.197180
119	AP	O&M + Capital Additions	EXPENDITURES	1.000000	0.050805	0.016552	0.389399	0.335018	0.098219	0.110007
120	AP									
121	AP	Depreciation Expense (total)	DEPREXP	1.000000	0.042745	0.049604	0.476737	0.379335	0.018432	0.033148
122	AP									
123	AP	NJ State Income Tax (CBT)	STATEINCTAX	1.000000	0.043148	0.034768	0.449176	0.375612	0.012043	0.085253
124	AP	NJ State Deferred Income Tax	DFSTATEINCTAX	1.000000	0.048398	-0.009513	0.240525	0.123148	0.416503	0.180940
125	AP									
126	AP	**Labor Expense Related**								
127	AP	Total Distribution Exp (Oper) Labor	TLABDO	1.000000	0.004399	0.000065	0.573465	0.190118	0.000000	0.231953
128	AP	Total Distribution Exp (Maint) Labor	TLABDM	1.000000	0.156108	0.002635	0.379127	0.445680	0.000000	0.016451
129	AP	Total Labor	LABOR	1.000000	0.047411	0.002194	0.299290	0.191536	0.316278	0.143291
130	AP									
131	AP	**REVENUES AND BILLING DETERMINANTS**								
132	AP									

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				(1)	(2)	(3)	(4)	(5)	(6)	(7)
133	AP	Base Rate Sales Revenue	SALESREV	1.000000	0.043120	0.030471	0.407627	0.349205	0.068548	0.101028
134	AP									
135	AP	Residential Service	REVRS	1.000000	0.000000	0.034568	0.449850	0.287711	0.090089	0.137782
136	AP	Residential Heating Service	REVRHS	1.000000	0.000000	0.043221	0.596205	0.197121	0.066799	0.096654
137	AP	Residential Load Management Service	REVRLM	1.000000	0.000000	0.040775	0.415091	0.389929	0.063019	0.091185
138	AP	Water Heating Service	REVWH	1.000000	0.000000	0.015294	0.056969	0.000000	0.082629	0.845108
139	AP	Water Heating Storage Service	REVWHS	1.000000	0.000000	0.015317	0.055544	0.000000	0.082754	0.846384
140	AP	Building Heating Service	REVHS	1.000000	0.000000	0.000000	0.790358	0.164172	0.009514	0.035957
141	AP	Body Police Lighting Service	REVBLP	1.000000	0.956303	0.000000	0.038378	0.000000	0.005319	0.000000
142	AP	Body Police Lighting Service from Publicly Owned	REVBLPPOF	1.000000	0.759444	0.000000	0.228257	0.000000	0.012298	0.000000
143	AP	Private Street and Area Lighting Service	REVPAL	1.000000	0.874843	0.000000	0.053770	0.000000	0.071387	0.000000
144	**AP**	**ALLOCATION FACTOR TABLE CONTINUED**								
145	**AP**	**INTERNALLY DEVELOPED ALLOCATION FACTORS**								
146	AP									
147	AP	General Power and Lighting Service	REVGLP	1.000000	0.000000	0.051712	0.361419	0.442262	0.060574	0.084033
148	AP	Large Power and Lighting Service - Secondary	REVLPLS	1.000000	0.000000	0.005236	0.413231	0.508173	0.031221	0.042139
149	AP	Large Power and Lighting Service - Primary	REVLPLP	1.000000	0.000000	0.002022	0.361184	0.606791	0.012055	0.017949
150	AP	High Tension Service - Subtransmission	REVHTSS	1.000000	0.000000	0.001232	0.471310	0.515152	0.003267	0.009038
151	AP	High Tension Service - High Voltage	REVHTSHV	1.000000	0.000000	0.000000	0.087034	0.000000	0.117027	0.795940
152	AP	HEP	REVHEP	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
153	AP									
154	AP	Total Rev Req @ desired ROR	REVREQ	1.000000	0.043120	0.030471	0.407627	0.349205	0.068548	0.101028
155	AP									
156	AP	**PRESENT REVENUES FROM SALES INPUT**								
157	AP									
158	AP	Total Sales of Electricity Revenues		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
159	AP	Sales of Electricity Revenues - Rates		1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000
160	AP	Sales of Electricity Revenues - Other		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
161	AP									
162	AP									
163	AP									
164	AP	Expense Reclassification Plus-local	ADJ_Plus_04	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000
165	AP	Expense Reclassification-local	ADJEXP_04	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000

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				(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	ADA	**ALLOCATED DIRECT ASSIGNMENTS**								
2	ADA	**DIRECT ASSIGN TO CLASSES W/SALES REV FUNCTIONS**								
3	ADA									
4	ADA	**Net Write-Offs**								
5	ADA	Residential Service	REVRS	0	0	0	0	0	0	0
6	ADA	Residential Heating Service	REVRHS	0	0	0	0	0	0	0
7	ADA	Residential Load Management Service	REVRLM	0	0	0	0	0	0	0
8	ADA	Water Heating Service	REVWH	0	0	0	0	0	0	0
9	ADA	Water Heating Storage Service	REVWHS	0	0	0	0	0	0	0
10	ADA	Building Heating Service	REVHS	0	0	0	0	0	0	0
11	ADA	Body Police Lighting Service	REVBLP	0	0	0	0	0	0	0
12	ADA	Body Police Lighting Service from Publicly Owned	REVBLPPOF	0	0	0	0	0	0	0
13	ADA	Private Street and Area Lighting Service	REVPAL	0	0	0	0	0	0	0
14	ADA	General Power and Lighting Service	REVGLP	0	0	0	0	0	0	0
15	ADA	Large Power and Lighting Service - Secondary	REVLPLS	0	0	0	0	0	0	0
16	ADA	Large Power and Lighting Service - Primary	REVLPLP	0	0	0	0	0	0	0
17	ADA	High Tension Service - Subtransmission	REVHTSS	0	0	0	0	0	0	0
18	ADA	High Tension Service - High Voltage	REVHTSHV	0	0	0	0	0	0	0
19	ADA	HEP	REVHEP	0	0	0	0	0	0	0
20	ADA									
21	ADA	Total Write-Offs	EXP_904	0	0	0	0	0	0	0
22	ADA									
23	ADA	Total Write-Offs	EXP_904	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
24	ADA									
25	ADA	Additional Net Write-Offs at Claimed Rate	EXP_904	0	0	0	0	0	0	0
26	ADA									
27	ADA									
28	ADA	**Rev to Customers w/Late Payment fees**								
29	ADA	Residential Service	REVRS	0	0	0	0	0	0	0
30	ADA	Residential Heating Service	REVRHS	0	0	0	0	0	0	0
31	ADA	Residential Load Management Service	REVRLM	0	0	0	0	0	0	0
32	ADA	Water Heating Service	REVWH	0	0	0	0	0	0	0
33	ADA	Water Heating Storage Service	REVWHS	0	0	0	0	0	0	0
34	ADA	Building Heating Service	REVHS	1,308,648	0	0	1,034,300	214,843	12,450	47,055
35	ADA	Body Police Lighting Service	REVBLP	0	0	0	0	0	0	0
36	ADA	Body Police Lighting Service from Publicly Owned	REVBLPPOF	0	0	0	0	0	0	0
37	ADA	Private Street and Area Lighting Service	REVPAL	22,801,929	19,948,110	0	1,226,049	0	1,627,771	0
38	ADA	General Power and Lighting Service	REVGLP	362,840,766	0	18,763,041	131,137,463	160,470,606	21,978,891	30,490,765
39	ADA	Large Power and Lighting Service - Secondary	REVLPLS	255,737,125	0	1,339,041	105,678,423	129,958,748	7,984,411	10,776,502
40	ADA	Large Power and Lighting Service - Primary	REVLPLP	55,996,770	0	113,208	20,225,124	33,978,317	675,033	1,005,088
41	ADA	High Tension Service - Subtransmission	REVHTSS	50,758,783	0	62,549	23,923,133	26,148,467	165,854	458,780
42	ADA	High Tension Service - High Voltage	REVHTSHV	190,699	0	0	16,597	0	22,317	151,785
43	ADA	HEP	REVHEP	0	0	0	0	0	0	0
44	ADA									

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				(1)	(2)	(3)	(4)	(5)	(6)	(7)
45	ADA	Total Late Payment Fees	REVLATEP	749,634,721	19,948,110	20,277,839	283,241,088	350,770,982	32,466,727	42,929,975
46	ADA	Total Late Payment Fees	REVLATEP	1.000000	0.026610	0.027050	0.377839	0.467923	0.043310	0.057268
47	ADA									
48	ADA	**ALLOCATED DIRECT ASSIGNMENTS**								
49	ADA	DIRECT ASSIGN TO CLASSES W/SALES REV FUNCTIONS								
50	ADA									
51	ADA	**AVAILABLE**								
52	ADA	Residential Service	REVRS	0	0	0	0	0	0	0
53	ADA	Residential Heating Service	REVRHS	0	0	0	0	0	0	0
54	ADA	Residential Load Management Service	REVRLM	0	0	0	0	0	0	0
55	ADA	Water Heating Service	REVWH	0	0	0	0	0	0	0
56	ADA	Water Heating Storage Service	REVWHS	0	0	0	0	0	0	0
57	ADA	Building Heating Service	REVHS	0	0	0	0	0	0	0
58	ADA	Body Police Lighting Service	REVBLP	0	0	0	0	0	0	0
59	ADA	Body Police Lighting Service from Publicly Owned	REVBLPPOF	0	0	0	0	0	0	0
60	ADA	Private Street and Area Lighting Service	REVPAL	0	0	0	0	0	0	0
61	ADA	General Power and Lighting Service	REVGLP	0	0	0	0	0	0	0
62	ADA	Large Power and Lighting Service - Secondary	REVLPLS	0	0	0	0	0	0	0
63	ADA	Large Power and Lighting Service - Primary	REVLPLP	0	0	0	0	0	0	0
64	ADA	High Tension Service - Subtransmission	REVHTSS	0	0	0	0	0	0	0
65	ADA	High Tension Service - High Voltage	REVHTSHV	0	0	0	0	0	0	0
66	ADA	HEP	REVHEP	0	0	0	0	0	0	0
67	ADA									
68	ADA	Total Available	REVAVAIL	0	0	0	0	0	0	0
69	ADA	Total Available	REVAVAIL	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000

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				(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	RRW	**REVENUE REQUIREMENTS**								
2	RRW									
3	RRW	PRESENT RATES								
4	RRW	--								
5	RRW	RATE BASE		9,785,622,095	416,384,944	315,899,282	4,274,125,914	3,595,051,949	177,482,704	1,006,677,303
6	RRW	NET OPER INC (PRESENT RATES)		738,814,468	31,437,063	23,850,396	322,696,506	271,426,422	13,399,944	76,004,136
7	RRW	RATE OF RETURN (PRES RATES)		7.55%	7.55%	7.55%	7.55%	7.55%	7.55%	7.55%
8	RRW	RELATIVE RATE OF RETURN		1.00	1.00	1.00	1.00	1.00	1.00	1.00
9	RRW	SALES REVENUE (PRE RATES)		1,899,915,237	81,924,279	57,892,994	774,456,024	663,460,281	130,236,339	191,945,320
10	RRW	REVENUE PRES RATES $/KWH		$0.0465	$0.0020	$0.0014	$0.0190	$0.0163	$0.0032	$0.0047
11	RRW	REVENUE REQUIRED - $/MO/CUST		$67.42	$2.91	$2.05	$27.48	$23.54	$4.62	$6.81
12	RRW	SALES REV REQUIRED $/KW								
13	RRW									
14	RRW	CLAIMED RATE OF RETURN								
15	RRW	--								
16	RRW	CLAIMED RATE OF RETURN		7.55%	7.55%	7.55%	7.55%	7.55%	7.55%	7.55%
17	RRW	RETURN REQ FOR CLAIMED ROR		738,814,468	31,437,063	23,850,396	322,696,506	271,426,422	13,399,944	76,004,136
18	RRW	SALES REVENUE REQ CLAIMED ROR		1,899,915,237	81,924,279	57,892,994	774,456,024	663,460,281	130,236,339	191,945,320
19	RRW	REVENUE DEFICIENCY SALES REV		0		0	0	0	0	(0)
20	RRW	PERCENT INCREASE REQUIRED								
21	RRW	ANNUAL BOOKED KWH SALES		40,816,033,564	40,816,033,564	40,816,033,564	40,816,033,564	40,816,033,564	40,816,033,564	40,816,033,564
22	RRW	SALES REV REQUIRED $/KWH		$0.0465	$0.0020	$0.0014	$0.0190	$0.0163	$0.0032	$0.0047
23	RRW	REVENUE DEFICIENCY $/KWH								

Based on 12 months actual

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

line #	FUNCTIONAL SEGMENTS REV REQ	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Street Lighting	$81,924,279	0	0	0	0	0	0	$61,591,337
2	Access	$57,892,994	$37,033,775	$216,948	$362,459	$1,943	$30	0	0
3	Local Delivery	$774,456,024	$481,937,668	$2,992,663	$3,689,825	$7,238	$110	$1,034,300	$2,471,767
4	System Delivery	$663,460,281	$308,233,692	$989,451	$3,466,156			$214,843	
5	Customer Service	$130,236,339	$96,514,663	$335,300	$560,191	$10,499	$164	$12,450	$342,564
6	Measurement	$191,945,320	$147,610,575	$485,158	$810,560	$107,377	$1,675	$47,055	0
7	Total	$1,899,915,237	$1,071,330,372	$5,019,520	$8,889,191	$127,057	$1,979	$1,308,648	$64,405,668

Based on 12 months actual

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

line #	FUNCTIONAL SEGMENTS REV REQ	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Subtransmission	HTS-High Voltage
		(9)	(10)	(11)	(12)	(13)	(14)	(15)
1	Street Lighting	$384,832	$19,948,110	0	0	0	0	0
2	Access	0	0	$18,763,041	$1,339,041	$113,208	$62,549	
3	Local Delivery	$115,664	$1,226,049	$131,137,463	$105,678,423	$20,225,124	$23,923,133	$16,597
4	System Delivery			$160,470,606	$129,958,748	$33,978,317	$26,148,467	0
5	Customer Service	$6,232	$1,627,771	$21,978,891	$7,984,411	$675,033	$165,854	$22,317
6	Measurement	0	0	$30,490,765	$10,776,502	$1,005,088	$458,780	$151,785
7	Total	$506,728	$22,801,929	$362,840,766	$255,737,125	$55,996,770	$50,758,783	$190,699

Cost of Service and Rate Design Sync

Step 1: Import Revenue Requirements by Functional Segment and Rate Class from SS-E7

line #	Rate Schedule	(1) Streetlighting	(2) Access	(3) Local Delivery	(4) System Delivery	(5) Customer Service	(6) Measurement	(7) Total
1	RS	$ -	$ 37,033,775	$ 481,937,668	$ 308,233,692	$ 96,514,663	$ 147,610,575	$ 1,071,330,372
2	RHS	$ -	$ 216,948	$ 2,992,663	$ 989,451	$ 335,300	$ 485,158	$ 5,019,520
3	RLM	$ -	$ 362,459	$ 3,689,825	$ 3,466,156	$ 560,191	$ 810,560	$ 8,889,191
4	WH	$ -	$ 1,943	$ 7,238	$ -	$ 10,499	$ 107,377	$ 127,057
5	WHS	$ -	$ 30	$ 110	$ -	$ 164	$ 1,675	$ 1,979
6	HS	$ -	$ -	$ 1,034,300	$ 214,843	$ 12,450	$ 47,055	$ 1,308,648
7	BPL	$ 61,591,337	$ -	$ 2,471,767	$ -	$ 342,564	$ -	$ 64,405,668
8	BPL-POF	$ 384,832	$ -	$ 115,664	$ -	$ 6,232	$ -	$ 506,728
9	PSAL	$ 19,948,110	$ -	$ 1,226,049	$ -	$ 1,627,771	$ -	$ 22,801,929
10	GLP	$ -	$ 18,763,041	$ 131,137,463	$ 160,470,606	$ 21,978,891	$ 30,490,765	$ 362,840,766
11	LPL-S	$ -	$ 1,339,041	$ 105,678,423	$ 129,958,748	$ 7,984,411	$ 10,776,502	$ 255,737,125
12	LPL-P	$ -	$ 113,208	$ 20,225,124	$ 33,978,317	$ 675,033	$ 1,005,088	$ 55,996,770
13	HTS-S	$ -	$ 62,549	$ 23,923,133	$ 26,148,467	$ 165,854	$ 458,780	$ 50,758,783
14	HTS-HV	$ -	$ -	$ 16,597	$ -	$ 22,317	$ 151,785	$ 190,699
15	Total	81,924,279	57,892,994	774,456,024	663,460,281	130,236,339	191,945,320	$ 1,899,915,237
Notes:		SS-E7, Line 1	SS-E7, Line 2	SS-E7, Line 3	SS-E7, Line 4	SS-E7, Line 5	SS-E7, Line 6	SS-E7, Line 7

Step 2: Create Sync Factors

		Customer Sync Factor Calc			**kWh Sync Factor Calc**		
		Customer Total - Rate Design	**Customer Total - COSS**	**Customer Sync Factor**	**kWh - Rate Design**	**kWh - COSS**	**kWh Sync Factor**
16	RS	1,981,089	$ 2,000,647	0.990	13,096,522,329	$ 13,286,613,062	0.986
17	RHS	6,404	$ 6,950	0.921	80,915,936	$ 93,109,748	0.869
18	RLM	11,197	$ 11,612	0.964	170,717,425	$ 189,891,666	0.899
19	WH	574	$ 662	0.866	514,918	$ 581,366	0.886
20	WHS	11	$ 10	1.040	8,213	$ 7,149	1.149
21	HS	714	$ 789	0.905	7,892,762	$ 11,877,324	0.665
22	BPL		$ 4,938	-	285,913,122	$ 283,298,553	1.009
23	BPL-POF		$ 90	-	14,293,500	$ 15,313,401	0.933
24	PSAL		$ 23,580	-	137,181,873	$ 137,520,699	0.998
25	GLP	272,921	$ 288,392	0.946	7,102,854,741	$ 7,289,563,210	0.974
26	LPL-S	9,379	$ 9,532	0.984	10,208,844,968	$ 10,497,945,935	0.972
27	LPL-P	770	$ 794	0.970	2,944,784,961	$ 3,083,571,353	0.955
28	HTS-S	189	$ 195	0.971	4,541,550,576	$ 4,669,504,753	0.973
29	HTS-HV	16	$ 26	0.622	435,990,949	$ 672,466,899	0.648
30	Total	2,283,265	2,348,219		39,027,986,274	40,231,265,119	
Notes:		SS-E11 Workpapers	COS Model	(1) / (2)	SS-E11 Workpapers	COS Model	(5) / (6)

Cost of Service and Rate Design Sync

Step 3: Initial Sync

line #	Rate Schedule (1)	Streetlighting (2)	Access (3)	Local Delivery (4)	System Delivery (5)	Customer Service (6)	Measurement (7)	Total (8)
1	RS	$ -	$ 36,671,747.74	$ 475,042,616	$ 303,823,812	$ 95,571,175	$ 146,167,595	$ 1,057,276,947
2	RHS	$ -	$ 199,883.78	$ 2,600,738	$ 859,871	$ 308,926	$ 446,997	$ 4,416,416
3	RLM	$ -	$ 349,509.18	$ 3,317,246	$ 3,116,163	$ 540,177	$ 781,601	$ 8,104,696
4	WH	$ -	$ 1,683.61	$ 6,411	$ -	$ 9,096	$ 93,031	$ 110,222
5	WHS	$ -	$ 31.54	$ 126	$ -	$ 170	$ 1,743	$ 2,071
6	HS	$ -	$ -	$ 687,316	$ 142,768	$ 11,262	$ 42,562	$ 883,908
7	BPL	$ 62,159,765	$ -	$ 2,494,579	$ -	$ 345,725	$ -	$ 65,000,070
8	BPL-POF	$ 359,201	$ -	$ 107,961	$ -	$ 5,817	$ -	$ 472,979
9	PSAL	$ 19,898,961	$ -	$ 1,223,028	$ -	$ 1,623,760	$ -	$ 22,745,749
10	GLP	$ -	$ 17,756,508.42	$ 127,778,623	$ 156,360,453	$ 20,799,846	$ 28,855,105	$ 351,550,536
11	LPL-S	$ -	$ 1,317,516.86	$ 102,768,164	$ 126,379,838	$ 7,856,067	$ 10,603,277	$ 248,924,863
12	LPL-P	$ -	$ 109,775.60	$ 19,314,825	$ 32,449,010	$ 654,568	$ 974,617	$ 53,502,796
13	HTS-S	$ -	$ 60,729.07	$ 23,267,589	$ 25,431,945	$ 161,027	$ 445,429	$ 49,366,720
14	HTS-HV	$ -	$ -	$ 10,761	$ -	$ 13,872	$ 94,352	$ 118,985
15	Total	$ 82,417,928	$ 56,467,386	$ 758,619,985	$ 648,563,859	$ 127,901,489	$ 188,506,308	$ 1,862,476,956
Notes:		2018 Rate Case Schedule SS-E8, page 2, lines 1-15	2018 Rate Case Schedule SS-E8, page 2, lines 1-15	2018 Rate Case Schedule SS-E8, page 2, lines 1-15	2018 Rate Case Schedule SS-E8, page 2, lines 1-15	2018 Rate Case Schedule SS-E8, page 2, lines 1-15	2018 Rate Case Schedule SS-E8, page 2, lines 1-15	Sum (Col 2 - Col 7)

Step 4: Rev Req Sync

line #	Description	Amount	Source
16	Total Rev Req Increase to be Recovered Through Rates	$ 535,063,902	Schedule SS-RC2023-2
17	Total Target Distribution Revenue Requirements	$ 1,810,124,292	= Line 16 + page 4, Col 3, Line 21
18	Rate Case Minus Streetlight Fixtures	$ 1,780,059,028	= col 8, line 15 - col 2, line 15
19	Target Minus Streetlight Fixtures	$ 1,727,706,364	= line 17 - col 2, line 15
20	Final Sync Adjustment Factor	0.97189	= line 17 / (line 15 column 8)

line #	Rate Schedule (1)	Streetlighting (2)	Access (3)	Local Delivery (4)	System Delivery (5)	Cust Svs (6)	Measurement (7)	Total (8)
21	RS	$ -	$ 35,640,936	$ 461,689,567	$ 295,283,580	$ 92,884,750	$ 142,058,947	$ 1,027,557,779
22	RHS	$ -	$ 194,265	$ 2,527,634	$ 835,700	$ 300,243	$ 434,432	$ 4,292,274
23	RLM	$ -	$ 339,685	$ 3,224,001	$ 3,028,570	$ 524,993	$ 759,631	$ 7,876,880
24	WH	$ -	$ 1,636	$ 6,231	$ -	$ 8,840	$ 90,416	$ 107,124
25	WHS	$ -	$ 31	$ 123	$ -	$ 166	$ 1,694	$ 2,013
26	HS	$ -	$ -	$ 667,997	$ 138,755	$ 10,945	$ 41,365	$ 859,062
27	BPL	$ 60,412,506	$ -	$ 2,424,459	$ -	$ 336,007	$ -	$ 63,172,972
28	BPL-POF	$ 349,105	$ -	$ 104,926	$ -	$ 5,653	$ -	$ 459,684
29	PSAL	$ 19,339,618	$ -	$ 1,188,650	$ -	$ 1,578,118	$ -	$ 22,106,385
30	GLP	$ -	$ 17,257,388	$ 124,186,874	$ 151,965,292	$ 20,215,180	$ 28,044,012	$ 341,668,745
31	LPL-S	$ -	$ 1,280,483	$ 99,879,437	$ 122,827,407	$ 7,635,239	$ 10,305,228	$ 241,927,794
32	LPL-P	$ -	$ 106,690	$ 18,771,901	$ 31,536,895	$ 636,169	$ 947,221	$ 51,998,877
33	HTS-S	$ -	$ 59,022	$ 22,613,557	$ 24,717,074	$ 156,501	$ 432,909	$ 47,979,063
34	HTS-HV	$ -	$ -	$ 10,458	$ -	$ 13,483	$ 91,700	$ 115,640
35	Total	$ 80,101,229	$ 54,880,135	$ 737,295,814	$ 630,333,274	$ 124,306,286	$ 183,207,554	$ 1,810,124,292
Notes:		Step 1 Rev Req * Line 20	Step 1 Rev Req * Line 20	Step 1 Rev Req * Line 20	Step 1 Rev Req * Line 20	Step 1 Rev Req * Line 20	Step 1 Rev Req * Line 20	Sum (Col 2 - Col 7)

Inter Class Revenue Increase Allocations

Calculation of Increase Limits

line #		(in $1,000)		Notes:
1	Requested Revenue Increase to be recovered from rate schedule charges =	$ 535,064		Schedule SS-RC2023-2
2	Present Distribution Revenue =	$ 1,275,060		Page 4, col 3, line 21
3	Present Total Customer Bills (all on BGS) =	$ 7,204,705		Page 4, col 5, line 21
4	Average Distribution Increase =	41.964%		= Line 1 / Line 2
5	Average Total Bill Increase =	7.427%		= Line 1 / Line 3
6	Lower Distribution increase limit =	20.982%	in Distribution charges	= 0.5 * Line 4
7	Upper Distribution increase limit #1 =	52.455%	in Distribution charges	= 1.25 * Line 4
8	Upper Bill increase limit #2 =	11.141%	in Bill Increase	= 1.5 * Line 5

all rounded to 0.001%

Inter Class Revenue Increase Calculations
Calculation of Increases

line #	(1) Rate Schedule	(2) Proposed Distribution Revenue Requirement (from COS) (in $1,000)	(3) Present Distribution Revenue (in $1,000)	(4) Unlimited COS Distribution Charge $ Increase (in $1,000)	(5) Present Total Bill Revenue (all on BGS) (in $1,000)	(6) Unlimited Distribution Charge Increase (%)	(7) Limited Final Distribution Charge Increase (%)	(8) Proposed Total Bill Increase (%)	(9) Proposed Distribution Revenue Increase (in $1,000)
1	RS	$ 1,027,558	$ 639,437	$ 388,121	$ 2,756,183	60.697%	48.021%	11.141%	$ 307,066
2	RHS	$ 4,292	$ 3,050	$ 1,242	$ 14,008	40.721%	51.144%	11.136%	$ 1,560
3	RLM	$ 7,877	$ 7,121	$ 756	$ 50,147	10.619%	20.982%	2.979%	$ 1,494
4	WH *	$ 107.124	$ 27.653	$ 79.471	$ 80.458	287.385%	32.412%	11.140%	$ 8.963
5	WHS *	$ 2.013	$ 0.084	$ 1.929	$ 0.760	2295.883%	52.455%	5.789%	$ 0.044
6	HS	$ 859	$ 516	$ 343	$ 2,079	66.433%	44.753%	11.112%	$ 231
7	BPL	$ 63,173	$ 57,290		$ 83,771				
8	Distribution Only	$ 2,760	$ 1,967	$ 793		40.339%	16.289%	0.382%	$ 320
9	Luminaires and Poles	$ 60,413	$ 55,323	$ 5,090		9.200%	10.000%	0.000%	$ 5,532
10	BPL-POF *	$ 459.684	$ 360.066		$ 1,696.137				
11	Distribution Only	$ 110.580	$ 101.566	$ 9.014		8.875%	20.982%	1.256%	$ 21.311
12	Luminaires and Poles	$ 349.105	$ 258.500	$ 90.605		35.050%	20.607%	0.000%	$ 53.270
13	PSAL	$ 22,106	$ 27,583		$ 40,491				
14	Distribution Only	$ 2,767	$ 991	$ 1,776		179.189%	16.354%	0.400%	$ 162
15	Luminaires and Poles	$ 19,340	$ 26,592	$ (7,253)		-27.273%	10.000%	0.000%	$ 2,659
16	GLP	$ 341,669	$ 253,096	$ 88,572	$ 1,371,556	34.995%	52.455%	9.680%	$ 132,762
17	LPL-S	$ 241,928	$ 213,634	$ 28,294	$ 1,654,103	13.244%	21.373%	2.760%	$ 45,660
18	LPL-P	$ 51,999	$ 38,640	$ 13,359	$ 491,981	34.574%	52.455%	4.120%	$ 20,268
19	HTS-S	$ 47,979	$ 31,989	$ 15,990	$ 680,749	49.986%	52.455%	2.465%	$ 16,780
20	HTS-HV	$ 116	$ 2,317	$ (2,201)	$ 57,858	-95.009%	20.982%	0.840%	$ 486
21	Total	$ 1,810,124	$ 1,275,060	$ 535,064	$ 7,204,705	41.964%	41.964%	7.427%	$ 535,064

* WH, WHS and & BPL-POF shown to 3 decimal points

Notes:		Page 2, Step 2, col 8		= (2) - (3)	Page 6	= (4) / (3)	calculated on limits	= (9) / (5)	= (3) * (7)

Inter Class Revenue Increase Calculations
Calculation of Increases

line #	Rate Schedule (1)	Proposed Distribution Revenue Increase (in $1,000) (2)	Proposed TAC Change (in $1,000) (3)	Proposed DAC - SRC (in $1,000) (4)	Net Distribution Revenue Increase (in $1,000) (5)	Net Total Bill Increase (%) (6)
1	RS	$ 307,066	$ (63,483)	$ 13,029	$ 256,612	9.3%
2	RHS	$ 1,560	$ (567)	$ 72	$ 1,065	7.6%
3	RLM	$ 1,494	$ (795)	$ 170	$ 869	1.7%
4	WH *	$ 8.963	$ -	$ 0.539	$ 9.502	11.8%
5	WHS *	$ 0.044	$ -	$ 0.007	$ 0.051	6.7%
6	HS	$ 231	$ 13	$ 10	$ 254	12.2%
7	BPL	$ -	$ -	$ -	$ -	
8	Distribution Only	$ 320	$ -	$ 243	$ 563	
9	Luminaires and Poles	$ 5,532	$ -	$ -	$ 5,532	
10	BPL-POF *	$ -	$ -	$ -	$ -	0.0%
11	Distribution Only	$ 21.311	$ 6.587	$ 13.601	$ 41.500	
12	Luminaires and Poles	$ 53.270	$ -	$ -	$ 53.270	
13	PSAL	$ -	$ -	$ -	$ -	0.0%
14	Distribution Only	$ 162	$ -	$ 106	$ 268	
15	Luminaires and Poles	$ 2,659	$ -	$ -	$ 2,659	
16	GLP	$ 132,762	$ (10,460)	$ 6,729	$ 129,031	9.4%
17	LPL-S	$ 45,660	$ (9,177)	$ 9,750	$ 46,233	2.8%
18	LPL-P	$ 20,268	$ (1,519)	$ 2,805	$ 21,554	4.4%
19	HTS-S	$ 16,780	$ (2,219)	$ 4,931	$ 19,492	2.9%
20	HTS-HV	$ 486	$ (100)	$ 652	$ 1,039	1.8%
21	Total	$ 535,064	$ (88,299)	$ 38,511	$ 485,276	6.7%
Notes:		Page 2, Col 9	SS-TAC-6E row 18	SS-SRC-3E, col 3	= (2) + (3) + (4)	= Col 4 / Page 2 Col 5

* WH, WHS and & BPL-POF shown to 3 decimal points

Service Charge Calculations

Service charges are comprised of revenue requirements for the Distribution Access and Measurement segments related to Minimum Size Facilities, plus the Revenue Requirements for the Customer Service segment.

line #	(1) Rate Schedule	(2) Access Segment Revenue Requirement	(3) Measurement Segment Revenue Requirement	(4) Customer Service Segment Revenue Requirements	(5) Rev Req to be recovered through Service Charge	(6) # of Customers	(7) Cost Based Monthly Service Charge ($/month)	(8) Current Monthly Service Charge ($/month)	(9) Proposed Limited Monthly Service Charge ($/month)	
1	Average Distribution Increase =		41.964%	page 3, Line 4						
2	RS	$ 35,640,936	$ 142,058,947	$ 92,884,750	$ 270,584,633	1,981,089	$ 11.38	$ 4.64	$ 7.56	see Note 2
3	RHS	$ 194,265	$ 434,432	$ 300,243	$ 928,940	6,404	$ 12.09	$ 4.64	$ 7.56	set equal to RS
4	RLM	$ 339,685	$ 759,631	$ 524,993	$ 1,624,309	11,197	$ 12.09	$ 13.07	$ 13.07	see Note 2
5	WH	no service charge								
6	WHS	$ 31	$ 1,694	$ 166	$ 1,890	11	$ 14.65	$ 0.64	$ 1.04	see Note 2
7	HS	$ -	$ 41,365	$ 10,945	$ 52,310	714	$ 6.10	$ 3.83	$ 6.10	see Note 2
8	BPL	no service charge								
9	BPL-POF	no service charge								
10	PSAL	no service charge								
11	GLP	$ 17,257,388	$ 28,044,012	$ 20,215,180		272,921				
12	GLP Metered					256,116	$ 20.57	$ 4.88	$ 7.95	see Note 3
13	GLP Unmetered					5,766	$ 11.44	$ 2.24	$ 3.65	see Note 4
14	GLP-NU					64			$ 7.95	see Note 3
15	LPL-S	$ 1,280,483	$ 10,305,228	$ 7,635,239	$ 19,220,949	9,379	$ 170.78	$ 347.77	$ 347.77	see Note 2
16	LPL-P	$ 106,690	$ 947,221	$ 636,169	$ 1,690,080	770	$ 182.93	$ 347.77	$ 347.77	see Note 2
17	LPL-P <100 kW						$ 113.96	$ 22.04	$ 35.91	see Note 5
18	HTS-S	$ 59,022	$ 432,909	$ 156,501	$ 648,432	189	$ 285.29	$ 1,911.39	$ 1,911.39	see Note 2
19	HTS-HV	$ -	$ 91,700	$ 13,483	$ 105,182	16	$ 537.17	$ 1,720.25	$ 1,720.25	see Note 2
Source:		for Cols 2, 3 and 4 from Page 2, Cols 3, 6 & 7 from Step 2			= (2) + (3) + (4)	2018 Rate Case SS-E8 R-2, Step 2, Col 1	= (5) / (6) / 12	From Tariff	based on methodology described	

Notes:
1 Agreed upon in Settlement
2 Move toward cost limited at no decrease from current service charge and no increase greater than 1.5 times the overall average distribution % increase.
3 Access and Customer Service Rev Req per total GLP Customer plus Measurement Rev Req divided by the number of metered customers divided by 12; limits the same as Note 2
4 Access and Customer Service Rev Req per total GLP Customer divided by 12; limits the same as Note 2
5 Calculated at the GLP Access Segment per customer plus the GLP Customer Service Segment Revenue Requirements per customer plus the LPL-P Measurement Segment per customer divided by 12; limits the same as Note 2

<u>Electric Proof of Revenue by Rate Schedule</u>
<u>Explanation of Format</u>
The summary and each rate schedule provide the details of 1) a) Actual and b) Weather Normalized and also 2) a) Annualized Weather Normalized (all customers assumed to be on BGS and revenue based on current tariff rates) and b) the proposed rate design.

<u>1) Actual and Weather Normalized</u>
All the components are separated into Delivery and Supply. In addition to the Distribution components of Delivery, also included in the schedule are lines for Societal Benefits Charge, Non-Utility Generation Charge, Zero Emission Certificate Recovery Charge, Solar Pilot Recovery Charge, Green Programs Recovery Charge, Conservation Incentive Program, Tax Adjustment Credit, CIEP Standby Fee (as applicable), Facilities Charges, Miscellaneous items, Minimums, and Unbilled Revenue. The first column shows the actual billing units for the test year from Schedule SS-E2. The second column shows annual average rates (without Sales and Use Tax, SUT) occurring during the test period. The third column presents annualized revenue for the test period. The fourth column shows the weather normalized billing units for the test year from SS-E2. The fifth column shows the applicable rates. Column 6 presents weather normalized revenue. Columns 7 and 8 show the differential revenue, in thousands of dollars and percent increase, respectively, for each of the billing unit blocks.

<u>2) Annualized Weather Normalized (all customers assumed to be on BGS) and the Proposed rate design.</u>
All the components are separated into Delivery and Supply. In addition to the Distribution components of Delivery, also included in the schedule are lines for Societal Benefits Charge, Non-Utility Generation Charge, Securitization Transition Charges, Solar Pilot Recovery Charge, CIEP Standby Fee (as applicable), Green Programs Recovery Charge, Tax Adjustment Credit, Green Enabling Mechanism, Facilities Charges, Miscellaneous items, Minimums, and Unbilled Revenue. The first column shows the annualized weather normalized billing units for the test year from Schedule SS-E2. The second column shows present Delivery rates (without Sales and Use Tax, SUT) effective April 1, 2024. The Supply-BGS rates in the second column reflect the rates in effect April 1, 2024 and for CIEP energy, reflect the latest available 12-month class average hourly rates. The third column presents annualized revenue for the test period assuming all customers are provided service under their applicable BGS provision. The fourth column repeats the billing units of the first column. The fifth column shows the proposed rates that result in the proposed revenues shown in column 6. Columns 7 and 8 show the proposed revenue increase, in thousands of dollars and percent increase, respectively, for each of the billing unit blocks.

WEATHER NORMALIZED
SUMMARY
Rate Case 2023
(kWhrs & Revenue in Thousands)

	Rate Schedule		Actual		Weather Normalized		Difference	
			kWhrs	**Revenue**	**kWhrs**	**Revenue**	**Revenue**	**Percent**
			(1)	(2)	(3)	(4)	(5)	(6)
1	Residential	RS	12,990,481	$2,422,228	13,166,714	$2,445,697	$23,469	0.97
2	Residential Heating	RHS	77,197	11,944	82,189	12,683	739	6.19
3	Residential Load Management	RLM	178,489	31,309	180,730	31,604	295	0.94
4	Water Heating	WH	551	72	551	72	0	0.04
5	Water Heating Storage	WHS	7	0.646	7	0.646	0	0.00
6								
7	Building Heating	HS	10,077	1,589	10,674	1,673	84	5.27
8	General Lighting and Power	GLP	7,264,093	1,003,964	7,325,083	1,010,434	6,470	0.64
9	Large Power & Lighting-Sec	LPL-S	10,133,007	770,494	10,174,460	772,624	2,131	0.28
10	Large Power & Lighting-Pri	LPL-P	3,056,341	143,963	3,056,341	144,046	83	0.06
11	High Tension-Subtr.	HTS-S	4,757,020	172,072	4,757,020	172,106	34	0.02
12	High Tension-HV	HTS-HV	454,332	12,649	454,332	12,673	23	0.18
13								
14	Body Politic Ligting	BPL	283,276	76,878	283,276	76,878	0	0.00
15	Body Politic Ligting-POF	BPL-POF	14,352	1,437	14,352	1,437	0	0.00
16	Private Street & Area Lighting	PSAL	132,104	37,399	132,104	37,804	405	1.08
17								
18								
19	Totals		39,351,326	$4,685,997	39,637,832	$4,719,731	$33,733	0.72
20								
21								
22								
23								
24	Notes:	WHS revenues shown to 3 decimals						

ELECTRIC PROOF OF REVENUE
SUMMARY
ELECTRIC RATE INCREASE
Rate Case 2023
(kWhrs & Revenue in Thousands)

			Annualized Weather Normalized		Proposed		Increase	
	Rate Schedule		**kWhrs**	**Revenue**	**kWhrs**	**Revenue**	**Revenue**	**Percent**
			(1)	(2)	(3)	(4)	(5)	(6)
1	Residential	RS	13,166,714	$2,756,183	13,166,714	$3,063,249	$307,066	11.14
2	Residential Heating	RHS	82,189	14,008	82,189	15,568	1,560	11.14
3	Residential Load Management	RLM	180,730	50,147	180,730	51,641	1,494	2.98
4	Water Heating	WH	551	80.458	551	89.421	8.963	11.14
5	Water Heating Storage	WHS	7	0.760	7	0.804	0.044	5.79
6								
7	Building Heating	HS	10,674	2,079	10,674	2,310	231	11.11
8	General Lighting and Power	GLP	7,325,083	1,371,556	7,325,083	1,504,318	132,762	9.68
9	Large Power & Lighting-Sec	LPL-S	10,174,460	1,654,103	10,174,460	1,699,763	45,660	2.76
10	Large Power & Lighting-Pri	LPL-P	3,056,341	491,981	3,056,341	512,249	20,268	4.12
11	High Tension-Subtr.	HTS-S	4,757,020	680,749	4,757,020	697,529	16,780	2.46
12	High Tension-HV	HTS-HV	454,332	57,858	454,332	58,344	486	0.84
13								
14	Body Politic Lighting	BPL	283,276	83,771	283,276	89,623	5,852	6.99
15	Body Politic Lighting-POF	BPL-POF	14,352	1,696.137	14,352	1,770.718	74.581	4.40
16	Private Street & Area Lighting	PSAL	132,104	40,491	132,104	43,312	2,821	6.97
17								
18								
19	Totals		39,637,832	$7,204,705	39,637,832	$7,739,768	$535,064	7.43
20								
21								
22	Notes:	All customers assumed to be on BGS.						
23		WH, WHS & BPL-POF revenues shown to 3 decimals.						
24		Annualized Weather Normalized Revenue reflects Delivery rates in effect 4/1/2024						

RATE SCHEDULE RS
RESIDENTIAL SERVICE
Rate Case 2023
(Units & Revenue in Thousands)

		Actual			Weather Normalized			Difference	
		Units	**Rate**	**Revenue**	**Units**	**Rate**	**Revenue**	**Revenue**	**Percent**
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Service Charge	23,803.61	4.64	$110,449	23,803.61	4.64	$110,449	0.00	0.00
2	Distribution 0-600 June - September	3,513,703	0.042774	150,294	3,482,326	0.042792	149,017	(1276.71)	(0.85)
3	Distribution 0-600 October - May	5,852,680	0.032983	193,041	6,040,970	0.032969	199,167	6126.38	3.17
4	Distribution over 600 June - September	1,962,907	0.051642	101,369	1,917,408	0.051638	99,010	(2358.81)	(2.33)
5	Distribution over 600 October - May	1,661,191	0.035015	58,167	1,726,010	0.035033	60,467	2300.86	3.96
6	SBC	12,990,481	0.008736	113,488	13,166,714	0.008712	114,705	1217.28	1.07
7	NGC	12,990,481	0.000024	312	13,166,714	0.000024	316	4.23	1.36
8	DAC	12,990,481	0.000000	0	13,166,714	0.000000	0	0.00	0.00
9	STC-MTC-Tax	12,990,481	0.000000	0	13,166,714	0.000000	0	0.00	0.00
10	ZECRC	12,990,481	0.004000	51,964	13,166,714	0.004000	52,669	704.86	1.36
11	Solar Pilot Recovery Charge	12,990,481	0.000063	818	13,166,714	0.000063	830	11.10	1.36
12	Green Programs Recovery Charge	12,990,481	0.004920	63,913	13,166,714	0.004920	64,780	867.07	1.36
13	Tax Adjustment Credit	12,990,481	(0.004784)	(62,144)	13,166,714	(0.004794)	(63,117)	(973.22)	1.57
14	ECIP	12,990,481	0.000238	3,095	13,166,714	0.000234	3,081	(13.85)	(0.45)
15	Green Enabling Mechanism	12,990,481	0.000000	0	13,166,714	0.000000	0	0.00	0.00
16	Facilities Chg.			0			0	0.00	0.00
17	Minimum			0			0	0.00	0.00
18	Miscellaneous			(1,335)			(1,356)	(21.82)	1.63
19	Delivery Subtotal	12,990,481		$783,431	13,166,714		$790,018	6587.36	0.84
20	Unbilled Delivery			6,837			5,413	(1424.10)	(20.83)
21	Delivery Subtotal w unbilled			$790,268			$795,432	5163.26	0.65
22									
23	**Supply-BGS**								
24	BGS 0-600 June - September	3,361,440	0.254801	$856,498	3,331,905	0.260436	$867,747	$11,250	1.31
25	BGS 0-600 October - May	5,612,889	0.000000	0	5,793,410	0.000000	0	0	0.00
26	BGS over 600 June - September	1,894,417	0.095209	180,366	1,850,958	0.097864	181,141	775	0.43
27	BGS over 600 October - May	1,572,305	0.000000	0	1,634,036	0.000000	0	0	0.00
28	Transmission	12,441,050	0.048949	$608,976	12,610,309	0.049076	$618,861	$9,885	1.62
29	BGS Reconciliation-RSCP	12,441,050	(0.001732)	(21,548)	12,610,309	(0.001734)	(21,864)	(316)	1.47
30	Miscellaneous			(1)			(1)	(0)	4.16
31	Supply subtotal	12,441,050		$1,624,291	12,610,309		$1,645,885	$21,594	1.33
32	Unbilled Supply			7,669			4,381	(3,288)	(42.88)
33	Supply subtotal w unbilled			$1,631,959			$1,650,265	$18,306	1.12
34									
35	Total Delivery + Supply	12,990,481		$2,422,228	13,166,714		$2,445,697	$23,469	0.97
36									
37	Notes:	Rates are annual averages derived from actual, excluding SUT.							

Filing "9 and 3"

RATE SCHEDULE RS
RESIDENTIAL SERVICE
Rate Case 2023
(Units & Revenue in Thousands)

		Annualized Weather Normalized			Proposed			Difference	
		Units	**Rate**	**Revenue**	**Units**	**Rate**	**Revenue**	**Revenue**	**Percent**
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Service Charge	23,803.61	$4.64	$110,449	23,803.61	$7.56	$179,955	$69,506	62.93
2	Distribution 0-600 June - September	3,482,326	0.048092	167,472	3,482,326	0.075946	264,469	96,997	57.92
3	Distribution 0-600 October - May	6,040,970	0.033344	201,430	6,040,970	0.044297	267,597	66,167	32.85
4	Distribution over 600 June - September	1,917,408	0.051913	99,538	1,917,408	0.079767	152,946	53,408	53.66
5	Distribution over 600 October - May	1,726,010	0.033344	57,552	1,726,010	0.044297	76,457	18,905	32.85
6	SBC	13,166,714	0.008451	111,272	13,166,714	0.008451	111,272	0	0.00
7	NGC	13,166,714	0.000024	316	13,166,714	0.000024	316	0	0.00
8	DAC	13,166,714	0.000000	0	13,166,714	0.000000	0	0	0.00
9	STC-MTC-Tax	13,166,714	0.000000	0	13,166,714	0.000000	0	0	0.00
10	ZECRC	13,166,714	0.004000	52,667	13,166,714	0.004000	52,667	0	0.00
11	Solar Pilot Recovery Charge	13,166,714	0.000057	751	13,166,714	0.000057	751	0	0.00
12	Green Programs Recovery Charge	13,166,714	0.004920	64,780	13,166,714	0.004920	64,780	0	0.00
13	Tax Adjustment Credit	13,166,714	(0.001853)	(24,398)	13,166,714	(0.001853)	(24,398)	0	0.00
14	ECIP	13,166,714	0.000271	3,568	13,166,714	0.000271	3,568	0	0.00
15	Green Enabling Mechanism	13,166,714	0.000000	0	13,166,714	0.000000	0	0	0.00
16	Facilities Chg.			0			0	0	0.00
17	Minimum			0			0	0	0.00
18	Miscellaneous			(1,356)			(1,363)	(7)	0.52
19	Delivery Subtotal	13,166,714		$844,041	13,166,714		$1,149,017	$304,976	36.13
20	Unbilled Delivery			5,784			7,874	2,090	36.13
21	Delivery Subtotal w unbilled			$849,825			$1,156,891	$307,066	36.13
22									
23	**Supply-BGS**								
24	BGS 0-600 June - September	3,482,326	0.084582	$294,542	3,482,326	0.084582	$294,542	$0	0.00
25	BGS 0-600 October - May	6,040,970	0.087604	529,213	6,040,970	0.087604	529,213	0	0.00
26	BGS over 600 June - September	1,917,408	0.093518	179,312	1,917,408	0.093518	179,312	0	0.00
27	BGS over 600 October - May	1,726,010	0.087604	151,205	1,726,010	0.087604	151,205	0	0.00
28	Transmission	13,166,714	0.056736	$747,027	13,166,714	0.056736	$747,027	0	0.00
29	BGS Reconciliation-RSCP	13,166,714	0.000000	0	13,166,714	0.000000	0	0	0.00
30	Miscellaneous			(1)			(1)	0	0.00
31	Supply Subtotal	13,166,714		$1,901,298	13,166,714		$1,901,298	$0	0.00
32	Unbilled Supply			5,060			5,060	0	0.00
33	Supply Subtotal w unbilled			$1,906,358			$1,906,358	$0	0.00
34									
35	Total Delivery + Supply	13,166,714		$2,756,183	13,166,714		$3,063,249	$307,066	11.14
36									
37	Notes:	All customers assumed to be on BGS.							
38		Annualized Weather Normalized Revenue reflects Delivery rates in effect 4/1/2024							

RATE SCHEDULE RHS
RESIDENTIAL HEATING SERVICE
Rate Case 2023
(Units & Revenue in Thousands)

		Actual			Weather Normalized			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Service Charge	76.30	4.64	$354	76.30	4.64	$354	0.00	0.00
2	Distribution 0-600 June - September	12,556	0.051150	642	12,463	0.051178	638	(4.37)	(0.68)
3	Distribution 0-600 October - May	26,958	0.036192	976	29,202	0.036297	1,060	84.27	8.64
4	Distribution over 600 June - September	6,003	0.061082	367	5,914	0.061104	361	(5.30)	(1.44)
5	Distribution over 600 October - May	31,681	0.018118	574	34,610	0.018128	627	53.44	9.31
6	SBC	77,197	0.008412	649	82,189	0.008369	688	38.41	5.91
7	NGC	77,197	0.000024	2	82,189	0.000024	2	0.12	6.47
8	DAC	77,197	0.000000	0	82,189	0.000000	0	0.00	0.00
9	STC-MTC-Tax	77,197	0.000000	0	82,189	0.000000	0	0.00	0.00
10	ZECRC	77,197	0.004000	309	82,189	0.004000	329	19.97	6.47
11	Solar Pilot Recovery Charge	77,197	0.000063	5	82,189	0.000063	5	0.31	6.47
12	Green Programs Recovery Charge	77,197	0.004920	380	82,189	0.004920	404	24.56	6.47
13	Tax Adjustment Credit	77,197	(0.005784)	(447)	82,189	(0.005836)	(480)	(33.12)	7.42
14	ECIP	77,197	0.000246	19	82,189	0.000245	20	1.16	6.11
15	Green Enabling Mechanism	77,197	0.000000	0	82,189	0.000000	0	0.00	0.00
16	Facilities Chg.			0			0	0.00	0.00
17	Minimum			0			0	0.00	0.00
18	Miscellaneous			(7)			(8)	(0.36)	4.84
19	Delivery Subtotal	77,197		$3,822	82,189		$4,001	179.10	4.69
20	Unbilled Delivery			34			42	7.15	20.74
21	Delivery Subtotal w unbilled			$3,857			$4,043	186.25	4.83
22									
23	**Supply-BGS**								
24	BGS 0-600 June - September	11,163	0.305087	$3,406	11,087	0.324231	$3,595	$189	5.55
25	BGS 0-600 October - May	23,782	0.000000	0	25,657	0.000000	0	0	0.00
26	BGS over 600 June - September	6,501	0.365288	2,375	6,414	0.396834	2,545	171	7.19
27	BGS over 600 October - May	32,351	0.000000	0	35,450	0.000000	0	0	0.00
28	Transmission	73,796	0.033750	$2,491	78,608	0.034068	$2,678	$187	7.52
29	BGS Reconciliation-RSCP	73,796	(0.002253)	(166)	78,608	(0.002364)	(186)	(20)	11.78
30	Miscellaneous			0			0	0	0.00
31	Supply subtotal	73,796		$8,105	78,608		$8,632	$528	6.51
32	Unbilled Supply			(18)			8	25	(143.82)
33	Supply subtotal w unbilled			$8,087			$8,640	$553	6.84
34									
35	Total Delivery + Supply	77,197		$11,944	82,189		$12,683	$739	6.19
36									
37									
38									
39									
40	Notes:	Rates are annual averages derived from actual, excluding SUT.							

RATE SCHEDULE RHS
RESIDENTIAL HEATING SERVICE
Rate Case 2023
(Units & Revenue in Thousands)

		Annualized Weather Normalized			Proposed			Difference	
		Units	**Rate**	**Revenue**	**Units**	**Rate**	**Revenue**	**Revenue**	**Percent**
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Service Charge	76.30	$4.64	$354	76.30	$7.56	$577	$223	62.99
2	Distribution 0-600 June - September	12,463	0.054209	676	12,463	0.088917	1,108	432	63.91
3	Distribution 0-600 October - May	29,202	0.035336	1,032	29,202	0.046057	1,345	313	30.33
4	Distribution over 600 June - September	5,914	0.059109	350	5,914	0.093817	555	205	58.57
5	Distribution over 600 October - May	34,610	0.017736	614	34,610	0.028457	985	371	60.42
6	SBC	82,189	0.008451	695	82,189	0.008451	695	0	0.00
7	NGC	82,189	0.000024	2	82,189	0.000024	2	0	0.00
8	DAC	82,189	0.000000	-	82,189	0.000000	0	0	0.00
9	STC-MTC-Tax	82,189	0.000000	-	82,189	0.000000	0	0	0.00
10	ZECRC	82,189	0.004000	329	82,189	0.004000	329	0	0.00
11	Solar Pilot Recovery Charge	82,189	0.000057	5	82,189	0.000057	5	0	0.00
12	Green Programs Recovery Charge	82,189	0.004920	404	82,189	0.004920	404	0	0.00
13	Tax Adjustment Credit	82,189	(0.002623)	(216)	82,189	(0.002623)	(216)	0	0.00
14	ECIP	82,189	0.000271	22	82,189	0.000271	22	0	0.00
15	Green Enabling Mechanism	82,189	0.000000	-	82,189	0.000000	0	0	0.00
16	Facilities Chg.			-			0	0	0.00
17	Minimum			-			0	0	0.00
18	Miscellaneous			(8)			(8)	(0)	0.00
19	Delivery Subtotal	82,189		$4,259	82,189		$5,803	$1,544	36.25
20	Unbilled Delivery			44			60	16	36.36
21	Delivery Subtotal w unbilled			$4,303			$5,863	$1,560	36.25
22									
23	**Supply-BGS**								
24	BGS 0-600 June - September	12,463	0.079973	$997	12,463	0.079973	$997	$0	0.00
25	BGS 0-600 October - May	29,202	0.085278	2,490	29,202	0.085278	2,490	0	0.00
26	BGS over 600 June - September	5,914	0.091921	544	5,914	0.091921	544	0	0.00
27	BGS over 600 October - May	34,610	0.085278	2,951	34,610	0.085278	2,951	0	0.00
28	Transmission	82,189	0.033024	2,714	82,189	0.033024	2,714	0	0.00
29	BGS Reconciliation-RSCP	82,189	0.000000	0	82,189	0.000000	0	0	0.00
30	Miscellaneous			0			0	0	0.00
31	Supply Subtotal	82,189		$9,696	82,189		$9,696	$0	0.00
32	Unbilled Supply			9			9	0	0.00
33	Supply Subtotal w unbilled			$9,705			$9,705	$0	0.00
34									
35	Total Delivery + Supply	82,189		$14,008	82,189		$15,568	$1,560	11.14
36									
37									
38	Notes:	All customers assumed to be on BGS.							
39		Annualized Weather Normalized Revenue reflects Delivery rates in effect 4/1/2024							

Filing "9 and 3"

RATE SCHEDULE RLM
RESIDENTIAL LOAD MANAGEMENT SERVICE
Rate Case 2023
(Units & Revenue in Thousands)

		Actual			Weather Normalized			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Service Charge	#REF!	#REF!	$1,783	136.45	13.07	$1,783	0.00	0.00
2	Distribution June - September On Peak	37,352	0.074552	2,785	36,917	0.074557	2,752	(32.29)	(1.16)
3	Distribution June - September Off Peak	40,882	0.016820	688	40,467	0.016820	681	(6.98)	(1.02)
4	Distribution October - May On Peak	42,858	0.015257	654	44,164	0.015253	674	19.78	3.03
5	Distribution October - May Off Peak	57,397	0.016942	972	59,183	0.016965	1,004	31.62	3.25
6	SBC	178,489	0.008767	1,565	180,730	0.008746	1,581	15.89	1.02
7	NGC	178,489	0.000024	4	180,730	0.000024	4	0.05	1.26
8	DAC	178,489	0.000000	0	180,730	0.000000	0	0.00	0.00
9	STC-MTC-Tax	178,489	0.000000	0	180,730	0.000000	0	0.00	0.00
10	ZECRC	178,489	0.004000	714	180,730	0.004000	723	8.97	1.26
11	Solar Pilot Recovery Charge	178,489	0.000063	11	180,730	0.000063	11	0.14	1.26
12	Green Programs Recovery Charge	178,489	0.004920	878	180,730	0.004920	889	11.03	1.26
13	Tax Adjustment Credit	178,489	(0.004416)	(788)	180,730	(0.004424)	-799	(11.20)	1.42
14	ECIP	178,489	0.000927	165	180,730	0.000924	167	1.53	0.93
15	Green Enabling Mechanism	178,489	0.000000	0	180,730	0.000000	0	0.00	0.00
16	Facilities Chg.			0			0	0.00	0.00
17	Minimum			0			0	0.00	0.00
18	Miscellaneous			(36)			-36	(0.67)	1.89
19	Delivery Subtotal	178,489		$9,396	180,730		$9,434	37.87	0.40
20	Unbilled Delivery			67			72	4.77	7.09
21	Delivery Subtotal w unbilled			$9,463			$9,506	42.65	0.45
22									
23	**Supply-BGS**								
24	BGS Sum On	35,282	0.119800	$4,227	34,909	0.119844	$4,184	($43)	(1.02)
25	BGS Sum Off	40,422	0.213323	8,623	41,613	0.213325	8,877	254	2.95
26	BGS Win On	38,709	0.035102	1,359	38,361	0.035085	1,346	(13)	(0.94)
27	BGS Win Off	54,254	0.063675	3,455	55,896	0.063673	3,559	104	3.02
28	Transmission	168,666	0.025401	$4,284	170,780	0.024819	$4,239	($46)	(1.07)
29	BGS Reconciliation-RSCP	168,666	(0.001657)	(279)	170,780	(0.001670)	(285)	(6)	2.03
30	Miscellaneous			98			94	(5)	(4.80)
31	Supply subtotal	168,666		$21,766	170,780		$22,013	$247	1.13
32	Unbilled Supply			79			85	6	7.34
33	Supply subtotal w unbilled			$21,846			$22,098	$252	1.16
34									
35	Total Delivery + Supply	178,489		$31,309	180,730		$31,604	$295	0.94
36									
37									
38									
39									
40	Notes:	Rates are annual averages derived from actual, excluding SUT.							

RATE SCHEDULE RLM
RESIDENTIAL LOAD MANAGEMENT SERVICE
Rate Case 2023
(Units & Revenue in Thousands)

		Annualized Weather Normalized			Proposed			Difference	
		Units	**Rate**	**Revenue**	**Units**	**Rate**	**Revenue**	**Revenue**	**Percent**
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Service Charge	136.45	13.07	$1,783	136.45	13.07	$1,783	$0	0.00
2	Distribution June - September On Peak	36,917	0.079439	2,933	36,917	0.108651	4,011	1078	36.75
3	Distribution June - September Off Peak	40,467	0.016586	671	40,467	0.019407	785	114	16.99
4	Distribution October - May On Peak	44,164	0.016586	733	44,164	0.019407	857	124	16.92
5	Distribution October - May Off Peak	59,183	0.016586	982	59,183	0.019407	1,149	167	17.01
6	SBC	180,730	0.008451	1,527	180,730	0.008451	1,527	0	0.00
7	NGC	180,730	0.000024	4	180,730	0.000024	4	0	0.00
8	DAC	180,730	0.000000	0	180,730	0.000000	0	0	0.00
9	STC-MTC-Tax	180,730	0.000000	0	180,730	0.000000	0	0	0.00
10	ZECRC	180,730	0.004000	723	180,730	0.004000	723	0	0.00
11	Solar Pilot Recovery Charge	180,730	0.000057	10	180,730	0.000057	10	0	0.00
12	Green Programs Recovery Charge	180,730	0.004920	889	180,730	0.004920	889	0	0.00
13	Tax Adjustment Credit	180,730	(0.001739)	(314)	180,730	(0.001739)	(314)	0	0.00
14	ECIP	180,730	0.000965	174	180,730	0.000965	174	0	0.00
15	Green Enabling Mechanism	180,730	0.000000	0	180,730	0.000000	0	0	0.00
16	Facilities Chg.			0			0	0	0.00
17	Minimum			0			0	0	0.00
18	Miscellaneous			(36)			(36)	(0)	0.00
19	Delivery Subtotal	180,730		$10,079	180,730		$11,562	$1,483	14.71
20	Unbilled Delivery			77			88	11	14.29
21	Delivery Subtotal w unbilled			$10,156			$11,650	$1,494	14.71
22									
23	**Supply-BGS**								
24	BGS June - September On Peak	36,917	0.110253	$4,070	36,917	0.110253	$4,070	$0	0.00
25	BGS June - September Off Peak	40,467	0.069723	2,821	40,467	0.069723	2,821	0	0.00
26	BGS October - May On Peak	44,164	0.103087	4,553	44,164	0.103087	4,553	0	0.00
27	BGS October - May Off Peak	59,183	0.076053	4,501	59,183	0.076053	4,501	0	0.00
28	Transmission - On Peak	180,730	0.131681	23,799	180,730	0.131681	23,799	0	0.00
29	BGS Reconciliation-RSCP	180,730	0.000000	0	180,730	0.000000	0	0	0.00
30	Miscellaneous			94			94	0	0.00
31	Supply Subtotal	180,730		$39,838	180,730		$39,838	$0	0.00
32	Unbilled Supply			154			154	0	0.00
33	Supply Subtotal w unbilled			$39,992			$39,992	$0	0.00
34									
35	Total Delivery + Supply	180,730		$50,147	180,730		$51,641	$1,494	2.98
36									
37									
38	Notes:	All customers assumed to be on BGS.							
39		Annualized Weather Normalized Revenue reflects Delivery rates in effect 4/1/2024							

RATE SCHEDULE WH
WATER HEATING SERVICE
Rate Case 2023
(Units & Revenue in Thousands)

			Actual			Weather Normalized		Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Distribution Sum	156.788	0.048948	$8	156.793	0.048948	$8	0.00	0.00
2	Distribution Win	394	0.049605	19.533	394	0.049605	19.559	0.03	0.13
3	SBC	551	0.008523	4.693	551	0.008523	4.697	0.00	0.09
4	NGC	551	0.000024	0.013	551	0.000024	0.013	0.00	0.10
5	DAC	551	0.000000	0.000	551	0.000000	0.000	0.00	0.00
6	STC-MTC-Tax	551	0.000000	0.000	551	0.000000	0.000	0.00	0.00
7	ZECRC	551	0.004005	2.205	551	0.004005	2.207	0.00	0.10
8	Solar Pilot Recovery Charge	551	0.000063	0.035	551	0.000063	0.035	0.00	0.10
9	Green Programs Recovery Charge	551	0.004920	2.709	551	0.004920	2.711	0.00	0.10
10	Tax Adjustment Credit	551	(0.000008)	-0.004	551	(0.000008)	-0.004	0.00	0.00
11	Green Enabling Mechanism	551	0.000000	0	551	0.000000	0	0.00	0.00
12	Facilities Chg.			0			0	0.00	0.00
13	Minimum			0			0	0.00	0.00
14	Miscellaneous			0			0	0.00	0.00
15	Delivery Subtotal	551		$37	551		$37	0.04	0.10
16	Unbilled Delivery			0			0	0.00	0.00
17	Delivery Subtotal w unbilled			$37			$37	0.04	0.10
18									
19	**Supply-BGS**								
20	BGS Summer	155	0.065477	$10	155	0.065477	$10	0.00	0.00
21	BGS Winter	383	0.067479	26	383	0.067478	26	0	0.13
22	BGS Reconciliation-RSCP	537	(0.002154)	(1)	538	(0.002157)	(1)	0	0.24
23	Miscellaneous			0			0	0	0.00
24	Supply subtotal	537		$35	538		$35	$0	0.09
25	Unbilled Supply			-0.127			-0.165	-0.04	29.85
26	Supply subtotal w unbilled			$35			$35	$0	-0.02
27									
28	Total Delivery + Supply	551		$72	551		$72	$0	0.04
29									
30									
31									
32	Notes:	Rates are annual averages derived from actual, excluding SUT.							

RATE SCHEDULE WH
WATER HEATING SERVICE
Rate Case 2023
(Units & Revenue in Thousands)

		Annualized Weather Normalized			Proposed			Difference	
		Units	**Rate**	**Revenue**	**Units**	**Rate**	**Revenue**	**Revenue**	**Percent**
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Distribution Sum	156.793	0.050179	$7.868	156.793	0.066443	$10.418	$2.550	32.41
2	Distribution Win	394	0.050179	$19.785	394	0.066443	$26.198	$6.413	32.41
3	SBC	551	0.008451	$4.657	551	0.008451	$4.657	$0.000	0.00
4	NGC	551	0.000024	$0.013	551	0.000024	$0.013	$0.000	0.00
5	DAC	551	0.000000	$0.000	551	0.000000	$0.000	$0.000	0.00
6	STC-MTC-Tax	551	0.000000	$0.000	551	0.000000	$0.000	$0.000	0.00
7	ZECRC	551	0.004000	$2.204	551	0.004000	$2.204	$0.000	0.00
8	Solar Pilot Recovery Charge	551	0.000057	$0.031	551	0.000057	$0.031	$0.000	0.00
9	Green Programs Recovery Charge	551	0.004920	$2.711	551	0.004920	$2.711	$0.000	0.00
10	Tax Adjustment Credit	551	0.000000	$0.000	551	0.000000	$0.000	$0.000	0.00
11	Green Enabling Mechanism	551	0.000000	$0.000	551	0.000000	$0.000	$0.000	0.00
12	Facilities Chg.			$0.000			$0.000	$0.000	0.00
13	Minimum			$0.000			$0.000	$0.000	0.00
14	Miscellaneous			$0.000			$0.000	$0.000	0.00
15	Delivery Subtotal	551		$37.269	551		$46.232	$8.963	24.05
16	Unbilled Delivery			$0.000			$0.000	$0.000	0.00
17	Delivery Subtotal w unbilled			$37.269			$46.232	$8.963	24.05
18									
19	**Supply-BGS**								
20	BGS Summer	157	0.077338	$12.126	157	0.077338	$12.126	$0.000	0.00
21	BGS Winter	394	0.078780	$31.063	394	0.078780	$31.063	$0.000	0.00
22	BGS Reconciliation-RSCP	551	0.000000	$0.000	551	0.000000	$0.000	$0.000	0.00
23	Miscellaneous			$0.000			$0.000	$0.000	0.00
24	Supply Subtotal	551		$43.189	551		$43.189	$0.000	0.00
25	Unbilled Supply			$0.000			$0.000	$0.000	0.00
26	Supply Subtotal w unbilled			$43.189			$43.189	$0.000	0.00
27									
28	Total Delivery + Supply	551		$80.458	551		$89.421	$8.963	11.14

32 Notes: All customers assumed to be on BGS.
33 WH, WHS & BPL-POF revenues shown to 3 decimals.
34 Annualized Weather Normalized Revenue reflects Delivery rates in effect 4/1/2024

RATE SCHEDULE WHS
WATER HEATING STORAGE SERVICE
Rate Case 2023
(Units & Revenue in Thousands)

		Actual			Weather Normalized			Difference	
		Units	**Rate**	**Revenue**	**Units**	**Rate**	**Revenue**	**Revenue**	**Percent**
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Service Charge	0.110	0.62	$0.069	0.110	0.62	$0.069	0.00	0.00
2	Distribution June - September	1.895	0.001760	0.003	1.895	0.001760	0.003	0.00	0.00
3	Distribution October - May	5.030	0.001998	0.010	5.030	0.001998	0.010	0.00	0.00
4	SBC	6.925	0.008556	0.059	6.925	0.008556	0.059	0.00	0.00
5	NGC	6.925	0.000024	0.000	6.925	0.000024	0.000	0.00	0.00
6	DAC	6.925	0.000000	0.000	6.925	0.000000	0.000	0.00	0.00
7	STC-MTC-Tax	6.925	0.000000	0.000	6.925	0.000000	0.000	0.00	0.00
8	ZECRC	6.925	0.004004	0.028	6.925	0.004004	0.028	0.00	0.00
9	Solar Pilot Recovery Charge	6.925	0.000063	0.000	6.925	0.000063	0.000	0.00	0.00
10	Green Programs Recovery Charge	6.925	0.004920	0.034	6.925	0.004920	0.034	0.00	0.00
11	Tax Adjustment Credit	6.925	0.000000	0.000	6.925	0.000000	0.000	0.00	0.00
12	Green Enabling Mechanism	6.925	0.000000	0.000	6.925	0.000000	0.000	0.00	0.00
13	Facilities Chg.			0.000			0.000	0.00	0.00
14	Minimum			0.000			0.000	0.00	0.00
15	Miscellaneous			0.000			0.000	0.00	0.00
16	Delivery Subtotal	6.925		$0.204	7		$0.204	0.00	0.00
17	Unbilled Delivery			0.000			0.000	0.00	0.00
18	Delivery Subtotal w unbilled			$0.204			$0.204	0.00	0.00
19									
20	**Supply-BGS**								
21	BGS- June - September	1.895	0.065652	$0.124	1.895	0.065652	$0.124	$0.000	0.00
22	BGS- October - May	5.030	0.066355	0.334	5.030	0.066355	0.334	0.000	0.00
23	BGS Reconciliation-RSCP	6.925	(0.002137)	(0.015)	6.925	(0.002137)	(0.015)	0.000	0.00
24	Miscellaneous			0.000			0.000	0.000	0.00
25	Supply subtotal	6.925		0.443	6.925		0.443	$0.000	0.00
26	Unbilled Supply			(0.001)			(0.001)	0.000	0.00
27	Supply subtotal w unbilled			$0.442			$0.442	$0.000	0.00
28									
29	Total Delivery + Supply	6.925		$0.646	6.925		$0.646	$0.000	0.00
30									
31									
32									
33	Notes:	Rates are annual averages derived from actual, excluding SUT.							
34		WHS revenues shown to 3 decimals							

RATE SCHEDULE WHS
WATER HEATING STORAGE SERVICE
Rate Case 2023
(Units & Revenue in Thousands)

	Annualized Weather Normalized			Proposed			Difference	
	Units	**Rate**	**Revenue**	**Units**	**Rate**	**Revenue**	**Revenue**	**Percent**
Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
Service Charge	0.110	0.64	$0.070	0.110	1.04	$0.114	$0.044	62.86
Distribution June - September	1.895	0.001988	0.004	1.895	0.002022	0.004	0.000	0.00
Distribution October - May	5.030	0.001988	0.010	5.030	0.002022	0.010	0.000	0.00
SBC	6.925	0.008451	0.059	6.925	0.008451	0.059	0.000	0.00
NGC	6.925	0.000024	0.000	6.925	0.000024	0.000	0.000	0.00
DAC	6.925	0.000000	0.000	6.925	0.000000	0.000	0.000	0.00
STC-MTC-Tax	6.925	0.000000	0.000	6.925	0.000000	0.000	0.000	0.00
ZECRC	6.925	0.004000	0.028	6.925	0.004000	0.028	0.000	0.00
Solar Pilot Recovery Charge	6.925	0.000057	0.000	6.925	0.000057	0.000	0.000	0.00
Green Programs Recovery Charge	6.925	0.004920	0.034	6.925	0.004920	0.034	0.000	0.00
Tax Adjustment Credit	6.925	0.000000	0.000	6.925	0.000000	0.000	0.000	0.00
Green Enabling Mechanism	6.925	0.000000	0.000	6.925	0.000000	0.000	0.000	0.00
Facilities Chg.			0.000			0.000	0.000	0.00
Minimum			0.000			0.000	0.000	0.00
Miscellaneous			0.000			0.000	0.000	0.00
Delivery Subtotal	7		$0.205	7		$0.249	$0.044	21.46
Unbilled Delivery			0.000			0.000	0.000	0.00
Delivery Subtotal w unbilled			$0.205			$0.249	$0.044	21.46
Supply-BGS								
BGS- June - September	1.895	0.079453	$0.151	1.895	0.079453	$0.151	$0.000	0.00
BGS- October - May	5.030	0.080785	0.406	5.030	0.080785	0.406	0.000	0.00
BGS Reconciliation-RSCP	6.925	0.000000	0.000	6.925	0.000000	0.000	0.000	0.00
Miscellaneous			0.000			0.000	0.000	0.00
Supply Subtotal	6.925		0.557	6.925		0.557	$0.000	0.00
Unbilled Supply			(0.002)			(0.002)	0.000	0.00
Supply Subtotal w unbilled			$0.555			$0.555	$0.000	0.00
Total Delivery + Supply	6.925		$0.760	6.925		$0.804	$0.044	5.79

Notes: All customers assumed to be on BGS.
WH, WHS & BPL-POF revenues shown to 3 decimals.
Annualized Weather Normalized Revenue reflects Delivery rates in effect 4/1/2024

Filing "9 and 3"

RATE SCHEDULE HS
BUILDING HEATING SERVICE
Rate Case 2023
(Units & Revenue in Thousands)

		Actual			Weather Normalized			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Service Charge	8.561	3.73	$32	8.561	3.73	$32	0.00	0.00
2	Distribution June - September	2,416	0.099356	240.053	2,394	0.099545	238.263	(1.79)	(0.75)
3	Distribution October - May	7,661	0.028996	222.129	8,280	0.029008	240.192	18.06	8.13
4	SBC	10,077	0.008429	84.938	10,674	0.008389	89.540	4.60	5.42
5	NGC	10,077	0.000024	0.242	10,674	0.000024	0.256	0.01	5.92
6	DAC	10,077	0.000000	0.000	10,674	0.000000	0.000	0.00	0.00
7	STC-MTC-Tax	10,077	0.000000	0.000	10,674	0.000000	0.000	0.00	0.00
8	ZECRC	10,077	0.004000	40.307	10,674	0.004000	42.695	2.39	5.92
9	Solar Pilot Recovery Charge	10,077	0.000063	0.635	10,674	0.000063	0.672	0.04	5.92
10	Green Programs Recovery Charge	10,077	0.004920	49.578	10,674	0.004920	52.515	2.94	5.92
11	Tax Adjustment Credit	10,077	(0.003078)	-31.020	10,674	(0.003115)	-33.250	(2.23)	7.19
12	Green Enabling Mechanism	10,077	0.000000	0	10,674	0.000000	0	0.00	0.00
13	Facilities Chg.			0			0	0.00	0.00
14	Minimum			0			0	0.00	0.00
15	Miscellaneous			-1			-1	(0.08)	10.10
16	Delivery Subtotal	10,077		$638	10,674		$662	23.94	3.75
17	Unbilled Delivery			2			2	0.03	1.63
18	Delivery Subtotal w unbilled			$640			$664	23.97	3.75
19									
20	**Supply-BGS**								
21	BGS- June - September	1,944	0.074996	$146	1,931	0.075001	$145	-$1	(0.68)
22	BGS- October - May	5,858	0.075079	440	6,344	0.074951	475	36	8.10
23	Transmission	7,803	0.048878	$381	8,274	0.048927	$405	$23	6.15
24	BGS Reconciliation-RSCP	7,803	(0.002042)	(16)	8,274	(0.002162)	(18)	(2)	12.26
25	BGS Miscellaneous			-0.290			-0.325	-0.04	12.29
26	Supply subtotal	7,803		$951	8,274		$1,007	$56	5.90
27	Unbilled Supply			(2)			2	4	(232.53)
28	Supply subtotal w unbilled			$949			$1,009	$60	6.30
29									
30	Total Delivery + Supply	10,077		$1,589	10,674		$1,673	$84	5.27
31									
32									
33									
34									
35									
36									
37	Notes:	Rates are annual averages derived from actual, excluding SUT.							

RATE SCHEDULE HS
BUILDING HEATING SERVICE
Rate Case 2023
(Units & Revenue in Thousands)

		Annualized Weather Normalized			Proposed			Difference	
		Units	**Rate**	**Revenue**	**Units**	**Rate**	**Revenue**	**Revenue**	**Percent**
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Service Charge	8.561	3.83	$33	8.561	6.10	$52	$19	57.58
2	Distribution June - September	2,394	0.098587	236	2,394	0.103613	248	12	5.09
3	Distribution October - May	8,280	0.029662	246	8,280	0.053742	445	199	80.89
4	SBC	10,674	0.008451	90	10,674	0.008451	90	0	0.00
5	NGC	10,674	0.000024	0	10,674	0.000024	0	0	0.00
6	DAC	10,674	0.000000	0	10,674	0.000000	0	0	0.00
7	STC-MTC-Tax	10,674	0.000000	0	10,674	0.000000	0	0	0.00
8	ZECRC	10,674	0.004000	43	10,674	0.004000	43	0	0.00
9	Solar Pilot Recovery Charge	10,674	0.000057	1	10,674	0.000057	1	0	0.00
10	Green Programs Recovery Charge	10,674	0.004920	53	10,674	0.004920	53	0	0.00
11	Tax Adjustment Credit	10,674	(0.001234)	-13	10,674	(0.001234)	-13	0	0.00
12	Green Enabling Mechanism	10,674	0.000000	0	10,674	0.000000	0	0	0.00
13	Facilities Chg.			0			0	0	0.00
14	Minimum			0			0	0	0.00
15	Miscellaneous			(1)			(1)	0	0.00
16	Delivery Subtotal	10,674		$688	10,674		$918	$230	33.42
17	Unbilled Delivery			2			3	1	50.00
18	Delivery Subtotal w unbilled			$690			$921	$231	33.47
19									
20	**Supply-BGS**								
21	BGS- June - September	2,394	0.086900	$208	2,394	0.086900	$208	$0	0.00
22	BGS- October - May	8,280	0.087123	721	8,280	0.087123	721	0	0.00
23	Transmission	10,674	0.042815	457	10,674	0.042815	457	0	0.00
24	BGS Reconciliation-RSCP	10,674	0.000000	0	10,674	0.000000	0	0	0.00
25	Miscellaneous			0			0	0	0.00
26	Supply Subtotal	10,674		$1,386	10,674		$1,386	$0	0.00
27	Unbilled Supply			3			3	0	0.00
28	Supply Subtotal w unbilled			$1,389			$1,389	$0	0.00
29									
30	Total Delivery + Supply	10,674		$2,079	10,674		$2,310	$231	11.11
31									
32									
33									
34	Notes:	All customers assumed to be on BGS.							
35		Annualized Weather Normalized Revenue reflects Delivery rates in effect 4/1/2024							
36									
37									
38									
39									

RATE SCHEDULE GLP
GENERAL LIGHTING AND POWER SERVICE
Rate Case 2023
(Units & Revenue in Thousands)

		Actual			Weather Normalized			Difference	
		Units	**Rate**	**Revenue**	**Units**	**Rate**	**Revenue**	**Revenue**	**Percent**
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Service Charge	3,268.523	4.78	$15,612	3,268.523	4.78	$15,612	0.00	0.00
2	Service Charge-unmetered	106.550	1.83	234	106.550	1.83	234	0.00	0.00
3	Service Charge-Night Use	0.406	347.77	141	0.406	347.77	141	0.00	0.00
4	Distrib. KW Annual	26,560	3.7296	99,060	26,770	3.7559	100,545	1485.81	1.50
5	Distrib. KW June - September	9,699	9.4171	91,338	9,664	9.4171	91,011	(326.58)	(0.36)
6	Distribution kWhr, June-September	2,603,595	0.002983	7,767	2,594,772	0.002969	7,704	(62.63)	(0.81)
7	Distribution kWhr, October-May	4,647,412	0.007806	36,277	4,717,230	0.007801	36,799	522.00	1.44
8	Distribution kWhr, Night use, June-September	4,798	0.005559	27	4,776	0.005532	26	(0.25)	(0.95)
9	Distribution kWhr, Night use, October-May	8,289	0.007744	64	8,305	0.007739	64	0.08	0.13
10	SBC	7,264,093	0.008630	62,689	7,325,083	0.008602	63,010	320.91	0.51
11	NGC	7,264,093	0.000024	174	7,325,083	0.000024	175	1.12	0.64
12	DAC	7,264,093	0.000000	0	7,325,083	0.000000	0	0.00	0.00
13	STC-MTC-Tax	7,264,093	0.000000	0	7,325,083	0.000000	0	0.00	0.00
14	ZECRC	7,264,093	0.003995	29,022	7,325,083	0.003987	29,208	185.72	0.64
15	Solar Pilot Recovery Charge	7,264,093	0.000063	458	7,325,083	0.000063	461	2.93	0.64
16	Green Programs Recovery Charge	7,264,093	0.004920	35,739	7,325,083	0.004910	35,969	229.16	0.64
17	Tax Adjustment Credit	7,264,093	(0.001434)	-10,418	7,325,083	(0.001433)	-10,494	(75.19)	0.72
18	ECIP	26,560	1.198947	31,845	26,770	1.193758	31,957	112.68	0.35
19	Green Enabling Mechanism	7,264,093	0.000000	0	7,325,083	0.000000	0	0.00	0.00
20	Duplicate Svc (Same Sub/Different Sub)		$2.22/$3.20	1		$2.22/$3.20	2	0.00	0.03
21	Facilities Chg.		1.45%	44.37		1.45%	45	0.40	0.91
22	Minimum			28.31			29	0	0.85
23	Distrib. Miscellaneous			-1688.01			(1,701)	(13)	0.79
24	Delivery Subtotal	7,264,093		$398,414	7,325,083		$400,797	$2,383	0.60
25	Unbilled Delivery			248			(542)	(790)	(318.64)
26	Delivery Subtotal w unbilled			$398,662			$400,255	$1,593	0.40

RATE SCHEDULE GLP
GENERAL LIGHTING AND POWER SERVICE
Rate Case 2023
(Units & Revenue in Thousands)

		Actual			Weather Normalized			Difference	
		Units	**Rate**	**Revenue**	**Units**	**Rate**	**Revenue**	**Revenue**	**Percent**
	Supply-BGS	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Generation Capacity Obl June-September	6,834	1.8023	$12,316	6,788	1.8071	$12,267	-$49	(0.40)
2	Generation Capacity Obl October-May	13,358	1.6324	21,806	13,511	1.6324	22,055	249	1.14
3	Transmission Capacity Obl	18,263	12.3738	225,985	18,357	12.3740	227,145	1,160	0.51
4	BGS kWhr June - September not night use	1,892,199	0.066990	126,759	1,877,715	0.066951	125,715	(1,044)	(0.82)
5	BGS kWhr October - May not night use	3,383,499	0.067439	228,179	3,423,883	0.067441	230,911	2,731	1.20
6	BGS kWhr June - September night use	3,358	0.062255	209	3,327	0.062238	207	(2)	(0.96)
7	BGS kWhr October - May night use	6,036	0.063418	383	6,043	0.063418	383	0	0.11
8	BGS Reconciliation-RSCP	5,285,093	(0.001864)	(9,854)	5,310,968	(0.001876)	(9,962)	(109)	1.10
9	BGS Miscellaneous			(138)			(139)	(1)	0.58
10	Supply subtotal	5,285,093		$605,646	5,310,968		$608,582	2,936	0.48
11	Unbilled Supply			(345)			1,596	1,941	(563.38)
12	Supply Subtotal w Unbilled			$605,302			$610,179	4,877	0.81
13									
14	Total Delivery + Supply	7,264,093		$1,003,964	7,325,083		$1,010,434	$6,470	0.64
15									
16									
17									
18									
19	Notes:	Rates are annual averages derived from actual, excluding SUT.							

RATE SCHEDULE GLP
GENERAL LIGHTING AND POWER SERVICE
Rate Case 2023
(Units & Revenue in Thousands)

		Annualized Weather Normalized			Proposed			Difference	
		Units	**Rate**	**Revenue**	**Units**	**Rate**	**Revenue**	**Revenue**	**Percent**
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Service Charge	3,268.523	4.88	$15,950	3,268.523	7.95	$25,985	$10,035	62.92
2	Service Charge-unmetered	106.550	2.24	239	106.550	3.65	389	150	62.76
3	Service Charge-Night Use	0.406	347.77	141	0.406	7.95	3	-138	-97.87
4	Distrib. KW Annual	26,770	3.7897	101,451	26,770	4.9787	133,281	31,830	31.37
5	Distrib. KW Summer	9,664	9.5030	91,842	9,664	16.8755	163,093	71,251	77.58
6	Distribution kWhr, June-September	2,594,772	0.003098	8,039	2,594,772	0.017846	46,305	38,266	476.00
7	Distribution kWhr, October-May	4,717,230	0.007907	37,299	4,717,230	0.004006	18,898	(18,401)	-49.33
8	Distribution kWhr, Night use, June-September	4,776	0.007907	38	4,776	0.004006	19	(19)	-50.00
9	Distribution kWhr, Night use, October-May	8,305	0.007907	66	8,305	0.004006	33	(33)	-50.00
10	SBC	7,325,083	0.008451	61,904	7,325,083	0.008451	61,904	0	0.00
11	NGC	7,325,083	0.000024	176	7,325,083	0.000024	176	0	0.00
12	DAC	7,325,083	0.000000	0	7,325,083	0.000000	0	0	0.00
13	STC-MTC-Tax	7,325,083	0.000000	0	7,325,083	0.000000	0	0	0.00
14	ZECRC	7,325,083	0.004000	29,300	7,325,083	0.004000	29,300	0	0.00
15	Solar Pilot Recovery Charge	7,325,083	0.000057	418	7,325,083	0.000057	418	0	0.00
16	Green Programs Recovery Charge	7,325,083	0.004920	36,039	7,325,083	0.004920	36,039	0	0.00
17	Tax Adjustment Credit	7,325,083	(0.000614)	-4,498	7,325,083	(0.000614)	-4,498	0	0.00
18	ECIP	26,770	1.2193	32,641	26,770	1.2193	32,641	0	0.00
19	Green Enabling Mechanism	7,325,083	0.000000	0	7,325,083	0.000000	0	0	0.00
20	Duplicate Svc (Same Sub/Different Sub)		$2.22/$3.20	2		$2.22/$3.20	2	0	0.00
21	Facilities Chg.		1.45%	45		1.45%	45	0	0.00
22	Minimum			29			29	0	0.00
23	Distrib. Miscellaneous			(1,701)			(1,700)	1	-0.06
24	Delivery Subtotal	7,325,083		$409,418	7,325,083		$542,360	$132,942	32.47
25	Unbilled Delivery			(554)			(734)	(180)	32.49
26	Delivery Subtotal w unbilled			$408,864			$541,626	$132,762	32.47

RATE SCHEDULE GLP
GENERAL LIGHTING AND POWER SERVICE
Rate Case 2023
(Units & Revenue in Thousands)

		Annualized Weather Normalized			Proposed			Difference	
		Units	**Rate**	**Revenue**	**Units**	**Rate**	**Revenue**	**Revenue**	**Percent**
	Supply-BGS	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Generation Capacity Obl June-September	9,011	1.5312	$13,798	9,011	1.5312	$13,798	$0	0.00
2	Generation Capacity Obl October-May	17,949	1.5312	27,483	17,949	1.5312	27,483	0	0.00
3	Transmission Capacity Obl	24,200	13.7104	331,792	24,200	13.7104	331,792	0	0.00
4	BGS kWhr June - September not night use	2,594,772	0.080282	208,313	2,594,772	0.080282	208,313	0	0.00
5	BGS kWhr October - May not night use	4,717,230	0.080124	377,963	4,717,230	0.080124	377,963	0	0.00
6	BGS kWhr June - September night use	4,776	0.069554	332	4,776	0.069554	332	0	0.00
7	BGS kWhr October - May night use	8,305	0.075812	630	8,305	0.075812	630	0	0.00
8	BGS Reconciliation-RSCP	7,325,083	0.000000	0	7,325,083	0.000000	0	0	0.00
9	BGS Miscellaneous			(138)			(138)	0	0.00
10	Supply Subtotal	7,325,083		$960,173	7,325,083		$960,173	$0	0.00
11	Unbilled Supply			2,519			2,519	0	0.00
12	Supply Subtotal w unbilled			$962,692			$962,692	$0	0.00
13									
14	Total Delivery + Supply	7,325,083		$1,371,556	7,325,083		$1,504,318	$132,762	9.68
15									
16									
17									
18									
19	Notes:	All customers assumed to be on BGS.							
20		Annualized Weather Normalized Revenue reflects Delivery rates in effect 4/1/2024							

RATE SCHEDULE LPL-Sec
LARGE POWER & LIGHTING SERVICE-SECONDARY
Rate Case 2023
(Units & Revenue in Thousands)

		Actual			Weather Normalized			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Service Charge	115.127	347.77	$40,038	115.127	347.77	$40,038	0.00	0.00
2	Distrib. KW Annual	25,725	3.6921	94,980	25,830	3.6907	95,330	350.34	0.37
3	Distrib. KW June - September	9,262	8.3224	77,083	9,215	8.3208	76,676	(407.54)	(0.53)
4	Distribution kWhr On Peak June-September	1,745,921	0.000000	0	1,736,207	0.000000	0	0.00	0.00
5	Distribution kWhr Off Peak June-September	1,882,832	0.000000	0	1,872,573	0.000000	0	0.00	0.00
6	Distribution kWhr On Peak October-May	3,148,853	0.000000	0	3,177,651	0.000000	0	0.00	0.00
7	Distribution kWhr Off Peak October-May	3,355,401	0.000000	0	3,388,028	0.000000	0	0.00	0.00
8	SBC	10,133,007	0.008624	87,391	10,174,460	0.008618	87,684	293.16	0.34
9	NGC	10,133,007	0.000024	243	10,174,460	0.000024	244	0.99	0.41
10	DAC	10,133,007	0.000000	0	10,174,460	0.000000	0	0.00	0.00
11	STC-MTC-Tax	10,133,007	0.000000	0	10,174,460	0.000000	0	0.00	0.00
12	ZECRC	10,133,007	0.003998	40,516	10,174,460	0.003998	40,681	165.53	0.41
13	Solar Pilot Recovery Charge	10,133,007	0.000063	638	10,174,460	0.000063	641	2.61	0.41
14	CIEP Standby Fee	248,480	0.000150	37	249,497	0.000150	38	0.15	0.41
15	Green Programs Recovery Charge	10,133,007	0.004920	49,854	10,174,460	0.004920	50,058	203.95	0.41
16	Tax Adjustment Credit	10,133,007	(0.000837)	(8,477)	10,174,460	(0.000837)	(8,518)	(40.48)	0.48
17	ECIP	25,725	1.008153	25,935	25,830	1.007562	26,025	90.29	0.35
18	Green Enabling Mechanism	10,133,007	0.000000	0	10,174,460	0.000000	0	0.00	0.00
19	Duplicate Svc (Same Sub/Different Sub)		$2.22/$3.20	99		$2.22/$3.20	99	0.56	0.57
20	Facilities Chg.		1.45%	191		1.45%	192	0.99	0.52
21	Minimum			0			0	0.00	0.00
22	Dist. Miscellaneous			(2,041)			(2,048)	(7)	0.36
23	Delivery Subtotal	10,133,007		$406,487	10,174,460		$407,140	653	0.16
24	Unbilled Delivery			2125			1754	(371)	(17.47)
25	Delivery Subtotal w unbilled			$408,612			$408,894	$282	0.07
26									
27									
28									
29									
30									
31									

Filing "9 and 3"

RATE SCHEDULE LPL-Sec
LARGE POWER & LIGHTING SERVICE-SECONDARY
Rate Case 2023
(Units & Revenue in Thousands)

EXHIBIT P-9E R-1
Schedule SS-E11 R-1

		Actual			Weather Normalized			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
		(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
	Supply-BGS								
	0-499								
1	Generation Capacity Obl - June-September	2,776	1.988400	$5,520	2,770	1.995100	$5,527	$7	0.12
2	Generation Capacity Obl - October-May	5,233	1.553900	8,131	5,277	1.554800	8,205	74	0.91
3	Transmission Capacity Obl	6,985	12.647800	88,342	7,017	12.646700	88,744	402	0.45
4	BGS kWhr June-September On Peak	995,323	0.039112	38,929	986,692	0.039273	38,751	(178)	(0.46)
5	BGS kWhr June-September Off Peak	570,003	0.063299	36,080	567,722	0.063276	35,923	(157)	(0.44)
6	BGS kWhr October-May On Peak	1,992,507	0.031725	63,213	2,010,333	0.031741	63,809	596	0.94
7	BGS kWhr October-May Off Peak	1,046,536	0.061745	64,619	1,055,976	0.061760	65,217	599	0.93
8	**500+**								
9	Generation Capacity Obl - June-September	561	9.797600	5,501	560	9.787800	5,483	(17)	(0.32)
10	Generation Capacity Obl - October-May	1,183	6.943600	8,216	1,192	6.967900	8,307	92	1.12
11	Transmission Capacity Obl	1,535	12.248300	18,796	1,541	12.247300	18,879	83	0.44
12	BGS kWhr June-September On Peak	258,582	0.025452	6,581	257,776	0.025411	6,550	(31)	(0.47)
13	Spare	0	0.000000	0	0	0.000000	0	0	0.00
14	BGS kWhr October-May On Peak	460,290	0.042775	19,689	463,914	0.042691	19,805	116	0.59
15	Spare	0	0.000000	0	0	0.000000	0	0	0.00
16									
17	BGS Reconciliation-RSCP	4,604,369	(0.001191)	(5,486)	4,620,722	(0.001196)	(5,524)	(39)	0.70
18	BGS Reconciliation-CIEP	718,872	0.001147	825	721,690	0.001120	809	(16)	(1.94)
19	BGS Miscellaneous	0		3,266	0		3,283	17	0.53
20	Supply subtotal	5,323,241		$362,222	5,342,412		$363,769	1547	0.43
21	Unbilled Supply			(341)			(39)	302	(88.56)
22	Supply w Unbilled			$361,881			$363,730	1,849	0.51
23									
24	Total Delivery + Supply	10,133,007		$770,494	10,174,460		$772,624	$2,131	0.28
25									
26									
27									
28	Notes:	Rates are annual averages derived from actual, excluding SUT.							

RATE SCHEDULE LPL-Sec
LARGE POWER & LIGHTING SERVICE-SECONDARY
Rate Case 2023
(Units & Revenue in Thousands)

		Annualized Weather Normalized			Proposed			Difference	
		Units	**Rate**	**Revenue**	**Units**	**Rate**	**Revenue**	**Revenue**	**Percent**
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Service Charge	115.127	347.77	$40,038	115.127	347.77	$40,038	$0	0.00
2	Distrib. KW Annual	25,830	3.6529	94,354	25,830	3.8181	98,621	4,267	4.52
3	Distrib. KW June - September	9,215	8.6904	80,082	9,215	13.1611	121,279	41,197	51.44
4	Distribution kWhr On Peak June-September	1,736,207	0.000000	0	1,736,207	0.000000	0	0	0.00
5	Distribution kWhr Off Peak June-September	1,872,573	0.000000	0	1,872,573	0.000000	0	0	0.00
6	Distribution kWhr On Peak October-May	3,177,651	0.000000	0	3,177,651	0.000000	0	0	0.00
7	Distribution kWhr Off Peak October-May	3,388,028	0.000000	0	3,388,028	0.000000	0	0	0.00
8	SBC	10,174,460	0.008451	85,984	10,174,460	0.008451	85,984	0	0.00
9	NGC	10,174,460	0.000024	244	10,174,460	0.000024	244	0	0.00
10	DAC	10,174,460	0.000000	0	10,174,460	0.000000	0	0	0.00
11	STC-MTC-Tax	10,174,460	0.000000	0	10,174,460	0.000000	0	0	0.00
12	ZECRC	10,174,460	0.004000	40,698	10,174,460	0.004000	40,698	0	0.00
13	Solar Pilot Recovery Charge	10,174,460	0.000057	580	10,174,460	0.000057	580	0	0.00
14	CIEP Standby Fee	249,497	0.000150	37	249,497	0.000150	37	0	0.00
15	Green Programs Recovery Charge	10,174,460	0.004920	50,058	10,174,460	0.004920	50,058	0	0.00
16	Tax Adjustment Credit	10,174,460	(0.000347)	-3,531	10,174,460	(0.000347)	-3,531	0	0.00
17	ECIP	25,830	1.029000	26,579	25,830	1.029000	26,579	0	0.00
17	Green Enabling Mechanism	10,174,460	0.000000	0	10,174,460	0.000000	0	0	0.00
18	Duplicate Svc (Same Sub/Different Sub)		$2.22/$3.20	99		$2.22/$3.20	99	0	0.00
19	Facilities Chg.		1.45%	192		1.45%	192	0	0.00
20	Minimum			0			0	0	0.00
21	Dist. Miscellaneous			(2,048)			(2,048)	(0)	0.00
22	Delivery Subtotal	10,174,460		$413,366	10,174,460		$458,830	$45,464	11.00
23	Unbilled Delivery			1,781			1,977	196	11.01
24	Delivery Subtotal w unbilled			$415,147			$460,807	$45,660	11.00

Filing "9 and 3"

EXHIBIT P-9E R-1
Schedule SS-E11 R-1

RATE SCHEDULE LPL-Sec
LARGE POWER & LIGHTING SERVICE-SECONDARY
Rate Case 2023
(Units & Revenue in Thousands)

		Annualized Weather Normalized			Proposed			Difference	
		Units	**Rate**	**Revenue**	**Units**	**Rate**	**Revenue**	**Revenue**	**Percent**
	Supply-BGS	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
	0-499								
1	Generation Capacity Obl - June-September	5,965	1.5312	$9,134	5,965	1.5312	$9,134	$0	0.00
2	Generation Capacity Obl - October-May	11,928	1.5312	18,264	11,928	1.5312	18,264	0	0.00
3	Transmission Capacity Obl	15,599	13.7104	213,873	15,599	13.7104	213,873	0	0.00
4	BGS kWhr June-September On Peak	1,226,041	0.089479	109,705	1,226,041	0.089479	109,705	0	0.00
5	BGS kWhr June-September Off Peak	1,322,338	0.069554	91,974	1,322,338	0.069554	91,974	0	0.00
6	BGS kWhr October-May On Peak	2,243,934	0.083608	187,611	2,243,934	0.083608	187,611	0	0.00
7	BGS kWhr October-May Off Peak	2,392,494	0.075812	181,380	2,392,494	0.075812	181,380	0	0.00
8	**500+**								
9	Generation Capacity Obl - June-September	2,453	11.5118	28,242	2,453	11.5118	28,242	0	0.00
10	Generation Capacity Obl - October-May	4,992	11.5118	57,467	4,992	11.5118	57,467	0	0.00
11	Transmission Capacity Obl	6,655	13.7104	91,243	6,655	13.7104	91,243	0	0.00
12	BGS kWhr June-September	1,060,400	0.094382	100,083	1,060,400	0.094382	100,083	0	0.00
13	Spare	0	0.094382	0	0	0.094382	0	0	0.00
14	BGS kWhr October-May	1,929,253	0.076107	146,830	1,929,253	0.076107	146,830	0	0.00
15	Spare	0	0.076107	0	0	0.076107	0	0	0.00
16									
17	BGS Reconciliation-RSCP	7,184,807	0.000000	0	7,184,807	0.000000	0	0	0.00
18	BGS Reconciliation-CIEP	2,989,653	0.000000	0	2,989,653	0.000000	0	0	0.00
19	BGS Miscellaneous			3,283			3,283	0	0.00
20	Supply Subtotal	10,174,460		$1,239,089	10,174,460		$1,239,089	$0	0.00
21	Unbilled Supply			(133)			(133)	0	0.00
22	Supply Subtotal w unbilled			$1,238,956			$1,238,956	$0	0.00
23									
24	Total Delivery + Supply	10,174,460		$1,654,103	10,174,460		$1,699,763	$45,660	2.76
25									
26									
27									
28									

29 Notes: All customers assumed to be on BGS.
30 Annualized Weather Normalized Revenue reflects Delivery rates in effect 4/1/2024

Filing "9 and 3"

RATE SCHEDULE LPL-Pri
LARGE POWER & LIGHTING SERVICE-PRIMARY
Rate Case 2023
(Units & Revenue in Thousands)

		Actual			Weather Normalized			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Service Charge	9.202	347.80	$3,201	9.202	347.80	$3,201	0.00	0.00
2	Service Charge-Alternate	0.193	38.14	7	0.193	38.14	7	0.00	0.00
3	Distrib. KW Annual	6,861	2.4507	16814	6,861	2.4507	16814	0.00	0.00
4	Distrib. KW June - September	2,463	7.3024	17983	2,463	7.3024	17983	0.00	0.00
5	Distribution kWhr On Peak June-September	501,564	0.000000	0	501,564	0.000000	0	0.00	0.00
6	Distribution kWhr Off Peak June-September	611,774	0.000000	0	611,774	0.000000	0	0.00	0.00
7	Distribution kWhr On Peak October-May	889,783	0.000000	0	889,783	0.000000	0	0.00	0.00
8	Distribution kWhr Off Peak October-May	1,053,220	0.000000	0	1,053,220	0.000000	0	0.00	0.00
9	SBC	3,056,341	0.008471	25891	3,056,341	0.008471	25891	0.00	0.00
10	NGC	3,056,341	0.000024	73	3,056,341	0.000024	73	0.00	0.00
11	DAC	3,056,341	0.000000	0	3,056,341	0.000000	0	0.00	0.00
12	STC-MTC-Tax	3,056,341	0.000000	0	3,056,341	0.000000	0	0.00	0.00
13	ZECRC	3,056,341	0.004000	12224	3,056,341	0.004000	12224	0.00	0.00
14	Solar Pilot Recovery Charge	3,056,341	0.000063	193	3,056,341	0.000063	193	0.00	0.00
15	CIEP Standby Fee	3,056,341	0.000000	0	3,056,341	0.000000	0	0.00	0.00
16	Green Programs Recovery Charge	3,056,341	0.004920	15037	3,056,341	0.004920	15037	0.00	0.00
17	Tax Adjustment Credit	3,056,341	(0.000534)	(1631)	3,056,341	(0.000534)	(1631)	0.00	0.00
18	Green Enabling Mechanism	3,056,341	0.000000	0	3,056,341	0.000000	0	0.00	0.00
19	Duplicate Svc (Same Sub/Different Sub)		$2.22/$3.20	434		$2.22/$3.20	434	0.00	0.00
20	Facilities Chg.		1.45%	324		1.45%	324	0.00	0.00
21	Minimum			0			0	0	0.00
22	Dist. Miscellaneous			(324)			(320)	5	(1.40)
23	Delivery Subtotal	3,056,341		$90,226	3,056,341		$90,230	$5	0.01
24	Unbilled Delivery			(172)			(172)	0	0.00
25	Delivery Subtotal w unbilled			$90,053			$90,058	$5	0.01
26									
27									
28									
29									
30									
31									

RATE SCHEDULE LPL-Pri
LARGE POWER & LIGHTING SERVICE-PRIMARY
Rate Case 2023
(Units & Revenue in Thousands)

		Actual			Weather Normalized			Difference	
		Units	**Rate**	**Revenue**	**Units**	**Rate**	**Revenue**	**Revenue**	**Percent**
		(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
	Supply-BGS								
1	Generation Capacity Obl June-September	485	9.8400	$4,774	485	9.8400	$4,774	$0	0.00
2	Generation Capacity Obl October-May	919	10.1109	9,295	919	10.1109	9,295	0	0.00
3	Transmission Capacity Obl	1,231	12.4765	15,362	1231	12.4765	15,362	0	0.00
4	BGS kWhr June-September On Peak	108,270	0.024750	2,680	108270	0.024750	2,680	0	0.00
5	BGS kWhr June-September Off Peak	131,915	0.000000	3,266	131915	0.000000	3,266	0	0.00
6	BGS kWhr October-May On Peak	193,753	0.031896	6,180	193753	0.031896	6,180	0	0.00
7	BGS kWhr October-May Off Peak	241,852	0.000000	7,725	241852	0.000000	7,725	0	0.00
8	BGS Reconciliation-CIEP	675,790	0.001475	997	675790	0.001475	997	0	0.00
9	BGS Miscellaneous			3,282			3,282	0	0.00
10	Supply subtotal	675,790		$53,560	675,790		$53,560	0	0.00
11	Unbilled Supply			349			428	78	22.46
12	Supply w Unbilled			$53,910			$53,988	78	0.15
13									
14	Total Delivery + Supply	3,056,341		$143,963	3,056,341		$144,046	$83	0.06

Notes: Rates are annual averages derived from actual, excluding SUT.

RATE SCHEDULE LPL-Pri
LARGE POWER & LIGHTING SERVICE-PRIMARY
Rate Case 2023
(Units & Revenue in Thousands)

		Annualized Weather Normalized			Proposed			Difference	
		Units	**Rate**	**Revenue**	**Units**	**Rate**	**Revenue**	**Revenue**	**Percent**
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Service Charge	9.202	347.77	$3,200	9.202	347.77	$3,200	$0	0.00
2	Service Charge-Alternate	0.193	22.04	4	0.193	35.91	7	3	75.00
3	Distrib. KW Annual	6,861	1.7082	11,719	6,861	3.0116	20,662	8,943	76.31
4	Distrib. KW June - September	2,463	9.4827	23,352	2,463	14.0963	34,713	11,361	48.65
5	Distribution kWhr On Peak June-September	501,564	0.000000	0	501,564	0.000000	0	0	0.00
6	Distribution kWhr Off Peak June-September	611,774	0.000000	0	611,774	0.000000	0	0	0.00
7	Distribution kWhr On Peak October-May	889,783	0.000000	0	889,783	0.000000	0	0	0.00
8	Distribution kWhr Off Peak October-May	1,053,220	0.000000	0	1,053,220	0.000000	0	0	0.00
9	SBC	3,056,341	0.008281	25,310	3,056,341	0.008281	25,310	0	0.00
10	NGC	3,056,341	0.000024	73	3,056,341	0.000024	73	0	0.00
11	DAC	3,056,341	0.000000	0	3,056,341	0.000000	0	0	0.00
12	STC-MTC-Tax	3,056,341	0.000000	0	3,056,341	0.000000	0	0	0.00
13	ZECRC	3,056,341	0.004000	12,225	3,056,341	0.004000	12,225	0	0.00
14	Solar Pilot Recovery Charge	3,056,341	0.000057	174	3,056,341	0.000057	174	0	0.00
15	CIEP Standby Fee	3,056,341	0.000150	458	3,056,341	0.000150	458	0	0.00
16	Green Programs Recovery Charge	3,056,341	0.004920	15,037	3,056,341	0.004920	15,037	0	0.00
17	Tax Adjustment Credit	3,056,341	(0.000222)	-679	3,056,341	(0.000222)	-679	0	0.00
18	Green Enabling Mechanism	3,056,341	0.000000	0	3,056,341	0.000000	0	0	0.00
19	Duplicate Svc (Same Sub/Different Sub)		$2.22/$3.20	434		$2.22/$3.20	434	0	0.00
20	Facilities Chg.		1.45%	324		1.45%	324	0	0.00
21	Minimum			0			0	0	0.00
22	Dist. Miscellaneous			(320)			(320)	0	0.00
23	Delivery Subtotal	3,056,341		$91,312	3,056,341		$111,619	$20,307	22.24
24	Unbilled Delivery			(174)			(213)	(39)	22.41
25	Delivery Subtotal w unbilled			$91,138			$111,406	$20,268	22.24

RATE SCHEDULE LPL-Pri
LARGE POWER & LIGHTING SERVICE-PRIMARY
Rate Case 2023
(Units & Revenue in Thousands)

		Annualized Weather Normalized			Proposed			Difference	
		Units	**Rate**	**Revenue**	**Units**	**Rate**	**Revenue**	**Revenue**	**Percent**
		(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
	Supply-BGS								
1	Generation Capacity Obl June-September	2,186	11.5118	$25,163	2,186	11.5118	$25,163	$0	0.00
2	Generation Capacity Obl October-May	4,357	11.5118	50,155	4,357	11.5118	50,155	0	0.00
3	Transmission Capacity Obl	5,785	13.7104	79,312	5,785	13.7104	79,312	0	0.00
4	BGS kWhr June-September On Peak	501,564	0.089014	44,646	501,564	0.089014	44,646	0	0.00
5	BGS kWhr June-September Off Peak	611,774	0.089014	54,456	611,774	0.089014	54,456	0	0.00
6	BGS kWhr October-May On Peak	889,783	0.072390	64,411	889,783	0.072390	64,411	0	0.00
7	BGS kWhr October-May Off Peak	1,053,220	0.072390	76,243	1,053,220	0.072390	76,243	0	0.00
8	BGS Reconciliation-CIEP	3,056,341	0.000000	0	3,056,341	0.000000	0	0	0.00
9	BGS Miscellaneous			3,282			3,282	0	0.00
10	Supply Subtotal	3,056,341		$397,668	3,056,341		$397,668	$0	0.00
11	Unbilled Supply			3,176			3,176	0	0.00
12	Supply Subtotal w unbilled			$400,844			$400,844	$0	0.00
13									
14	Total Delivery + Supply	3,056,341		$491,981	3,056,341		$512,249	$20,268	4.12

Notes: All customers assumed to be on BGS.
Annualized Weather Normalized Revenue reflects Delivery rates in effect 4/1/2024

RATE SCHEDULE HTS-SUBTR.
HIGH TENSION SERVICE-SUBTRANSMISSION
Rate Case 2023
(Units & Revenue in Thousands)

			Actual		Weather Normalized			Difference	
		Units	**Rate**	**Revenue**	**Units**	**Rate**	**Revenue**	**Revenue**	**Percent**
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Service Charge	2.237	1,911.39	$4,276	2.237	1,911.39	$4,276	0.00	0.00
2	Distrib. KW Annual	12,059	1.1483	13,848	12,059	1.1483	13,848	0.00	0.00
3	Distrib. KW June - September	3,246	4.1084	13,335	3,246	4.1084	13,335	0.00	0.00
4	Distribution kWhr On Peak	2,125,645	0.000000	0	2,125,645	0.000000	0	0.00	0.00
5	Spare	0	0.000000	0	0	0.000000	0	0.00	0.00
6	Distribution kWhr Off Peak	2,631,375	0.000000	0	2,631,375	0.000000	0	0.00	0.00
7	Spare	0	0.000000	0	0	0.000000	0	0.00	0.00
8	SBC	4,757,020	0.008386	39,890	4,757,020	0.008386	39,890	0.00	0.00
9	NGC	4,757,020	0.000023	109	4,757,020	0.000023	109	0.00	0.00
10	DAC	4,757,020	0.000000	0	4,757,020	0.000000	0	0.00	0.00
11	STC-MTC-Tax	4,757,020	0.000000	0	4,757,020	0.000000	0	0.00	0.00
12	ZECRC	4,757,020	0.004000	19,028	4,757,020	0.004000	19,028	0.00	0.00
13	Solar Pilot Recovery Charge	4,757,020	0.000063	300	4,757,020	0.000023	109	(190.28)	-63.49
14	CIEP Standby Fee	4,757,020	0.000000	0	4,757,020	0.000000	0	0.00	0.00
15	Green Programs Recovery Charge	4,757,020	0.004920	23,405	4,757,020	0.004920	23,405	0.00	0.00
16	Tax Adjustment Credit	4,757,020	(0.000496)	-2,359	4,757,020	(0.000496)	-2,359	0.00	0.00
17	Green Enabling Mechanism	4,757,020	0.000000	0	4,757,020	0.000000	0	0.00	0.00
18	Duplicate Svc (Same Sub/Different Sub)		$1.83/$2.20	66		$1.83/$2.20	66	0.00	0.00
19	Facilities Chg.		1.45%	194		1.45%	194	0.00	0.00
20	Minimum			0			0	0.00	0.00
21	Dist. Miscellaneous			(265)			(265)	0	0.00
22	Delivery Subtotal	4,757,020		$111,827	4,757,020		$111,637	-$190	-0.17
23	Unbilled Delivery			(1,236)			(1,046)	190	-15.40
24	Delivery Subtotal w unbilled			$110,592			$110,592	$0	0.00
25									
26									
27									
28									
29									
30									

Filing "9 and 3"

RATE SCHEDULE HTS-SUBTR.
HIGH TENSION SERVICE-SUBTRANSMISSION
Rate Case 2023
(Units & Revenue in Thousands)

EXHIBIT P-9E R-1
Schedule SS-E11 R-1

		Actual			Weather Normalized			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
		(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
	Supply-BGS								
1	Generation Capacity Obl June-September	493	9.7165	$4,794	493	9.7165	$4,794	$0	0.00
2	Generation Capacity Obl October-May	926	10.0837	9,340	926	10.0837	9,340	0	0.00
3	Transmission Capacity Obl	1,277	12.2867	15,694	1,277	12.2867	15,694	0	0.00
4	BGS kWhr June-September	304,415	0.023766	7,235	304,415	0.023766	7,235	0	0.00
5	Spare	0	0.000000	0	0	0.000000	0	0	0.00
6	BGS kWhr October-May	561,557	0.032777	18,406	561,557	0.032777	18,406	0	0.00
7	Spare	0	0.000000	0	0	0.000000	0	0	0.00
8	BGS Reconciliation-CIEP	865,972	0.000986	853	865,972	0.000986	853	0	0.00
9	BGS Miscellaneous			3,897			3,897	0	0.00
10	Supply subtotal	865,972		$60,220	865,972		$60,220	$0	0.00
11	Unbilled Supply			1,260			1,295	34	2.72
12	Supply w Unbilled			$61,480			$61,514	$34	0.06
13									
14	Total Delivery + Supply	4,757,020		$172,072	4,757,020		$172,106	$34	0.02
15									
16									
17									
18	Notes:	Rates are annual averages derived from actual, excluding SUT.							

Filing "9 and 3"

RATE SCHEDULE HTS-SUBTR.
HIGH TENSION SERVICE-SUBTRANSMISSION
Rate Case 2023
(Units & Revenue in Thousands)

		Annualized Weather Normalized			Proposed			Difference	
		Units	**Rate**	**Revenue**	**Units**	**Rate**	**Revenue**	**Revenue**	**Percent**
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Service Charge	2.237	1,911.39	$4,276	2.237	1,911.39	$4,276	$0	0.00
2	Distrib. KW Annual	12,059	1.1777	14,202	12,059	1.8897	22,788	8,586	60.46
3	Distrib. KW June - September	3,246	4.2573	13,818	3,246	6.8310	22,172	8,354	60.46
4	Distribution kWhr On Peak	2,125,645	0.000000	0	2,125,645	0.000000	0	0	0.00
5	Spare	0	0.000000	0	0	0.000000	0	0	0.00
6	Distribution kWhr Off Peak	2,631,375	0.000000	0	2,631,375	0.000000	0	0	0.00
7	Spare	0	0.000000	0	0	0.000000	0	0	0.00
8	SBC	4,757,020	0.008199	39,003	4,757,020	0.008199	39,003	0	0.00
9	NGC	4,757,020	0.000023	109	4,757,020	0.000023	109	0	0.00
10	DAC	4,757,020	0.000000	0	4,757,020	0.000000	0	0	0.00
11	STC-MTC-Tax	4,757,020	0.000000	0	4,757,020	0.000000	0	0	0.00
12	ZECRC	4,757,020	0.004000	19,028	4,757,020	0.004000	19,028	0	0.00
13	Solar Pilot Recovery Charge	4,757,020	0.000057	271	4,757,020	0.000057	271	0	0.00
14	CIEP Standby Fee	4,757,020	0.000150	714	4,757,020	0.000150	714	0	0.00
15	Green Programs Recovery Charge	4,757,020	0.004920	23,405	4,757,020	0.004920	23,405	0	0.00
16	Tax Adjustment Credit	4,757,020	(0.000205)	-975	4,757,020	(0.000205)	-975	0	0.00
17	Green Enabling Mechanism	4,757,020	0.000000	0	4,757,020	0.000000	0	0	0.00
18	Duplicate Svc (Same Sub/Different Sub)		$1.83/$2.20	66		$1.83/$2.20	66	0	0.00
19	Facilities Chg.		1.45%	194		1.45%	194	0	0.00
20	Minimum			0			0	0	0.00
21	Dist. Miscellaneous			(265)			(266)	-1	0.38
22	Delivery Subtotal	4,757,020		$113,847	4,757,020		$130,786	$16,939	14.88
23	Unbilled Delivery			(1,066)			(1,225)	(159)	14.92
24	Delivery Subtotal w unbilled			$112,781			$129,561	$16,780	14.88

RATE SCHEDULE HTS-SUBTR.
HIGH TENSION SERVICE-SUBTRANSMISSION
Rate Case 2023
(Units & Revenue in Thousands)

		Annualized Weather Normalized			Proposed			Difference	
		Units	**Rate**	**Revenue**	**Units**	**Rate**	**Revenue**	**Revenue**	**Percent**
	Supply-BGS	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Generation Capacity Obl June-September	2,621	11.5118	$30,171	2,621	11.5118	$30,171	$0	0.00
2	Generation Capacity Obl October-May	5,270	11.5118	60,666	5,270	11.5118	60,666	0	0.00
3	Transmission Capacity Obl	6,985	13.7104	95,770	6,985	13.7104	95,770	0	0.00
4	BGS kWhr June-September On	747,840	0.086107	64,394	747,840	0.086107	64,394	0	0.00
5	BGS kWhr June-September Off	1,377,805	0.086107	118,639	1,377,805	0.086107	118,639	0	0.00
6	BGS kWhr October-May On	911,549	0.069347	63,213	911,549	0.069347	63,213	0	0.00
7	BGS kWhr October-May Off	1,719,826	0.069347	119,265	1,719,826	0.069347	119,265	0	0.00
8	BGS Reconciliation-CIEP	4,757,020	0.000000	0	4,757,020	0.000000	0	0	0.00
9	BGS Miscellaneous			3,897			3,897	0	0.00
10	Supply Subtotal	4,757,020		$556,015	4,757,020		$556,015	$0	0.00
11	Unbilled Supply			11,953			11,953	0	0.00
12	Supply Subtotal w unbilled			$567,968			$567,968	$0	0.00
13									
14	Total Delivery + Supply	4,757,020		$680,749	4,757,020		$697,529	$16,780	2.46
15									
16									
17									
18									
19	Notes:	All customers assumed to be on BGS.							
20		Annualized Weather Normalized Revenue reflects Delivery rates in effect 4/1/2024							

(Units & Revenue in Thousands)

		Actual			Weather Normalized			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Service Charge	0.125	1,720.25	$215	0.125	1,720.25	$215	0.00	0.00
2	Distrib. KW Annual	3,230	0.6676	2,156	3,230	0.6676	2,156	0.00	0.00
3	Distrib. KW June - September	0	0.0000	0	0	0.0000	0	0.00	0.00
4	Distribution kWhr On Peak	202,466	0.000000	0	202,466	0.000000	0	0.00	0.00
5	Spare	0	0.000000	0	0	0.000000	0	0.00	0.00
6	Distribution kWhr Off Peak	251,866	0.000000	0	251,866	0.000000	0	0.00	0.00
7	Spare	0	0.000000	0	0	0.000000	0	0.00	0.00
8	SBC	454,332	0.008165	3,710	454,332	0.008165	3,710	0.00	0.00
9	NGC	454,332	0.000023	10	454,332	0.000023	10	0.00	0.00
10	DAC	454,332	0.000000	0	454,332	0.000000	0	0.00	0.00
11	STC-MTC-Tax	454,332	0.000000	0	454,332	0.000000	0	0.00	0.00
12	ZECRC	454,332	0.004000	1,817	454,332	0.004000	1,817	0.00	0.00
13	Solar Pilot Recovery Charge	454,332	0.000063	29	454,332	0.000023	10	(18.17)	-63.49
14	CIEP Standby Fee	454,332	0.000000	0	454,332	0.000000	0	0.00	0.00
15	Green Programs Recovery Charge	454,332	0.004920	2,235	454,332	0.004920	2,235	0.00	0.00
16	Tax Adjustment Credit	454,332	(0.000178)	-81	454,332	(0.000178)	-81	0.00	0.00
17	Green Enabling Mechanism	454,332	0.000000	0	454,332	0.000000	0	0.00	0.00
18	Facilities Chg.			22			22	0.00	0.00
19	Minimum			0			0	0.00	0.00
20	Dist. Miscellaneous			(109)			(72)	36.95	-33.99
21	Delivery Subtotal	454,332		$10,005	454,332		$10,024	$19	0.19
22	Unbilled Delivery			436			417	-19	-4.31
23	Delivery Subtotal w unbilled			$10,441			$10,441	$0	0.00

RATE SCHEDULE HTS-HV
HIGH TENSION SERVICE-HIGH VOLTAGE
Rate Case 2023
(Units & Revenue in Thousands)

		Actual			Weather Normalized			Difference	
		Units	**Rate**	**Revenue**	**Units**	**Rate**	**Revenue**	**Revenue**	**Percent**
		(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
	Supply-BGS								
1	Generation Capacity Obl June-September	0.956	10.0352	$10	0.956	10.0352	$10	$0	0.00
2	Generation Capacity Obl October-May	4	10.0663	39	4	10.0663	39	0	0.00
3	Transmission Capacity Obl	11	12.2338	134	11	12.2338	134	0	0.00
4	BGS kWhr June-September	16,311	0.023675	386	16,311	0.023675	386	0	0.00
5	Spare	0	0.000000	0	0	0.000000	0	0	0.00
6	BGS kWhr October-May	63,187	0.027935	1,765	63,187	0.027935	1,765	0	0.00
7	Spare	0	0.000000	0	0	0.000000	0	0	0.00
8	BGS Reconciliation-CIEP	79,498	0.001976	157	79,498	0.001976	157	0	0.00
9	BGS Miscellaneous			469	0		469	0	0.00
10	Supply subtotal	79,498		$2,960	79,498		$2,960	$0	0.00
11	Unbilled Supply			(752)			(729)	23	-3.11
12	Supply w Unbilled			$2,208			$2,231	$23	1.06
13									
14	Total Delivery + Supply	454,332		$12,649	454,332		$12,673	$23	0.18
15									
16									
17									
18	Notes:	Rates are annual averages derived from actual, excluding SUT.							

Filing "9 and 3"

RATE SCHEDULE HTS-HV
HIGH TENSION SERVICE-HIGH VOLTAGE
Rate Case 2023
(Units & Revenue in Thousands)

		Annualized Weather Normalized			Proposed			Difference	
		Units	**Rate**	**Revenue**	**Units**	**Rate**	**Revenue**	**Revenue**	**Percent**
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Service Charge	0.125	1,720.25	$215	0.125	1,720.25	$215	$0	0.00
2	Distrib. KW Annual	3,230	0.6374	2,059	3,230	0.7820	2,526	467	22.68
3	Distrib. KW June - September	0	0.0000	0	0	0.0000	0	0	0.00
4	Distribution kWhr On Peak	202,466	0.000000	0	202,466	0.000000	0	0	0.00
5	Spare	0	0.000000	0	0	0.000000	0	0	0.00
6	Distribution kWhr Off Peak	251,866	0.000000	0	251,866	0.000000	0	0	0.00
7	Spare	0	0.000000	0	0	0.000000	0	0	0.00
8	SBC	454,332	0.008124	3,691	454,332	0.008124	3,691	0	0.00
9	NGC	454,332	0.000023	10	454,332	0.000023	10	0	0.00
10	DAC	454,332	0.000000	0	454,332	0.000000	0	0	0.00
11	STC-MTC-Tax	454,332	0.000000	0	454,332	0.000000	0	0	0.00
12	ZECRC	454,332	0.004000	1,817	454,332	0.004000	1,817	0	0.00
13	Solar Pilot Recovery Charge	454,332	0.000057	26	454,332	0.000057	26	0	0.00
14	CIEP Standby Fee	454,332	0.000150	68	454,332	0.000150	68	0	0.00
15	Green Programs Recovery Charge	454,332	0.004920	2,235	454,332	0.004920	2,235	0	0.00
16	Tax Adjustment Credit	454,332	(0.000080)	-36	454,332	(0.000080)	-36	0	0.00
17	Green Enabling Mechanism	454,332	0.000000	0	454,332	0.000000	0	0	0.00
18	Facilities Chg.			22			22	0	0.00
19	Minimum			0			0	0	0.00
20	Dist. Miscellaneous			(72)			(72)	(0)	0.00
21	Delivery Subtotal	454,332		$10,035	454,332		$10,502	$467	4.65
22	Unbilled Delivery			418			437	19	4.55
23	Delivery Subtotal w unbilled			$10,453			$10,939	$486	4.65

RATE SCHEDULE HTS-HV
HIGH TENSION SERVICE-HIGH VOLTAGE
Rate Case 2023
(Units & Revenue in Thousands)

		Annualized Weather Normalized			Proposed			Difference	
		Units	**Rate**	**Revenue**	**Units**	**Rate**	**Revenue**	**Revenue**	**Percent**
	Supply-BGS	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Generation Capacity Obl June-September	246	11.5118	$2,833	246	11.5118	$2,833	$0	0.00
2	Generation Capacity Obl October-May	443	11.5118	5,095	443	11.5118	5,095	0	0.00
3	Transmission Capacity Obl	619	13.7104	8,487	619	13.7104	8,487	0	0.00
4	BGS kWhr June-September On	56,600	0.084959	4,809	56,600	0.084959	4,809	0	0.00
5	BGS kWhr June-September Off	145,865	0.084959	12,393	145,865	0.084959	12,393	0	0.00
6	BGS kWhr October-May On	69,004	0.052881	3,649	69,004	0.052881	3,649	0	0.00
7	BGS kWhr October-May Off	182,862	0.052881	9,670	182,862	0.052881	9,670	0	0.00
8	BGS Reconciliation-CIEP	454,332	0.000000	0	454,332	0.000000	0	0	0.00
9	BGS Miscellaneous			469			469	0	0.00
10	Supply Subtotal	454,332		$47,405	454,332		$47,405	$0	0.00
11	Unbilled Supply			0			0	0	0.00
12	Supply Subtotal w unbilled			$47,405			$47,405	$0	0.00
13									
14	Total Delivery + Supply	454,332		$57,858	454,332		$58,344	$486	0.84
15									
16	Notes:	All customers assumed to be on BGS.							
17		Annualized Weather Normalized Revenue reflects Delivery rates in effect 4/1/2024							

Filing "9 and 3"

RATE SCHEDULE BPL
BODY POLITIC LIGHTING SERVICE
Rate Case 2023
(Units & Revenue in Thousands)

EXHIBIT P-9E R-1
Schedule SS-E11 R-1

		Actual			Weather Normalized			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	High Pressure Sodium	2,219.184	0	$26,640	2,219.184	0	$26,640	0.00	0.00
2	Metal Halide	286.644	0	6,214	286.644	0	6,214	0.00	0.00
3	Filament/Incandescent	142.200	0	618	142.200	0	618	0.00	0.00
4	Mercury Vapor	312.204	0	2,607	312.204	0	2,607	0.00	0.00
5	Induction	1,320.456	0	12,882	1,320.456	0	12,882	0.00	0.00
6	LED	248.520	0	3,767	248.520	0	3,767	0.00	0.00
7									
8	Distribution June-September	75,127	0.007185	$570	75,127	0.007185	$570	0.00	0.00
9	Distribution October-May	208,148	0.007185	1,465	208,148	0.007185	1,465	0.00	0.00
10	SBC	283,276	0.008447	2,393	283,276	0.008447	2,393	0.00	0.00
11	NGC	283,276	0.000075	21	283,276	0.000075	21	0.00	0.00
12	ZECRC	283,276	0.004001	1,133	283,276	0.004001	1,133	0.00	0.00
13	Solar Pilot Recovery Charge	283,276	0.000063	18	283,276	0.000063	18	0.00	0.00
14	Green Programs Recovery Charge	283,276	0.004920	1,394	283,276	0.004920	1,394	0.00	0.00
15	Tax Adjustment Credit	283,276	0.000000	0	283,276	0.000000	0	0.00	0.00
16	ECIP	283,276	0.000000	0	283,276	0.000000	0	0.00	0.00
17									
18	Pole Charges	721.980		2,492	721.980		2,492	0.00	0.00
19	Minimum			0			0	0.00	0.00
20	Miscellaneous			-84			-84	0	0.00
21	Delivery Subtotal	283,276		$62,131	283,276		$62,131	$0	0.00
22	Unbilled Delivery			0			0	0	0.00
23	Delivery Subtotal w unbilled			$62,131			$62,131	$0	0.00
24									
25	**Supply-BGS**								
26	BGS June-September	61,732	0.060525	3,736	61,732	0.060525	3,736	0	0.00
27	BGS October-May	182,603	0.063115	11,525	182,603	0.063115	11,525	0	0.00
28	BGS Reconciliation-RSCP	244,335	(0.002100)	(513)	244,335	(0.002100)	(513)	0	0.00
29	Miscellaneous			(1)			(1)	0	0.00
30	Supply subtotal	244,335		$14,747	244,335		$14,747	$0	0.00
31	Unbilled Supply			0			0	0	0.00
32	Supply subtotal w unbilled			$14,747			$14,747	$0	0.00
33									
34	Total Delivery + Supply	283,276		$76,878	283,276		$76,878	$0	0.00
35									
36	Notes:	Rates are annual averages derived from actual, excluding SUT.							
37									

Filing "9 and 3"

RATE SCHEDULE BPL
BODY POLITIC LIGHTING SERVICE
Rate Case 2023
(Units & Revenue in Thousands)

		Annualized Weather Normalized			Proposed			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	High Pressure Sodium	2,219.184	0	$ 26,640	2,219.184	0	$ 28,497	$1,857	6.97
2	Metal Halide	286.644	0	6,214	286.644	0	6,499	285	4.59
3	Filament/Incandescent	142.200	0	618	142.200	0	1,011	393	63.59
4	Mercury Vapor	312.204	0	2,607	312.204	0	3,432	825	31.65
5	Induction	1,320.456	0	12,882	1,320.456	0	14,704	1,822	14.14
6	LED	248.520	0	3,768	248.520	0	4,017	249	6.61
7									
8	Distribution June-September	75,127	0.006943	$522	75,127	0.008160	$613	91	17.43
9	Distribution October-May	208,148	0.006943	1,445	208,148	0.008160	1,699	254	17.58
10	SBC	283,276	0.008451	2,394	283,276	0.008451	2,394	0	0.00
11	NGC	283,276	0.000024	7	283,276	0.000024	7	0	0.00
12	ZECRC	283,276	0.004000	1,133	283,276	0.004000	1,133	0	0.00
13	Solar Pilot Recovery Charge	283,276	0.000057	16	283,276	0.000057	16	0	0.00
14	Green Programs Recovery Charge	283,276	0.004920	1,394	283,276	0.004920	1,394	0	0.00
15	Tax Adjustment Credit	283,276	0.000000	0	283,276	0.000000	0	0	0.00
16	ECIP	283,276	0.000000	0	283,276	0.000000	0	0	0.00
17									
18	Pole Charges	721.980		2,678	721.980		$2,754	76	2.84
19	Minimum			0			0	0	0.00
20	Miscellaneous			-84			-84	(0)	0.00
21	Delivery Subtotal			$62,234			$68,086	$5,852	9.40
22	Unbilled Delivery			0			0	0	0.00
23	Delivery Subtotal w unbilled			$62,234			$68,086	$5,852	9.40
24									
25	**Supply-BGS**								
26	BGS June-September	75,127	0.071754	5,391	75,127	0.071754	5,391	0	0.00
27	BGS October-May	208,148	0.077576	16,147	208,148	0.077576	16,147	0	0.00
28	BGS Reconciliation-RSCP	283,276	0.000000	0	283,276	0.000000	0	0	0.00
29	Miscellaneous			(1)			(1)	0	0.00
30	Supply Subtotal			$21,537			$21,537	$0	0.00
31	Unbilled Supply			0			0	0	0.00
32	Supply Subtotal w unbilled			$21,537			$21,537	$0	0.00
33									
34	Total Delivery + Supply	283,276		$83,771	283,276		$89,623	$5,852	6.99
35									
36	Notes:	All customers assumed to be on BGS.							
37		Annualized Weather Normalized Revenue reflects Delivery rates in effect 4/1/2024							

RATE SCHEDULE BPL-POF
BODY POLITIC LIGHTING SERVICE-POF
Rate Case 2023
(Units & Revenue in Thousands)

			Actual			Weather Normalized		Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	High Pressure Sodium	124.548	0	$233	124.548	0	$233	0.00	0.00
2	Metal Halide	1.476	0	6	1.476	0	6	0.00	0.00
3	Filament	6.048	0	32	6.048	0	32	0.00	0.00
4	Mercury Vapor	4.140	0	3	4.140	0	3	0.00	0.00
5	Fluorescent	0.024	0	0	0.024	0	0	0.00	0.00
6	Induction	0.000	0	0	0.000	0	0	0.00	0.00
7	LED	0.000	0	0	0.000	0	0	0.00	0.00
8									
9	Distribution June-September	3,632	0.006763	$27	3,632	0.006763	$27	0.00	0.00
10	Distribution October-May	10,719	0.006763	70	10,719	0.006763	$70	0.00	0.00
11	SBC	14,352	0.008427	121	14,352	0.008427	$121	0.00	0.00
12	NGC	14,352	0.000077	1	14,352	0.000077	$1	0.00	0.00
13	ZECRC	14,352	0.004003	57	14,352	0.004003	$57	0.00	0.00
14	Solar Pilot Recovery Charge	14,352	0.000063	1	14,352	0.000063	$1	0.00	0.00
15	Green Programs Recovery Charge	14,352	0.004920	71	14,352	0.004920	$71	0.00	0.00
16	Tax Adjustment Credit	14,352	(0.001199)	-17	14,352	(0.001199)	-$17	0.00	0.00
17	ECIP	14,352	0.000000	0	14,352	0.000000	$0	0.00	0.00
18									
19	Pole Charges	0.000		0	0.000		0	0.00	0.00
20	Minimum			0			0	0.00	0.00
21	Miscellaneous			(15)			(15)	0	0.00
22	Delivery Subtotal	14,352		$589	14,352		$589	$0	0.00
23	Unbilled Delivery			0			0	0	0.00
24	Delivery Subtotal w unbilled			$589			$589	$0	0.00
25									
26	**Supply-BGS**								
27	BGS June-September	3,513	0.061231	215	3,513	0.061231	215	0	0.00
28	BGS October-May	10,465	0.063025	660	10,465	0.063025	660	0	0.00
29	BGS Reconciliation-RSCP	13,978	(0.001960)	(27)	13,978	(0.001960)	(27)	0	0.00
30	Miscellaneous			0			0	0	0.00
31	Supply subtotal	13,978		$847	13,978		$847	$0	0.00
32	Unbilled Supply			0			0	0	0.00
33	Supply subtotal w unbilled			$847			$847	$0	0.00
34									
35	Total Delivery + Supply	14,352		$1,437	14,352		$1,437	$0	0.00
36									
37	Notes:	Rates are annual averages derived from actual, excluding SUT.							

RATE SCHEDULE BPL-POF
BODY POLITIC LIGHTING SERVICE-POF
Rate Case 2023
(Units & Revenue in Thousands)

		Annualized Weather Normalized			Proposed			Difference	
		Units	**Rate**	**Revenue**	**Units**	**Rate**	**Revenue**	**Revenue**	**Percent**
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	High Pressure Sodium	124.548	0	$ 233.224	124.548	0	$ 280.077	$46.853	20.09
2	Metal Halide	1.476	0	$ 6.066	1.476	0	$ 7.180	$1.114	18.36
3	Filament	6.048	0	$ 31.739	6.048	0	$ 38.847	$7.108	22.40
4	Mercury Vapor	4.140	0	$ 2.848	4.140	0	$ 3.638	$0.790	27.74
5	Fluorescent	0.024	0	$ -	0.024	0	$ -	$0.000	0.00
6	Induction	0.000	0	$ -	0.000	0	$ -	$0.000	0.00
7	LED	0.000	0	$ -	0.000	0	$ -	$0.000	0.00
8									
9	Distribution June-September	3,632	0.007077	$ 25.706	3,632	0.008381	$ 30.443	$4.737	18.43
10	Distribution October-May	10,719	0.007077	$ 75.860	10,719	0.008381	$ 89.839	$13.979	18.43
11	SBC	14,352	0.008451	$ 121.286	14,352	0.008451	$ 121.286	$0.000	0.00
12	NGC	14,352	0.000024	$ 0.344	14,352	0.000024	$ 0.344	$0.000	0.00
13	ZECRC	14,352	0.004000	$ 57.406	14,352	0.004000	$ 57.406	$0.000	0.00
14	Solar Pilot Recovery Charge	14,352	0.000057	$ 0.818	14,352	0.000057	$ 0.818	$0.000	0.00
15	Green Programs Recovery Charge	14,352	0.004920	$ 70.610	14,352	0.004920	$ 70.610	$0.000	0.00
16	Tax Adjustment Credit	14,352	(0.000459)	$ (6.587)	14,352	(0.000459)	$ (6.587)	$0.000	0.00
17	ECIP	14,352	0.000000	$ -	14,352	0.000000	$ -	$0.000	0.00
18									
19	Pole Charges			$ -			$ -	$0.000	0.00
20	Minimum			$ -			$ -	$0.000	0.00
21	Miscellaneous			$ (15.377)			$ (15.377)	$0.000	0.00
22	Delivery Subtotal			$ 603.943			$ 678.524	$74.581	12.35
23	Unbilled Delivery			$ -			$ -	$0.000	0.00
24	Delivery Subtotal w unbilled			$ 603.943			$ 678.524	$74.581	12.35
25									
26	**Supply-BGS**								
27	BGS June-September	3,632	0.071754	$ 260.635	3,632	0.071754	$ 260.635	$0.000	0.00
28	BGS October-May	10,719	0.077576	$ 831.559	10,719	0.077576	$ 831.559	$0.000	0.00
29	BGS Reconciliation-RSCP	14,352	0.000000	$ -	14,352	0.000000	$ -	$0.000	0.00
30	Miscellaneous			$ -			$ -	$0.000	0.00
31	Supply Subtotal			$ 1,092.194			$ 1,092.194	$0.000	0.00
32	Unbilled Supply			$ -			$ -	$0.000	0.00
33	Supply Subtotal w unbilled			$ 1,092.194			$ 1,092.194	$0.000	0.00
34									
35	Total Delivery + Supply	14,352		$ 1,696.137	14,352		$ 1,770.718	$74.581	4.40
36									
37	Notes:	All customers assumed to be on BGS.							
38		WH, WHS & BPL-POF revenues shown to 3 decimals.							
39		Annualized Weather Normalized Revenue reflects Delivery rates in effect 4/1/2024							

Filing "9 and 3"

RATE SCHEDULE PSAL
PRIVATE STREET AND AREA LIGHTING SERVICE
Rate Case 2023
(Units & Revenue in Thousands)

EXHIBIT P-9E R-1
Schedule SS-E11 R-1

		Actual			Weather Normalized			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	High Pressure Sodium	719.940	0	$13,779	719.940	0	$13,779	0.00	0.00
2	Metal Halide	175.920	0	4,901	175.920	0	4,901	0.00	0.00
3	Filament/Incandescent	0.960	0	7	0.960	0	7	0.00	0.00
4	Mercury Vapor	65.940	0	795	65.940	0	795	0.00	0.00
5	Induction	7.836	0	117	7.836	0	117	0.00	0.00
6	LED	168.036	0	3,421	168.036	0	3,421	0.00	0.00
7									
8	Distribution June-September	36,506	0.008083	$299	36,506	0.008083	$299	0.00	0.00
9	Distribution October-May	95,599	0.008083	769	95,599	0.008083	769	0.00	0.00
10	SBC	132,104	0.008466	1,118	132,104	0.008466	1,118	0.00	0.00
11	NGC	132,104	0.000074	10	132,104	0.000074	10	0.00	0.00
12	ZECRC	132,104	0.004001	529	132,104	0.004001	529	0.00	0.00
13	Solar Pilot Recovery Charge	132,104	0.000063	8	132,104	0.000063	8	0.00	0.00
14	Green Programs Recovery Charge	132,104	0.004920	650	132,104	0.004920	650	0.00	0.00
15	Tax Adjustment Credit	132,104	0.000000	0	132,104	0.000000	0	0.00	0.00
16	ECIP	132,104	0.000000	0	132,104	0.000000	0	0.00	0.00
17									
18	Pole Charges	361.188		4,037	361.188		4,037	0.00	0.00
19	Minimum			0			0	0.00	0.00
20	Miscellaneous			-734			-734	0	0.00
21	Delivery Subtotal	132,104		$29,706	132,104		$29,706	$0	0.00
22	Unbilled Delivery			317			317	0	0.00
23	Delivery Subtotal w unbilled			$30,023			$30,023	$0	0.00
24									
25	**Supply-BGS**								
26	BGS June-September	32,074	0.062855	2,016	32,074	0.062855	2,016	0	0.00
27	BGS October-May	87,351	0.064585	5,642	87,351	0.064585	5,642	0	0.00
28	BGS Reconciliation-RSCP	119,425	(0.002313)	(276)	119,425	(0.002313)	(276)	0	0.00
29	Miscellaneous			-2			-2	0	0.00
30	Supply subtotal			$7,380	119,425		$7,380	$0	0.00
31	Unbilled Supply			(4)			401	405	-10,310.30
32	Supply subtotal w unbilled			$7,376			$7,780	$405	5.49
33									
34	Total Delivery + Supply	132,104		$37,399	132,104		$37,804	$405	1.08
35									
36	Notes:	Rates are annual averages derived from actual, excluding SUT.							

RATE SCHEDULE PSAL
PRIVATE STREET AND AREA LIGHTING SERVICE
Rate Case 2023
(Units & Revenue in Thousands)

		Annualized Weather Normalized			Proposed			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	High Pressure Sodium	719.940	0	$ 13,779	719.940	0	$ 15,053	$1,274	9.25
2	Metal Halide	175.920	0	4,901	175.920	0	5,063	162	3.31
3	Filament/Incandescent	0.960	0	7	0.960	0	7	0	0.00
4	Mercury Vapor	65.940	0	795	65.940	0	1,308	513	64.53
5	Induction	7.836	0	117	7.836	0	126	9	7.69
6	LED	168.036	0	3,421	168.036	0	3,597	176	5.14
7									
8	Distribution June-September	36,506	0.007415	$271	36,506	0.008719	$318	47	17.34
9	Distribution October-May	95,599	0.007415	709	95,599	0.008719	834	125	17.63
10	SBC	132,104	0.008451	1,116	132,104	0.008451	1,116	0	0.00
11	NGC	132,104	0.000024	3	132,104	0.000024	3	0	0.00
12	ZECRC	132,104	0.004000	528	132,104	0.004000	528	0	0.00
13	Solar Pilot Recovery Charge	132,104	0.000057	8	132,104	0.000057	8	0	0.00
14	Green Programs Recovery Charge	132,104	0.004920	650	132,104	0.004920	650	0	0.00
15	Tax Adjustment Credit	132,104	0.000000	0	132,104	0.000000	0	0	0.00
16	ECIP	132,104	0.000000	0	132,104	0.000000	0	0	0.00
17									
18	Pole Charges	361.188		4,026	361.188		4,511	485	12.05
19	Minimum			0			0	0	0.00
20	Miscellaneous			(734)			(734)	0	0.00
21	Delivery Subtotal			$29,597			$32,388	$2,791	9.43
22	Unbilled Delivery			316			346	30	9.49
23	Delivery Subtotal w unbilled			$29,913			$32,734	$2,821	9.43
24									
25	**Supply-BGS**								
26	BGS June-September	36,506	0.071754	2,619	36,506	0.071754	2,619	0	0.00
27	BGS October-May	95,599	0.077576	7,416	95,599	0.077576	7,416	0	0.00
28	BGS Reconciliation-RSCP	132,104	0.000000	0	132,104	0.000000	0	0	0.00
29	Miscellaneous			-2			-2	0	0.00
30	Supply Subtotal			$10,033			$10,033	$0	0.00
31	Unbilled Supply			545			545	0	0.00
32	Supply Subtotal w unbilled			$10,578			$10,578	$0	0.00
33									
34	Total Delivery + Supply	132,104		$40,491	132,104		$43,312	$2,821	6.97
35									
36	Notes:	All customers assumed to be on BGS.							
37		Annualized Weather Normalized Revenue reflects Delivery rates in effect 4/1/2024							

Electric Tariff Rates

Proposed Revenue Requirement Increase $ 535,063,902

Rate Schedules		Current Total Distribution Charges: Charge w/out SUT	Current Total Distribution Charges: Charge w/ SUT	Proposed Total Distribution Charges: Charge w/out SUT	Proposed Total Distribution Charges: Charge w/ SUT	Difference: w/out SUT	Difference: % w/out SUT
RS	Service Charge	$4.64	$4.95	$7.56	$8.06	$2.92	62.93%
	Distribution 0-600 Sum	$0.048092	$0.051278	$0.075946	$0.080977	$0.027854	57.92%
	Distribution 0-600 Win	$0.033344	$0.035553	$0.044297	$0.047232	$0.010953	32.85%
	Distribution over 600 Sum	$0.051913	$0.055352	$0.079767	$0.085052	$0.027854	53.66%
	Distribution over 600 Win	$0.033344	$0.035553	$0.044297	$0.047232	$0.010953	32.85%
RHS	Service Charge	$4.64	$4.95	$7.56	$8.06	$2.92	62.93%
	Distribution 0-600 Sum	$0.054209	$0.057800	$0.088917	$0.094808	$0.034708	64.03%
	Distribution 0-600 Win	$0.035336	$0.037677	$0.046057	$0.049108	$0.010721	30.34%
	Distribution over 600 Sum	$0.059109	$0.063025	$0.093817	$0.100032	$0.034708	58.72%
	Distribution over 600 Win	$0.017736	$0.018911	$0.028457	$0.030342	$0.010721	60.45%
	Common Use	$0.059109	$0.063025	$0.093817	$0.100032	$0.034708	58.72%
RLM	Service Charge	$13.07	$13.94	$13.07	$13.94	$0.00	0.00%
	Distrib. kWhr Summer On	$0.079439	$0.084702	$0.108651	$0.115849	$0.029212	36.77%
	Distrib. kWhr Summer Off	$0.016586	$0.017685	$0.019407	$0.020693	$0.002821	17.01%
	Distrib. kWhr Winter On	$0.016586	$0.017685	$0.019407	$0.020693	$0.002821	17.01%
	Distrib. kWhr Winter Off	$0.016586	$0.017685	$0.019407	$0.020693	$0.002821	17.01%
WH	Distribution	$0.050179	$0.053503	$0.066443	$0.070845	$0.016264	32.41%
WHS	Service Charge	$0.64	$0.68	$1.04	$1.11	$0.40	62.50%
	Distribution	$0.001988	$0.002120	$0.002022	$0.002156	$0.000034	1.71%
HS	Service Charge	$3.83	$4.08	$6.10	$6.50	$2.27	59.27%
	Distribution June-September	$0.098587	$0.105118	$0.103613	$0.110477	$0.005026	5.10%
	Distribution October-May	$0.029662	$0.031627	$0.053742	$0.057302	$0.024080	81.18%
GLP	Service Charge	$4.88	$5.20	$7.95	$8.48	$3.07	62.91%
	Service Charge-unmetered	$2.24	$2.39	$3.65	$3.89	$1.41	62.95%
	Service Charge-Night Use	$347.77	$370.81	$7.95	$8.48	($339.82)	-97.71%
	Distrib. KW Annual	$3.7897	$4.0408	$4.9787	$5.3085	$1.1890	31.37%
	Distrib. KW Summer	$9.5030	$10.1326	$16.8755	$17.9935	$7.3725	77.58%
	Distribution kWhr, June-September	$0.003098	$0.003303	$0.017846	$0.019028	$0.014748	476.05%
	Distribution kWhr, October-May	$0.007907	$0.008431	$0.004006	$0.004272	($0.003901)	-49.34%
	Distribution kWhr, Night use, June-Septembe	$0.007907	$0.008431	$0.004006	$0.004272	($0.003901)	-49.34%
	Distribution kWhr, Night use, October-May	$0.007907	$0.008431	$0.004006	$0.004272	($0.003901)	-49.34%

Electric Tariff Rates

Proposed Revenue Requirement Increase $ 535,063,902

		Current Total Distribution Charges		Proposed Total Distribution Charges		Difference	
Rate Schedules		**Charge w/out SUT**	**Charge w/ SUT**	**Charge w/out SUT**	**Charge w/ SUT**	**w/out SUT**	**% w/out SUT**
LPL-Secondary	Service Charge	$347.77	$370.81	$347.77	$370.81	$0.00	0.00%
	Distrib. KW Annual	$3.6529	$3.8949	$3.8181	$4.0710	$0.1652	4.52%
	Distrib. KW Summer	$8.6904	$9.2661	$13.1611	$14.0330	$4.4707	51.44%
	Distribution kWhr	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	0.00%
LPL-Primary	Service Charge	$347.77	$370.81	$347.77	$370.81	$0.00	0.00%
	Service Charge-Alternate	$22.04	$23.50	$35.91	$38.29	$13.87	62.93%
	Distrib. KW Annual	$1.7082	$1.8214	$3.0116	$3.2111	$1.3034	76.30%
	Distrib. KW Summer	$9.4827	$10.1109	$14.0963	$15.0302	$4.6136	48.65%
	Distribution kWhr	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	0.00%
HTS-Subtransmission	Service Charge	$1,911.39	$2,038.02	$1,911.39	$2,038.02	$0.00	0.00%
	Distrib. KW Annual	$1.1777	$1.2557	$1.8897	$2.0149	$0.7120	60.46%
	Distrib. KW Summer	$4.2573	$4.5393	$6.8310	$7.2836	$2.5737	60.45%
	Distribution kWhr	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	0.00%
HTS-HV	Service Charge	$1,720.25	$1,834.22	$1,720.25	$1,834.22	$0.00	0.00%
	Distrib. KW Annual	$0.6374	$0.6796	$0.7820	$0.8338	$0.1446	22.69%
	Distribution kWhr	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	0.00%
BPL	Distribution Sum	$0.006943	$0.007403	$0.008160	$0.008701	$0.001217	17.53%
	Distribution Winter	$0.006943	$0.007403	$0.008160	$0.008701	$0.001217	17.53%
BPL-POF	Distribution Sum	$0.007077	$0.007546	$0.008381	$0.008936	$0.001304	18.43%
	Distribution Winter	$0.007077	$0.007546	$0.008381	$0.008936	$0.001304	18.43%
PSAL	Distribution Sum	$0.007415	$0.007906	$0.008719	$0.009297	$0.001304	17.59%
	Distribution Winter	$0.007415	$0.007906	$0.008719	$0.009297	$0.001304	17.59%

TYPICAL RESIDENTIAL ELECTRIC BILL IMPACTS

The effect of the proposed changes in the Rate Case 2023 (RC 2023) on typical residential Electric bills, if approved by the Board, is illustrated below:

Residential Electric Service - Average Monthly Bill					
If Your Average Monthly kWh Use Is:	And Your Jun. to Sep. Avg. Monthly kWh Use Is:	Then Your Present Monthly Bill (1) Would Be:	And Your Proposed Monthly Bill (2) Would Be:	Your Monthly Bill Change Would Be:	And Your Percent Change Would Be:
138	171	$34.22	$39.40	$5.18	15.14 %
277	342	63.47	70.72	7.25	11.42
553	684	122.38	133.79	11.41	9.32
650	803	143.36	156.21	12.85	8.96
1,000	1,300	219.92	238.41	18.49	8.41

(1) Based upon current Basic Generation Service Residential Small Commercial Pricing (BGS-RSCP) and Delivery Rates in effect April 1, 2024, and assumes that the customer receives BGS-RSCP service from Public Service.

(2) Same as (1) except includes increase in the RC 2023.

Residential Electric Service - Monthly Summer Bill				
If Your Monthly Summer kWh Use Is:	Then Your Present Monthly Summer Bill Would Be:	And Your Proposed Monthly Summer Bill (4) Would Be:	Your Monthly Summer Bill Change Would Be:	And Your Percent Change Would Be:
171	$42.37	$49.86	$7.49	17.68 %
342	79.80	91.66	11.86	14.86
684	155.82	176.43	20.61	13.23
803	183.47	207.14	23.67	12.90
1,300	299.01	335.40	36.39	12.17

(3) Based upon current Basic Generation Service Residential Small Commercial Pricing (BGS-RSCP) and Delivery Rates in effect April 1, 2024, and assumes that the customer receives BGS-RSCP service from Public Service.

(4) Same as (3) except includes increase in the RC 2023.

COMPARISON OF TYPICAL BILLS
Rate Schedule RS
Distribution Only

	Annual Usages										
Units	**Class Avg**	**Band 1**	**Band 2**	**Band 3**	**Band 4**	**Band 5**	**Band 6**	**Band 7**	**Band 8**	**Band 9**	**Band 10**
Serv Chg	12	12	12	12	12	12	12	12	12	12	12
Distribution 0-600 June - September	1,762	748	1,343	1,768	2,088	2,251	2,329	2,349	2,370	2,380	2,390
Distribution 0-600 October - May	3,039	944	1,620	2,112	2,590	3,095	3,603	4,163	4,590	4,769	4,796
Distribution over 600 June - September	971	3	26	108	273	530	890	1,313	1,887	2,737	5,240
Distribution over 600 October - May	813	2	7	20	38	89	163	387	839	1,840	5,457
Total	6,585	1,697	2,996	4,008	4,988	5,965	6,985	8,212	9,686	11,727	17,882
Avg Summer Use	683	188	342	469	590	695	805	916	1,064	1,279	1,907
Avg Winter Use	482	118	203	266	328	398	471	569	679	826	1,282
Present Bill											
Total Delivery	$451.90	$160.28	$238.26	$299.64	$359.40	$418.31	$480.20	$553.24	$642.34	$766.40	$1,139.09
Total Supply	1,013.96	258.79	456.94	611.81	762.75	914.13	1,073.13	1,264.54	1,495.04	1,814.39	2,777.48
	$1,465.86	$419.07	$695.20	$911.45	$1,122.15	$1,332.44	$1,553.33	$1,817.78	$2,137.38	$2,580.79	$3,916.57
Proposed Bill											
Total Delivery	$615.38	$230.95	$335.24	$417.57	$497.53	$575.40	$657.11	$752.46	$869.50	$1,032.89	$1,522.76
Total Supply	1,013.96	258.79	456.94	611.81	762.75	914.13	1,073.13	1,264.54	1,495.04	1,814.39	2,777.48
Totals	$1,629.34	$489.74	$792.18	$1,029.38	$1,260.28	$1,489.53	$1,730.24	$2,017.00	$2,364.54	$2,847.28	$4,300.24
Increase Amount											
Delivery	$163.48	$70.67	$96.98	$117.93	$138.13	$157.09	$176.91	$199.22	$227.16	$266.49	$383.67
Supply	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Totals	$163.48	$70.67	$96.98	$117.93	$138.13	$157.09	$176.91	$199.22	$227.16	$266.49	$383.67
Increase Percent											
Delivery	36.2	44.1	40.7	39.4	38.4	37.6	36.8	36.0	35.4	34.8	33.7
Supply	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Totals	11.2	16.9	13.9	12.9	12.3	11.8	11.4	11.0	10.6	10.3	9.8

Notes: Bills include SUT
Each band represents a decile of customers segmented by annual kWhr usage.

COMPARISON OF TYPICAL BILLS
Rate Schedule RS
Including Tax Adjustment Credit and Distribution Adjustment Charge

		Annual Usages										
	Units	**Class Avg**	**Band 1**	**Band 2**	**Band 3**	**Band 4**	**Band 5**	**Band 6**	**Band 7**	**Band 8**	**Band 9**	**Band 10**
1	Serv Chg	12	12	12	12	12	12	12	12	12	12	12
2	Distribution 0-600 June - September	1,762	748	1,343	1,768	2,088	2,251	2,329	2,349	2,370	2,380	2,390
3	Distribution 0-600 October - May	3,039	944	1,620	2,112	2,590	3,095	3,603	4,163	4,590	4,769	4,796
4	Distribution over 600 June - September	971	3	26	108	273	530	890	1,313	1,887	2,737	5,240
5	Distribution over 600 October - May	813	2	7	20	38	89	163	387	839	1,840	5,457
6	Total	6,585	1,697	2,996	4,008	4,988	5,965	6,985	8,212	9,686	11,727	17,882
7												
8	Avg Summer Use	683	188	342	469	590	695	805	916	1,064	1,279	1,907
9	Avg Winter Use	482	118	203	266	328	398	471	569	679	826	1,282
10												
11	**Present Bill**											
12	Total Delivery	$451.90	$160.28	$238.26	$299.64	$359.40	$418.31	$480.20	$553.24	$642.34	$766.40	$1,139.09
13	Total Supply	1,013.96	258.79	456.94	611.81	762.75	914.13	1,073.13	1,264.54	1,495.04	1,814.39	2,777.48
14		$1,465.86	$419.07	$695.20	$911.45	$1,122.15	$1,332.44	$1,553.33	$1,817.78	$2,137.38	$2,580.79	$3,916.57
15												
16												
17												
18	**Proposed Bill**											
19	Total Delivery	$588.36	$223.98	$322.95	$401.13	$477.06	$550.93	$628.44	$718.77	$829.75	$984.77	$1,449.39
20	Total Supply	1,013.96	258.79	456.94	611.81	762.75	914.13	1,073.13	1,264.54	1,495.04	1,814.39	2,777.48
21	Totals	$1,602.32	$482.77	$779.89	$1,012.94	$1,239.81	$1,465.06	$1,701.57	$1,983.31	$2,324.79	$2,799.16	$4,226.87
22												
23												
24												
25	**Increase Amount**											
26	Delivery	$136.46	$63.70	$84.69	$101.49	$117.66	$132.62	$148.24	$165.53	$187.41	$218.37	$310.30
27	Supply	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
28	Totals	$136.46	$63.70	$84.69	$101.49	$117.66	$132.62	$148.24	$165.53	$187.41	$218.37	$310.30
29												
30												
31												
32	**Increase Percent**											
33	Delivery	30.2	39.7	35.5	33.9	32.7	31.7	30.9	29.9	29.2	28.5	27.2
34	Supply	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
35	Totals	9.3	15.2	12.2	11.1	10.5	10.0	9.5	9.1	8.8	8.5	7.9
36												
37												
38												

39 Notes: Bills include SUT
40 Each band represents a decile of customers segmented by annual kWhr usage.
41 Assumes approval of 2023 TAC filing, plus proposed TAC and DAC

COMPARISON OF TYPICAL BILLS
Rate Schedule RHS
Distribution Only

	Annual Usages										
Units	**Class Avg**	**Band 1**	**Band 2**	**Band 3**	**Band 4**	**Band 5**	**Band 6**	**Band 7**	**Band 8**	**Band 9**	**Band 10**
Serv Chg	12	12	12	12	12	12	12	12	12	12	12
Distribution 0-600 June - September	1,912	211	1,365	1,776	2,000	2,121	2,225	2,293	2,329	2,368	2,385
Distribution 0-600 October - May	3,937	375	3,320	4,460	4,730	4,791	4,799	4,800	4,800	4,800	4,800
Distribution over 600 June - September	907	152	53	195	369	587	920	1,307	1,858	2,569	4,637
Distribution over 600 October - May	6,256	292	222	900	1,709	2,763	3,895	5,549	7,547	10,365	18,596
Total	13,011	1,029	4,960	7,332	8,808	10,262	11,840	13,949	16,534	20,102	30,417
Avg Summer Use	705	91	354	493	592	677	786	900	1,047	1,234	1,755
Avg Winter Use	1,274	83	443	670	805	944	1,087	1,294	1,543	1,896	2,924
Present Bill											
Total Delivery	$703.15	$117.39	$350.76	$477.48	$550.59	$617.00	$691.12	$784.67	$900.92	$1,058.71	$1,511.75
Total Supply	1,636.83	129.75	618.29	916.15	1,102.28	1,286.60	1,487.36	1,755.76	2,085.56	2,540.48	3,856.21
Totals	$2,339.98	$247.14	$969.05	$1,393.63	$1,652.87	$1,903.60	$2,178.48	$2,540.43	$2,986.48	$3,599.19	$5,367.96
Proposed Bill											
Total Delivery	$961.28	$175.76	$481.03	$649.00	$749.18	$840.88	$944.22	$1,073.51	$1,234.32	$1,452.08	$2,076.35
Total Supply	1,636.83	129.75	618.29	916.15	1,102.28	1,286.60	1,487.36	1,755.76	2,085.56	2,540.48	3,856.21
Totals	$2,598.11	$305.51	$1,099.32	$1,565.15	$1,851.46	$2,127.48	$2,431.58	$2,829.27	$3,319.88	$3,992.56	$5,932.56
Increase Amount											
Delivery	$258.13	$58.37	$130.27	$171.52	$198.59	$223.88	$253.10	$288.84	$333.40	$393.37	$564.60
Supply	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Totals	$258.13	$58.37	$130.27	$171.52	$198.59	$223.88	$253.10	$288.84	$333.40	$393.37	$564.60
Increase Percent											
Delivery	36.7	49.7	37.1	35.9	36.1	36.3	36.6	36.8	37.0	37.2	37.3
Supply	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Totals	11.0	23.6	13.4	12.3	12.0	11.8	11.6	11.4	11.2	10.9	10.5

Notes: Bills include SUT
Each band represents a decile of customers segmented by annual kWhr usage.

COMPARISON OF TYPICAL BILLS
Rate Schedule RHS
Including Tax Adjustment Credit and Distribution Adjustment Charge

	Annual Usages										
Units	**Class Avg**	**Band 1**	**Band 2**	**Band 3**	**Band 4**	**Band 5**	**Band 6**	**Band 7**	**Band 8**	**Band 9**	**Band 10**
Serv Chg	12	12	12	12	12	12	12	12	12	12	12
Distribution 0-600 June - September	1,912	211	1,365	1,776	2,000	2,121	2,225	2,293	2,329	2,368	2,385
Distribution 0-600 October - May	3,937	375	3,320	4,460	4,730	4,791	4,799	4,800	4,800	4,800	4,800
Distribution over 600 June - September	907	152	53	195	369	587	920	1,307	1,858	2,569	4,637
Distribution over 600 October - May	6,256	292	222	900	1,709	2,763	3,895	5,549	7,547	10,365	18,596
Total	13,011	1,029	4,960	7,332	8,808	10,262	11,840	13,949	16,534	20,102	30,417
Avg Summer Use	705	91	354	493	592	677	786	900	1,047	1,234	1,755
Avg Winter Use	1,274	83	443	670	805	944	1,087	1,294	1,543	1,896	2,924
Present Bill											
Total Delivery	$703.15	$117.39	$350.76	$477.48	$550.59	$617.00	$691.12	$784.67	$900.92	$1,058.71	$1,511.75
Total Supply	1,636.83	129.75	618.29	916.15	1,102.28	1,286.60	1,487.36	1,755.76	2,085.56	2,540.48	3,856.21
Totals	$2,339.98	$247.14	$969.05	$1,393.63	$1,652.87	$1,903.60	$2,178.48	$2,540.43	$2,986.48	$3,599.19	$5,367.96
Proposed Bill											
Total Delivery	$879.11	$169.26	$449.70	$602.70	$693.55	$776.07	$869.46	$985.42	$1,129.92	$1,325.14	$1,884.26
Total Supply	1,636.83	129.75	618.29	916.15	1,102.28	1,286.60	1,487.36	1,755.76	2,085.56	2,540.48	3,856.21
Totals	$2,515.94	$299.01	$1,067.99	$1,518.85	$1,795.83	$2,062.67	$2,356.82	$2,741.18	$3,215.48	$3,865.62	$5,740.47
Increase Amount											
Delivery	$175.96	$51.87	$98.94	$125.22	$142.96	$159.07	$178.34	$200.75	$229.00	$266.43	$372.51
Supply	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Totals	$175.96	$51.87	$98.94	$125.22	$142.96	$159.07	$178.34	$200.75	$229.00	$266.43	$372.51
Increase Percent											
Delivery	25.0	44.2	28.2	26.2	26.0	25.8	25.8	25.6	25.4	25.2	24.6
Supply	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Totals	7.5	21.0	10.2	9.0	8.6	8.4	8.2	7.9	7.7	7.4	6.9

Notes: Bills include SUT
Each band represents a decile of customers segmented by annual kWhr usage.
Assumes approval of 2023 TAC filing, plus proposed TAC and DAC

COMPARISON OF TYPICAL BILLS
Rate Schedule RLM
Distribution Only

		Annual Usages										
	Units	**Class Avg**	**Band 1**	**Band 2**	**Band 3**	**Band 4**	**Band 5**	**Band 6**	**Band 7**	**Band 8**	**Band 9**	**Band 10**
1	Serv Chg	12	12	12	12	12	12	12	12	12	12	12
2	Distribution June - September On Peak	3,223	1,204	1,922	2,302	2,670	3,043	3,452	3,829	4,380	5,280	7,999
3	Distribution June - September Off Peak	3,531	1,344	2,045	2,425	2,781	3,186	3,553	3,970	4,629	5,518	8,678
4	Distribution October - May On Peak	3,877	1,315	1,931	2,323	2,717	3,070	3,565	4,081	4,708	5,759	9,680
5	Distribution October - May Off Peak	5,091	1,816	2,571	3,169	3,602	4,093	4,619	5,331	6,186	7,647	12,837
6	Total	15,722	5,679	8,469	10,218	11,770	13,392	15,189	17,210	19,903	24,203	39,194
8	Avg Summer Use	1,689	637	992	1,182	1,363	1,557	1,751	1,950	2,252	2,699	4,169
9	Avg Winter Use	1,121	391	563	686	790	895	1,023	1,176	1,362	1,676	2,815
11	**Present Bill**											
12	Total Delivery	$940.94	$449.40	$596.44	$683.93	$763.66	$846.21	$937.40	$1,034.32	$1,166.76	$1,379.60	$2,093.47
13	Total Supply	3,687.90	1,330.71	1,987.77	2,397.69	2,763.87	3,144.29	3,569.10	4,042.53	4,672.68	5,682.20	9,193.41
14	Totals	$4,628.84	$1,780.11	$2,584.21	$3,081.62	$3,527.53	$3,990.50	$4,506.50	$5,076.85	$5,839.44	$7,061.80	$11,286.88
18	**Proposed Bill**											
19	Total Delivery	$1,078.95	$500.35	$676.00	$779.43	$874.20	$972.10	$1,080.23	$1,193.83	$1,349.88	$1,600.96	$2,436.43
20	Total Supply	3,687.90	1,330.71	1,987.77	2,397.69	2,763.87	3,144.29	3,569.10	4,042.53	4,672.68	5,682.20	9,193.41
21	Totals	$4,766.85	$1,831.06	$2,663.77	$3,177.12	$3,638.07	$4,116.39	$4,649.33	$5,236.36	$6,022.56	$7,283.16	$11,629.84
25	**Increase Amount**											
26	Delivery	$138.01	$50.95	$79.56	$95.50	$110.54	$125.89	$142.83	$159.51	$183.12	$221.36	$342.96
27	Supply	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
28	Totals	$138.01	$50.95	$79.56	$95.50	$110.54	$125.89	$142.83	$159.51	$183.12	$221.36	$342.96
32	**Increase Percent**											
33	Delivery	14.7	11.3	13.3	14.0	14.5	14.9	15.2	15.4	15.7	16.0	16.4
34	Supply	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
35	Totals	3.0	2.9	3.1	3.1	3.1	3.2	3.2	3.1	3.1	3.1	3.0

39 Notes: Bills include SUT.
40 Each band represents a decile of customers segmented by annual kWhr usage.

Filing "9 and 3"

COMPARISON OF TYPICAL BILLS
Rate Schedule RLM
Including Tax Adjustment Credit and Distribution Adjustment Charge

	Annual Usages										
Units	**Class Avg**	**Band 1**	**Band 2**	**Band 3**	**Band 4**	**Band 5**	**Band 6**	**Band 7**	**Band 8**	**Band 9**	**Band 10**
Serv Chg	12	12	12	12	12	12	12	12	12	12	12
Distribution June - September On Peak	3,223	1,204	1,922	2,302	2,670	3,043	3,452	3,829	4,380	5,280	7,999
Distribution June - September Off Peak	3,531	1,344	2,045	2,425	2,781	3,186	3,553	3,970	4,629	5,518	8,678
Distribution October - May On Peak	3,877	1,315	1,931	2,323	2,717	3,070	3,565	4,081	4,708	5,759	9,680
Distribution October - May Off Peak	5,091	1,816	2,571	3,169	3,602	4,093	4,619	5,331	6,186	7,647	12,837
Total	15,722	5,679	8,469	10,218	11,770	13,392	15,189	17,210	19,903	24,203	39,194
Avg Summer Use	1,689	637	992	1,182	1,363	1,557	1,751	1,950	2,252	2,699	4,169
Avg Winter Use	1,121	391	563	686	790	895	1,023	1,176	1,362	1,676	2,815
Present Bill											
Total Delivery	$940.94	$449.40	$596.44	$683.93	$763.66	$846.21	$937.40	$1,034.32	$1,166.76	$1,379.60	$2,093.47
Total Supply	3,687.90	1,330.71	1,987.77	2,397.69	2,763.87	3,144.29	3,569.10	4,042.53	4,672.68	5,682.20	9,193.41
Totals	$4,628.84	$1,780.11	$2,584.21	$3,081.62	$3,527.53	$3,990.50	$4,506.50	$5,076.85	$5,839.44	$7,061.80	$11,286.88
Proposed Bill											
Total Delivery	$1,021.50	$479.60	$645.05	$742.10	$831.20	$923.17	$1,024.72	$1,130.95	$1,277.15	$1,512.52	$2,293.22
Total Supply	3,687.90	1,330.71	1,987.77	2,397.69	2,763.87	3,144.29	3,569.10	4,042.53	4,672.68	5,682.20	9,193.41
Totals	$4,709.40	$1,810.31	$2,632.82	$3,139.79	$3,595.07	$4,067.46	$4,593.82	$5,173.48	$5,949.83	$7,194.72	$11,486.63
Increase Amount											
Delivery	$80.56	$30.20	$48.61	$58.17	$67.54	$76.96	$87.32	$96.63	$110.39	$132.92	$199.75
Supply	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Totals	$80.56	$30.20	$48.61	$58.17	$67.54	$76.96	$87.32	$96.63	$110.39	$132.92	$199.75
Increase Percent											
Delivery	8.6	6.7	8.2	8.5	8.8	9.1	9.3	9.3	9.5	9.6	9.5
Supply	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Totals	1.7	1.7	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.8

Notes: Bills include SUT.
Each band represents a decile of customers segmented by annual kWhr usage.
Assumes approval of 2023 TAC filing, plus proposed TAC and DAC

COMPARISON OF TYPICAL BILLS
Rate Schedule GLP
Estimated Demand
Distribution Only

		Annual Usages										
Units		**GLP Class Avg**	**Band 1**	**Band 2**	**Band 3**	**Band 4**	**Band 5**	**Band 6**	**Band 7**	**Band 8**	**Band 9**	**Band 10**
Serv Chg		12	12	12	12	12	12	12	12	12	12	12
Distrib. KW Annual		96	8	17	26	38	54	74	103	145	213	512
Distrib. KW June-September		96	3	6	9	14	19	27	37	53	79	188
Distribution kWhr, June-September		9,444	266	895	1,584	2,398	3,431	5,153	8,006	12,998	23,784	66,911
Distribution kWhr, October-May		16,431	563	1,802	3,070	4,502	6,407	9,281	14,101	22,702	39,147	113,456
	Total	25,875	829	2,697	4,654	6,900	9,838	14,434	22,107	35,700	62,932	180,367
Gen Cap Obl June-September		25	2	5	8	12	17	24	34	48	72	173
Gen Cap Obl October-May		46	5	10	16	24	34	48	68	96	145	347
Trans Cap Obl		64	7	15	25	36	51	72	102	144	217	520
Present Bill												
Total Delivery		$2,186.77	$152.24	$276.06	$406.10	$573.18	$783.47	$1,083.94	$1,535.02	$2,250.69	$3,540.56	$9,117.60
Total Supply		3,263.10	187.46	480.02	798.97	1,177.57	1,672.48	2,398.28	3,546.85	5,384.56	8,908.63	23,878.82
Totals		$5,449.87	$339.70	$756.08	$1,205.07	$1,750.75	$2,455.95	$3,482.22	$5,081.87	$7,635.25	$12,449.19	$32,996.42
Proposed Bill												
Total Delivery		$3,185.39	$224.51	$388.36	$561.97	$786.41	$1,067.70	$1,469.48	$2,067.03	$3,001.12	$4,682.53	$11,864.29
Total Supply		3,263.10	187.46	480.02	798.97	1,177.57	1,672.48	2,398.28	3,546.85	5,384.56	8,908.63	23,878.82
Totals		$6,448.49	$411.97	$868.38	$1,360.94	$1,963.98	$2,740.18	$3,867.76	$5,613.88	$8,385.68	$13,591.16	$35,743.11
Increase Amount												
Delivery		$998.62	$72.27	$112.30	$155.87	$213.23	$284.23	$385.54	$532.01	$750.43	$1,141.97	$2,746.69
Supply		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Totals		$998.62	$72.27	$112.30	$155.87	$213.23	$284.23	$385.54	$532.01	$750.43	$1,141.97	$2,746.69
Increase Percent												
Delivery		45.7	47.5	40.7	38.4	37.2	36.3	35.6	34.7	33.3	32.3	30.1
Supply		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Totals		18.3	21.3	14.9	12.9	12.2	11.6	11.1	10.5	9.8	9.2	8.3

Notes: Bills include SUT
Each band represents a decile of customers segmented by annual kWhr usage.

COMPARISON OF TYPICAL BILLS
Rate Schedule GLP
Estimated Demand
Including Tax Adjustment Credit and Distribution Adjustment Charge

	Annual Usages										
Units	**GLP Class Avg**	**Band 1**	**Band 2**	**Band 3**	**Band 4**	**Band 5**	**Band 6**	**Band 7**	**Band 8**	**Band 9**	**Band 10**
Serv Chg	12	12	12	12	12	12	12	12	12	12	12
Distrib. KW Annual	96	8	17	26	38	54	74	103	145	213	512
Distrib. KW June-September	96	3	6	9	14	19	27	37	53	79	188
Distribution kWhr, June-September	9,444	266	895	1,584	2,398	3,431	5,153	8,006	12,998	23,784	66,911
Distribution kWhr, October-May	16,431	563	1,802	3,070	4,502	6,407	9,281	14,101	22,702	39,147	113,456
Total	25,875	829	2,697	4,654	6,900	9,838	14,434	22,107	35,700	62,932	180,367
Gen Cap Obl June-September	25	2	5	8	12	17	24	34	48	72	173
Gen Cap Obl October-May	46	5	10	16	24	34	48	68	96	145	347
Trans Cap Obl	64	7	15	25	36	51	72	102	144	217	520
Present Bill											
Total Delivery	$2,186.77	$152.24	$276.06	$406.10	$573.18	$783.47	$1,083.94	$1,535.02	$2,250.69	$3,540.56	$9,117.60
Total Supply	3,263.10	187.46	480.02	798.97	1,177.57	1,672.48	2,398.28	3,546.85	5,384.56	8,908.63	23,878.82
Totals	$5,449.87	$339.70	$756.08	$1,205.07	$1,750.75	$2,455.95	$3,482.22	$5,081.87	$7,635.25	$12,449.19	$32,996.42
Proposed Bill											
Total Delivery	$3,172.84	$224.10	$387.06	$559.72	$783.07	$1,062.92	$1,462.48	$2,056.31	$2,983.80	$4,652.01	$11,776.81
Total Supply	3,263.10	187.46	480.02	798.97	1,177.57	1,672.48	2,398.28	3,546.85	5,384.56	8,908.63	23,878.82
Totals	$6,435.94	$411.56	$867.08	$1,358.69	$1,960.64	$2,735.40	$3,860.76	$5,603.16	$8,368.36	$13,560.64	$35,655.63
Increase Amount											
Delivery	$986.07	$71.86	$111.00	$153.62	$209.89	$279.45	$378.54	$521.29	$733.11	$1,111.45	$2,659.21
Supply	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Totals	$986.07	$71.86	$111.00	$153.62	$209.89	$279.45	$378.54	$521.29	$733.11	$1,111.45	$2,659.21
Increase Percent											
Delivery	45.1	47.2	40.2	37.8	36.6	35.7	34.9	34.0	32.6	31.4	29.2
Supply	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Totals	18.1	21.2	14.7	12.7	12.0	11.4	10.9	10.3	9.6	8.9	8.1

Notes: Bills include SUT
Each band represents a decile of customers segmented by annual kWhr usage.
Assumes approval of 2023 TAC filing, plus proposed TAC and DAC

COMPARISON OF TYPICAL BILLS
Rate Schedule GLP
Measured Demand
Distribution Only

	Annual Usages										
Units	**Class Avg**	**Band 1**	**Band 2**	**Band 3**	**Band 4**	**Band 5**	**Band 6**	**Band 7**	**Band 8**	**Band 9**	**Band 10**
Serv Chg	12	12	12	12	12	12	12	12	12	12	12
Distrib. KW Annual	96	2	4	7	10	13	18	25	34	48	95
Distrib. KW June-September	96	1	1	2	3	4	6	9	12	16	30
Distribution kWhr, June-September	9,444	50	126	207	308	437	612	849	1,162	1,611	3,003
Distribution kWhr, October-May	16,431	110	274	448	654	901	1,231	1,659	2,256	3,195	6,487
Total	25,875	160	400	655	962	1,339	1,843	2,508	3,417	4,805	9,490
Gen Cap Obl June-September	25	0	1	2	3	4	5	7	10	14	24
Gen Cap Obl October-May	46	1	2	4	5	8	11	15	20	28	49
Trans Cap Obl	64	1	3	6	8	11	16	22	30	41	73
Present Bill											
Total Delivery	$2,186.77	$80.25	$106.94	$135.08	$169.19	$211.77	$268.83	$344.75	$447.23	$601.08	$1,108.81
Total Supply	3,263.10	37.64	88.97	146.16	213.88	300.54	419.19	576.75	782.50	1,083.21	1,997.19
Totals	$5,449.87	$117.89	$195.91	$281.24	$383.07	$512.31	$688.02	$921.50	$1,229.73	$1,684.29	$3,106.00
Proposed Bill											
Total Delivery	$3,185.39	$126.03	$162.34	$200.63	$247.26	$305.81	$384.38	$489.34	$630.28	$840.17	$1,524.87
Total Supply	3,263.10	37.64	88.97	146.16	213.88	300.54	419.19	576.75	782.50	1,083.21	1,997.19
Totals	$6,448.49	$163.67	$251.31	$346.79	$461.14	$606.35	$803.57	$1,066.09	$1,412.78	$1,923.38	$3,522.06
Increase Amount											
Delivery	$998.62	$45.78	$55.40	$65.55	$78.07	$94.04	$115.55	$144.59	$183.05	$239.09	$416.06
Supply	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Totals	$998.62	$45.78	$55.40	$65.55	$78.07	$94.04	$115.55	$144.59	$183.05	$239.09	$416.06
Increase Percent											
Delivery	45.7	57.0	51.8	48.5	46.1	44.4	43.0	41.9	40.9	39.8	37.5
Supply	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Totals	18.3	38.8	28.3	23.3	20.4	18.4	16.8	15.7	14.9	14.2	13.4

Notes: Bills include SUT
Each band represents a decile of customers segmented by annual load factor.

COMPARISON OF TYPICAL BILLS
Rate Schedule GLP
Measured Demand
Including Tax Adjustment Credit and Distribution Adjustment Charge

	Annual Usages										
Units	**Class Avg**	**Band 1**	**Band 2**	**Band 3**	**Band 4**	**Band 5**	**Band 6**	**Band 7**	**Band 8**	**Band 9**	**Band 10**
Serv Chg	12	12	12	12	12	12	12	12	12	12	12
Distrib. KW Annual	96	2	4	7	10	13	18	25	34	48	95
Distrib. KW June-September	96	1	1	2	3	4	6	9	12	16	30
Distribution kWhr, June-September	9,444	50	126	207	308	437	612	849	1,162	1,611	3,003
Distribution kWhr, October-May	16,431	110	274	448	654	901	1,231	1,659	2,256	3,195	6,487
Total	25,875	160	400	655	962	1,339	1,843	2,508	3,417	4,805	9,490
Gen Cap Obl June-September	25	0	1	2	3	4	5	7	10	14	24
Gen Cap Obl October-May	46	1	2	4	5	8	11	15	20	28	49
Trans Cap Obl	64	1	3	6	8	11	16	22	30	41	73
Present Bill											
Total Delivery	$2,186.77	$80.25	$106.94	$135.08	$169.19	$211.77	$268.83	$344.75	$447.23	$601.08	$1,108.81
Total Supply	3,263.10	37.64	88.97	146.16	213.88	300.54	419.19	576.75	782.50	1,083.21	1,997.19
Totals	$5,449.87	$117.89	$195.91	$281.24	$383.07	$512.31	$688.02	$921.50	$1,229.73	$1,684.29	$3,106.00
Proposed Bill											
Total Delivery	$3,172.84	$125.95	$162.14	$200.31	$246.80	$305.17	$383.49	$488.12	$628.62	$837.84	$1,520.27
Total Supply	3,263.10	37.64	88.97	146.16	213.88	300.54	419.19	576.75	782.50	1,083.21	1,997.19
Totals	$6,435.94	$163.59	$251.11	$346.47	$460.68	$605.71	$802.68	$1,064.87	$1,411.12	$1,921.05	$3,517.46
Increase Amount											
Delivery	$986.07	$45.70	$55.20	$65.23	$77.61	$93.40	$114.66	$143.37	$181.39	$236.76	$411.46
Supply	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Totals	$986.07	$45.70	$55.20	$65.23	$77.61	$93.40	$114.66	$143.37	$181.39	$236.76	$411.46
Increase Percent											
Delivery	45.1	56.9	51.6	48.3	45.9	44.1	42.7	41.6	40.6	39.4	37.1
Supply	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Totals	18.1	38.8	28.2	23.2	20.3	18.2	16.7	15.6	14.8	14.1	13.2

Notes: Bills include SUT
Each band represents a decile of customers segmented by annual load factor.
Assumes approval of 2023 TAC filing, plus proposed TAC and DAC

COMPARISON OF TYPICAL BILLS
Rate Schedule LPL-Secondary
Distribution Only

	Annual Usages										
Units	**Class Avg**	**Band 1**	**Band 2**	**Band 3**	**Band 4**	**Band 5**	**Band 6**	**Band 7**	**Band 8**	**Band 9**	**Band 10**
Serv Chg	12	12	12	12	12	12	12	12	12	12	12
Distrib. KW Annual	2,714	1,400	2,275	2,529	2,950	3,530	4,212	5,262	6,769	9,438	18,652
Distrib. KW June - September	963	279	433	497	577	686	808	992	1,272	1,754	3,390
Distribution kWhr On Peak June-September	181,334	25,399	53,843	74,938	96,866	120,012	151,553	192,571	262,442	383,894	843,794
Distribution kWhr Off Peak June-September	195,549	25,268	54,364	74,625	95,933	118,964	149,828	191,282	256,008	373,056	813,112
Distribution kWhr On Peak October-May	356,006	47,089	97,005	131,980	161,477	201,435	244,692	316,210	421,554	621,580	1,359,169
Distribution kWhr Off Peak October-May	354,467	44,613	90,036	122,749	163,984	209,972	270,059	351,617	480,408	714,766	1,634,643
Total	1,087,356	142,369	295,247	404,292	518,261	650,383	816,132	1,051,680	1,420,413	2,093,296	4,650,718
Gen Cap Obl June-September	292	117	271	377	457	554	684	853	1,132	1,641	3,366
Gen Cap Obl October-May	591	234	541	753	915	1,109	1,367	1,706	2,265	3,282	6,733
Trans Cap Obl	764	351	812	1,130	1,372	1,663	2,051	2,558	3,397	4,924	10,099
Present Bill											
Total Delivery	$46,929.33	$16,645.18	$25,250.01	$29,119.87	$34,057.39	$40,391.37	$47,977.91	$59,257.68	$76,161.88	$106,332.92	$214,539.48
Total Supply	106,693.84	18,789.15	40,603.78	55,964.68	70,231.69	86,984.50	108,422.39	138,042.87	185,348.14	271,528.54	586,829.21
Totals	$153,623.17	$35,434.33	$65,853.79	$85,084.55	$104,289.08	$127,375.87	$156,400.30	$197,300.55	$261,510.02	$377,861.46	$801,368.69
Proposed Bill											
Total Delivery	$51,999.01	$18,221.75	$27,714.69	$31,935.75	$37,327.85	$44,281.67	$52,571.51	$64,911.80	$83,418.41	$116,355.77	$233,982.00
Total Supply	106,693.84	18,789.15	40,603.78	55,964.68	70,231.69	86,984.50	108,422.39	138,042.87	185,348.14	271,528.54	586,829.21
Totals	$158,692.85	$37,010.90	$68,318.47	$87,900.43	$107,559.54	$131,266.17	$160,993.90	$202,954.67	$268,766.55	$387,884.31	$820,811.21
Increase Amount											
Delivery	$5,069.68	$1,576.57	$2,464.68	$2,815.88	$3,270.46	$3,890.30	$4,593.60	$5,654.12	$7,256.53	$10,022.85	$19,442.52
Supply	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Totals	$5,069.68	$1,576.57	$2,464.68	$2,815.88	$3,270.46	$3,890.30	$4,593.60	$5,654.12	$7,256.53	$10,022.85	$19,442.52
Increase Percent											
Delivery	10.8	9.5	9.8	9.7	9.6	9.6	9.6	9.5	9.5	9.4	9.1
Supply	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Totals	3.3	4.4	3.7	3.3	3.1	3.1	2.9	2.9	2.8	2.7	2.4

Notes: Bills include SUT
Each band represents a decile of customers segmented by annual load factor.
For presentation purposes, all bands billed at LPL-S BGS weighted average of the three subsets.

COMPARISON OF TYPICAL BILLS
Rate Schedule LPL-Secondary
Including Tax Adjustment Credit and Distribution Adjustment Charge

	Annual Usages										
Units	**Class Avg**	**Band 1**	**Band 2**	**Band 3**	**Band 4**	**Band 5**	**Band 6**	**Band 7**	**Band 8**	**Band 9**	**Band 10**
Serv Chg	12	12	12	12	12	12	12	12	12	12	12
Distrib. KW Annual	2,714	1,400	2,275	2,529	2,950	3,530	4,212	5,262	6,769	9,438	18,652
Distrib. KW June - September	963	279	433	497	577	686	808	992	1,272	1,754	3,390
Distribution kWhr On Peak June-September	181,334	25,399	53,843	74,938	96,866	120,012	151,553	192,571	262,442	383,894	843,794
Distribution kWhr Off Peak June-September	195,549	25,268	54,364	74,625	95,933	118,964	149,828	191,282	256,008	373,056	813,112
Distribution kWhr On Peak October-May	356,006	47,089	97,005	131,980	161,477	201,435	244,692	316,210	421,554	621,580	1,359,169
Distribution kWhr Off Peak October-May	354,467	44,613	90,036	122,749	163,984	209,972	270,059	351,617	480,408	714,766	1,634,643
Total	1,087,356	142,369	295,247	404,292	518,261	650,383	816,132	1,051,680	1,420,413	2,093,296	4,650,718
Gen Cap Obl June-September	292	117	271	377	457	554	684	853	1,132	1,641	3,366
Gen Cap Obl October-May	591	234	541	753	915	1,109	1,367	1,706	2,265	3,282	6,733
Trans Cap Obl	764	351	812	1,130	1,372	1,663	2,051	2,558	3,397	4,924	10,099
Present Bill											
Total Delivery	$46,929.33	$16,645.18	$25,250.01	$29,119.87	$34,057.39	$40,391.37	$47,977.91	$59,257.68	$76,161.88	$106,332.92	$214,539.48
Total Supply	106,693.84	18,789.15	40,603.78	55,964.68	70,231.69	86,984.50	108,422.39	138,042.87	185,348.14	271,528.54	586,829.21
Totals	$153,623.17	$35,434.33	$65,853.79	$85,084.55	$104,289.08	$127,375.87	$156,400.30	$197,300.55	$261,510.02	$377,861.46	$801,368.69
Proposed Bill											
Total Delivery	$52,080.56	$18,232.43	$27,736.83	$31,966.07	$37,366.73	$44,330.45	$52,632.72	$64,990.67	$83,524.94	$116,512.77	$234,330.80
Total Supply	106,693.84	18,789.15	40,603.78	55,964.68	70,231.69	86,984.50	108,422.39	138,042.87	185,348.14	271,528.54	586,829.21
Totals	$158,774.40	$37,021.58	$68,340.61	$87,930.75	$107,598.42	$131,314.95	$161,055.11	$203,033.54	$268,873.08	$388,041.31	$821,160.01
Increase Amount											
Delivery	$5,151.23	$1,587.25	$2,486.82	$2,846.20	$3,309.34	$3,939.08	$4,654.81	$5,732.99	$7,363.06	$10,179.85	$19,791.32
Supply	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Totals	$5,151.23	$1,587.25	$2,486.82	$2,846.20	$3,309.34	$3,939.08	$4,654.81	$5,732.99	$7,363.06	$10,179.85	$19,791.32
Increase Percent											
Delivery	11.0	9.5	9.8	9.8	9.7	9.8	9.7	9.7	9.7	9.6	9.2
Supply	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Totals	3.4	4.5	3.8	3.3	3.2	3.1	3.0	2.9	2.8	2.7	2.5

Notes: Bills include SUT
Each band represents a decile of customers segmented by annual load factor.
For presentation purposes, all bands billed at LPL-S BGS weighted average of the three subsets.
Assumes approval of 2023 TAC filing, plus proposed TAC and DAC

COMPARISON OF TYPICAL BILLS
Rate Schedule LPL-Primary
Distribution Only

		Annual Usages										
	Units	**Class Avg**	**Band 1**	**Band 2**	**Band 3**	**Band 4**	**Band 5**	**Band 6**	**Band 7**	**Band 8**	**Band 9**	**Band 10**
1	Serv Chg	12	12	12	12	12	12	12	12	12	12	12
2	Distrib. KW Annual	2,714	1,100	2,811	4,768	7,573	10,236	14,038	19,799	25,940	35,106	57,845
3	Distrib. KW Summer	963	165	494	859	1,346	1,883	2,523	3,796	4,772	6,480	10,839
4	Distribution kWhr On Peak June-September	181,334	20,156	67,741	130,817	204,213	335,781	498,004	752,300	1,045,259	1,559,226	2,988,621
5	Distribution kWhr Off Peak June-September	195,549	20,326	66,030	127,966	200,581	333,081	482,184	754,173	1,018,973	1,544,192	2,895,629
6	Distribution kWhr On Peak October-May	356,006	46,689	130,894	238,866	368,645	575,666	826,909	1,189,320	1,649,063	2,332,737	4,409,388
7	Distribution kWhr Off Peak October-May	354,467	57,709	144,733	263,185	425,957	673,746	1,023,554	1,382,934	1,999,682	3,007,330	5,579,838
8	Total	1,087,356	144,880	409,398	760,834	1,199,396	1,918,274	2,830,651	4,078,727	5,712,977	8,443,485	15,873,475
9												
10	Gen Cap Obl June-September	292	69	271	433	822	1,223	1,779	3,203	3,906	5,459	10,838
11	Gen Cap Obl October-May	591	137	541	866	1,644	2,445	3,559	6,407	7,812	10,917	21,675
12	Trans Cap Obl	764	206	812	1,298	2,465	3,668	5,338	9,610	11,718	16,376	32,513
13												
14												
15	**Present Bill**											
16	Total Delivery	$39,086.20	$10,777.42	$22,074.50	$35,784.98	$53,863.49	$77,335.90	$107,473.29	$153,738.38	$204,789.45	$288,852.19	$510,694.93
17	Total Supply	112,620.76	17,430.11	55,798.66	98,231.25	166,050.12	258,569.15	379,419.15	599,968.24	792,691.56	1,147,116.90	2,203,885.64
18	Totals	$151,706.96	$28,207.53	$77,873.16	$134,016.23	$219,913.61	$335,905.05	$486,892.44	$753,706.62	$997,481.01	$1,435,969.09	$2,714,580.57
19												
20												
21												
22	**Proposed Bill**											
23	Total Delivery	$47,596.18	$13,116.40	$28,409.68	$46,638.23	$71,009.39	$100,824.32	$139,392.96	$199,925.26	$264,315.51	$369,513.62	$644,402.66
24	Total Supply	112,620.76	17,430.11	55,798.66	98,231.25	166,050.12	258,569.15	379,419.15	599,968.24	792,691.56	1,147,116.90	2,203,885.64
25	Totals	$160,216.94	$30,546.51	$84,208.34	$144,869.48	$237,059.51	$359,393.47	$518,812.11	$799,893.50	$1,057,007.07	$1,516,630.52	$2,848,288.30
26												
27												
28												
29	**Increase Amount**											
30	Delivery	$8,509.98	$2,338.98	$6,335.18	$10,853.25	$17,145.90	$23,488.42	$31,919.67	$46,186.88	$59,526.06	$80,661.43	$133,707.73
31	Supply	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
32	Totals	$8,509.98	$2,338.98	$6,335.18	$10,853.25	$17,145.90	$23,488.42	$31,919.67	$46,186.88	$59,526.06	$80,661.43	$133,707.73
33												
34												
35												
36	**Increase Percent**											
37	Delivery	21.8	21.7	28.7	30.3	31.8	30.4	29.7	30.0	29.1	27.9	26.2
38	Supply	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
39	Totals	5.6	8.3	8.1	8.1	7.8	7.0	6.6	6.1	6.0	5.6	4.9
40												
41												
42												
43	Notes:	Bills include SUT										
44		Each band represents a decile of customers segmented by annual load factor.										

COMPARISON OF TYPICAL BILLS
Rate Schedule LPL-Primary
Including Tax Adjustment Credit and Distribution Adjustment Charge

	Annual Usages										
Units	**Class Avg**	**Band 1**	**Band 2**	**Band 3**	**Band 4**	**Band 5**	**Band 6**	**Band 7**	**Band 8**	**Band 9**	**Band 10**
Serv Chg	12	12	12	12	12	12	12	12	12	12	12
Distrib. KW Annual	2,714	1,100	2,811	4,768	7,573	10,236	14,038	19,799	25,940	35,106	57,845
Distrib. KW Summer	963	165	494	859	1,346	1,883	2,523	3,796	4,772	6,480	10,839
Distribution kWhr On Peak June-September	181,334	20,156	67,741	130,817	204,213	335,781	498,004	752,300	1,045,259	1,559,226	2,988,621
Distribution kWhr Off Peak June-September	195,549	20,326	66,030	127,966	200,581	333,081	482,184	754,173	1,018,973	1,544,192	2,895,629
Distribution kWhr On Peak October-May	356,006	46,689	130,894	238,866	368,645	575,666	826,909	1,189,320	1,649,063	2,332,737	4,409,388
Distribution kWhr Off Peak October-May	354,467	57,709	144,733	263,185	425,957	673,746	1,023,554	1,382,934	1,999,682	3,007,330	5,579,838
Total	1,087,356	144,880	409,398	760,834	1,199,396	1,918,274	2,830,651	4,078,727	5,712,977	8,443,485	15,873,475
Gen Cap Obl June-September	292	69	271	433	822	1,223	1,779	3,203	3,906	5,459	10,838
Gen Cap Obl October-May	591	137	541	866	1,644	2,445	3,559	6,407	7,812	10,917	21,675
Trans Cap Obl	764	206	812	1,298	2,465	3,668	5,338	9,610	11,718	16,376	32,513
Present Bill											
Total Delivery	$39,086.20	$10,777.42	$22,074.50	$35,784.98	$53,863.49	$77,335.90	$107,473.29	$153,738.38	$204,789.45	$288,852.19	$510,694.93
Total Supply	112,620.76	17,430.11	55,798.66	98,231.25	166,050.12	258,569.15	379,419.15	599,968.24	792,691.56	1,147,116.90	2,203,885.64
Totals	$151,706.96	$28,207.53	$77,873.16	$134,016.23	$219,913.61	$335,905.05	$486,892.44	$753,706.62	$997,481.01	$1,435,969.09	$2,714,580.57
Proposed Bill											
Total Delivery	$48,147.47	$13,189.86	$28,617.25	$47,023.97	$71,617.48	$101,796.88	$140,828.09	$201,993.18	$267,212.00	$373,794.47	$652,450.50
Total Supply	112,620.76	17,430.11	55,798.66	98,231.25	166,050.12	258,569.15	379,419.15	599,968.24	792,691.56	1,147,116.90	2,203,885.64
Totals	$160,768.23	$30,619.97	$84,415.91	$145,255.22	$237,667.60	$360,366.03	$520,247.24	$801,961.42	$1,059,903.56	$1,520,911.37	$2,856,336.14
Increase Amount											
Delivery	$9,061.27	$2,412.44	$6,542.75	$11,238.99	$17,753.99	$24,460.98	$33,354.80	$48,254.80	$62,422.55	$84,942.28	$141,755.57
Supply	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Totals	$9,061.27	$2,412.44	$6,542.75	$11,238.99	$17,753.99	$24,460.98	$33,354.80	$48,254.80	$62,422.55	$84,942.28	$141,755.57
Increase Percent											
Delivery	23.2	22.4	29.6	31.4	33.0	31.6	31.0	31.4	30.5	29.4	27.8
Supply	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Totals	6.0	8.6	8.4	8.4	8.1	7.3	6.9	6.4	6.3	5.9	5.2

Notes: Bills include SUT
Each band represents a decile of customers segmented by annual load factor.
Assumes approval of 2023 TAC filing, plus proposed TAC and DAC

COMPARISON OF TYPICAL BILLS
Rate Schedule HTS-Subtransmission
Distribution Only

		Annual Usages										
	Units	**Class Avg**	**Band 1**	**Band 2**	**Band 3**	**Band 4**	**Band 5**	**Band 6**	**Band 7**	**Band 8**	**Band 9**	**Band 10**
1	Serv Chg	12	12	12	12	12	12	12	12	12	12	12
2	Distrib. KW Annual	8,510	16,016	33,517	43,054	53,114	64,352	92,050	118,125	126,668	205,192	304,897
3	Distrib. KW Summer	3,229	2,835	5,634	7,592	8,661	11,865	18,147	20,700	22,409	37,283	54,058
4	Distribution kWhr June-September/ On Peak	657,674	261,688	745,560	1,347,361	1,702,401	2,668,654	3,764,815	4,407,798	6,032,750	10,071,192	15,427,406
5	Spare/Distribution kWhr June-September Off Peak	802,348	245,371	716,258	1,294,689	1,697,360	2,581,557	3,537,903	4,076,519	5,732,295	9,604,244	14,878,490
6	Distribution kWhr October-May/ On Peak	1,119,467	460,351	1,284,320	2,422,003	3,059,030	4,074,529	4,889,331	6,818,869	9,162,160	15,671,095	24,184,459
7	Spare/Distribution kWhr October-May Off Peak	1,248,432	485,083	1,728,891	2,634,840	4,175,256	5,130,556	6,538,649	9,239,434	12,604,177	21,281,831	32,307,388
8	Total	3,827,922	1,452,493	4,475,029	7,698,893	10,634,047	14,455,295	18,730,698	24,542,620	33,531,382	56,628,362	86,797,743
9												
10	Gen Cap Obl June-September	640	777	1,993	4,850	5,444	9,776	12,896	12,947	19,450	31,425	43,055
11	Gen Cap Obl October-May	1,354	1,553	3,986	9,701	10,887	19,552	25,792	25,893	38,900	62,849	86,109
12	Trans Cap Obl	1,758	2,330	5,980	14,551	16,331	29,328	38,688	38,840	58,350	94,274	129,164
13												
14												
15	**Present Bill**											
16	Total Delivery	$119,772.94	$83,986.11	$173,922.66	$253,717.52	$324,855.07	$423,365.75	$564,815.76	$715,388.66	$898,187.65	$1,486,518.53	$2,239,364.46
17	Total Supply	359,294.15	179,124.58	517,820.85	1,007,799.97	1,286,235.45	1,951,393.52	2,555,921.15	3,010,864.65	4,258,821.06	7,074,108.41	10,433,142.28
18	Totals	$479,067.09	$263,110.69	$691,743.51	$1,261,517.49	$1,611,090.52	$2,374,759.27	$3,120,736.91	$3,726,253.31	$5,157,008.71	$8,560,626.94	$12,672,506.74
19												
20												
21												
22	**Proposed Bill**											
23	Total Delivery	$135,094.40	$103,924.40	$214,830.87	$307,239.00	$388,946.59	$504,783.58	$684,501.24	$861,876.31	$1,055,850.77	$1,744,614.53	$2,619,194.16
24	Total Supply	359,294.15	179,124.58	517,820.85	1,007,799.97	1,286,235.45	1,951,393.52	2,555,921.15	3,010,864.65	4,258,821.06	7,074,108.41	10,433,142.28
25	Totals	$494,388.55	$283,048.98	$732,651.72	$1,315,038.97	$1,675,182.04	$2,456,177.10	$3,240,422.39	$3,872,740.96	$5,314,671.83	$8,818,722.94	$13,052,336.44
26												
27												
28												
29	**Increase Amount**											
30	Delivery	$15,321.46	$19,938.29	$40,908.21	$53,521.48	$64,091.52	$81,417.83	$119,685.48	$146,487.65	$157,663.12	$258,096.00	$379,829.70
31	Supply	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
32	Totals	$15,321.46	$19,938.29	$40,908.21	$53,521.48	$64,091.52	$81,417.83	$119,685.48	$146,487.65	$157,663.12	$258,096.00	$379,829.70
33												
34												
35												
36	**Increase Percent**											
37	Delivery	12.8	23.7	23.5	21.1	19.7	19.2	21.2	20.5	17.6	17.4	17.0
38	Supply	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
39	Totals	3.2	7.6	5.9	4.2	4.0	3.4	3.8	3.9	3.1	3.0	3.0
40												
41												
42												

43 Notes: Bills include SUT
44 Each band represents a decile of customers segmented by annual load factor.

COMPARISON OF TYPICAL BILLS
Rate Schedule HTS-Subtransmission
Including Tax Adjustment Credit and Distribution Adjustment Charge

	Annual Usages										
Units	**Class Avg**	**Band 1**	**Band 2**	**Band 3**	**Band 4**	**Band 5**	**Band 6**	**Band 7**	**Band 8**	**Band 9**	**Band 10**
Serv Chg	12	12	12	12	12	12	12	12	12	12	12
Distrib. KW Annual	8,510	16,016	33,517	43,054	53,114	64,352	92,050	118,125	126,668	205,192	304,897
Distrib. KW Summer	3,229	2,835	5,634	7,592	8,661	11,865	18,147	20,700	22,409	37,283	54,058
Distribution kWhr June-September/ On Peak	657,674	261,688	745,560	1,347,361	1,702,401	2,668,654	3,764,815	4,407,798	6,032,750	10,071,192	15,427,406
Spare/Distribution kWhr June-September Off Peak	802,348	245,371	716,258	1,294,689	1,697,360	2,581,557	3,537,903	4,076,519	5,732,295	9,604,244	14,878,490
Distribution kWhr October-May/ On Peak	1,119,467	460,351	1,284,320	2,422,003	3,059,030	4,074,529	4,889,331	6,818,869	9,162,160	15,671,095	24,184,459
Spare/Distribution kWhr October-May Off Peak	1,248,432	485,083	1,728,891	2,634,840	4,175,256	5,130,556	6,538,649	9,239,434	12,604,177	21,281,831	32,307,388
Total	3,827,922	1,452,493	4,475,029	7,698,893	10,634,047	14,455,295	18,730,698	24,542,620	33,531,382	56,628,362	86,797,743
Gen Cap Obl June-September	640	777	1,993	4,850	5,444	9,776	12,896	12,947	19,450	31,425	43,055
Gen Cap Obl October-May	1,354	1,553	3,986	9,701	10,887	19,552	25,792	25,893	38,900	62,849	86,109
Trans Cap Obl	1,758	2,330	5,980	14,551	16,331	29,328	38,688	38,840	58,350	94,274	129,164
Present Bill											
Total Delivery	$119,772.94	$83,986.11	$173,922.66	$253,717.52	$324,855.07	$423,365.75	$564,815.76	$715,388.66	$898,187.65	$1,486,518.53	$2,239,364.46
Total Supply	359,294.15	179,124.58	517,820.85	1,007,799.97	1,286,235.45	1,951,393.52	2,555,921.15	3,010,864.65	4,258,821.06	7,074,108.41	10,433,142.28
Totals	$479,067.09	$263,110.69	$691,743.51	$1,261,517.49	$1,611,090.52	$2,374,759.27	$3,120,736.91	$3,726,253.31	$5,157,008.71	$8,560,626.94	$12,672,506.74
Proposed Bill											
Total Delivery	$137,157.65	$104,707.29	$217,242.91	$311,388.70	$394,678.35	$512,574.98	$694,597.08	$875,104.78	$1,073,924.18	$1,775,137.21	$2,665,978.15
Total Supply	359,294.15	179,124.58	517,820.85	1,007,799.97	1,286,235.45	1,951,393.52	2,555,921.15	3,010,864.65	4,258,821.06	7,074,108.41	10,433,142.28
Totals	$496,451.80	$283,831.87	$735,063.76	$1,319,188.67	$1,680,913.80	$2,463,968.50	$3,250,518.23	$3,885,969.43	$5,332,745.24	$8,849,245.62	$13,099,120.43
Increase Amount											
Delivery	$17,384.71	$20,721.18	$43,320.25	$57,671.18	$69,823.28	$89,209.23	$129,781.32	$159,716.12	$175,736.53	$288,618.68	$426,613.69
Supply	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Totals	$17,384.71	$20,721.18	$43,320.25	$57,671.18	$69,823.28	$89,209.23	$129,781.32	$159,716.12	$175,736.53	$288,618.68	$426,613.69
Increase Percent											
Delivery	14.5	24.7	24.9	22.7	21.5	21.1	23.0	22.3	19.6	19.4	19.1
Supply	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Totals	3.6	7.9	6.3	4.6	4.3	3.8	4.2	4.3	3.4	3.4	3.4

Notes: Bills include SUT
Each band represents a decile of customers segmented by annual load factor.
Assumes approval of 2023 TAC filing, plus proposed TAC and DAC

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	S	**SUMMARY OF RESULTS**									
2	S	**DEVELOPMENT OF RETURN**									
3	S										
4	S	**RATE BASE**									
5	S	Plant in Service									
6	S	Production Plant E310-E346	CALCULATED	0	0	0	0	0	0	0	0
7	S	Transmission Plant E350-E359	CALCULATED	0	0	0	0	0	0	0	0
8	S	Distribution Plant									
9	S	Land & Structures E360-E361	CALCULATED	293,570,614	115,892,513	580,978	1,461,893	2,460	30	91,721	1,191,740
10	S	Station Equipment E362	CALCULATED	1,565,418,169	617,978,217	3,097,969	7,795,309	13,118	160	489,085	6,354,762
11	S	Poles, Towers, and Fixtures E364	CALCULATED	1,027,443,483	433,581,460	2,157,854	5,455,077	9,018	110	342,481	12,482,595
12	S	OH Conductors and Devices E365	CALCULATED	2,856,184,590	1,193,105,100	5,877,809	14,956,690	24,103	295	939,868	13,903,094
13	S	UG Conductors E366	CALCULATED	512,107,003	222,350,106	1,098,632	2,809,297	49,885	248	175,262	3,071,260
14	S	UG Conduits and Devices E367	CALCULATED	1,431,183,475	621,400,988	3,070,344	7,851,131	139,414	692	489,805	8,583,237
15	S	Line Transformers E368	CALCULATED	1,591,690,631	731,076,335	3,630,886	9,191,170	15,115	185	577,148	7,322,506
16	S	Services E369	CALCULATED	535,269,333	838,818	5,280,717	143,188,891	330,263,894	1,401,425	0	0
17	S	Meters E370	CALCULATED	365,421,442	219,378,176	762,138	1,273,316	171,335	2,673	86,562	0
18	S	Street Lighting E373	CALCULATED	499,027,153	13,889,907	87,308	674,847	1,154,367	4,901	10,958	341,917,862
19	S	Asset Retirement Obligations E374	CALCULATED	96,512,525	40,728,315	202,697	512,421	847	10	32,171	1,172,548
20	S	Other Distribution and Unallocated Plant	CALCULATED	0	0	0	0	0	0	0	0
21	S	Total Distribution Plant	CALCULATED	10,773,828,418	4,210,219,934	25,847,331	195,170,040	331,843,556	1,410,730	3,235,061	395,999,604
22	S	General Plant E389-E399	CALCULATED	429,584,593	164,713,403	1,035,337	8,002,670	13,689,057	58,115	129,947	16,344,031
23	S	Common Plant C389-C399	CALCULATED	126,654,044	67,736,462	345,628	1,081,945	1,086,672	4,711	121,195	1,611,631
24	S	Intangible Plant E301-E303, E399, C303-C390	CALCULATED	126,923,895	66,821,708	343,194	1,154,805	1,256,176	5,431	115,567	1,791,287
25	S	Total Plant in Service	CALCULATED	11,456,990,950	4,509,491,507	27,571,490	205,409,461	347,875,461	1,478,986	3,601,770	415,746,553
26	S										
27	S	Less: Reserve for Depreciation and Amorization	CALCULATED	3,099,332,698	1,206,907,087	8,335,934	81,854,978	155,879,252	662,476	999,183	103,115,208
28	S	Plus: Rate Base Additions									
29	S	Working Capital	CALCULATED	1,183,336,038	502,892,157	2,588,794	11,128,539	12,687,490	54,600	439,901	50,809,730
30	S	Plant Held for Future Use	CALCULATED	489,291	192,586	1,177	8,772	14,857	63	154	17,755
31	S	Capital Stimulus	CALCULATED	0	0	0	0	0	0	0	0
32	S	Other Rate Base Additions		2,066,897,171	1,083,551,380	5,055,155	27,141,802	40,955,173	179,254	623,527	51,951,310
33	S	Plus: Rate Base Deductions									
34	S	Customer Advances	CALCULATED	-63,907,492	-27,751,477	-149,270	-819,363	-1,187,423	-5,090	-23,848	-2,271,963
35	S	Unbilled Revenue	CALCULATED	0	0	0	0	0	0	0	0
36	S	Deferred Income Taxes and Credits	CALCULATED	-1,717,952,304	-678,440,528	-4,141,808	-30,672,767	-51,859,282	-220,481	-552,528	-61,958,984
37	S	Other Rate Base Deductions		-40,898,861	-17,084,554	-84,167	-214,171	-345	-4	-13,458	-199,084
38	S										
39	S	TOTAL RATE BASE		9,785,622,095	4,165,943,983	22,505,436	130,127,297	192,606,679	824,852	3,076,333	350,980,110
40	S										
41	S										
42	S										
43	S										
44	S										
45	S										
46	S										
47	S										
48	S										
49	S										
50	S	**SUMMARY OF RESULTS**									

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
1	S	**SUMMARY OF RESULTS**								
2	S	**DEVELOPMENT OF RETURN**								
3	S									
4	S	**RATE BASE**								
5	S	Plant in Service								
6	S	Production Plant E310-E346	CALCULATED	0	0	0	0	0	0	0
7	S	Transmission Plant E350-E359	CALCULATED	0	0	0	0	0	0	0
8	S	Distribution Plant								
9	S	Land & Structures E360-E361	CALCULATED	64,418	578,502	62,421,674	70,570,214	19,334,206	21,380,266	0
10	S	Station Equipment E362	CALCULATED	343,500	3,084,771	332,853,557	376,304,339	103,096,548	114,006,835	0
11	S	Poles, Towers, and Fixtures E364	CALCULATED	236,131	3,933,380	233,568,272	262,593,524	38,910,712	34,172,869	0
12	S	OH Conductors and Devices E365	CALCULATED	631,159	12,104,603	642,849,684	717,141,426	186,643,064	68,007,696	0
13	S	UG Conductors E366	CALCULATED	118,401	1,392,172	119,804,922	133,875,585	21,072,679	6,288,555	0
14	S	UG Conduits and Devices E367	CALCULATED	330,894	3,890,698	334,818,356	374,141,583	58,891,734	17,574,600	0
15	S	Line Transformers E368	CALCULATED	395,810	3,554,541	393,843,633	442,083,302	0	0	0
16	S	Services E369	CALCULATED	0	0	53,039,066	1,013,079	243,028	415	0
17	S	Meters E370	CALCULATED	0	0	114,562,020	17,717,782	8,334,371	2,831,414	301,654
18	S	Street Lighting E373	CALCULATED	7,483	122,789,628	7,666,746	8,390,589	1,508,270	924,286	0
19	S	Asset Retirement Obligations E374	CALCULATED	22,181	369,481	21,940,150	24,666,626	3,655,063	3,210,016	0
20	S	Other Distribution and Unallocated Plant	CALCULATED	0	0	0	0	0	0	0
21	S	Total Distribution Plant	CALCULATED	2,149,976	151,697,776	2,317,368,080	2,428,498,049	441,689,675	268,396,952	301,654
22	S	General Plant E389-E399	CALCULATED	88,736	6,260,999	90,916,078	99,499,766	17,885,807	10,960,646	0
23	S	Common Plant C389-C399	CALCULATED	20,663	1,091,256	25,189,287	18,477,440	3,731,250	4,465,781	1,690,125
24	S	Intangible Plant E301-E303, E399, C303-C390	CALCULATED	20,849	1,121,837	25,501,178	19,025,068	3,822,878	4,367,181	1,576,735
25	S	Total Plant in Service	CALCULATED	2,280,224	160,171,869	2,458,974,623	2,565,500,323	467,129,611	288,190,559	3,568,514
26	S									
27	S	Less: Reserve for Depreciation and Amorization	CALCULATED	585,098	40,022,961	660,087,229	658,722,048	115,325,242	64,723,429	2,112,572
28	S	Plus: Rate Base Additions								
29	S	Working Capital	CALCULATED	647,124	20,760,373	258,969,818	240,553,235	49,432,335	30,538,511	1,833,433
30	S	Plant Held for Future Use	CALCULATED	97	6,840	105,015	109,564	19,950	12,308	152
31	S	Capital Stimulus	CALCULATED	0	0	0	0	0	0	0
32	S	Other Rate Base Additions		290,245	19,950,296	425,621,608	317,670,610	58,045,487	35,714,221	147,103
33	S	Plus: Rate Base Deductions								
34	S	Customer Advances	CALCULATED	-24,926	-919,826	-13,441,276	-13,056,531	-2,504,089	-1,655,135	-97,273
35	S	Unbilled Revenue	CALCULATED	0	0	0	0	0	0	0
36	S	Deferred Income Taxes and Credits	CALCULATED	-341,619	-23,942,578	-368,203,938	-383,543,778	-69,857,991	-43,432,283	-783,739
37	S	Other Rate Base Deductions		-9,038	-173,331	-9,205,224	-10,269,038	-2,672,617	-973,830	0
38	S									
39	S	TOTAL RATE BASE		2,257,009	135,830,682	2,092,733,396	2,058,242,336	384,267,442	243,670,921	2,555,619
40	S									
41	S									
42	S									
43	S									
44	S									
45	S									
46	S									
47	S									
48	S									
49	S									
50	S	**SUMMARY OF RESULTS**								

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
51	S	**DEVELOPMENT OF RETURN**	CALCULATED								
52	S										
53	S	**RATE BASE**	CALCULATED	9,785,622,095	4,165,943,983	22,505,436	130,127,297	192,606,679	824,852	3,076,333	350,980,110
54	S										
55	S	**OPERATING REVENUES**									
56	S	Rate Revenues from Customers	CALCULATED	1,899,915,237	825,027,762	4,437,681	24,358,956	35,301,077	151,307	708,990	67,543,508
57	S	Other Operating Revenues	CALCULATED	25,104,439	9,297,260	50,008	274,502	397,809	1,705	10,769	761,150
58	S	Revenues from Other Sources	CALCULATED	0	0	0	0	0	0	0	0
59	S	Less: Provisions for Rate Refunds	CALCULATED	0	0	0	0	0	0	0	0
60	S	TOTAL OPERATING REVENUES		1,925,019,676	834,325,022	4,487,689	24,633,458	35,698,885	153,013	719,759	68,304,658
61	S										
62	S	**OPERATING EXPENSES**									
63	S	Operation and Maintenance Expense									
64	S	Production Expense	CALCULATED	0	0	0	0	0	0	0	0
65	S	Transmission Expense	CALCULATED	0	0	0	0	0	0	0	0
66	S	Distribution Expense	CALCULATED	178,009,259	73,234,083	346,050	871,978	58,430	387	53,760	9,412,940
67	S	Customer Accounts Expense	CALCULATED	94,394,062	54,630,961	269,518	459,527	8,652	132	117,538	337,369
68	S	Customer Service & Information Expense	CALCULATED	5,318,001	4,196,182	14,170	25,852	936	14	1,649	11,564
69	S	Sales Expense	CALCULATED	40,922	29,919	96	204	2	0	14	205
70	S	Administrative and General Expense	CALCULATED	33,695,393	9,085,296	94,562	1,394,410	2,758,639	11,655	-9,015	1,173,551
71	S	Total Operation and Maintenance Expense	CALCULATED	311,457,637	141,176,442	724,395	2,751,971	2,826,660	12,188	163,946	10,935,628
72	S	Depreciation Expense	CALCULATED	286,771,855	113,247,114	691,247	5,116,873	8,649,117	36,772	92,204	10,344,570
73	S	Amortization Expense	CALCULATED	21,391,564	11,463,240	58,165	187,552	194,968	844	19,589	282,931
74	S	Taxes Other Than Income Taxes	CALCULATED	-11,551,217	-5,819,089	-26,704	-56,076	-11,329	-65	-7,326	-439,127
75	S	Proforma Expense Adjustments	CALCULATED	82,048,703	43,516,333	199,010	863,335	1,148,870	5,161	33,152	2,240,800
76	S	State Income Taxes	CALCULATED	119,869,746	50,058,998	276,368	1,671,983	2,536,972	10,842	36,986	4,356,445
77	S	Federal Income Taxes	CALCULATED	231,691,305	97,275,463	531,786	3,142,783	4,698,215	20,094	71,192	8,426,575
78	S	Provision for Deferred Income Taxes	CALCULATED	144,525,616	68,877,750	334,262	1,130,425	1,113,608	4,900	77,753	5,657,838
79	S	Income Taxes Deferred in Prior Years	CALCULATED	0	0	0	0	0	0	0	0
80	S	Investment Tax Credit Adjustement (Net)	CALCULATED	0	0	0	0	0	0	0	0
81	S	TOTAL OPERATING EXPENSES		1,186,205,208	519,796,251	2,788,529	14,808,847	21,157,081	90,736	487,496	41,805,660
82	S										
83	S	**OPERATING INCOME (RETURN)**		738,814,468	314,528,771	1,699,160	9,824,611	14,541,804	62,276	232,263	26,498,998
84	S	Plus Operating Income Adjustment	CALCULATED	0	0	0	0	0	0	0	0
85	S	TOTAL NET OPERATING INCOME		738,814,468	314,528,771	1,699,160	9,824,611	14,541,804	62,276	232,263	26,498,998
86	S										
87	S	**RATE OF RETURN ON RATE BASE (PRESENT)**		7.55%	7.55%	7.55%	7.55%	7.55%	7.55%	7.55%	7.55%
88	S	**INDEX RATE OF RETURN (PRESENT)**		1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
89	S										
90	S	**EQUALIZED RETURN AT PROPOSED ROR**									
91	S										
92	S	**DEVELOPMENT OF RETURN (EQUALIZED RATE LEVELS**									
93	S										
94	S	**RATE BASE**	CALCULATED	9,785,622,095	4,165,943,983	22,505,436	130,127,297	192,606,679	824,852	3,076,333	350,980,110
95	S										
96	S	**RATE OF RETURN**		7.55%	7.55%	7.55%	7.55%	7.55%	7.55%	7.55%	7.55%
97	S										
98	S	**RETURN (RATE BASE * 7.40% ROR)**		738,814,468	314,528,771	1,699,160	9,824,611	14,541,804	62,276	232,263	26,498,998
99	S	**PLUS:**	CALCULATED								
100	S	**OPERATING EXPENSES**									

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
51	S	**DEVELOPMENT OF RETURN**	CALCULATED							
52	S									
53	S	**RATE BASE**	CALCULATED	2,257,009	135,830,682	2,092,733,396	2,058,242,336	384,267,442	243,670,921	2,555,619
54	S									
55	S	**OPERATING REVENUES**								
56	S	Rate Revenues from Customers	CALCULATED	741,039	27,345,651	399,597,683	388,159,549	74,444,444	49,205,760	2,891,829
57	S	Other Operating Revenues	CALCULATED	8,351	415,360	6,069,592	5,895,855	1,130,756	747,399	43,925
58	S	Revenues from Other Sources	CALCULATED	0	0	0	0	0	0	0
59	S	Less: Provisions for Rate Refunds	CALCULATED	0	0	0	0	0	0	0
60	S	TOTAL OPERATING REVENUES		749,390	27,761,012	405,667,274	394,055,404	75,575,200	49,953,159	2,935,754
61	S									
62	S	**OPERATING EXPENSES**								
63	S	Operation and Maintenance Expense								
64	S	Production Expense	CALCULATED	0	0	0	0	0	0	0
65	S	Transmission Expense	CALCULATED	0	0	0	0	0	0	0
66	S	Distribution Expense	CALCULATED	377,588	4,311,614	36,374,761	38,969,244	8,872,940	5,073,136	52,347
67	S	Customer Accounts Expense	CALCULATED	14,476	608,165	18,490,686	11,291,938	2,483,301	3,866,794	1,815,005
68	S	Customer Service & Information Expense	CALCULATED	214	34,498	876,964	140,606	11,945	3,040	367
69	S	Sales Expense	CALCULATED	4	555	9,167	677	61	17	1
70	S	Administrative and General Expense	CALCULATED	14,394	368,380	10,095,343	6,483,504	1,908,048	750,411	-433,785
71	S	Total Operation and Maintenance Expense	CALCULATED	406,676	5,323,213	65,846,920	56,885,968	13,276,295	9,693,399	1,433,935
72	S	Depreciation Expense	CALCULATED	57,030	3,997,233	61,464,680	64,030,515	11,662,973	7,251,328	130,196
73	S	Amortization Expense	CALCULATED	3,439	184,066	4,260,031	3,112,020	624,321	730,459	269,940
74	S	Taxes Other Than Income Taxes	CALCULATED	-1,722	-189,253	-2,053,778	-2,170,086	-381,518	-312,178	-82,967
75	S	Proforma Expense Adjustments	CALCULATED	11,109	906,023	16,140,563	12,829,350	2,326,036	1,627,221	201,742
76	S	State Income Taxes	CALCULATED	26,877	1,680,031	25,672,740	25,734,167	4,781,534	3,008,644	17,158
77	S	Federal Income Taxes	CALCULATED	52,528	3,249,015	49,618,107	49,544,251	9,224,212	5,811,019	26,067
78	S	Provision for Deferred Income Taxes	CALCULATED	23,050	2,355,466	26,716,640	28,691,924	5,049,155	3,746,112	746,733
79	S	Income Taxes Deferred in Prior Years	CALCULATED	0	0	0	0	0	0	0
80	S	Investment Tax Credit Adjustement (Net)	CALCULATED	0	0	0	0	0	0	0
81	S	TOTAL OPERATING EXPENSES		578,986	17,505,795	247,665,903	238,658,108	46,563,008	31,556,005	2,742,805
82	S									
83	S	**OPERATING INCOME (RETURN)**		170,404	10,255,216	158,001,371	155,397,296	29,012,192	18,397,155	192,949
84	S	Plus Operating Income Adjustment	CALCULATED	0	0	0	0	0	0	0
85	S	TOTAL NET OPERATING INCOME		170,404	10,255,216	158,001,371	155,397,296	29,012,192	18,397,155	192,949
86	S									
87	S	**RATE OF RETURN ON RATE BASE (PRESENT)**		7.55%	7.55%	7.55%	7.55%	7.55%	7.55%	7.55%
88	S	**INDEX RATE OF RETURN (PRESENT)**		1.00	1.00	1.00	1.00	1.00	1.00	1.00
89	S									
90	S	**EQUALIZED RETURN AT PROPOSED ROR**								
91	S									
92	S	**DEVELOPMENT OF RETURN (EQUALIZED RATE LEVELS**								
93	S									
94	S	**RATE BASE**	CALCULATED	2,257,009	135,830,682	2,092,733,396	2,058,242,336	384,267,442	243,670,921	2,555,619
95	S									
96	S	**RATE OF RETURN**		7.55%	7.55%	7.55%	7.55%	7.55%	7.55%	7.55%
97	S									
98	S	**RETURN (RATE BASE * 7.40% ROR)**		170,404	10,255,216	158,001,371	155,397,296	29,012,192	18,397,155	192,949
99	S	**PLUS:**	CALCULATED							
100	S	**OPERATING EXPENSES**								

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
101	S	Total Operation and Maintenance Expense	CALCULATED	311,457,637	141,176,442	724,395	2,751,971	2,826,660	12,188	163,946	10,935,628
102	S	Depreciation Expense	CALCULATED	286,771,855	113,247,114	691,247	5,116,873	8,649,117	36,772	92,204	10,344,570
103	S	Amortization Expense	CALCULATED	21,391,564	11,463,240	58,165	187,552	194,968	844	19,589	282,931
104	S	Taxes Other Than Income Taxes	CALCULATED	-11,551,217	-5,819,089	-26,704	-56,076	-11,329	-65	-7,326	-439,127
105	S	Proforma Expense Adjustments	CALCULATED	82,048,703	43,516,333	199,010	863,335	1,148,870	5,161	33,152	2,240,800
106	S	Income Taxes	CALCULATED	351,561,051	147,334,461	808,154	4,814,766	7,235,187	30,937	108,177	12,783,020
107	S	Provision for Deferred Income Taxes	CALCULATED	144,525,616	68,877,750	334,262	1,130,425	1,113,608	4,900	77,753	5,657,838
108	S	Income Taxes Deferred in Prior Years	CALCULATED	0	0	0	0	0	0	0	0
109	S	Investment Tax Credit Adjustement (Net)	CALCULATED	0	0	0	0	0	0	0	0
110	S	**TOTAL OPERATING EXPENSES**		1,186,205,208	519,796,251	2,788,529	14,808,847	21,157,081	90,736	487,496	41,805,660
111	S										
112	S	**EQUALS TOTAL COST OF SERVICE**		1,925,019,676	834,325,022	4,487,689	24,633,458	35,698,885	153,013	719,759	68,304,658
113	S										
114	S	**LESS:**									
115	S	Other Operating Revenues	CALCULATED	25,104,439	9,297,260	50,008	274,502	397,809	1,705	10,769	761,150
116	S	Revenues from Other Sources	CALCULATED	0	0	0	0	0	0	0	0
117	S	Plus: Provisions for Rate Refunds		0	0	0	0	0	0	0	0
118	S	**EQUALS:**									
119	S	**BASE RATE SALES @ EQUALIZED ROR 7.40%**		1,899,915,237	825,027,762	4,437,681	24,358,956	35,301,077	151,307	708,990	67,543,508
120	S										
121	S	**TOTAL COST OF SERVICE INCREASE/DECREASE**		0	0	0	0	0	0	0	0
122	S	**REVENUE INCREASE TO RETAIL REVENUES (%)**		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
101	S	Total Operation and Maintenance Expense	CALCULATED	406,676	5,323,213	65,846,920	56,885,968	13,276,295	9,693,399	1,433,935
102	S	Depreciation Expense	CALCULATED	57,030	3,997,233	61,464,680	64,030,515	11,662,973	7,251,328	130,196
103	S	Amortization Expense	CALCULATED	3,439	184,066	4,260,031	3,112,020	624,321	730,459	269,940
104	S	Taxes Other Than Income Taxes	CALCULATED	-1,722	-189,253	-2,053,778	-2,170,086	-381,518	-312,178	-82,967
105	S	Proforma Expense Adjustments	CALCULATED	11,109	906,023	16,140,563	12,829,350	2,326,036	1,627,221	201,742
106	S	Income Taxes	CALCULATED	79,405	4,929,046	75,290,847	75,278,417	14,005,746	8,819,663	43,225
107	S	Provision for Deferred Income Taxes	CALCULATED	23,050	2,355,466	26,716,640	28,691,924	5,049,155	3,746,112	746,733
108	S	Income Taxes Deferred in Prior Years	CALCULATED	0	0	0	0	0	0	0
109	S	Investment Tax Credit Adjustement (Net)	CALCULATED	0	0	0	0	0	0	0
110	S	**TOTAL OPERATING EXPENSES**		578,986	17,505,795	247,665,903	238,658,108	46,563,008	31,556,005	2,742,805
111	S									
112	S	**EQUALS TOTAL COST OF SERVICE**		749,390	27,761,012	405,667,274	394,055,404	75,575,200	49,953,159	2,935,754
113	S									
114	S	**LESS:**								
115	S	Other Operating Revenues	CALCULATED	8,351	415,360	6,069,592	5,895,855	1,130,756	747,399	43,925
116	S	Revenues from Other Sources	CALCULATED	0	0	0	0	0	0	0
117	S	Plus: Provisions for Rate Refunds		0	0	0	0	0	0	0
118	S	**EQUALS:**								
119	S	**BASE RATE SALES @ EQUALIZED ROR 7.40%**		741,039	27,345,651	399,597,683	388,159,549	74,444,444	49,205,760	2,891,829
120	S									
121	S	**TOTAL COST OF SERVICE INCREASE/DECREASE**		0	0	0	0	0	0	0
122	S	**REVENUE INCREASE TO RETAIL REVENUES (%)**		0.00	0.00	0.00	0.00	0.00	0.00	0.00

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	RBP	**DEVELOPMENT OF RATE BASE**									
2	RBP										
3	RBP	**ELECTRIC PLANT IN SERVICE**									
4	RBP										
5	RBP	PRODUCTION PLANT									
6	RBP	E304-E346 - Production Plant	not_used	0	0	0	0	0	0	0	0
7	RBP	Not Used	not_used	0	0	0	0	0	0	0	0
8	RBP	TOTAL PRODUCTION PLANT		0	0	0	0	0	0	0	0
9	RBP										
10	RBP	TRANSMISSION PLANT									
11	RBP	E350 Land & Land Rights	not_used	0	0	0	0	0	0	0	0
12	RBP	E352 Structures & Improvements	not_used	0	0	0	0	0	0	0	0
13	RBP	E353 Station Equipment	not_used	0	0	0	0	0	0	0	0
14	RBP	E354/E355 Towers and Fixtures	not_used	0	0	0	0	0	0	0	0
15	RBP	E356-E359 Transmission Plant - Others	not_used	0	0	0	0	0	0	0	0
16	RBP	TOTAL TRANSMISSION PLANT		0	0	0	0	0	0	0	0
17	RBP										
18	RBP	DISTRIBUTION PLANT									
19	RBP	E360-E361 Land & Structures									
20	RBP	E360 - Land and Land Rights									
21	RBP	- Headquarters related	E362PLT	14,080,608	5,558,584	27,866	70,117	118	1	4,399	57,160
22	RBP	- Direct - HTS-HV	E362PLT	0	0	0	0	0	0	0	0
23	RBP	- Direct - HEP	E362PLT	0	0	0	0	0	0	0	0
24	RBP	- Substation related	E362PLT	37,233,560	14,698,647	73,685	185,412	312	4	11,633	151,148
25	RBP	E361 - Structures and improvements		0	0	0	0	0	0	0	0
26	RBP	- Headquarters related	E362PLT	124,204,880	49,032,209	245,802	618,503	1,041	13	38,805	504,205
27	RBP	- Substation related	E362PLT	118,051,566	46,603,073	233,625	587,861	989	12	36,883	479,226
28	RBP	Total Accounts E360-E361		293,570,614	115,892,513	580,978	1,461,893	2,460	30	91,721	1,191,740
29	RBP	E362 - Station Equipment									
30	RBP	Switching Stations - Energy Related - System		269,637,863	64,688,814	441,813	922,235	2,764	34	56,190	1,339,094
31	RBP	Switching Stations - Demand Related - System		68,805,545	27,072,878	87,168	297,615	0	0	19,363	0
32	RBP	H Class Substations - Energy Related - System		626,002,523	242,296,289	1,654,839	3,454,295	10,354	127	210,463	5,015,667
33	RBP	H Class Substations - Demand Related - System		600,972,238	283,920,236	914,150	3,121,164	0	0	203,070	0
34	RBP	4 kV Class Substations - Energy Related - System		0	0	0	0	0	0	0	0
35	RBP	4 kV Class Substations - Demand Related - System		0	0	0	0	0	0	0	0
36	RBP	Total Account E362		1,565,418,169	617,978,217	3,097,969	7,795,309	13,118	160	489,085	6,354,762
37	RBP	E364 - Poles Towers & Fixtures									
38	RBP	Streetlight poles - direct to BPL	DIR_BPL_02	8,114,160	0	0	0	0	0	0	8,114,160
39	RBP	Streetlight poles - direct to PSAL	DIR_PSAL_02	1,812,825	0	0	0	0	0	0	0
40	RBP	Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0	0
41	RBP	Subtransmission lines - Energy Related - System		80,822,343	19,390,087	132,431	276,435	829	10	16,843	401,386
42	RBP	Subtransmission lines - Demand Related - System		20,624,052	8,114,934	26,128	89,208	0	0	5,804	0
43	RBP	Primary Lines - Energy Related - Local		123,061,406	47,631,313	325,313	679,055	2,035	25	41,373	985,995
44	RBP	Primary Lines - Energy Related - System		123,061,406	47,631,313	325,313	679,055	2,035	25	41,373	985,995
45	RBP	Primary Lines - Demand Related - Local		118,140,880	55,813,870	179,706	613,567	0	0	39,920	0
46	RBP	Primary Lines - Demand Related - System		118,140,880	55,813,870	179,706	613,567	0	0	39,920	0
47	RBP	Secondary Lines - Energy Related - Local		227,674,404	96,377,143	658,238	1,374,000	4,118	50	83,715	1,995,060
48	RBP	Secondary Lines - Demand Related - Local		205,991,127	102,808,931	331,018	1,130,189	0	0	73,532	0
49	RBP	Total Account E364		1,027,443,483	433,581,460	2,157,854	5,455,077	9,018	110	342,481	12,482,595
50	RBP										

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2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
1	RBP	**DEVELOPMENT OF RATE BASE**								
2	RBP									
3	RBP	**ELECTRIC PLANT IN SERVICE**								
4	RBP									
5	RBP	PRODUCTION PLANT								
6	RBP	E304-E346 - Production Plant	not_used	0	0	0	0	0	0	0
7	RBP	Not Used	not_used	0	0	0	0	0	0	0
8	RBP	TOTAL PRODUCTION PLANT		0	0	0	0	0	0	0
9	RBP									
10	RBP	TRANSMISSION PLANT								
11	RBP	E350 Land & Land Rights	not_used	0	0	0	0	0	0	0
12	RBP	E352 Structures & Improvements	not_used	0	0	0	0	0	0	0
13	RBP	E353 Station Equipment	not_used	0	0	0	0	0	0	0
14	RBP	E354/E355 Towers and Fixtures	not_used	0	0	0	0	0	0	0
15	RBP	E356-E359 Transmission Plant - Others	not_used	0	0	0	0	0	0	0
16	RBP	TOTAL TRANSMISSION PLANT		0	0	0	0	0	0	0
17	RBP									
18	RBP	DISTRIBUTION PLANT								
19	RBP	E360-E361 Land & Structures								
20	RBP	E360 - Land and Land Rights								
21	RBP	- Headquarters related	E362PLT	3,090	27,747	2,993,948	3,384,778	927,332	1,025,468	0
22	RBP	- Direct - HTS-HV	E362PLT	0	0	0	0	0	0	0
23	RBP	- Direct - HEP	E362PLT	0	0	0	0	0	0	0
24	RBP	- Substation related	E362PLT	8,170	73,371	7,916,941	8,950,420	2,452,157	2,711,659	0
25	RBP	E361 - Structures and improvements		0	0	0	0	0	0	0
26	RBP	- Headquarters related	E362PLT	27,254	244,755	26,409,580	29,857,093	8,179,983	9,045,637	0
27	RBP	- Substation related	E362PLT	25,904	232,629	25,101,206	28,377,923	7,774,733	8,597,502	0
28	RBP	Total Accounts E360-E361		64,418	578,502	62,421,674	70,570,214	19,334,206	21,380,266	0
29	RBP	E362 - Station Equipment								
30	RBP	Switching Stations - Energy Related - System		72,383	650,032	34,588,792	50,054,033	14,315,393	102,506,285	0
31	RBP	Switching Stations - Demand Related - System		0	0	14,686,720	12,080,305	3,060,947	11,500,549	0
32	RBP	H Class Substations - Energy Related - System		271,117	2,434,739	129,554,637	187,480,734	53,619,263	0	0
33	RBP	H Class Substations - Demand Related - System		0	0	154,023,408	126,689,266	32,100,944	0	0
34	RBP	4 kV Class Substations - Energy Related - System		0	0	0	0	0	0	0
35	RBP	4 kV Class Substations - Demand Related - System		0	0	0	0	0	0	0
36	RBP	Total Account E362		343,500	3,084,771	332,853,557	376,304,339	103,096,548	114,006,835	0
37	RBP	E364 - Poles Towers & Fixtures								
38	RBP	Streetlight poles - direct to BPL	DIR_BPL_02	0	0	0	0	0	0	0
39	RBP	Streetlight poles - direct to PSAL	DIR_PSAL_02	0	1,812,825	0	0	0	0	0
40	RBP	Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0
41	RBP	Subtransmission lines - Energy Related - System		21,696	194,843	10,367,784	15,003,398	4,290,954	30,725,648	0
42	RBP	Subtransmission lines - Demand Related - System		0	0	4,402,257	3,620,999	917,501	3,447,221	0
43	RBP	Primary Lines - Energy Related - Local		53,297	478,628	25,468,229	36,855,511	10,540,632	0	0
44	RBP	Primary Lines - Energy Related - System		53,297	478,628	25,468,229	36,855,511	10,540,632	0	0
45	RBP	Primary Lines - Demand Related - Local		0	0	30,278,372	24,904,946	6,310,497	0	0
46	RBP	Primary Lines - Demand Related - System		0	0	30,278,372	24,904,946	6,310,497	0	0
47	RBP	Secondary Lines - Energy Related - Local		107,841	968,456	51,532,386	74,573,398	0	0	0
48	RBP	Secondary Lines - Demand Related - Local		0	0	55,772,643	45,874,814	0	0	0
49	RBP	Total Account E364		236,131	3,933,380	233,568,272	262,593,524	38,910,712	34,172,869	0
50	RBP									

PUBLIC SERVICE ELECTRIC & GAS COMPANY
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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
51	RBP										
52	RBP										
53	RBP										
54	RBP										
55	RBP										
56	RBP										
57	RBP	**ELECTRIC PLANT IN SERVICE CONTINUED**									
58	RBP										
59	RBP	DISTRIBUTION PLANT CONTINUED									
60	RBP	E365 - OH Conductors and Devices									
61	RBP	Direct - BPL	DIR_BPL_02	2,226,625	0	0	0	0	0	0	2,226,625
62	RBP	Direct - PSAL	DIR_PSAL_02	6,436,532	0	0	0	0	0	0	0
63	RBP	Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0	0
64	RBP	Subtransmission lines - Energy Related - System		160,845,181	38,588,364	263,551	550,135	1,649	20	33,519	798,801
65	RBP	Subtransmission lines - Demand Related - System		41,044,089	16,149,594	51,998	177,534	0	0	11,551	0
66	RBP	Primary lines - Energy Related - Local		643,665,448	249,132,781	1,701,531	3,551,759	10,646	130	216,401	5,157,186
67	RBP	Primary lines - Energy Related - System		643,665,448	249,132,781	1,701,531	3,551,759	10,646	130	216,401	5,157,186
68	RBP	Primary lines - Demand Related - Local		617,928,923	291,931,165	939,943	3,209,229	0	0	208,799	0
69	RBP	Primary lines - Demand Related - System		617,928,923	291,931,165	939,943	3,209,229	0	0	208,799	0
70	RBP	Secondary lines -Energy Related - Local		64,282,796	27,211,633	185,850	387,942	1,163	14	23,636	563,296
71	RBP	Secondary lines -Demand Related - Local		58,160,625	29,027,618	93,461	319,104	0	0	20,762	0
72	RBP	Other	DISTPLT	0	0	0	0	0	0	0	0
73	RBP	Total Account E365		2,856,184,590	1,193,105,100	5,877,809	14,956,690	24,103	295	939,868	13,903,094
74	RBP										
75	RBP	E366 - Underground Conduit									
76	RBP	Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0	0
77	RBP	Direct - HEP	DIR_HEP_03	0	0	0	0	0	0	0	0
78	RBP	Underground Conduits	E367PLT	512,107,003	222,350,106	1,098,632	2,809,297	49,885	248	175,262	3,071,260
79	RBP	Not Used	not_used								
80	RBP	Total Account E366		512,107,003	222,350,106	1,098,632	2,809,297	49,885	248	175,262	3,071,260
81	RBP										
82	RBP	E367 - Underground Conductors & Devices									
83	RBP	Direct - BPL	DIR_BPL_02	2,325,498	0	0	0	0	0	0	2,325,498
84	RBP	Direct - PSAL	DIR_PSAL_02	868,520	0	0	0	0	0	0	0
85	RBP	UG BPL Poles in UG areas	DISTPLTXMTR	3,979,461	1,525,824	9,591	74,133	126,809	538	1,204	151,403
86	RBP	Direct - HEP	DIR_HEP_03	0	0	0	0	0	0	0	0
87	RBP	367.1 - Conventional UG									
88	RBP	Subtransmission lines - Energy Related - System	KWH_SUBT_09	40,943,727	9,822,809	67,088	140,039	420	5	8,532	203,338
89	RBP	Subtransmission lines - Demand Related - System	CP_SUBT_05	10,447,922	4,110,938	13,236	45,192	0	0	2,940	0
90	RBP	Primary lines - Energy Related - Local	KWH_PRI_10	90,324,112	34,960,238	238,772	498,410	1,494	18	30,367	723,696
91	RBP	Primary lines - Energy Related - System	KWH_PRI_09	90,324,112	34,960,238	238,772	498,410	1,494	18	30,367	723,696
92	RBP	Primary lines - Demand Related - Local	CP_PRI_04	86,712,563	40,966,038	131,900	450,344	0	0	29,300	0
93	RBP	Primary lines - Demand Related - System	CP_PRI_05	86,712,563	40,966,038	131,900	450,344	0	0	29,300	0
94	RBP	Secondary lines -Energy Related - Local	KWH_SEC_10	283,098,081	119,838,610	818,476	1,708,478	5,121	63	104,094	2,480,726
95	RBP	Secondary lines -Demand Related - Local	CP_SEC_04	256,136,359	127,836,114	411,599	1,405,315	0	0	91,433	0
96	RBP	367.2 - BUD									
97	RBP	Subtransmission lines - Energy Related - System	KWH_SUBT_09	381,867	91,614	626	1,306	4	0	80	1,896
98	RBP	Subtransmission lines - Demand Related - System	CP_SUBT_05	97,444	38,341	123	421	0	0	27	0
99	RBP	Primary lines - Energy Related - Local	KWH_PRI_10	114,385,571	44,273,303	302,379	631,182	1,892	23	38,457	916,482
100	RBP	Primary lines - Energy Related - System	KWH_PRI_09	114,385,571	44,273,303	302,379	631,182	1,892	23	38,457	916,482

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				(9)	(10)	(11)	(12)	(13)	(14)	(15)
51	RBP									
52	RBP									
53	RBP									
54	RBP									
55	RBP									
56	RBP									
57	RBP	**ELECTRIC PLANT IN SERVICE CONTINUED**								
58	RBP									
59	RBP	DISTRIBUTION PLANT CONTINUED								
60	RBP	E365 - OH Conductors and Devices								
61	RBP	Direct - BPL	DIR_BPL_02	0	0	0	0	0	0	0
62	RBP	Direct - PSAL	DIR_PSAL_02	0	6,436,532	0	0	0	0	0
63	RBP	Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0
64	RBP	Subtransmission lines - Energy Related - System		43,178	387,759	20,633,009	29,858,381	8,539,461	61,147,355	0
65	RBP	Subtransmission lines - Demand Related - System		0	0	8,760,966	7,206,179	1,825,926	6,860,342	0
66	RBP	Primary lines - Energy Related - Local		278,766	2,503,436	133,210,076	192,770,582	55,132,153	0	0
67	RBP	Primary lines - Energy Related - System		278,766	2,503,436	133,210,076	192,770,582	55,132,153	0	0
68	RBP	Primary lines - Demand Related - Local		0	0	158,369,244	130,263,857	33,006,686	0	0
69	RBP	Primary lines - Demand Related - System		0	0	158,369,244	130,263,857	33,006,686	0	0
70	RBP	Secondary lines -Energy Related - Local		30,448	273,439	14,549,926	21,055,448	0	0	0
71	RBP	Secondary lines -Demand Related - Local		0	0	15,747,143	12,952,538	0	0	0
72	RBP	Other	DISTPLT	0	0	0	0	0	0	0
73	RBP	Total Account E365		631,159	12,104,603	642,849,684	717,141,426	186,643,064	68,007,696	0
74	RBP									
75	RBP	E366 - Underground Conduit								
76	RBP	Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0
77	RBP	Direct - HEP	DIR_HEP_03	0	0	0	0	0	0	0
78	RBP	Underground Conduits	E367PLT	118,401	1,392,172	119,804,922	133,875,585	21,072,679	6,288,555	0
79	RBP	Not Used	not_used							
80	RBP	Total Account E366		118,401	1,392,172	119,804,922	133,875,585	21,072,679	6,288,555	0
81	RBP									
82	RBP	E367 - Underground Conductors & Devices								
83	RBP	Direct - BPL	DIR_BPL_02	0	0	0	0	0	0	0
84	RBP	Direct - PSAL	DIR_PSAL_02	0	868,520	0	0	0	0	0
85	RBP	UG BPL Poles in UG areas	DISTPLTXMTR	822	57,999	842,202	921,717	165,685	101,534	0
86	RBP	Direct - HEP	DIR_HEP_03	0	0	0	0	0	0	0
87	RBP	367.1 - Conventional UG								
88	RBP	Subtransmission lines - Energy Related - System	KWH_SUBT_09	10,991	98,706	5,252,208	7,600,560	2,173,751	15,565,282	0
89	RBP	Subtransmission lines - Demand Related - System	CP_SUBT_05	0	0	2,230,136	1,834,359	464,796	1,746,325	0
90	RBP	Primary lines - Energy Related - Local	KWH_PRI_10	39,119	351,302	18,693,068	27,051,058	7,736,570	0	0
91	RBP	Primary lines - Energy Related - System	KWH_PRI_09	39,119	351,302	18,693,068	27,051,058	7,736,570	0	0
92	RBP	Primary lines - Demand Related - Local	CP_PRI_04	0	0	22,223,597	18,279,631	4,631,753	0	0
93	RBP	Primary lines - Demand Related - System	CP_PRI_05	0	0	22,223,597	18,279,631	4,631,753	0	0
94	RBP	Secondary lines -Energy Related - Local	KWH_SEC_10	134,093	1,204,211	64,077,117	92,727,094	0	0	0
95	RBP	Secondary lines -Demand Related - Local	CP_SEC_04	0	0	69,349,597	57,042,301	0	0	0
96	RBP	367.2 - BUD								
97	RBP	Subtransmission lines - Energy Related - System	KWH_SUBT_09	103	921	48,985	70,888	20,274	145,172	0
98	RBP	Subtransmission lines - Demand Related - System	CP_SUBT_05	0	0	20,800	17,108	4,335	16,287	0
99	RBP	Primary lines - Energy Related - Local	KWH_PRI_10	49,539	444,885	23,672,718	34,257,196	9,797,516	0	0
100	RBP	Primary lines - Energy Related - System	KWH_PRI_09	49,539	444,885	23,672,718	34,257,196	9,797,516	0	0

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				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
101	RBP	Primary lines - Demand Related - Local	CP_PRI_04	109,811,942	51,878,990	167,037	570,311	0	0	37,106	0
102	RBP	Primary lines - Demand Related - System	CP_PRI_05	109,811,942	51,878,990	167,037	570,311	0	0	37,106	0
103	RBP	Secondary lines -Energy Related - Local	KWH_SEC_10	15,979,016	6,764,098	46,198	96,432	289	4	5,875	140,021
104	RBP	Secondary lines -Demand Related - Local	CP_SEC_04	14,457,205	7,215,504	23,232	79,321	0	0	5,161	0
105	RBP	Other	E367PLT	0	0	0	0	0	0	0	0
106	RBP	Total Account E367		1,431,183,475	621,400,988	3,070,344	7,851,131	139,414	692	489,805	8,583,237
107	RBP										
108	RBP	E368 - Line Transformers									
109	RBP	Line Transformers - Energy Related - Local	KWH_SEC_10	835,637,581	353,734,812	2,415,944	5,043,017	15,115	185	307,260	7,322,506
110	RBP	Line Transformers - Demand Related - Local	CP_SEC_04	756,053,050	377,341,523	1,214,942	4,148,153	0	0	269,888	0
111	RBP	Not Used	not_used	0	0	0	0	0	0	0	0
112	RBP	Total Account E368		1,591,690,631	731,076,335	3,630,886	9,191,170	15,115	185	577,148	7,322,506
113	RBP	E369 - Services									
114	RBP	Basic portion (minimum size)	SERVICESMIN_03	535,269,333	838,818	5,280,717	143,188,891	330,263,894	1,401,425	0	0
115	RBP	E369 - Excess portion	SERVICESEXC_04	0	0	0	0	0	0	0	0
116	RBP	Total Account E369		535,269,333	838,818	5,280,717	143,188,891	330,263,894	1,401,425	0	0
117	RBP										
118	RBP										
119	RBP										
120	RBP										
121	RBP										
122	RBP										
123	RBP	**ELECTRIC PLANT IN SERVICE CONTINUED**		0	0	0	0	0	0	0	0
124	RBP										
125	RBP	E370 - Meters		0	0	0	0	0	0	0	0
126	RBP	Load profiling meters	KWHMETERX_04	0	0	0	0	0	0	0	0
127	RBP	Customer Component	METERSMIN_07	76,316,914	44,092,057	153,180	255,919	171,335	2,673	17,398	0
128	RBP	Excess portion - Demand (Commercial Customers)	METERSEXC_04	122,177,671	74,077,186	257,350	429,959	0	0	29,229	0
129	RBP	Excess portion - Demand (Residential Customers)	METERSEXC_10	166,926,857	101,208,934	351,608	587,437	0	0	39,935	0
130	RBP	Total Account E370		365,421,442	219,378,176	762,138	1,273,316	171,335	2,673	86,562	0
131	RBP										
132	RBP	E373 - Street Lighting & Signal Systems									
133	RBP	BPL luminaires & poles	DIR_BPL_02	340,539,607	0	0	0	0	0	0	340,539,607
134	RBP	PSAL luminaires & poles	DIR_PSAL_02	122,261,652	0	0	0	0	0	0	0
135	RBP	UG BPL Poles in UG areas	DISTPLTXMTR	36,225,893	13,889,907	87,308	674,847	1,154,367	4,901	10,958	1,378,255
136	RBP	Total Account E373		499,027,153	13,889,907	87,308	674,847	1,154,367	4,901	10,958	341,917,862
137	RBP										
138	RBP	E374 - Asset Retirement Obligations	E364PLT	96,512,525	40,728,315	202,697	512,421	847	10	32,171	1,172,548
139	RBP										
140	RBP	Other Distribution and Unallocated Plant									
141	RBP	Not Used	not_used	0	0	0	0	0	0	0	0
142	RBP	Total Other Plant and Unallocated Plant		0	0	0	0	0	0	0	0
143	RBP										
144	RBP	TOTAL DISTRIBUTION PLANT		10,773,828,418	4,210,219,934	25,847,331	195,170,040	331,843,556	1,410,730	3,235,061	395,999,604
145	RBP										
146	RBP	GENERAL AND COMMON PLANT									
147	RBP	E390-E398 GENERAL PLANT									
148	RBP	Meter Related	METERPLT	0	0	0	0	0	0	0	0
149	RBP	Customer Service Related	CUSTSVSX	0	0	0	0	0	0	0	0
150	RBP	Substation Related	E362PLT	0	0	0	0	0	0	0	0

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				(9)	(10)	(11)	(12)	(13)	(14)	(15)
101	RBP	Primary lines - Demand Related - Local	CP_PRI_04	0	0	28,143,745	23,149,146	5,865,607	0	0
102	RBP	Primary lines - Demand Related - System	CP_PRI_05	0	0	28,143,745	23,149,146	5,865,607	0	0
103	RBP	Secondary lines -Energy Related - Local	KWH_SEC_10	7,569	67,970	3,616,730	5,233,832	0	0	0
104	RBP	Secondary lines -Demand Related - Local	CP_SEC_04	0	0	3,914,326	3,219,661	0	0	0
105	RBP	Other	E367PLT	0	0	0	0	0	0	0
106	RBP	Total Account E367		330,894	3,890,698	334,818,356	374,141,583	58,891,734	17,574,600	0
107	RBP									
108	RBP	E368 - Line Transformers								
109	RBP	Line Transformers - Energy Related - Local	KWH_SEC_10	395,810	3,554,541	189,140,269	273,708,123	0	0	0
110	RBP	Line Transformers - Demand Related - Local	CP_SEC_04	0	0	204,703,364	168,375,179	0	0	0
111	RBP	Not Used	not_used	0	0	0	0	0	0	0
112	RBP	Total Account E368		395,810	3,554,541	393,843,633	442,083,302	0	0	0
113	RBP	E369 - Services								
114	RBP	Basic portion (minimum size)	SERVICESMIN_03	0	0	53,039,066	1,013,079	243,028	415	0
115	RBP	E369 - Excess portion	SERVICESEXC_04	0	0	0	0	0	0	0
116	RBP	Total Account E369		0	0	53,039,066	1,013,079	243,028	415	0
117	RBP									
118	RBP									
119	RBP									
120	RBP									
121	RBP									
122	RBP									
123	RBP	**ELECTRIC PLANT IN SERVICE CONTINUED**		0	0	0	0	0	0	0
124	RBP									
125	RBP	E370 - Meters		0	0	0	0	0	0	0
126	RBP	Load profiling meters	KWHMETERX_04	0	0	0	0	0	0	0
127	RBP	Customer Component	METERSMIN_07	0	0	26,382,336	2,862,678	747,318	1,330,366	301,654
128	RBP	Excess portion - Demand (Commercial Customers)	METERSEXC_04	0	0	37,265,374	6,277,875	3,206,344	634,354	0
129	RBP	Excess portion - Demand (Residential Customers)	METERSEXC_10	0	0	50,914,309	8,577,230	4,380,709	866,694	0
130	RBP	Total Account E370		0	0	114,562,020	17,717,782	8,334,371	2,831,414	301,654
131	RBP									
132	RBP	E373 - Street Lighting & Signal Systems								
133	RBP	BPL luminaires & poles	DIR_BPL_02	0	0	0	0	0	0	0
134	RBP	PSAL luminaires & poles	DIR_PSAL_02	0	122,261,652	0	0	0	0	0
135	RBP	UG BPL Poles in UG areas	DISTPLTXMTR	7,483	527,976	7,666,746	8,390,589	1,508,270	924,286	0
136	RBP	Total Account E373		7,483	122,789,628	7,666,746	8,390,589	1,508,270	924,286	0
137	RBP									
138	RBP	E374 - Asset Retirement Obligations	E364PLT	22,181	369,481	21,940,150	24,666,626	3,655,063	3,210,016	0
139	RBP									
140	RBP	Other Distribution and Unallocated Plant								
141	RBP	Not Used	not_used	0	0	0	0	0	0	0
142	RBP	Total Other Plant and Unallocated Plant		0	0	0	0	0	0	0
143	RBP									
144	RBP	TOTAL DISTRIBUTION PLANT		2,149,976	151,697,776	2,317,368,080	2,428,498,049	441,689,675	268,396,952	301,654
145	RBP									
146	RBP	GENERAL AND COMMON PLANT								
147	RBP	E390-E398 GENERAL PLANT								
148	RBP	Meter Related	METERPLT	0	0	0	0	0	0	0
149	RBP	Customer Service Related	CUSTSVSX	0	0	0	0	0	0	0
150	RBP	Substation Related	E362PLT	0	0	0	0	0	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
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12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
151	RBP	Distribution Delivery	DISTPLTXMTR	429,584,593	164,713,403	1,035,337	8,002,670	13,689,057	58,115	129,947	16,344,031
152	RBP	Service & Support Related	UTILWORK_04	0	0	0	0	0	0	0	0
153	RBP	Unassigned	GENPLT	0	0	0	0	0	0	0	0
154	RBP	Total Accounts E390-E398		429,584,593	164,713,403	1,035,337	8,002,670	13,689,057	58,115	129,947	16,344,031
155	RBP										
156	RBP	C389-C399 COMMON PLANT									
157	RBP	Not Used	not_used	0	0	0	0	0	0	0	0
158	RBP	Meter Plant Related	METERPLT	0	0	0	0	0	0	0	0
159	RBP	Customer Related - Measurement	MRCOST_07	0	0	0	0	0	0	0	0
160	RBP	Demand Related - Measurement	NCP_MTR_07	0	0	0	0	0	0	0	0
161	RBP	Customer Service Related	CUSTSVSX	92,605,476	54,634,469	263,469	450,786	8,905	135	110,692	324,063
162	RBP	Distribution Delivery Related	DISTPLTXMTR	33,738,596	12,936,216	81,313	628,511	1,075,107	4,564	10,206	1,283,623
163	RBP	Service & Support Related	UTILWORK_04	0	0	0	0	0	0	0	0
164	RBP	Unassigned	COMPLT	309,972	165,778	846	2,648	2,660	12	297	3,944
165	RBP	Not Used	not_used	0	0	0	0	0	0	0	0
166	RBP	Total Accounts C389-C399		126,654,044	67,736,462	345,628	1,081,945	1,086,672	4,711	121,195	1,611,631
167	RBP										
168	RBP	TOTAL GENERAL AND COMMON PLANT		556,238,637	232,449,865	1,380,965	9,084,615	14,775,729	62,826	251,142	17,955,662
169	RBP										
170	RBP	**ELECTRIC PLANT IN SERVICE CONTINUED**									
171	RBP										
172	RBP	INTANGIBLE PLANT - E301-E303									
173	RBP	Customer Service Related	TOTPLT	40,584,928	15,974,298	97,668	727,637	1,232,304	5,239	12,759	1,472,729
174	RBP	Not Used	not_used	0	0	0	0	0	0	0	0
175	RBP	TOTAL INTANGIBLE PLANT		40,584,928	15,974,298	97,668	727,637	1,232,304	5,239	12,759	1,472,729
176	RBP										
177	RBP	C303 - INTANGIBLE PLANT									
178	RBP	- Customer Related - Measurement	MRCOST_07	606,400	477,370	1,658	2,771	32	0	38	0
179	RBP	- Demand Related - Measurement	NCP_MTR_07	606,400	249,462	1,890	3,270	70	1	1,457	3,721
180	RBP	Customer Service Related	CUSTSVSX	84,635,615	49,932,488	240,794	411,990	8,138	124	101,166	296,174
181	RBP	Distribution Related	INTANGPLT	0	0	0	0	0	0	0	0
182	RBP	C390.4 / C111.000 Capital Lease	TOTPLT	0	0	0	0	0	0	0	0
183	RBP	E399 Oth Tangible Plant	GENPLT	0	0	0	0	0	0	0	0
184	RBP	E399.1 Asset Retirement Obligations	GENPLT	490,552	188,090	1,182	9,138	15,632	66	148	18,664
185	RBP	TOTAL ACCOUNTS C303-C390.4,E399		86,338,967	50,847,410	245,525	427,169	23,872	192	102,808	318,558
186	RBP										
187	RBP	TOTAL INTANGIBLE PLANT		126,923,895	66,821,708	343,194	1,154,805	1,256,176	5,431	115,567	1,791,287
188	RBP										
189	RBP	**TOTAL ELECTRIC PLANT IN SERVICE**		11,456,990,950	4,509,491,507	27,571,490	205,409,461	347,875,461	1,478,986	3,601,770	415,746,553

PUBLIC SERVICE ELECTRIC & GAS COMPANY
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12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
151	RBP	Distribution Delivery	DISTPLTXMTR	88,736	6,260,999	90,916,078	99,499,766	17,885,807	10,960,646	0
152	RBP	Service & Support Related	UTILWORK_04	0	0	0	0	0	0	0
153	RBP	Unassigned	GENPLT	0	0	0	0	0	0	0
154	RBP	Total Accounts E390-E398		88,736	6,260,999	90,916,078	99,499,766	17,885,807	10,960,646	0
155	RBP									
156	RBP	C389-C399 COMMON PLANT								
157	RBP	Not Used	not_used	0	0	0	0	0	0	0
158	RBP	Meter Plant Related	METERPLT	0	0	0	0	0	0	0
159	RBP	Customer Related - Measurement	MRCOST_07	0	0	0	0	0	0	0
160	RBP	Demand Related - Measurement	NCP_MTR_07	0	0	0	0	0	0	0
161	RBP	Customer Service Related	CUSTSVSX	13,643	596,860	17,987,297	10,617,734	2,317,408	3,594,027	1,685,988
162	RBP	Distribution Delivery Related	DISTPLTXMTR	6,969	491,725	7,140,342	7,814,485	1,404,711	860,824	
163	RBP	Service & Support Related	UTILWORK_04	0	0	0	0	0	0	0
164	RBP	Unassigned	COMPLT	51	2,671	61,648	45,222	9,132	10,930	4,136
165	RBP	Not Used	not_used	0	0	0	0	0	0	0
166	RBP	Total Accounts C389-C399		20,663	1,091,256	25,189,287	18,477,440	3,731,250	4,465,781	1,690,125
167	RBP									
168	RBP	TOTAL GENERAL AND COMMON PLANT		109,399	7,352,255	116,105,365	117,977,206	21,617,058	15,426,426	1,690,125
169	RBP									
170	RBP	**ELECTRIC PLANT IN SERVICE CONTINUED**								
171	RBP									
172	RBP	INTANGIBLE PLANT - E301-E303								
173	RBP	Customer Service Related	TOTPLT	8,077	567,388	8,710,604	9,087,957	1,654,747	1,020,878	12,641
174	RBP	Not Used	not_used	0	0	0	0	0	0	0
175	RBP	TOTAL INTANGIBLE PLANT		8,077	567,388	8,710,604	9,087,957	1,654,747	1,020,878	12,641
176	RBP									
177	RBP	C303 - INTANGIBLE PLANT								
178	RBP	- Customer Related - Measurement	MRCOST_07	0	0	116,981	6,824	568	140	19
179	RBP	- Demand Related - Measurement	NCP_MTR_07	201	1,806	130,510	112,721	29,173	48,931	23,188
180	RBP	Customer Service Related	CUSTSVSX	12,469	545,493	16,439,265	9,703,945	2,117,966	3,284,716	1,540,888
181	RBP	Distribution Related	INTANGPLT	0	0	0	0	0	0	0
182	RBP	C390.4 / C111.000 Capital Lease	TOTPLT	0	0	0	0	0	0	0
183	RBP	E399 Oth Tangible Plant	GENPLT	0	0	0	0	0	0	0
184	RBP	E399.1 Asset Retirement Obligations	GENPLT	101	7,150	103,819	113,621	20,424	12,516	
185	RBP	TOTAL ACCOUNTS C303-C390.4,E399		12,772	554,449	16,790,575	9,937,110	2,168,131	3,346,303	1,564,094
186	RBP									
187	RBP	TOTAL INTANGIBLE PLANT		20,849	1,121,837	25,501,178	19,025,068	3,822,878	4,367,181	1,576,735
188	RBP									
189	RBP	**TOTAL ELECTRIC PLANT IN SERVICE**		2,280,224	160,171,869	2,458,974,623	2,565,500,323	467,129,611	288,190,559	3,568,514

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12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	RBD	**LESS: DEPRECIATION RESERVE & AMORT**									
2	RBD										
3	RBD	E301-E303 - INTANGILE PLANT - RESERVE									
4	RBD	Customer Service Related - Reserve	CUSTSVSX	15,757,979	9,296,738	44,833	76,707	1,515	23	18,836	55,143
5	RBD	Not Used	not_used	0	0	0	0	0	0	0	0
6	RBD	Not used	not_used	0	0	0	0	0	0	0	0
7	RBD	Total Accounts E301-E303 Reserve		15,757,979	9,296,738	44,833	76,707	1,515	23	18,836	55,143
8	RBD										
9	RBD	E304-E346 - PRODUCTION PLANT - RESERVE	not_used	0	0	0	0	0	0	0	0
10	RBD	E350-E359 - TRANSMISSION PLANT - RESERVE	not_used	0	0	0	0	0	0	0	0
11	RBD										
12	RBD	DISTRIBUTION PLANT RESERVE									
13	RBD	E360-E361 Land & Structures - Reserve									
14	RBD	E360 - Land and Land Rights									
15	RBD	- Headquarters Related	DISTPLT	0	0	0	0	0	0	0	0
16	RBD	- Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0	0
17	RBD	- Direct - HEP	DIR_HEP_03	0	0	0	0	0	0	0	0
18	RBD	- Substation Related	E362PLT	667,893	263,663	1,322	3,326	6	0	209	2,711
19	RBD	E361 - Structures and improvements									
20	RBD	- Headquarters Related	DISTPLT	40,449,681	15,807,014	97,042	732,754	1,245,886	5,296	12,146	1,486,756
21	RBD	- Substation Related	E362PLT	36,319,499	14,337,804	71,876	180,860	304	4	11,347	147,438
22	RBD	Total Accounts E360-E361		77,437,073	30,408,481	170,240	916,940	1,246,196	5,300	23,702	1,636,905
23	RBD	E362 Station Equipment - Rsrv	E362PLT	279,293,104	110,256,197	552,722	1,390,795	2,340	29	87,260	1,133,781
24	RBD	E364 Poles Towers and Fixtures Rsrv									
25	RBD	- Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0	0
26	RBD	- All Other	E364PLT	200,061,625	84,426,066	420,173	1,062,201	1,756	21	66,687	2,430,585
27	RBD	E365 OH Conductors and Devices - Rsrv									
28	RBD	- Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0	0
29	RBD	- All Other	E365PLT	609,997,837	254,812,498	1,255,329	3,194,313	5,148	63	200,728	2,969,296
30	RBD	E366 UG Conduit - Rsrv									
31	RBD	- Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0	0
32	RBD	- All Other	E366PLT	258,299,502	112,150,237	554,135	1,416,969	25,161	125	88,400	1,549,100
33	RBD	E367 UG Conductors and Devices - Rsrv									
34	RBD	- Direct - HTS-HV	DIR_HEP_03	0	0	0	0	0	0	0	0
35	RBD	- All Other	E367PLT	512,800,757	222,651,325	1,100,121	2,813,103	49,953	248	175,500	3,075,420
36	RBD	E368 Line Transformers - Rsrv Energy Related - Local	KWH_SEC_10	198,944,531	84,215,463	575,176	1,200,617	3,599	44	73,151	1,743,307
37	RBD	E368 Line Transformers - Rsrv Demand Related - Local	CP_SEC_04	179,997,433	89,835,634	289,247	987,572	0	0	64,254	0
38	RBD	E369 Services - Rsrv									
39	RBD	Services	E369PLT	240,814,772	377,380	2,375,766	64,419,906	148,583,936	630,494	0	0
40	RBD	Not used	not_used	0	0	0	0	0	0	0	0
41	RBD	Total Accounts E369 Rsrv		240,814,772	377,380	2,375,766	64,419,906	148,583,936	630,494	0	0
42	RBD	E370 Meters - Rsrv									
43	RBD	Load profile meters	KWHMETERX_04	0	0	0	0	0	0	0	0
44	RBD	All other Meters	METERPLTXPR	136,921,647	82,199,942	285,570	477,105	64,199	1,001	32,435	0
45	RBD	Total Account E370 Rsrv		136,921,647	82,199,942	285,570	477,105	64,199	1,001	32,435	0
46	RBD	E373 Street Lighting - Rsrv									
47	RBD	Streetlight fixtures	E373PLT	118,939,285	3,310,553	20,809	160,845	275,135	1,168	2,612	81,493,494
48	RBD	Not used	not_used	0	0	0	0	0	0	0	0
49	RBD	Total Account E373 Rsrv		118,939,285	3,310,553	20,809	160,845	275,135	1,168	2,612	81,493,494
50	RBD										

PUBLIC SERVICE ELECTRIC & GAS COMPANY
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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
1	RBD	**LESS: DEPRECIATION RESERVE & AMORT**								
2	RBD									
3	RBD	E301-E303 - INTANGILE PLANT - RESERVE								
4	RBD	Customer Service Related - Reserve	CUSTSVSX	2,322	101,563	3,060,763	1,806,740	394,336	611,569	286,892
5	RBD	Not Used	not_used	0	0	0	0	0	0	0
6	RBD	Not used	not_used	0	0	0	0	0	0	0
7	RBD	Total Accounts E301-E303 Reserve		2,322	101,563	3,060,763	1,806,740	394,336	611,569	286,892
8	RBD									
9	RBD	E304-E346 - PRODUCTION PLANT - RESERVE	not_used	0	0	0	0	0	0	0
10	RBD	E350-E359 - TRANSMISSION PLANT - RESERVE	not_used	0	0	0	0	0	0	0
11	RBD									
12	RBD	DISTRIBUTION PLANT RESERVE								
13	RBD	E360-E361 Land & Structures - Reserve								
14	RBD	E360 - Land and Land Rights								
15	RBD	- Headquarters Related	DISTPLT	0	0	0	0	0	0	0
16	RBD	- Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0
17	RBD	- Direct - HEP	DIR_HEP_03	0	0	0	0	0	0	0
18	RBD	- Substation Related	E362PLT	147	1,316	142,014	160,552	43,987	48,642	0
19	RBD	E361 - Structures and improvements								
20	RBD	- Headquarters Related	DISTPLT	8,072	569,540	8,700,417	9,117,648	1,658,297	1,007,680	1,133
21	RBD	- Substation Related	E362PLT	7,970	71,570	7,722,585	8,730,693	2,391,958	2,645,089	0
22	RBD	Total Accounts E360-E361		16,188	642,426	16,565,015	18,008,892	4,094,242	3,701,411	1,133
23	RBD	E362 Station Equipment - Rsrv	E362PLT	61,285	550,368	59,385,859	67,138,103	18,393,906	20,340,458	0
24	RBD	E364 Poles Towers and Fixtures Rsrv								
25	RBD	- Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0
26	RBD	- All Other	E364PLT	45,979	765,899	45,479,921	51,131,656	7,576,612	6,654,069	0
27	RBD	E365 OH Conductors and Devices - Rsrv								
28	RBD	- Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0
29	RBD	- All Other	E365PLT	134,797	2,585,191	137,293,968	153,160,520	39,861,522	14,524,463	0
30	RBD	E366 UG Conduit - Rsrv								
31	RBD	- Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0
32	RBD	- All Other	E366PLT	59,720	702,192	60,427,902	67,524,944	10,628,760	3,171,858	0
33	RBD	E367 UG Conductors and Devices - Rsrv								
34	RBD	- Direct - HTS-HV	DIR_HEP_03	0	0	0	0	0	0	0
35	RBD	- All Other	E367PLT	118,561	1,394,058	119,967,222	134,056,947	21,101,226	6,297,074	0
36	RBD	E368 Line Transformers - Rsrv Energy Related - Local	KWH_SEC_10	94,233	846,248	45,029,595	65,163,099	0	0	0
37	RBD	E368 Line Transformers - Rsrv Demand Related - Local	CP_SEC_04	0	0	48,734,781	40,085,944	0	0	0
38	RBD	E369 Services - Rsrv								
39	RBD	Services	E369PLT	0	0	23,861,988	455,779	109,337	187	0
40	RBD	Not used	not_used	0	0	0	0	0	0	0
41	RBD	Total Accounts E369 Rsrv		0	0	23,861,988	455,779	109,337	187	0
42	RBD	E370 Meters - Rsrv								
43	RBD	Load profile meters	KWHMETERX_04	0	0	0	0	0	0	0
44	RBD	All other Meters	METERPLTXPR	0	0	42,925,835	6,638,767	3,122,849	1,060,917	113,028
45	RBD	Total Account E370 Rsrv		0	0	42,925,835	6,638,767	3,122,849	1,060,917	113,028
46	RBD	E373 Street Lighting - Rsrv								
47	RBD	Streetlight fixtures	E373PLT	1,783	29,265,964	1,827,310	1,999,832	359,484	220,297	0
48	RBD	Not used	not_used	0	0	0	0	0	0	0
49	RBD	Total Account E373 Rsrv		1,783	29,265,964	1,827,310	1,999,832	359,484	220,297	0
50	RBD									

PUBLIC SERVICE ELECTRIC & GAS COMPANY
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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
51	RBD	**DEPRECIATION RESERVE & AMORT CONTINUED**									
52	RBD	Other Plant Unallocated - Reserve									
53	RBD	Not Used	not_used	0	0	0	0	0	0	0	0
54	RBD	Not Used	not_used	0	0	0	0	0	0	0	0
55	RBD	Total Other Plant Unallocated - Reserve		0	0	0	0	0	0	0	0
56	RBD										
57	RBD	Not Used	not_used	0	0	0	0	0	0	0	0
58	RBD	Not Used	not_used	0	0	0	0	0	0	0	0
59	RBD	Not Used	not_used	0	0	0	0	0	0	0	0
60	RBD										
61	RBD	TOTAL DISTRIBUTION PLANT RESERVE		2,813,507,566	1,074,643,776	7,599,288	78,040,366	150,257,422	638,494	814,728	96,031,887
62	RBD										
63	RBD	GENERAL AND COMMON PLANT RESERVE									
64	RBD	E390-E398 GENERAL PLANT - RESERVE									
65	RBD	Meter Plant Related	METERPLT	0	0	0	0	0	0	0	0
66	RBD	Customer Service Related	CUSTSVSX	0	0	0	0	0	0	0	0
67	RBD	Substation Related	E362PLT	0	0	0	0	0	0	0	0
68	RBD	Distribution Delivery Related	DISTPLTXMTR	156,424,740	59,977,131	376,998	2,914,014	4,984,600	21,161	47,318	5,951,356
69	RBD	Service & Support Related	UTILWORK_04	0	0	0	0	0	0	0	0
70	RBD	Unassigned	GENPLT	0	0	0	0	0	0	0	0
71	RBD	Total Accounts E390-E398 Reserve		156,424,740	59,977,131	376,998	2,914,014	4,984,600	21,161	47,318	5,951,356
72	RBD										
73	RBD	C389-C399 COMMON PLANT RESERVE									
74	RBD	Not Used	not_used	0	0	0	0	0	0	0	0
75	RBD	Meter Plant Related	METERPLT	0	0	0	0	0	0	0	0
76	RBD	Meter Reading Related - Customer Related Measurement	MRCOST_07	0	0	0	0	0	0	0	0
77	RBD	Meter Reading Related - Demand Related Measurement	NCP_MTR_07	0	0	0	0	0	0	0	0
78	RBD	Customer Service Related	CUSTSVSX	46,782,308	27,600,166	133,099	227,727	4,498	68	55,919	163,710
79	RBD	Distribution Delivery Related	DISTPLTXMTR	19,175,874	7,352,507	46,216	357,225	611,055	2,594	5,801	729,568
80	RBD	Sales and Service Dept. Related	UTILWORK_04	0	0	0	0	0	0	0	0
81	RBD	Unassigned	COMPLT	0	0	0	0	0	0	0	0
82	RBD	Not Used	not_used	0	0	0	0	0	0	0	0
83	RBD	Total Accounts C389-C399 Reserve		65,958,182	34,952,673	179,314	584,952	615,553	2,663	61,720	893,278
84	RBD										
85	RBD	C303 - INTANGIBLE PLANT									
86	RBD	- Customer Related - Measurement	MRCOST_07	311,743	245,410	853	1,424	16	0	19	0
87	RBD	- Demand Related - Measurement	NCP_MTR_07	311,743	128,246	972	1,681	36	1	749	1,913
88	RBD	Customer Service Related	CUSTSVSX	46,570,192	27,475,024	132,495	226,695	4,478	68	55,666	162,968
89	RBD	Distribution Related	INTANGPLT	0	0	0	0	0	0	0	0
90	RBD	C390.4 / C111.000 Capital Lease	TOTPLT	0	0	0	0	0	0	0	0
91	RBD	E399 Oth Tangible Plant	GENPLT	0	0	0	0	0	0	0	0
92	RBD	E399.1 Asset Retirement Obligations	GENPLT	490,552	188,090	1,182	9,138	15,632	66	148	18,664
93	RBD	Total Accounts C303-C390.4,E399		47,684,230	28,036,770	135,502	238,938	20,162	135	56,582	183,544
94	RBD										
95	RBD	**TOTAL DEPRECIATION RESERVE & AMORT.**		3,099,332,698	1,206,907,087	8,335,934	81,854,978	155,879,252	662,476	999,183	103,115,208
96	RBD										
97	RBD	**NET ELECTRIC PLANT IN SERVICE**		8,357,658,252	3,302,584,420	19,235,556	123,554,483	191,996,209	816,510	2,602,586	312,631,345

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
51	RBD	**DEPRECIATION RESERVE & AMORT CONTINUED**								
52	RBD	Other Plant Unallocated - Reserve								
53	RBD	Not Used	not_used	0	0	0	0	0	0	0
54	RBD	Not Used	not_used	0	0	0	0	0	0	0
55	RBD	Total Other Plant Unallocated - Reserve		0	0	0	0	0	0	0
56	RBD									
57	RBD	Not Used	not_used	0	0	0	0	0	0	0
58	RBD	Not Used	not_used	0	0	0	0	0	0	0
59	RBD	Not Used	not_used	0	0	0	0	0	0	0
60	RBD									
61	RBD	TOTAL DISTRIBUTION PLANT RESERVE		532,546	36,752,346	601,499,397	605,364,485	105,247,938	55,970,733	114,161
62	RBD									
63	RBD	GENERAL AND COMMON PLANT RESERVE								
64	RBD	E390-E398 GENERAL PLANT - RESERVE								
65	RBD	Meter Plant Related	METERPLT	0	0	0	0	0	0	0
66	RBD	Customer Service Related	CUSTSVSX	0	0	0	0	0	0	0
67	RBD	Substation Related	E362PLT	0	0	0	0	0	0	0
68	RBD	Distribution Delivery Related	DISTPLTXMTR	32,311	2,279,819	33,105,293	36,230,874	6,512,763	3,991,103	0
69	RBD	Service & Support Related	UTILWORK_04	0	0	0	0	0	0	0
70	RBD	Unassigned	GENPLT	0	0	0	0	0	0	0
71	RBD	Total Accounts E390-E398 Reserve		32,311	2,279,819	33,105,293	36,230,874	6,512,763	3,991,103	0
72	RBD									
73	RBD	C389-C399 COMMON PLANT RESERVE								
74	RBD	Not Used	not_used	0	0	0	0	0	0	0
75	RBD	Meter Plant Related	METERPLT	0	0	0	0	0	0	0
76	RBD	Meter Reading Related - Customer Related Measurement	MRCOST_07	0	0	0	0	0	0	0
77	RBD	Meter Reading Related - Demand Related Measurement	NCP_MTR_07	0	0	0	0	0	0	0
78	RBD	Customer Service Related	CUSTSVSX	6,892	301,521	9,086,798	5,363,852	1,170,705	1,815,626	851,725
79	RBD	Distribution Delivery Related	DISTPLTXMTR	3,961	279,480	4,058,328	4,441,488	798,390	489,263	0
80	RBD	Sales and Service Dept. Related	UTILWORK_04	0	0	0	0	0	0	0
81	RBD	Unassigned	COMPLT	0	0	0	0	0	0	0
82	RBD	Not Used	not_used	0	0	0	0	0	0	0
83	RBD	Total Accounts C389-C399 Reserve		10,853	581,001	13,145,126	9,805,341	1,969,095	2,304,889	851,725
84	RBD									
85	RBD	C303 - INTANGIBLE PLANT								
86	RBD	- Customer Related - Measurement	MRCOST_07	0	0	60,139	3,508	292	72	10
87	RBD	- Demand Related - Measurement	NCP_MTR_07	103	929	67,094	57,949	14,997	25,155	11,920
88	RBD	Customer Service Related	CUSTSVSX	6,861	300,154	9,045,598	5,339,532	1,165,397	1,807,393	847,863
89	RBD	Distribution Related	INTANGPLT	0	0	0	0	0	0	0
90	RBD	C390.4 / C111.000 Capital Lease	TOTPLT	0	0	0	0	0	0	0
91	RBD	E399 Oth Tangible Plant	GENPLT	0	0	0	0	0	0	0
92	RBD	E399.1 Asset Retirement Obligations	GENPLT	101	7,150	103,819	113,621	20,424	12,516	0
93	RBD	Total Accounts C303-C390.4,E399		7,066	308,232	9,276,649	5,514,609	1,201,111	1,845,136	859,793
94	RBD									
95	RBD	**TOTAL DEPRECIATION RESERVE & AMORT.**		585,098	40,022,961	660,087,229	658,722,048	115,325,242	64,723,429	2,112,572
96	RBD									
97	RBD	**NET ELECTRIC PLANT IN SERVICE**		1,695,126	120,148,908	1,798,887,394	1,906,778,275	351,804,368	223,467,130	1,455,942

Updated for 9 and 3

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	RBO	**ADDITIONS AND DEDUCTIONS TO RATE BASE**									
2	RBO										
3	RBO	**PLUS: ADDITIONS TO RATE BASE**									
4	RBO										
5	RBO	Working Capital									
6	RBO	Cash (lead/lag)	EXPENDITURES	884,882,332	376,055,803	1,935,864	8,321,768	9,487,529	40,829	328,952	37,994,814
7	RBO	Materials and Supplies	EXPENDITURES	297,953,440	126,623,751	651,835	2,802,067	3,194,597	13,748	110,763	12,793,436
8	RBO	Prepayments	EXPENDITURES	500,266	212,602	1,094	4,705	5,364	23	186	21,480
9	RBO	Working Funds	EXPENDITURES								
10	RBO	Total Working Capital		1,183,336,038	502,892,157	2,588,794	11,128,539	12,687,490	54,600	439,901	50,809,730
11	RBO	Net Plant Adds - Distribution	DISTPLT	1,061,820,806	414,940,628	2,547,398	19,235,095	32,705,031	139,035	318,833	39,027,967
12	RBO	Capital Lease Plant & Reserve Deduction	TOTPLT	489,291	192,586	1,177	8,772	14,857	63	154	17,755
13	RBO	Capital Stimulas Adjust	DISTPLT	0	0	0	0	0	0	0	0
14	RBO	Net Plant Adds - General & Other	TOTPLTNET	305,589,989	120,755,923	703,330	4,517,655	7,020,163	29,855	95,161	11,431,074
15	RBO	CEF-EC Adjustment	ECPRO_07	657,429,985	529,627,120	1,706,383	2,850,880	450,057	7,021	193,808	
16	RBO	CEF-EV Adjustment	TOTREV	42,056,391	18,227,709	98,044	538,173	779,923	3,343	15,725	1,492,269
17	RBO	TOTAL ADDITIONS TO RATE BASE		3,250,722,500	1,586,636,122	7,645,126	38,279,114	53,657,520	233,917	1,063,582	102,778,795
18	RBO										
19	RBO										
20	RBO	**PLUS: DEDUCTIONS TO RATE BASE**									
21	RBO										
22	RBO	Customer Advances for Construction	REVREQ	(63,907,492)	(27,751,477)	(149,270)	(819,363)	(1,187,423)	(5,090)	(23,848)	(2,271,963)
23	RBO	Unbilled Revenue	TOTREV								
24	RBO	IAP Adjustment	E365PLT	(40,898,861)	(17,084,554)	(84,167)	(214,171)	(345)	(4)	(13,458)	(199,084)
25	RBO	Deferred Income Taxes and Credits									
26	RBO	ADIT Test/Post year	TOTPLT								
27	RBO	Liberalized Depreciation	TOTPLT	(2,247,763)	(884,723)	(5,409)	(40,300)	(68,250)	(290)	(707)	(81,566)
28	RBO	Cost of Removal	TOTPLT	15,629,066	6,151,627	37,612	280,210	474,555	2,018	4,913	567,141
29	RBO	3% Investment Tax Credit	DISTPLT								
30	RBO	Computer Software	INTANGPLT								
31	RBO	Capitalized Interest	TOTPLTNET	312,066	123,315	718	4,613	7,169	30	97	11,673
32	RBO	NJ Corporate Business Tax	TOTPLTNET	6,378,736	2,520,600	14,681	94,299	146,535	623	1,986	238,607
33	RBO	Defrd Tax & Consolidated Tax Adjustment	DEPREXP	(1,738,024,409)	(686,351,347)	(4,189,410)	(31,011,589)	(52,419,290)	(222,862)	(558,819)	(62,694,839)
34	RBO	Total Deferred Income Taxes and Credits		(1,717,952,304)	(678,440,528)	(4,141,808)	(30,672,767)	(51,859,282)	(220,481)	(552,528)	(61,958,984)
35	RBO										
36	RBO	TOTAL DEDUCTIONS TO RATE BASE		(1,822,758,657)	(723,276,560)	(4,375,246)	(31,706,300)	(53,047,050)	(225,575)	(589,835)	(64,430,030)
37	RBO										
38	RBO										
39	RBO	**TOTAL RATE BASE**		9,785,622,095	4,165,943,983	22,505,436	130,127,297	192,606,679	824,852	3,076,333	350,980,110

Updated for 9 and 3

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
1	RBO	**ADDITIONS AND DEDUCTIONS TO RATE BASE**								
2	RBO									
3	RBO	**PLUS: ADDITIONS TO RATE BASE**								
4	RBO									
5	RBO	Working Capital								
6	RBO	Cash (lead/lag)	EXPENDITURES	483,910	15,524,320	193,654,050	179,882,384	36,964,817	22,836,276	1,371,016
7	RBO	Materials and Supplies	EXPENDITURES	162,940	5,227,276	65,206,286	60,569,155	12,446,620	7,689,324	461,642
8	RBO	Prepayments	EXPENDITURES	274	8,777	109,482	101,696	20,898	12,910	775
9	RBO	Working Funds	EXPENDITURES							
10	RBO	Total Working Capital		647,124	20,760,373	258,969,818	240,553,235	49,432,335	30,538,511	1,833,433
11	RBO	Net Plant Adds - Distribution	DISTPLT	211,892	14,950,661	228,389,533	239,342,011	43,530,978	26,452,015	29,730
12	RBO	Capital Lease Plant & Reserve Deduction	TOTPLT	97	6,840	105,015	109,564	19,950	12,308	152
13	RBO	Capital Stimulas Adjust	DISTPLT	0	0	0	0	0	0	0
14	RBO	Net Plant Adds - General & Other	TOTPLTNET	61,981	4,393,133	65,774,642	69,719,572	12,863,399	8,170,867	53,235
15	RBO	CEF-EC Adjustment	ECPRO_07			122,594,717				
16	RBO	CEF-EV Adjustment	TOTREV	16,372	606,502	8,862,715	8,609,028	1,651,110	1,091,339	64,138
17	RBO	TOTAL ADDITIONS TO RATE BASE		937,466	40,717,509	684,696,440	558,333,409	107,497,772	66,265,040	1,980,688
18	RBO									
19	RBO									
20	RBO	**PLUS: DEDUCTIONS TO RATE BASE**								
21	RBO									
22	RBO	Customer Advances for Construction	REVREQ	(24,926)	(919,826)	(13,441,276)	(13,056,531)	(2,504,089)	(1,655,135)	(97,273)
23	RBO	Unbilled Revenue	TOTREV							
24	RBO	IAP Adjustment	E365PLT	(9,038)	(173,331)	(9,205,224)	(10,269,038)	(2,672,617)	(973,830)	
25	RBO	Deferred Income Taxes and Credits								
26	RBO	ADIT Test/Post year	TOTPLT							
27	RBO	Liberalized Depreciation	TOTPLT	(447)	(31,424)	(482,430)	(503,329)	(91,647)	(56,541)	(700)
28	RBO	Cost of Removal	TOTPLT	3,111	218,499	3,354,413	3,499,730	637,235	393,135	4,868
29	RBO	3% Investment Tax Credit	DISTPLT							
30	RBO	Computer Software	INTANGPLT							
31	RBO	Capitalized Interest	TOTPLTNET	63	4,486	67,168	71,197	13,136	8,344	54
32	RBO	NJ Corporate Business Tax	TOTPLTNET	1,294	91,700	1,372,948	1,455,292	268,504	170,555	1,111
33	RBO	Defrd Tax & Consolidated Tax Adjustment	DEPREXP	(345,639)	(24,225,839)	(372,516,037)	(388,066,668)	(70,685,220)	(43,947,777)	(789,073)
34	RBO	Total Deferred Income Taxes and Credits		(341,619)	(23,942,578)	(368,203,938)	(383,543,778)	(69,857,991)	(43,432,283)	(783,739)
35	RBO									
36	RBO	TOTAL DEDUCTIONS TO RATE BASE		(375,583)	(25,035,735)	(390,850,438)	(406,869,347)	(75,034,698)	(46,061,248)	(881,012)
37	RBO									
38	RBO									
39	RBO	**TOTAL RATE BASE**		2,257,009	135,830,682	2,092,733,396	2,058,242,336	384,267,442	243,670,921	2,555,619

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	REV	**OPERATING REVENUES**									
2	REV										
3	REV	**SALES REVENUES**									
4	REV	BASE RATE SALES @ EQUALIZED ROR 7.40%		1,899,915,237	825,027,762	4,437,681	24,358,956	35,301,077	151,307	708,990	67,543,508
5	REV	Not Used	not_used	0	0	0	0	0	0	0	0
6	REV	Not Used	not_used	0	0	0	0	0	0	0	0
7	REV	TOTAL SALES OF ELECTRICITY		1,899,915,237	825,027,762	4,437,681	24,358,956	35,301,077	151,307	708,990	67,543,508
8	REV										
9	REV	**OTHER OPERATING REVENUES**									
10	REV	450-Forfeited Discounts	REVLATEP	3,653,078	0	0	0	0	0	2,748	0
11	REV	456-Other Electric Revenues	TOTREV	21,451,361	9,297,260	50,008	274,502	397,809	1,705	8,021	761,150
12	REV	Not Used	not_used	0	0	0	0	0	0	0	0
13	REV	Not Used	not_used	0	0	0	0	0	0	0	0
14	REV	TOTAL OTHER OPERATING REV		25,104,439	9,297,260	50,008	274,502	397,809	1,705	10,769	761,150
15	REV										
16	REV	**OTHER REVENUE SOURCES**									
17	REV	Not Used	not_used	0	0	0	0	0	0	0	0
18	REV	Not Used	not_used	0	0	0	0	0	0	0	0
19	REV	TOTAL OTHER REVENUE SOURCES		0	0	0	0	0	0	0	0
20	REV										
21	REV	LESS: E496 Provision for Rate Refunds	TOTREV	0	0	0	0	0	0	0	0
22	REV										
23	REV	**TOTAL OPERATING REVENUES**		1,925,019,676	834,325,022	4,487,689	24,633,458	35,698,885	153,013	719,759	68,304,658

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
1	REV	**OPERATING REVENUES**								
2	REV									
3	REV	**SALES REVENUES**								
4	REV	BASE RATE SALES @ EQUALIZED ROR 7.40%		741,039	27,345,651	399,597,683	388,159,549	74,444,444	49,205,760	2,891,829
5	REV	Not Used	not_used	0	0	0	0	0	0	0
6	REV	Not Used	not_used	0	0	0	0	0	0	0
7	REV	TOTAL SALES OF ELECTRICITY		741,039	27,345,651	399,597,683	388,159,549	74,444,444	49,205,760	2,891,829
8	REV									
9	REV	**OTHER OPERATING REVENUES**								
10	REV	450-Forfeited Discounts	REVLATEP	0	106,007	1,549,059	1,504,718	288,587	190,748	11,210
11	REV	456-Other Electric Revenues	TOTREV	8,351	309,353	4,520,533	4,391,137	842,168	556,651	32,714
12	REV	Not Used	not_used	0	0	0	0	0	0	0
13	REV	Not Used	not_used	0	0	0	0	0	0	0
14	REV	TOTAL OTHER OPERATING REV		8,351	415,360	6,069,592	5,895,855	1,130,756	747,399	43,925
15	REV									
16	REV	**OTHER REVENUE SOURCES**								
17	REV	Not Used	not_used	0	0	0	0	0	0	0
18	REV	Not Used	not_used	0	0	0	0	0	0	0
19	REV	TOTAL OTHER REVENUE SOURCES		0	0	0	0	0	0	0
20	REV									
21	REV	LESS: E496 Provision for Rate Refunds	TOTREV	0	0	0	0	0	0	0
22	REV									
23	REV	**TOTAL OPERATING REVENUES**		749,390	27,761,012	405,667,274	394,055,404	75,575,200	49,953,159	2,935,754

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	E	**OPERATION & MAINTENANCE EXPENSE**									
2	E	PRODUCTION EXPENSE									
3	E	E500-E557 Production Expenses									
4	E	Not Used	not_used	0	0	0	0	0	0	0	0
5	E	Total Production Expense		0	0	0	0	0	0	0	0
6	E	TOTAL PRODUCTION EXPENSE		0	0	0	0	0	0	0	0
7	E										
8	E	TRANSMISSION EXPENSES									
9	E	E560-E573 Transmission Exp	not_used	0	0	0	0	0	0	0	0
10	E	TOTAL TRANSMISSION EXPENSE		0	0	0	0	0	0	0	0
11	E										
12	E	DISTRIBUTION EXPENSES									
13	E	Operation									
14	E	E580 Operation Supervision & Eng'g	DISTEXPO	0	0	0	0	0	0	0	0
15	E	E581 Load Dispatching	CP_SUBT_05	0	0	0	0	0	0	0	0
16	E	E582 Station Expenses	E362PLT	2,539,578	1,002,546	5,026	12,646	21	0	793	10,309
17	E	E583 OH Line Expenses	E365PLT	4,195,894	1,752,738	8,635	21,972	35	0	1,381	20,424
18	E	E584 Underground Line Expenses	E367PLT	6,199,909	2,691,919	13,301	34,011	604	3	2,122	37,183
19	E	E585 Street Lighting and System Expenses	E373PLT	173,106	4,818	30	234	400	2	4	118,607
20	E	E586 Meter Expenses									
21	E	- Basic portion (minimum size)	METERPLT_07	5,865,310	4,892,223	15,762	26,334	4,157	65	1,790	0
22	E	- Excess portion	not_used	0	0	0	0	0	0	0	0
23	E	E587 Customer Installations Expenses	MTROMMIN_07								
24	E	-E587 Customer Installation Expenses - Local	CUSTAVG_04	-1,314,125	-1,119,615	-3,890	-6,498	-371	-6	-442	-2,764
25	E	-E587 Customer Installation Expenses - System	CUSTAVG_04	-1,314,125	-1,119,615	-3,890	-6,498	-371	-6	-442	-2,764
26	E	E588 Miscellaneous Distribution Expenses	DISTEXPO	35,897,260	17,799,821	76,809	180,525	9,832	129	11,434	397,495
27	E	E589 Rents	DISTPLT	1,330,133	519,792	3,191	24,096	40,969	174	399	48,890
28	E	Total Distribution Operation		53,572,940	26,424,628	114,975	286,822	55,278	362	17,040	627,381
29	E	Maintenance									
30	E	E590 Maint. Supervision & Eng'g	DISTEXPM	0	0	0	0	0	0	0	0
31	E	E591 Maint of Structures	E360PLT	12,325,542	4,865,739	24,392	61,377	103	1	3,851	50,035
32	E	E592 Maint of Station Equipment	E362PLT	17,215,431	6,796,115	34,069	85,728	144	2	5,379	69,885
33	E	E593 Maint of Overhead Lines									
34	E	- Direct assigned - BPL poles	DIR_BPL_02	40,988	0	0	0	0	0	0	40,988
35	E	- Direct assigned - PSAL poles	DIR_PSAL_02	118,210	0	0	0	0	0	0	0
36	E	- all other O&M	E365PLT	56,305,216	23,520,203	115,872	294,848	475	6	18,528	274,078
37	E	E594.0 Maint of Underground Lines	E367PLT	20,076,605	8,716,997	43,071	110,135	1,956	10	6,871	120,405
38	E	Not used	not_used	0	0	0	0	0	0	0	0
39	E	E595 Maint of Line Transformers - Energy Related Local	KWH_SEC_10	2,207,903	934,630	6,383	13,325	40	0	812	19,347
40	E	E595 Maint of Line Transformers - Demand Related Local	CP_SEC_04	1,997,626	997,003	3,210	10,960	0	0	713	0
41	E	E596 Maint of Street Lighting & Signal Systems									
42	E	- BPL luminaires	DIR_BPL_02	8,123,869	0	0	0	0	0	0	8,123,869
43	E	- BPL-POF luminaires	DIR_BPLPOF_02	340,052	0	0	0	0	0	0	0
44	E	- PSAL luminaires	DIR_PSAL_02	3,594,664	0	0	0	0	0	0	0
45	E	E597 Maint of Meters									
46	E	- Load profiling meters O&M	KWHMETERX_04	0	0	0	0	0	0	0	0
47	E	- Basic portion (minimum size)	METERPLTXPR	858,670	515,496	1,791	2,992	403	6	203	0
48	E	- Excess portion	METERSEXC_04	0	0	0	0	0	0	0	0
49	E	E598 Other Dist Maint Exp	DISTEXPM	1,231,542	463,272	2,287	5,791	31	0	363	86,950
50	E	Total Distribution Maintenance		124,436,319	46,809,455	231,075	585,156	3,152	26	36,720	8,785,559

PUBLIC SERVICE ELECTRIC & GAS COMPANY
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12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
1	E	**OPERATION & MAINTENANCE EXPENSE**								
2	E	PRODUCTION EXPENSE								
3	E	E500-E557 Production Expenses								
4	E	Not Used	not_used	0	0	0	0	0	0	0
5	E	Total Production Expense		0	0	0	0	0	0	0
6	E	TOTAL PRODUCTION EXPENSE		0	0	0	0	0	0	0
7	E									
8	E	TRANSMISSION EXPENSES								
9	E	E560-E573 Transmission Exp	not_used	0	0	0	0	0	0	0
10	E	TOTAL TRANSMISSION EXPENSE		0	0	0	0	0	0	0
11	E									
12	E	DISTRIBUTION EXPENSES								
13	E	Operation								
14	E	E580 Operation Supervision & Eng'g	DISTEXPO	0	0	0	0	0	0	0
15	E	E581 Load Dispatching	CP_SUBT_05	0	0	0	0	0	0	0
16	E	E582 Station Expenses	E362PLT	557	5,004	539,988	610,479	167,254	184,953	0
17	E	E583 OH Line Expenses	E365PLT	927	17,782	944,382	1,053,521	274,189	99,907	0
18	E	E584 Underground Line Expenses	E367PLT	1,433	16,855	1,450,438	1,620,787	255,120	76,133	0
19	E	E585 Street Lighting and System Expenses	E373PLT	3	42,594	2,659	2,911	523	321	
20	E	E586 Meter Expenses								
21	E	- Basic portion (minimum size)	METERPLT_07	0	0	788,936	69,459	18,133	32,280	16,172
22	E	- Excess portion	not_used	0	0	0	0	0	0	0
23	E	E587 Customer Installations Expenses	MTROMMIN_07							
24	E	-E587 Customer Installation Expenses - Local	CUSTAVG_04	-50	-13,196	-161,392	-5,335	-444	-109	-15
25	E	-E587 Customer Installation Expenses - System	CUSTAVG_04	-50	-13,196	-161,392	-5,335	-444	-109	-15
26	E	E588 Miscellaneous Distribution Expenses	DISTEXPO	6,193	122,641	7,474,858	7,349,384	1,568,775	863,912	35,452
27	E	E589 Rents	DISTPLT	265	18,729	286,101	299,821	54,531	33,136	37
28	E	Total Distribution Operation		9,278	197,213	11,164,580	10,995,693	2,337,635	1,290,423	51,631
29	E	Maintenance								
30	E	E590 Maint. Supervision & Eng'g	DISTEXPM	0	0	0	0	0	0	0
31	E	E591 Maint of Structures	E360PLT	2,705	24,288	2,620,770	2,962,886	811,745	897,649	0
32	E	E592 Maint of Station Equipment	E362PLT	3,778	33,924	3,660,503	4,138,346	1,133,787	1,253,772	0
33	E	E593 Maint of Overhead Lines								
34	E	- Direct assigned - BPL poles	DIR_BPL_02	0	0	0	0	0	0	0
35	E	- Direct assigned - PSAL poles	DIR_PSAL_02	0	118,210	0	0	0	0	0
36	E	- all other O&M	E365PLT	12,442	238,623	12,672,777	14,137,323	3,679,376	1,340,665	0
37	E	E594.0 Maint of Underground Lines	E367PLT	4,642	54,579	4,696,823	5,248,449	826,132	246,536	0
38	E	Not used	not_used	0	0	0	0	0	0	0
39	E	E595 Maint of Line Transformers - Energy Related Local	KWH_SEC_10	1,046	9,392	499,742	723,185	0	0	0
40	E	E595 Maint of Line Transformers - Demand Related Local	CP_SEC_04	0	0	540,863	444,877	0	0	0
41	E	E596 Maint of Street Lighting & Signal Systems								
42	E	- BPL luminaires	DIR_BPL_02	0	0	0	0	0	0	0
43	E	- BPL-POF luminaires	DIR_BPLPOF_02	340,052	0	0	0	0	0	0
44	E	- PSAL luminaires	DIR_PSAL_02	0	3,594,664	0	0	0	0	0
45	E	E597 Maint of Meters								
46	E	- Load profiling meters O&M	KWHMETERX_04	0	0	0	0	0	0	0
47	E	- Basic portion (minimum size)	METERPLTXPR	0	0	269,199	41,633	19,584	6,653	709
48	E	- Excess portion	METERSEXC_04	0	0	0	0	0	0	0
49	E	E598 Other Dist Maint Exp	DISTEXPM	3,645	40,720	249,504	276,853	64,680	37,437	7
50	E	Total Distribution Maintenance		368,309	4,114,401	25,210,180	27,973,551	6,535,305	3,782,713	716

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
51	E										
52	E	**OPERATION & MAINTENANCE EXPENSE CONTINUED**									
53	E										
54	E	TOTAL DISTRIBUTION PLANT O&M EXPENSES		178,009,259	73,234,083	346,050	871,978	58,430	387	53,760	9,412,940
55	E										
56	E	TOTAL OPER & MAINT EXP (PROD,TRAN,& DIST)		178,009,259	73,234,083	346,050	871,978	58,430	387	53,760	9,412,940
57	E										
58	E										
59	E	CUSTOMER ACCOUNTS EXPENSES									
60	E	E901 Supervision	CUSTACCTS	0	0	0	0	0	0	0	0
61	E	E902 Meter Reading									
62	E	- Meter O&M - Customer Related - Cust Svs	METERPLT	0	0	0	0	0	0	0	0
63	E	- Meter O&M - Demand Related - Cust Svs	NCP_MTR_06	0	0	0	0	0	0	0	0
64	E	- Meter Reading - Customer Related Measurement	MRCOST_07	9,323,486	7,339,625	25,498	42,601	486	8	579	0
65	E	- Meter Reading - Demand Related Measurement	NCPXSL_MTR_07	9,323,486	3,872,092	29,343	50,748	1,084	16	22,608	0
66	E	- Billing - Customer Related - Cust Svs	BILLING_06	0	0	0	0	0	0	0	0
67	E	- Billing - Customer Related - Cust Svs	NCPXSL_MTR_07	0	0	0	0	0	0	0	0
68	E	- Remaining - Customer Related - Measurement	MRCOST_07	-283,695	-223,330	-776	-1,296	-15	0	-18	0
69	E	- Remaining - Demand Related - Measurement	NCPXSL_MTR_07	-283,695	-117,820	-893	-1,544	-33	0	-688	0
70	E	E903 Customer Records and Collection									
71	E	- SONP/RNP - Customer Related - Local D	CUSTAVG_04	275,332	234,579	815	1,362	78	1	93	579
72	E	- SONP/RNP - Demand Related - Local D	NCP_MTR_04	275,332	113,267	858	1,484	32	0	661	1,689
73	E	- Meter O&M - Customer Related - Cust Svs	METERPLT	0	0	0	0	0	0	0	0
74	E	- Meter O&M - Demand Related - Cust Svs	NCP_MTR_06	0	0	0	0	0	0	0	0
75	E	- Meter Reading - Customer Related Measurement	MRCOST_07	266,527	209,815	729	1,218	14	0	17	0
76	E	- Meter Reading - Demand Related Measurement	NCPXSL_MTR_07	266,527	110,690	839	1,451	31	0	646	0
77	E	- Billing - Customer Related - Cust Svs	BILLING_06	40,496	29,269	102	170	2	0	2	123
78	E	- Billing - Customer Related - Cust Svs	NCP_MTR_06	40,496	16,660	126	218	5	0	97	248
79	E	- Acct Maint Related - Customer Related - Cust Svs	ACCTMAINT_06	3,872,512	3,225,657	11,206	18,722	1,019	16	1,215	920
80	E	- Acct Maint Related - Demand Related - Cust Svs	NCP_MTR_06	3,872,512	1,593,082	12,072	20,879	446	7	9,302	23,761
81	E	- Utility Work Related -Customer related - Local D	UTILWORK_04	531,469	388,574	1,242	2,651	32	0	179	2,656
82	E	- Utility Work Related -Demand Related - Local D	NCP_MTR_04	531,469	218,637	1,657	2,865	61	1	1,277	3,261
83	E	- Remaining - Customer Related - Cust Svs	BILLING_06	33,170,904	23,974,248	83,289	139,151	1,588	25	1,892	100,598
84	E	- Remaining - Demand Related - Cust Svs	NCP_MTR_06	33,170,904	13,645,918	103,410	178,846	3,822	58	79,675	203,532
85	E	Not used	not_used	0	0	0	0	0	0	0	0
86	E	E904 Uncollectible Accounts	not_used	0	0	0	0	0	0	0	0
87	E	E905 Misc Customer Accounts	CUSTACCTS	0	0	0	0	0	0	0	0
88	E	TOTAL CUSTOMER ACCTS EXPENSE		94,394,062	54,630,961	269,518	459,527	8,652	132	117,538	337,369
89	E										
90	E										
91	E	CUSTOMER SERVICE & INFO EXPENSES									
92	E	E907 & 908 - Cust Svs & Info									
93	E	- SONP/RNP	CUSTAVG_06	0	0	0	0	0	0	0	0
94	E	- Acct Maint related	ACCTMAINT_06	2,356,739	1,963,075	6,820	11,394	620	10	739	560
95	E	- Utility work related	UTILWORK_04	847,228	619,436	1,980	4,226	51	0	286	4,234
96	E	- Sales	SALES_06	0	0	0	0	0	0	0	0
97	E	- Billing	BILLING_06	41,297	29,847	104	173	2	0	2	125
98	E	- Remaining	ACCTMAINT_06	0	0	0	0	0	0	0	0
99	E	E909 Info & Instr Advertising	CUSTNUMX_04	0	0	0	0	0	0	0	0
100	E	E910 - Misc Cust Svs & Info									

PUBLIC SERVICE ELECTRIC & GAS COMPANY
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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
51	E									
52	E	**OPERATION & MAINTENANCE EXPENSE CONTINUED**								
53	E									
54	E	TOTAL DISTRIBUTION PLANT O&M EXPENSES		377,588	4,311,614	36,374,761	38,969,244	8,872,940	5,073,136	52,347
55	E									
56	E	TOTAL OPER & MAINT EXP (PROD,TRAN,& DIST)		377,588	4,311,614	36,374,761	38,969,244	8,872,940	5,073,136	52,347
57	E									
58	E									
59	E	CUSTOMER ACCOUNTS EXPENSES								
60	E	E901 Supervision	CUSTACCTS	0	0	0	0	0	0	0
61	E	E902 Meter Reading								
62	E	- Meter O&M - Customer Related - Cust Svs	METERPLT	0	0	0	0	0	0	0
63	E	- Meter O&M - Demand Related - Cust Svs	NCP_MTR_06	0	0	0	0	0	0	0
64	E	- Meter Reading - Customer Related Measurement	MRCOST_07	0	0	1,798,602	104,913	8,739	2,147	289
65	E	- Meter Reading - Demand Related Measurement	NCPXSL_MTR_07	0	0	2,025,741	1,749,632	452,811	759,497	359,912
66	E	- Billing - Customer Related - Cust Svs	BILLING_06	0	0	0	0	0	0	0
67	E	- Billing - Customer Related - Cust Svs	NCPXSL_MTR_07	0	0	0	0	0	0	0
68	E	- Remaining - Customer Related - Measurement	MRCOST_07	0	0	-54,728	-3,192	-266	-65	-9
69	E	- Remaining - Demand Related - Measurement	NCPXSL_MTR_07	0	0	-61,639	-53,238	-13,778	-23,110	-10,951
70	E	E903 Customer Records and Collection								
71	E	- SONP/RNP - Customer Related - Local D	CUSTAVG_04	11	2,765	33,814	1,118	93	23	3
72	E	- SONP/RNP - Demand Related - Local D	NCP_MTR_04	91	820	59,257	51,180	13,246	22,217	10,528
73	E	- Meter O&M - Customer Related - Cust Svs	METERPLT	0	0	0	0	0	0	0
74	E	- Meter O&M - Demand Related - Cust Svs	NCP_MTR_06	0	0	0	0	0	0	0
75	E	- Meter Reading - Customer Related Measurement	MRCOST_07	0	0	51,416	2,999	250	61	8
76	E	- Meter Reading - Demand Related Measurement	NCPXSL_MTR_07	0	0	57,909	50,016	12,944	21,711	10,289
77	E	- Billing - Customer Related - Cust Svs	BILLING_06	2	586	7,172	2,773	231	57	8
78	E	- Billing - Customer Related - Cust Svs	NCP_MTR_06	13	121	8,716	7,528	1,948	3,268	1,549
79	E	- Acct Maint Related - Customer Related - Cust Svs	ACCTMAINT_06	17	4,393	483,506	113,727	9,473	2,327	313
80	E	- Acct Maint Related - Demand Related - Cust Svs	NCP_MTR_06	1,284	11,534	833,444	719,846	186,299	312,477	148,078
81	E	- Utility Work Related -Customer related - Local D	UTILWORK_04	49	7,206	119,052	8,790	794	223	19
82	E	- Utility Work Related -Demand Related - Local D	NCP_MTR_04	176	1,583	114,383	98,793	25,568	42,885	20,322
83	E	- Remaining - Customer Related - Cust Svs	BILLING_06	1,830	480,357	5,874,979	2,271,049	189,166	46,478	6,254
84	E	- Remaining - Demand Related - Cust Svs	NCP_MTR_06	11,002	98,800	7,139,061	6,166,005	1,595,784	2,676,598	1,268,393
85	E	Not used	not_used	0	0	0	0	0	0	0
86	E	E904 Uncollectible Accounts	not_used	0	0	0	0	0	0	0
87	E	E905 Misc Customer Accounts	CUSTACCTS	0	0	0	0	0	0	0
88	E	TOTAL CUSTOMER ACCTS EXPENSE		14,476	608,165	18,490,686	11,291,938	2,483,301	3,866,794	1,815,005
89	E									
90	E									
91	E	CUSTOMER SERVICE & INFO EXPENSES								
92	E	E907 & 908 - Cust Svs & Info								
93	E	- SONP/RNP	CUSTAVG_06	0	0	0	0	0	0	0
94	E	- Acct Maint related	ACCTMAINT_06	10	2,673	294,253	69,212	5,765	1,416	191
95	E	- Utility work related	UTILWORK_04	79	11,488	189,785	14,013	1,266	355	30
96	E	- Sales	SALES_06	0	0	0	0	0	0	0
97	E	- Billing	BILLING_06	2	598	7,314	2,827	236	58	8
98	E	- Remaining	ACCTMAINT_06	0	0	0	0	0	0	0
99	E	E909 Info & Instr Advertising	CUSTNUMX_04	0	0	0	0	0	0	0
100	E	E910 - Misc Cust Svs & Info								

PUBLIC SERVICE ELECTRIC & GAS COMPANY
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12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
101	E	- Utility work related	UTILWORK_04	1,163,089	850,371	2,718	5,801	71	1	392	5,813
102	E	- Acct Maint related	ACCTMAINT_06	689,620	574,428	1,996	3,334	182	3	216	164
103	E	- Not used	not_used	0	0	0	0	0	0	0	0
104	E	- Not used	not_used	0	0	0	0	0	0	0	0
105	E	- Not used	not_used	0	0	0	0	0	0	0	0
106	E	- Not used	not_used	0	0	0	0	0	0	0	0
107	E	- Remaining	BILLING_06	220,028	159,025	552	923	11	0	13	667
108	E	TOTAL CUSTOMER SERVICE & INFO EXPENSES		5,318,001	4,196,182	14,170	25,852	936	14	1,649	11,564
109	E										
110	E										
111	E										
112	E	**OPERATION & MAINTENANCE EXPENSE CONTINUED**									
113	E										
114	E	SALES EXPENSES									
115	E	E911-E916 Sales Expenses									
116	E	- Sales	SALES_06	0	0	0	0	0	0	0	0
117	E	- Billing related	BILLING_06	0	0	0	0	0	0	0	0
118	E	- Acct Maint related	ACCTMAINT_06	0	0	0	0	0	0	0	0
119	E	- Utility work related	UTILWORK_04	40,922	29,919	96	204	2	0	14	205
120	E	- Remaining	UTILWORK_04	0	0	0	0	0	0	0	0
121	E	- Clause	not_used	0	0	0	0	0	0	0	0
122	E	SALES EXPENSES TOTAL (ACCT 916)		40,922	29,919	96	204	2	0	14	205
123	E										
124	E	TOTAL OPER & MAINT EXCL A&G		277,762,244	132,091,145	629,833	1,357,561	68,021	533	172,961	9,762,077
125	E										
126	E	ADMINISTRATIVE & GENERAL EXPENSE									
127	E	E920 A&G Salaries	REVREQ	5,694,688	2,472,887	13,301	73,012	105,809	454	2,125	202,451
128	E	E921 Office Supplies & Exp	REVREQ	622,444	270,293	1,454	7,980	11,565	50	232	22,128
129	E	E923 Outside Services Employed	DISTPLT	68,020,983	26,581,387	163,188	1,232,214	2,095,107	8,907	20,425	2,500,159
130	E	E924 Property Insurance	TOTPLT	1,802,573	709,496	4,338	32,318	54,733	233	567	65,411
131	E	E925 Injuries & Damages	LABOR	14,161,029	7,171,933	32,705	64,222	3,722	37	9,092	538,939
132	E	E926 Employee Pension & Benefits	LABOR	-77,966,713	-39,486,679	-180,064	-353,590	-20,494	-202	-50,058	-2,967,248
133	E	E928 Regulatory Comm Exp	REVREQ	15,042,373	6,532,068	35,135	192,859	279,492	1,198	5,613	534,768
134	E	E929 Duplicate Charges - credit	REVLPLS	-3,363,888	0	0	0	0	0	0	0
135	E	E930.1 General Advertising Expenses	CUSTAVG_04	2,277,517	1,940,410	6,741	11,263	642	10	766	4,789
136	E	E930.2 Misc General Expenses	DISTPLT	2,932,568	1,145,995	7,035	53,124	90,326	384	881	107,789
137	E	E931 Rents	DISTPLT	4,471,819	1,747,507	10,728	81,008	137,736	586	1,343	164,365
138	E	E932 Maint of General Plant	COMGENPLT	0	0	0	0	0	0	0	0
139	E	E935 Other A&G Maint	COMGENPLT	0	0	0	0	0	0	0	0
140	E	Not Used	not_used	0	0	0	0	0	0	0	0
141	E	TOTAL A&G EXPENSE		33,695,393	9,085,296	94,562	1,394,410	2,758,639	11,655	-9,015	1,173,551
142	E										
143	E	**TOTAL OPERATION & MAINTENANCE EXPENSES**		311,457,637	141,176,442	724,395	2,751,971	2,826,660	12,188	163,946	10,935,628

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
101	E	- Utility work related	UTILWORK_04	108	15,771	260,539	19,237	1,737	487	41
102	E	- Acct Maint related	ACCTMAINT_06	3	782	86,103	20,253	1,687	414	56
103	E	- Not used	not_used	0	0	0	0	0	0	0
104	E	- Not used	not_used	0	0	0	0	0	0	0
105	E	- Not used	not_used	0	0	0	0	0	0	0
106	E	- Not used	not_used	0	0	0	0	0	0	0
107	E	- Remaining	BILLING_06	12	3,186	38,970	15,064	1,255	308	41
108	E	TOTAL CUSTOMER SERVICE & INFO EXPENSES		214	34,498	876,964	140,606	11,945	3,040	367
109	E									
110	E									
111	E									
112	E	**OPERATION & MAINTENANCE EXPENSE CONTINUED**								
113	E									
114	E	SALES EXPENSES								
115	E	E911-E916 Sales Expenses								
116	E	- Sales	SALES_06	0	0	0	0	0	0	0
117	E	- Billing related	BILLING_06	0	0	0	0	0	0	0
118	E	- Acct Maint related	ACCTMAINT_06	0	0	0	0	0	0	0
119	E	- Utility work related	UTILWORK_04	4	555	9,167	677	61	17	1
120	E	- Remaining	UTILWORK_04	0	0	0	0	0	0	0
121	E	- Clause	not_used	0	0	0	0	0	0	0
122	E	SALES EXPENSES TOTAL (ACCT 916)		4	555	9,167	677	61	17	1
123	E									
124	E	TOTAL OPER & MAINT EXCL A&G		392,282	4,954,833	55,751,578	50,402,464	11,368,248	8,942,987	1,867,720
125	E									
126	E	ADMINISTRATIVE & GENERAL EXPENSE								
127	E	E920 A&G Salaries	REVREQ	2,221	81,964	1,197,729	1,163,445	223,135	147,486	8,668
128	E	E921 Office Supplies & Exp	REVREQ	243	8,959	130,915	127,168	24,389	16,121	947
129	E	E923 Outside Services Employed	DISTPLT	13,574	957,750	14,630,793	15,332,416	2,788,625	1,694,535	1,905
130	E	E924 Property Insurance	TOTPLT	359	25,200	386,880	403,640	73,495	45,342	561
131	E	E925 Injuries & Damages	LABOR	2,094	232,843	2,505,054	2,647,907	465,037	383,357	104,089
132	E	E926 Employee Pension & Benefits	LABOR	-11,528	-1,281,967	-13,792,136	-14,578,643	-2,560,364	-2,110,657	-573,084
133	E	E928 Regulatory Comm Exp	REVREQ	5,867	216,506	3,163,771	3,073,211	589,406	389,581	22,896
134	E	E929 Duplicate Charges - credit	REVLPLS	0	0	0	-3,363,888	0	0	0
135	E	E930.1 General Advertising Expenses	CUSTAVG_04	87	22,870	279,709	9,245	770	189	25
136	E	E930.2 Misc General Expenses	DISTPLT	585	41,291	630,773	661,022	120,225	73,056	82
137	E	E931 Rents	DISTPLT	892	62,964	961,854	1,007,980	183,329	111,402	125
138	E	E932 Maint of General Plant	COMGENPLT	0	0	0	0	0	0	0
139	E	E935 Other A&G Maint	COMGENPLT	0	0	0	0	0	0	0
140	E	Not Used	not_used	0	0	0	0	0	0	0
141	E	TOTAL A&G EXPENSE		14,394	368,380	10,095,343	6,483,504	1,908,048	750,411	-433,785
142	E									
143	E	**TOTAL OPERATION & MAINTENANCE EXPENSES**		406,676	5,323,213	65,846,920	56,885,968	13,276,295	9,693,399	1,433,935

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	DE	**DEPRECIATION AND AMORTIZATION EXPENSES**									
2	DE										
3	DE	E403 DEPRECIATION EXPENSE									
4	DE	Production Plant	not_used	0	0	0	0	0	0	0	0
5	DE	Transmission Plant	not_used	0	0	0	0	0	0	0	0
6	DE	Distribution Plant	DISTPLT	257,769,144	100,731,583	618,410	4,669,539	7,939,520	33,752	77,400	9,474,485
7	DE	General Plant	GENPLT	19,786,964	7,586,813	47,688	368,609	630,527	2,677	5,985	752,817
8	DE	Common Plant	COMPLT	9,215,747	4,928,718	25,149	78,726	79,070	343	8,818	117,267
9	DE	Other Plant & Misc	DISTPLT	0	0	0	0	0	0	0	0
10	DE	TOTAL DEPRECIATION EXPENSE		286,771,855	113,247,114	691,247	5,116,873	8,649,117	36,772	92,204	10,344,570
11	DE										
12	DE	E404.3 AMORT OF OTHER LIMITED TERM PLANT									
13	DE	not used	not_used	0	0	0	0	0	0	0	0
14	DE	Distribution Delivery Related	DISTPLTXMTR	6,072,872	2,328,490	14,636	113,131	193,517	822	1,837	231,049
15	DE	Meter Reading	MRCOST_07	492,670	387,839	1,347	2,251	26	0	31	0
16	DE	Customer Service related	CUSTSVSX	14,826,022	8,746,911	42,181	72,170	1,426	22	17,722	51,882
17	DE	not used	not_used	0	0	0	0	0	0	0	0
18	DE	not used	not_used	0	0	0	0	0	0	0	0
19	DE	TOTAL AMORT OF OTHER LIMITED TERM PLT		21,391,564	11,463,240	58,165	187,552	194,968	844	19,589	282,931
20	DE										
21	DE	E407 AMORT OF PROPERTY LOSSES									
22	DE	Regulatory assets	KWHMETER_04	0	0	0	0	0	0	0	0
23	DE	Securitization amortization	not_used	0	0	0	0	0	0	0	0
24	DE	not used	not_used	0	0	0	0	0	0	0	0
25	DE	TOTAL AMORT OF PROPERTY LOSSES		0	0	0	0	0	0	0	0
26	DE										
27	DE	TOTAL AMORTIZATION EXPENSE		21,391,564	11,463,240	58,165	187,552	194,968	844	19,589	282,931
28	DE										
29	DE	**TOTAL DEPRECIATION AND AMORTIZATION EXPENSES**		308,163,419	124,710,354	749,412	5,304,425	8,844,086	37,616	111,794	10,627,501

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
1	DE	**DEPRECIATION AND AMORTIZATION EXPENSES**								
2	DE									
3	DE	E403 DEPRECIATION EXPENSE								
4	DE	Production Plant	not_used	0	0	0	0	0	0	0
5	DE	Transmission Plant	not_used	0	0	0	0	0	0	0
6	DE	Distribution Plant	DISTPLT	51,439	3,629,444	55,444,171	58,103,010	10,567,643	6,421,529	7,217
7	DE	General Plant	GENPLT	4,087	288,386	4,187,658	4,583,028	823,833	504,855	0
8	DE	Common Plant	COMPLT	1,504	79,403	1,832,852	1,344,477	271,498	324,944	122,979
9	DE	Other Plant & Misc	DISTPLT	0	0	0	0	0	0	0
10	DE	TOTAL DEPRECIATION EXPENSE		57,030	3,997,233	61,464,680	64,030,515	11,662,973	7,251,328	130,196
11	DE									
12	DE	E404.3 AMORT OF OTHER LIMITED TERM PLANT								
13	DE	not used	not_used	0	0	0	0	0	0	0
14	DE	Distribution Delivery Related	DISTPLTXMTR	1,254	88,509	1,285,245	1,406,590	252,845	154,946	0
15	DE	Meter Reading	MRCOST_07	0	0	95,041	5,544	462	113	15
16	DE	Customer Service related	CUSTSVSX	2,184	95,557	2,879,744	1,699,886	371,014	575,399	269,925
17	DE	not used	not_used	0	0	0	0	0	0	0
18	DE	not used	not_used	0	0	0	0	0	0	0
19	DE	TOTAL AMORT OF OTHER LIMITED TERM PLT		3,439	184,066	4,260,031	3,112,020	624,321	730,459	269,940
20	DE									
21	DE	E407 AMORT OF PROPERTY LOSSES								
22	DE	Regulatory assets	KWHMETER_04	0	0	0	0	0	0	0
23	DE	Securitization amortization	not_used	0	0	0	0	0	0	0
24	DE	not used	not_used	0	0	0	0	0	0	0
25	DE	TOTAL AMORT OF PROPERTY LOSSES		0	0	0	0	0	0	0
26	DE									
27	DE	TOTAL AMORTIZATION EXPENSE		3,439	184,066	4,260,031	3,112,020	624,321	730,459	269,940
28	DE									
29	DE	**TOTAL DEPRECIATION AND AMORTIZATION EXPENSES**		60,469	4,181,299	65,724,711	67,142,535	12,287,294	7,981,787	400,136

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	EO	**OTHER OPERATING EXPENSES**									
2	EO	**E408 TAXES OTHER THAN INCOME TAXES**									
3	EO	TEFA	TEFA_04	0	0	0	0	0	0	0	0
4	EO	Real Estate Taxes	TOTPLT	0	0	0	0	0	0	0	0
5	EO	Miscellaneous State and Municipal Tax	TOTPLT	-275,485	-108,431	-663	-4,939	-8,365	-36	-87	-9,997
6	EO	State Unemploy Insur (SUI) Tax	LABOR	0	0	0	0	0	0	0	0
7	EO	FICA & UnempTax	LABOR	-11,275,732	-5,710,658	-26,041	-51,137	-2,964	-29	-7,239	-429,130
8	EO	Other Taxes	TOTPLT	0	0	0	0	0	0	0	0
9	EO	not used	not_used	0	0	0	0	0	0	0	0
10	EO	**TOTAL TAXES OTHER THAN INCOME**		-11,551,217	-5,819,089	-26,704	-56,076	-11,329	-65	-7,326	-439,127
11	EO	**PROFORMA EXPENSE ADJUSTMENTS**									
12	EO	Amortization of CEF-EC Program Regulatory Assets	ECPRO_07	20,893,898	16,832,173	54,231	90,604	14,303	223	6,159	0
13	EO	Amortization of CEF-EV Program Regulatory Assets	TOTPLTNET	3,943,445	1,558,279	9,076	58,297	90,591	385	1,228	147,511
14	EO	BGS Administrative Expense Adjustment	A_GEXP	671,374	292,042	1,651	10,510	16,710	71	247	24,897
15	EO	CIP Revenue Accrual Adjustment	not_used	0	0	0	0	0	0	0	0
16	EO	Deferred Compensation & Severance Expense	LABOR	-785,085	-397,611	-1,813	-3,560	-206	-2	-504	-29,879
17	EO	Gas Bad Debt Adjustment		0	0	0	0	0	0	0	0
18	EO	TAC Revenue Accrual Adjustment	not_used	0	0	0	0	0	0	0	0
19	EO	Tax Bad Debt Adjustment	not_used	0	0	0	0	0	0	0	0
20	EO	TSG-NF Gas Margin Reset		0	0	0	0	0	0	0	0
21	EO	Wage Increases (Rate Year)	LABOR	7,691,360	3,895,332	17,763	34,881	2,022	20	4,938	292,717
22	EO	Payroll Taxes (Rate Year)	LABOR	541,904	274,450	1,252	2,458	142	1	348	20,624
23	EO	Interest Syncronization	TOTPLTNET	-459,649	-181,633	-1,058	-6,795	-10,559	-45	-143	-17,194
24	EO	- add'l tax effects on rev req	TOTPLTNET	-179,729	-71,021	-414	-2,657	-4,129	-18	-56	-6,723
25	EO	Pension & Fringe Benefit (Rate Year)	LABOR	11,745,951	5,948,803	27,127	53,270	3,088	30	7,541	447,026
26	EO	COLI Interest Expense Recovery	LABOR	2,434,135	1,232,781	5,622	11,039	640	6	1,563	92,638
27	EO	- add'l tax effects on rev req	LABOR	951,781	482,035	2,198	4,316	250	2	611	36,223
28	EO	ASB Margin	TOTPLT	0	0	0	0	0	0	0	0
29	EO	BPU / Rate Counsel Assessment	KWHMETER_04	377,877	126,702	865	1,806	5	0	110	2,623
30	EO	Adj #6 - Weather Normalization	not_used	0	0	0	0	0	0	0	0
31	EO	Gains / Losses Normalization	TOTPLT	-44,137	-17,372	-106	-791	-1,340	-6	-14	-1,602
32	EO	- add'l tax effects on rev req	TOTPLT	-17,258	-6,793	-42	-309	-524	-2	-5	-626
33	EO	Other Regulatory Asset / Liability Amortizations	TOTPLT	0	0	0	0	0	0	0	0
34	EO	Adj #15 - Excess COR Refund Recovery	TOTPLT	0	0	0	0	0	0	0	0
35	EO	Real Estate Tax Increases (Rate Year)	TOTPLT	700,231	275,612	1,685	12,554	21,262	90	220	25,410
36	EO	Test Year Amortization Adjustments	TOTPLT	-17,276,070	-6,799,891	-41,575	-309,738	-524,564	-2,230	-5,431	-626,907
37	EO	Insurance Premium Increases (Rate Year)	TOTPLT	481,185	189,395	1,158	8,627	14,610	62	151	17,461
38	EO	Rate Case Expenses	TOTPLT	166,097	65,376	400	2,978	5,043	21	52	6,027
39	EO	Depreciation Rate Change	DEPREXP	50,211,393	19,828,638	121,032	895,922	1,514,389	6,438	16,144	1,811,249
40	EO	Adj #14 Post Rate Case Storm Cost Normalization	TOTPLT	0	0	0	0	0	0	0	0
41	EO	Adj #13 - Storm Cost Amortization	TOTPLTNET	0	0	0	0	0	0	0	0
42	EO	Adj #20 - Vacation Accrual	LABOR	0	0	0	0	0	0	0	0
43	EO	Energy Strong II / IAP Revenue Adjustment	TOTPLT	0	0	0	0	0	0	0	0
44	EO	Recovery of Credit Card Fees	CUSTSVSX	0	0	0	0	0	0	0	0
45	EO	Test Year Corrections	TOTPLT								
46	EO	TOTAL PROFORMA EXPENSE ADJUSTMENTS		82,048,703	43,516,333	199,010	863,335	1,148,870	5,161	33,152	2,240,800
47	EO										
48	EO	**TOTAL OTHER OPERATING EXPENSES**		70,497,486	37,697,244	172,305	807,259	1,137,541	5,096	25,826	1,801,673
49	EO	TOTAL OPERATING REVENUES	CALCULATED	1,925,019,676	834,325,022	4,487,689	24,633,458	35,698,885	153,013	719,759	68,304,658
50	EO	LESS:									

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
1	EO	**OTHER OPERATING EXPENSES**								
2	EO	**E408 TAXES OTHER THAN INCOME TAXES**								
3	EO	TEFA	TEFA_04	0	0	0	0	0	0	0
4	EO	Real Estate Taxes	TOTPLT	0	0	0	0	0	0	0
5	EO	Miscellaneous State and Municipal Tax	TOTPLT	-55	-3,851	-59,126	-61,688	-11,232	-6,930	-86
6	EO	State Unemploy Insur (SUI) Tax	LABOR	0	0	0	0	0	0	0
7	EO	FICA & UnempTax	LABOR	-1,667	-185,401	-1,994,652	-2,108,398	-370,286	-305,248	-82,881
8	EO	Other Taxes	TOTPLT	0	0	0	0	0	0	0
9	EO	not used	not_used	0	0	0	0	0	0	0
10	EO	**TOTAL TAXES OTHER THAN INCOME**		-1,722	-189,253	-2,053,778	-2,170,086	-381,518	-312,178	-82,967
11	EO	**PROFORMA EXPENSE ADJUSTMENTS**								
12	EO	Amortization of CEF-EC Program Regulatory Assets	ECPRO_07	0	0	3,896,204	0	0	0	0
13	EO	Amortization of CEF-EV Program Regulatory Assets	TOTPLTNET	800	56,691	848,780	899,687	165,994	105,440	687
14	EO	BGS Administrative Expense Adjustment	A_GEXP	156	9,923	143,625	126,637	26,867	17,202	838
15	EO	CIP Revenue Accrual Adjustment	not_used	0	0	0	0	0	0	0
16	EO	Deferred Compensation & Severance Expense	LABOR	-116	-12,909	-138,880	-146,799	-25,782	-21,253	-5,771
17	EO	Gas Bad Debt Adjustment		0	0	0	0	0	0	0
18	EO	TAC Revenue Accrual Adjustment	not_used	0	0	0	0	0	0	0
19	EO	Tax Bad Debt Adjustment	not_used	0	0	0	0	0	0	0
20	EO	TSG-NF Gas Margin Reset		0	0	0	0	0	0	0
21	EO	Wage Increases (Rate Year)	LABOR	1,137	126,465	1,360,584	1,438,173	252,578	208,215	56,534
22	EO	Payroll Taxes (Rate Year)	LABOR	80	8,910	95,862	101,328	17,796	14,670	3,983
23	EO	Interest Syncronization	TOTPLTNET	-93	-6,608	-98,934	-104,868	-19,348	-12,290	-80
24	EO	- add'l tax effects on rev req	TOTPLTNET	-36	-2,584	-38,685	-41,005	-7,565	-4,806	-31
25	EO	Pension & Fringe Benefit (Rate Year)	LABOR	1,737	193,133	2,077,832	2,196,322	385,728	317,978	86,337
26	EO	COLI Interest Expense Recovery	LABOR	360	40,023	430,593	455,148	79,935	65,895	17,892
27	EO	- add'l tax effects on rev req	LABOR	141	15,650	168,368	177,969	31,256	25,766	6,996
28	EO	ASB Margin	TOTPLT	0	0	0	0	0	0	0
29	EO	BPU / Rate Counsel Assessment	KWHMETER_04	142	1,273	68,069	98,038	28,788	43,231	6,226
30	EO	Adj #6 - Weather Normalization	not_used	0	0	0	0	0	0	0
31	EO	Gains / Losses Normalization	TOTPLT	-9	-617	-9,473	-9,883	-1,800	-1,110	-14
32	EO	- add'l tax effects on rev req	TOTPLT	-3	-241	-3,704	-3,865	-704	-434	-5
33	EO	Other Regulatory Asset / Liability Amortizations	TOTPLT	0	0	0	0	0	0	0
34	EO	Adj #15 - Excess COR Refund Recovery	TOTPLT	0	0	0	0	0	0	0
35	EO	Real Estate Tax Increases (Rate Year)	TOTPLT	139	9,789	150,288	156,799	28,550	17,614	218
36	EO	Test Year Amortization Adjustments	TOTPLT	-3,438	-241,524	-3,707,904	-3,868,534	-704,388	-434,564	-5,381
37	EO	Insurance Premium Increases (Rate Year)	TOTPLT	96	6,727	103,275	107,749	19,619	12,104	150
38	EO	Rate Case Expenses	TOTPLT	33	2,322	35,649	37,193	6,772	4,178	52
39	EO	Depreciation Rate Change	DEPREXP	9,985	699,883	10,761,960	11,211,217	2,042,091	1,269,648	22,796
40	EO	Adj #14 Post Rate Case Storm Cost Normalization	TOTPLT	0	0	0	0	0	0	0
41	EO	Adj #13 - Storm Cost Amortization	TOTPLTNET	0	0	0	0	0	0	0
42	EO	Adj #20 - Vacation Accrual	LABOR	0	0	0	0	0	0	0
43	EO	Energy Strong II / IAP Revenue Adjustment	TOTPLT	0	0	0	0	0	0	0
44	EO	Recovery of Credit Card Fees	CUSTSVSX	0	0	0	0	0	0	0
45	EO	Test Year Corrections	TOTPLT							
46	EO	TOTAL PROFORMA EXPENSE ADJUSTMENTS		11,109	906,023	16,140,563	12,829,350	2,326,036	1,627,221	201,742
47	EO									
48	EO	**TOTAL OTHER OPERATING EXPENSES**		9,386	716,771	14,086,785	10,659,264	1,944,518	1,315,043	118,775
49	EO	TOTAL OPERATING REVENUES	CALCULATED	749,390	27,761,012	405,667,274	394,055,404	75,575,200	49,953,159	2,935,754
50	EO	LESS:								

PUBLIC SERVICE ELECTRIC & GAS COMPANY
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12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
51	EO	OPERATION & MAINTAINENCE EXPENSE	CALCULATED	311,457,637	141,176,442	724,395	2,751,971	2,826,660	12,188	163,946	10,935,628
52	EO	DEPRECIATION & AMORTIZATION EXPENSE	CALCULATED	308,163,419	124,710,354	749,412	5,304,425	8,844,086	37,616	111,794	10,627,501
53	EO	OTHER OPERATING EXPENSES	CALCULATED	70,497,486	37,697,244	172,305	807,259	1,137,541	5,096	25,826	1,801,673
54	EO	NET OPERATING INCOME BEFORE TAXES		1,234,901,135	530,740,982	2,841,576	15,769,802	22,890,599	98,113	418,193	44,939,856
55	EO	LESS:									
56	EO	E427 - E432 INTEREST CHARGES	TOTPLTNET	(137,585,275)	(54,367,739)	(316,659)	(2,033,976)	(3,160,676)	(13,442)	(42,844)	(5,146,593)
57	EO	**TOTAL OPERATING INCOME BEFORE TAXES**		1,372,486,410	585,108,722	3,158,235	17,803,778	26,051,275	111,554	461,037	50,086,449
58	EO	Adjustment Reclassification Minus	ADJEXP_04	-17,563	-10,963	-42	-77	0	0	-7	-674
59	EO	Adjustment Reclassification Plus	ADJ_Plus_04	17,563	0	0	0	7,136	111	0	0

Updated for 9 and 3

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
51	EO	OPERATION & MAINTAINENCE EXPENSE	CALCULATED	406,676	5,323,213	65,846,920	56,885,968	13,276,295	9,693,399	1,433,935
52	EO	DEPRECIATION & AMORTIZATION EXPENSE	CALCULATED	60,469	4,181,299	65,724,711	67,142,535	12,287,294	7,981,787	400,136
53	EO	OTHER OPERATING EXPENSES	CALCULATED	9,386	716,771	14,086,785	10,659,264	1,944,518	1,315,043	118,775
54	EO	NET OPERATING INCOME BEFORE TAXES		272,859	17,539,729	260,008,858	259,367,638	48,067,093	30,962,930	982,908
55	EO	LESS:								
56	EO	E427 - E432 INTEREST CHARGES	TOTPLTNET	(27,905)	(1,977,913)	(29,613,608)	(31,389,727)	(5,791,467)	(3,678,756)	(23,968)
57	EO	**TOTAL OPERATING INCOME BEFORE TAXES**		300,764	19,517,642	289,622,466	290,757,365	53,858,560	34,641,686	1,006,876
58	EO	Adjustment Reclassification Minus	ADJEXP_04	-1	-283	-2,947	-1,955	-350	-262	0
59	EO	Adjustment Reclassification Plus	ADJ_Plus_04	0	0	0	0	0	0	10,316

PUBLIC SERVICE ELECTRIC & GAS COMPANY
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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	TI	**[TI] DEVELOPMENT OF INCOME TAXES**									
2	TI										
3	TI	**[TI] TAX ADJUSTMENTS - FEDERAL**									
4	TI	[TI][Fed Tax Adj.] Additional Expenses on Rental Property	TOTPLT	-108,083	-42,542	-260	-1,938	-3,282	-14	-34	-3,922
5	TI	[TI][Fed Tax Adj.] Additional Rental Income - NJ Properties	TOTPLT	16,349	6,435	39	293	496	2	5	593
6	TI	[TI][Fed Tax Adj.] Amort of Def Gain on Sale of Services Asse	not_used	0	0	0	0	0	0	0	0
7	TI	[TI][Fed Tax Adj.] Amort of Deferred Gain on Sale of Generati	not_used	0	0	0	0	0	0	0	0
8	TI	[TI][Fed Tax Adj.] Amortization of Reacquisition of Pref Stock	TOTPLT	11,771	4,633	28	211	357	2	4	427
9	TI	[TI][Fed Tax Adj.] CECL Reserve	not_used	0	0	0	0	0	0	0	0
10	TI	[TI][Fed Tax Adj.] CEF- EC AMI	TOTPLT	-20,866,765	-8,213,195	-50,216	-374,115	-633,590	-2,694	-6,560	-757,205
11	TI	[TI][Fed Tax Adj.] CEF- EV Deferral	TOTPLT	-1,855,840	-730,462	-4,466	-33,273	-56,350	-240	-583	-67,344
12	TI	[TI][Fed Tax Adj.] Clause - Demographic Studies	not_used	0	0	0	0	0	0	0	0
13	TI	[TI][Fed Tax Adj.] Clause - Navigant Studies	not_used	0	0	0	0	0	0	0	0
14	TI	[TI][Fed Tax Adj.] Clause - RAC (Environmental Clean Up)	not_used	0	0	0	0	0	0	0	0
15	TI	[TI][Fed Tax Adj.] Clause - Societal Benefits Clause (AAP)	not_used	0	0	0	0	0	0	0	0
16	TI	[TI][Fed Tax Adj.] Company Owned Life Insurance - Book	LABOR	-1,117,127	-565,775	-2,580	-5,066	-294	-3	-717	-42,515
17	TI	[TI][Fed Tax Adj.] Company Owned Life Insurance - Tax	LABOR	-58,279	-29,516	-135	-264	-15	0	-37	-2,218
18	TI	[TI][Fed Tax Adj.] COVID Deferrals	not_used	0	0	0	0	0	0	0	0
19	TI	[TI][Fed Tax Adj.] Current SHARE -- FT	DEPREXP	-11,513,122	-4,546,568	-27,752	-205,429	-347,239	-1,476	-3,702	-415,307
20	TI	[TI][Fed Tax Adj.] Customer Advances	TOTPLTNET	4,645,423	1,835,670	10,692	68,675	106,717	454	1,447	173,769
21	TI	[TI][Fed Tax Adj.] Customer Connection Fees (Contributions i	TOTPLTNET	6,684,538	2,641,440	15,385	98,820	153,560	653	2,082	250,046
22	TI	[TI][Fed Tax Adj.] Deduction for Retention Payments (c)	LABOR	-5,352	-2,710	-12	-24	-1	0	-3	-204
23	TI	[TI][Fed Tax Adj.] Deferred Employer ER FICA	LABOR	-7,086,760	-3,589,129	-16,367	-32,139	-1,863	-18	-4,550	-269,707
24	TI	[TI][Fed Tax Adj.] Diesel Fuel Tax Credit	TOTPLT	82	32	0	1	2	0	0	3
25	TI	[TI][Fed Tax Adj.] Entertainment (100%)	LABOR	38,419	19,458	89	174	10	0	25	1,462
26	TI	[TI][Fed Tax Adj.] FAS 5 (ASC40) Reserve - Sales Tax	not_used	0	0	0	0	0	0	0	0
27	TI	[TI][Fed Tax Adj.] Fed Amort of Deferred Gain on Sale of Gen	not_used	0	0	0	0	0	0	0	0
28	TI	[TI][Fed Tax Adj.] Injuries & Damages - FT	TOTPLT	1,298,774	511,200	3,126	23,285	39,435	168	408	47,129
29	TI	[TI][Fed Tax Adj.] Line Pack Adjustment	not_used	0	0	0	0	0	0	0	0
30	TI	[TI][Fed Tax Adj.] Plant Related	DEPREXP	-33,454,683	-13,211,361	-80,641	-596,932	-1,009,002	-4,290	-10,757	-1,206,793
31	TI	[TI][Fed Tax Adj.] Previously Deducted Amort - Reacquired Bo	not_used	0	0	0	0	0	0	0	0
32	TI	[TI][Fed Tax Adj.] Qualified Transportation Fringe	LABOR	162,269	82,182	375	736	43	0	104	6,176
33	TI	[TI][Fed Tax Adj.] R & D Credits CF	not_used	0	0	0	0	0	0	0	0
34	TI	[TI][Fed Tax Adj.] R&D Expenditure	TOTPLT	-5,622	-2,213	-14	-101	-171	-1	-2	-204
35	TI	[TI][Fed Tax Adj.] Rabbi Trust	not_used	0	0	0	0	0	0	0	0
36	TI	[TI][Fed Tax Adj.] RE - Lease Liability	TOTPLT	-236,259	-92,992	-569	-4,236	-7,174	-30	-74	-8,573
37	TI	[TI][Fed Tax Adj.] RE - ROU Lease Asset	TOTPLT	319,172	125,627	768	5,722	9,691	41	100	11,582
38	TI	[TI][Fed Tax Adj.] Reversal of Book Income from Partnerships	TOTPLT	42,165	16,596	101	756	1,280	5	13	1,530
39	TI	[TI][Fed Tax Adj.] Severance Pay (nc)	LABOR	154,681	78,339	357	702	41	0	99	5,887
40	TI	[TI][Fed Tax Adj.] State NOL CF (c)	DEPREXP	17,908,279	7,072,036	43,167	319,538	540,119	2,296	5,758	645,996
41	TI	[TI][Fed Tax Adj.] Tax Net Bad Debt Writeoffs - FT	TOTPLT	-460,907	-181,414	-1,109	-8,263	-13,995	-59	-145	-16,725
42	TI	[TI][Fed Tax Adj.] Unicap book/tax inventory FS	not_used	0	0	0	0	0	0	0	0
43	TI	[TI][Fed Tax Adj.] Unrealized G/L on Equity Securities	TOTPLT	125,367	49,345	302	2,248	3,807	16	39	4,549
44	TI	[TI][Fed Tax Adj.] Stock-Based Compensation - Reverse Book	TOTPLTNET	-328,125	-129,661	-755	-4,851	-7,538	-32	-102	-12,274
45	TI	[TI][Fed Tax Adj.] GainState LILOAudit Refunds not yet receiv	TOTPLTNET	0	0	0	0	0	0	0	0
46	TI	[TI][Fed Tax Adj.] Repair Allowance	TOTPLT	0	0	0	0	0	0	0	0
47	TI	[TI][Fed Tax Adj.] Uncollectible Accounts	REVREQ	0	0	0	0	0	0	0	0
48	TI	[TI][Fed Tax Adj.] Injuries and Damages ;	TOTPLT	0	0	0	0	0	0	0	0
49	TI	[TI][Fed Tax Adj.] Diesel Fuel Credit	not_used	0	0	0	0	0	0	0	0
50	TI	[TI][Fed Tax Adj.] Partnership Income/Loss (nc)	TOTPLT	-42,165	-16,596	-101	-756	-1,280	-5	-13	-1,530

PUBLIC SERVICE ELECTRIC & GAS COMPANY
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12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
1	TI	**[TI] DEVELOPMENT OF INCOME TAXES**								
2	TI									
3	TI	**[TI] TAX ADJUSTMENTS - FEDERAL**								
4	TI	[TI][Fed Tax Adj.] Additional Expenses on Rental Property	TOTPLT	-22	-1,511	-23,198	-24,203	-4,407	-2,719	-34
5	TI	[TI][Fed Tax Adj.] Additional Rental Income - NJ Properties	TOTPLT	3	229	3,509	3,661	667	411	5
6	TI	[TI][Fed Tax Adj.] Amort of Def Gain on Sale of Services Asse	not_used	0	0	0	0	0	0	0
7	TI	[TI][Fed Tax Adj.] Amort of Deferred Gain on Sale of Generati	not_used	0	0	0	0	0	0	0
8	TI	[TI][Fed Tax Adj.] Amortization of Reacquisition of Pref Stock	TOTPLT	2	165	2,526	2,636	480	296	4
9	TI	[TI][Fed Tax Adj.] CECL Reserve	not_used	0	0	0	0	0	0	0
10	TI	[TI][Fed Tax Adj.] CEF- EC AMI	TOTPLT	-4,153	-291,723	-4,478,562	-4,672,579	-850,789	-524,885	-6,499
11	TI	[TI][Fed Tax Adj.] CEF- EV Deferral	TOTPLT	-369	-25,945	-398,313	-415,568	-75,667	-46,682	-578
12	TI	[TI][Fed Tax Adj.] Clause - Demographic Studies	not_used	0	0	0	0	0	0	0
13	TI	[TI][Fed Tax Adj.] Clause - Navigant Studies	not_used	0	0	0	0	0	0	0
14	TI	[TI][Fed Tax Adj.] Clause - RAC (Environmental Clean Up)	not_used	0	0	0	0	0	0	0
15	TI	[TI][Fed Tax Adj.] Clause - Societal Benefits Clause (AAP)	not_used	0	0	0	0	0	0	0
16	TI	[TI][Fed Tax Adj.] Company Owned Life Insurance - Book	LABOR	-165	-18,368	-197,617	-208,887	-36,686	-30,242	-8,211
17	TI	[TI][Fed Tax Adj.] Company Owned Life Insurance - Tax	LABOR	-9	-958	-10,309	-10,897	-1,914	-1,578	-428
18	TI	[TI][Fed Tax Adj.] COVID Deferrals	not_used	0	0	0	0	0	0	0
19	TI	[TI][Fed Tax Adj.] Current SHARE -- FT	DEPREXP	-2,290	-160,478	-2,467,642	-2,570,654	-468,237	-291,121	-5,227
20	TI	[TI][Fed Tax Adj.] Customer Advances	TOTPLTNET	942	66,782	999,873	1,059,841	195,543	124,209	809
21	TI	[TI][Fed Tax Adj.] Customer Connection Fees (Contributions i	TOTPLTNET	1,356	96,096	1,438,768	1,525,060	281,377	178,731	1,164
22	TI	[TI][Fed Tax Adj.] Deduction for Retention Payments (c)	LABOR	-1	-88	-947	-1,001	-176	-145	-39
23	TI	[TI][Fed Tax Adj.] Deferred Employer ER FICA	LABOR	-1,048	-116,524	-1,253,632	-1,325,121	-232,723	-191,848	-52,090
24	TI	[TI][Fed Tax Adj.] Diesel Fuel Tax Credit	TOTPLT	0	1	18	18	3	2	0
25	TI	[TI][Fed Tax Adj.] Entertainment (100%)	LABOR	6	632	6,796	7,184	1,262	1,040	282
26	TI	[TI][Fed Tax Adj.] FAS 5 (ASC40) Reserve - Sales Tax	not_used	0	0	0	0	0	0	0
27	TI	[TI][Fed Tax Adj.] Fed Amort of Deferred Gain on Sale of Gen	not_used	0	0	0	0	0	0	0
28	TI	[TI][Fed Tax Adj.] Injuries & Damages - FT	TOTPLT	258	18,157	278,751	290,827	52,954	32,670	405
29	TI	[TI][Fed Tax Adj.] Line Pack Adjustment	not_used	0	0	0	0	0	0	0
30	TI	[TI][Fed Tax Adj.] Plant Related	DEPREXP	-6,653	-466,316	-7,170,444	-7,469,773	-1,360,597	-845,937	-15,189
31	TI	[TI][Fed Tax Adj.] Previously Deducted Amort - Reacquired B	not_used	0	0	0	0	0	0	0
32	TI	[TI][Fed Tax Adj.] Qualified Transportation Fringe	LABOR	24	2,668	28,705	30,342	5,329	4,393	1,193
33	TI	[TI][Fed Tax Adj.] R & D Credits CF	not_used	0	0	0	0	0	0	0
34	TI	[TI][Fed Tax Adj.] R&D Expenditure	TOTPLT	-1	-79	-1,207	-1,259	-229	-141	-2
35	TI	[TI][Fed Tax Adj.] Rabbi Trust	not_used	0	0	0	0	0	0	0
36	TI	[TI][Fed Tax Adj.] RE - Lease Liability	TOTPLT	-47	-3,303	-50,708	-52,904	-9,633	-5,943	-74
37	TI	[TI][Fed Tax Adj.] RE - ROU Lease Asset	TOTPLT	64	4,462	68,503	71,470	13,013	8,028	99
38	TI	[TI][Fed Tax Adj.] Reversal of Book Income from Partnerships	TOTPLT	8	589	9,050	9,442	1,719	1,061	13
39	TI	[TI][Fed Tax Adj.] Severance Pay (nc)	LABOR	23	2,543	27,363	28,923	5,080	4,187	1,137
40	TI	[TI][Fed Tax Adj.] State NOL CF (c)	DEPREXP	3,561	249,619	3,838,336	3,998,567	728,327	452,830	8,130
41	TI	[TI][Fed Tax Adj.] Tax Net Bad Debt Writeoffs - FT	TOTPLT	-92	-6,444	-98,923	-103,208	-18,792	-11,594	-144
42	TI	[TI][Fed Tax Adj.] Unicap book/tax inventory FS	not_used	0	0	0	0	0	0	0
43	TI	[TI][Fed Tax Adj.] Unrealized G/L on Equity Securities	TOTPLT	25	1,753	26,907	28,073	5,112	3,154	39
44	TI	[TI][Fed Tax Adj.] Stock-Based Compensation - Reverse Book	TOTPLTNET	-67	-4,717	-70,625	-74,861	-13,812	-8,773	-57
45	TI	[TI][Fed Tax Adj.] GainState LILOAudit Refunds not yet receiv	TOTPLTNET	0	0	0	0	0	0	0
46	TI	[TI][Fed Tax Adj.] Repair Allowance	TOTPLT	0	0	0	0	0	0	0
47	TI	[TI][Fed Tax Adj.] Uncollectible Accounts	REVREQ	0	0	0	0	0	0	0
48	TI	[TI][Fed Tax Adj.] Injuries and Damages ;	TOTPLT	0	0	0	0	0	0	0
49	TI	[TI][Fed Tax Adj.] Diesel Fuel Credit	not_used	0	0	0	0	0	0	0
50	TI	[TI][Fed Tax Adj.] Partnership Income/Loss (nc)	TOTPLT	-8	-589	-9,050	-9,442	-1,719	-1,061	-13

PUBLIC SERVICE ELECTRIC & GAS COMPANY
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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
51	TI	[TI][Fed Tax Adj.] Meals and Entertainment (50%)	LABOR	-417,376	-211,383	-964	-1,893	-110	-1	-268	-15,884
52	TI	[TI][Fed Tax Adj.] Company owned life insurance	LABOR	0	0	0	0	0	0	0	0
53	TI	[TI][Fed Tax Adj.] ESOP/401(k) Cash Dividends	TOTPLTNET	-1,032,350	-407,940	-2,376	-15,262	-23,716	-101	-321	-38,617
54	TI	[TI][Fed Tax Adj.] Medicare Subsidy	LABOR	0	0	0	0	0	0	0	0
55	TI	[TI][Fed Tax Adj.] Dividends Received Deduction-2	TOTPLTNET	0	0	0	0	0	0	0	0
56	TI	[TI][Fed Tax Adj.] W-2 Earnings Exceeding $1.000.000	LABOR	1,841,683	932,731	4,253	8,352	484	5	1,182	70,091
57	TI	[TI][Fed Tax Adj.] Allowable Depreciation	DEPREXP	0	0	0	0	0	0	0	0
58	TI	[TI][Fed Tax Adj.] Previously Ded Amort-Reacq Bonds	not_used	0	0	0	0	0	0	0	0
59	TI	[TI][Fed Tax Adj.] Amortization of Computer Software	INTANGPLT	0	0	0	0	0	0	0	0
60	TI	[TI][Fed Tax Adj.] Amort Def Gain - Sale of Gen Asset	not_used	0	0	0	0	0	0	0	0
61	TI	[TI][Fed Tax Adj.] Gain on Sale of Services Corp Asset	not_used	0	0	0	0	0	0	0	0
62	TI	[TI][Fed Tax Adj.] AFUDC / IDC - Debt	TOTPLT	-1,076,666	-423,778	-2,591	-19,303	-32,691	-139	-338	-39,070
63	TI	[TI][Fed Tax Adj.] Capitalized Interest - Section 263A	TOTPLT	3,363,340	1,323,816	8,094	60,300	102,123	434	1,057	122,047
64	TI	[TI][Fed Tax Adj.] Cost of removal	TOTPLT	0	0	0	0	0	0	0	0
65	TI	[TI][Fed Tax Adj.] Utility Commodity Costs	not_used	0	0	0	0	0	0	0	0
66	TI	[TI][Fed Tax Adj.] RAC-Environmental Cleanup Costs	not_used	0	0	0	0	0	0	0	0
67	TI	[TI][Fed Tax Adj.] SBC-Societal Benefits Clause	not_used	0	0	0	0	0	0	0	0
68	TI	[TI][Fed Tax Adj.] Def Comp - Off/Dir/NOC (c)	LABOR	11,058	5,600	26	50	3	0	7	421
69	TI	[TI][Fed Tax Adj.] Deduction of Securitizartion	not_used	0	0	0	0	0	0	0	0
70	TI	[TI][Fed Tax Adj.] Additional Vacation Pay Adj (c)	LABOR	-344,695	-174,573	-796	-1,563	-91	-1	-221	-13,118
71	TI	[TI][Fed Tax Adj.] Third Party Claims	TOTPLT	87,346	34,379	210	1,566	2,652	11	27	3,170
72	TI	[TI][Fed Tax Adj.] Deduction for New Network Meter Equipme	TOTPLT	0	0	0	0	0	0	0	0
73	TI	[TI][Fed Tax Adj.] Gain/loss bond reacq	not_used	0	0	0	0	0	0	0	0
74	TI	[TI][Fed Tax Adj.] Amortization of Call Option Sale	LABOR	0	0	0	0	0	0	0	0
75	TI	[TI][Fed Tax Adj.] Defer Dividend Equivalents/Restricted Stocl	LABOR	0	0	0	0	0	0	0	0
76	TI	[TI][Fed Tax Adj.] Repair Allow Deferral Carrying Charges	TOTPLT	0	0	0	0	0	0	0	0
77	TI	[TI][Fed Tax Adj.] CIAC Tax Gross Up	TOTPLTNET	905,779	357,925	2,085	13,390	20,808	88	282	33,882
78	TI	[TI][Fed Tax Adj.] FIN48 Services Allocation	TOTPLT	0	0	0	0	0	0	0	0
79	TI	[TI][Fed Tax Adj.] Pension	LABOR	-3,671,962	-1,859,686	-8,480	-16,653	-965	-9	-2,358	-139,747
80	TI	[TI][Fed Tax Adj.] OPEB	LABOR	-105,080,197	-53,218,455	-242,682	-476,553	-27,621	-272	-67,466	-3,999,130
81	TI	[TI][Fed Tax Adj.] Deferred Return on CIP ll	TOTPLT	66,348	26,115	160	1,190	2,015	9	21	2,408
82	TI	[TI][Fed Tax Adj.] Deferred Depreciation on CIP ll	TOTPLT	52,458	20,648	126	941	1,593	7	16	1,904
83	TI	[TI][Fed Tax Adj.] FIN48 Reg Asset Reversal	LABOR	0	0	0	0	0	0	0	0
84	TI	[TI][Fed Tax Adj.] Assessment by Board of Public Utilities of tl	TOTPLTNET	91,151	36,019	210	1,348	2,094	9	28	3,410
85	TI	[TI][Fed Tax Adj.] Misc Adj - Permanent	TOTPLTNET	0	0	0	0	0	0	0	0
86	TI	[TI][Fed Tax Adj.] Casualty Loss Deferred O&M	TOTPLTNET	1,120,547	442,792	2,579	16,565	25,742	109	349	41,916
87	TI	[TI][Fed Tax Adj.] Performance Incentive Plan Adj (c)	TOTPLTNET	-1,045,327	-413,068	-2,406	-15,453	-24,014	-102	-326	-39,102
88	TI										
89	TI										
90	TI	[TI][Fed Tax Adj.] LCAPP	TOTPLTNET	0	0	0	0	0	0	0	0
91	TI	[TI][Fed Tax Adj.] Clause - Deferred Fuel	not_used	0	0	0	0	0	0	0	0
92	TI	[TI][Fed Tax Adj.] Penalties	not_used	0	0	0	0	0	0	0	0
93	TI	[TI][Fed Tax Adj.] Restricted Stock - Permanent	TOTPLTNET	-82,615	-32,646	-190	-1,221	-1,898	-8	-26	-3,090
94	TI	[TI][Fed Tax Adj.] Environmental Accrual	TOTPLTNET	0	0	0	0	0	0	0	0
95	TI	[TI][Fed Tax Adj.] Legal Reserves (nc)	TOTPLTNET	401,853	158,795	925	5,941	9,232	39	125	15,032
96	TI	[TI][Fed Tax Adj.] Material & Supplies Reserve (c)	TOTPLT	107,143	42,172	258	1,921	3,253	14	34	3,888
97	TI	[TI][Fed Tax Adj.] Lobbying Expenses	LABOR	0	0	0	0	0	0	0	0
98	TI	[TI][Fed Tax Adj.] Bankruptcies and Accum Provision for Rent	TOTPLTNET	62,834	24,829	145	929	1,443	6	20	2,350
99	TI	[TI][Fed Tax Adj.] Real Estate Taxes (nc)	TOTPLTNET	1,046,714	413,616	2,409	15,474	24,046	102	326	39,154
100	TI	[TI][Fed Tax Adj.] Credits & Adjustments	TOTPLTNET	0	0	0	0	0	0	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
51	TI	[TI][Fed Tax Adj.] Meals and Entertainment (50%)	LABOR	-62	-6,863	-73,833	-78,043	-13,706	-11,299	-3,068
52	TI	[TI][Fed Tax Adj.] Company owned life insurance	LABOR	0	0	0	0	0	0	0
53	TI	[TI][Fed Tax Adj.] ESOP/401(k) Cash Dividends	TOTPLTNET	-209	-14,841	-222,201	-235,528	-43,455	-27,603	-180
54	TI	[TI][Fed Tax Adj.] Medicare Subsidy	LABOR	0	0	0	0	0	0	0
55	TI	[TI][Fed Tax Adj.] Dividends Received Deduction-2	TOTPLTNET	0	0	0	0	0	0	0
56	TI	[TI][Fed Tax Adj.] W-2 Earnings Exceeding $1.000.000	LABOR	272	30,282	325,790	344,368	60,479	49,857	13,537
57	TI	[TI][Fed Tax Adj.] Allowable Depreciation	DEPREXP	0	0	0	0	0	0	0
58	TI	[TI][Fed Tax Adj.] Previously Ded Amort-Reacq Bonds	not_used	0	0	0	0	0	0	0
59	TI	[TI][Fed Tax Adj.] Amortization of Computer Software	INTANGPLT	0	0	0	0	0	0	0
60	TI	[TI][Fed Tax Adj.] Amort Def Gain - Sale of Gen Asset	not_used	0	0	0	0	0	0	0
61	TI	[TI][Fed Tax Adj.] Gain on Sale of Services Corp Asset	not_used	0	0	0	0	0	0	0
62	TI	[TI][Fed Tax Adj.] AFUDC / IDC - Debt	TOTPLT	-214	-15,052	-231,081	-241,092	-43,898	-27,083	-335
63	TI	[TI][Fed Tax Adj.] Capitalized Interest - Section 263A	TOTPLT	669	47,020	721,862	753,134	137,132	84,602	1,048
64	TI	[TI][Fed Tax Adj.] Cost of removal	TOTPLT	0	0	0	0	0	0	0
65	TI	[TI][Fed Tax Adj.] Utility Commodity Costs	not_used	0	0	0	0	0	0	0
66	TI	[TI][Fed Tax Adj.] RAC-Environmental Cleanup Costs	not_used	0	0	0	0	0	0	0
67	TI	[TI][Fed Tax Adj.] SBC-Societal Benefits Clause	not_used	0	0	0	0	0	0	0
68	TI	[TI][Fed Tax Adj.] Def Comp - Off/Dir/NOC (c)	LABOR	2	182	1,956	2,068	363	299	81
69	TI	[TI][Fed Tax Adj.] Deduction of Securitizartion	not_used	0	0	0	0	0	0	0
70	TI	[TI][Fed Tax Adj.] Additional Vacation Pay Adj (c)	LABOR	-51	-5,668	-60,976	-64,453	-11,319	-9,331	-2,534
71	TI	[TI][Fed Tax Adj.] Third Party Claims	TOTPLT	17	1,221	18,747	19,559	3,561	2,197	27
72	TI	[TI][Fed Tax Adj.] Deduction for New Network Meter Equipme	TOTPLT	0	0	0	0	0	0	0
73	TI	[TI][Fed Tax Adj.] Gain/loss bond reacq	not_used	0	0	0	0	0	0	0
74	TI	[TI][Fed Tax Adj.] Amortization of Call Option Sale	LABOR	0	0	0	0	0	0	0
75	TI	[TI][Fed Tax Adj.] Defer Dividend Equivalents/Restricted Stoc	LABOR	0	0	0	0	0	0	0
76	TI	[TI][Fed Tax Adj.] Repair Allow Deferral Carrying Charges	TOTPLT	0	0	0	0	0	0	0
77	TI	[TI][Fed Tax Adj.] CIAC Tax Gross Up	TOTPLTNET	184	13,021	194,958	206,651	38,128	24,219	158
78	TI	[TI][Fed Tax Adj.] FIN48 Services Allocation	TOTPLT	0	0	0	0	0	0	0
79	TI	[TI][Fed Tax Adj.] Pension	LABOR	-543	-60,376	-649,562	-686,604	-120,584	-99,405	-26,990
80	TI	[TI][Fed Tax Adj.] OPEB	LABOR	-15,537	-1,727,781	-18,588,450	-19,648,470	-3,450,749	-2,844,653	-772,378
81	TI	[TI][Fed Tax Adj.] Deferred Return on CIP ll	TOTPLT	13	928	14,240	14,857	2,705	1,669	21
82	TI	[TI][Fed Tax Adj.] Deferred Depreciation on CIP ll	TOTPLT	10	733	11,259	11,747	2,139	1,320	16
83	TI	[TI][Fed Tax Adj.] FIN48 Reg Asset Reversal	LABOR	0	0	0	0	0	0	0
84	TI	[TI][Fed Tax Adj.] Assessment by Board of Public Utilities of th	TOTPLTNET	18	1,310	19,619	20,796	3,837	2,437	16
85	TI	[TI][Fed Tax Adj.] Misc Adj - Permanent	TOTPLTNET	0	0	0	0	0	0	0
86	TI	[TI][Fed Tax Adj.] Casualty Loss Deferred O&M	TOTPLTNET	227	16,109	241,184	255,650	47,168	29,961	195
87	TI	[TI][Fed Tax Adj.] Performance Incentive Plan Adj (c)	TOTPLTNET	-212	-15,028	-224,994	-238,489	-44,002	-27,950	-182
88	TI									
89	TI									
90	TI	[TI][Fed Tax Adj.] LCAPP	TOTPLTNET	0	0	0	0	0	0	0
91	TI	[TI][Fed Tax Adj.] Clause - Deferred Fuel	not_used	0	0	0	0	0	0	0
92	TI	[TI][Fed Tax Adj.] Penalties	not_used	0	0	0	0	0	0	0
93	TI	[TI][Fed Tax Adj.] Restricted Stock - Permanent	TOTPLTNET	-17	-1,188	-17,782	-18,849	-3,478	-2,209	-14
94	TI	[TI][Fed Tax Adj.] Environmental Accrual	TOTPLTNET	0	0	0	0	0	0	0
95	TI	[TI][Fed Tax Adj.] Legal Reserves (nc)	TOTPLTNET	82	5,777	86,494	91,682	16,915	10,745	70
96	TI	[TI][Fed Tax Adj.] Material & Supplies Reserve (c)	TOTPLT	21	1,498	22,996	23,992	4,369	2,695	33
97	TI	[TI][Fed Tax Adj.] Lobbying Expenses	LABOR	0	0	0	0	0	0	0
98	TI	[TI][Fed Tax Adj.] Bankruptcies and Accum Provision for Rent	TOTPLTNET	13	903	13,524	14,335	2,645	1,680	11
99	TI	[TI][Fed Tax Adj.] Real Estate Taxes (nc)	TOTPLTNET	212	15,047	225,293	238,805	44,060	27,987	182
100	TI	[TI][Fed Tax Adj.] Credits & Adjustments	TOTPLTNET	0	0	0	0	0	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
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12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
101	TI	**[TI][Fed Tax Adj.] Miscellaneous**	TOTPLT								
102	TI	**[TI] TOTAL TAX ADJUSTMENTS - FEDERAL**		-149,324,736	-71,833,233	-349,555	-1,166,162	-1,141,853	-5,024	-85,044	-5,603,458
103	TI										
104	TI	**[TI] TAX ADJUSTMENTS - STATE**									
105	TI	[TI] TEFA	TEFA_04	0	0	0	0	0	0	0	0
106	TI	[TI] Federal Depreciation Reversal	DEPREXP	72,042,765	28,449,916	173,655	1,285,460	2,172,829	9,238	23,164	2,598,761
107	TI	[TI] State Tax Depreciation	DEPREXP	36,681,624	14,485,690	88,419	654,511	1,106,328	4,704	11,794	1,323,197
108	TI	[Electric] Not Used_42	not_used	0	0	0	0	0	0	0	0
109	TI	**[TI] TOTAL TAX ADJUSTMENTS - STATE**		108,724,389	42,935,606	262,074	1,939,971	3,279,157	13,941	34,958	3,921,958
110	TI										
111	TI	**[TI] TAXABLE NET INCOME - STATE**		1,331,886,063	556,211,094	3,070,755	18,577,587	28,188,580	120,472	410,951	48,404,948
112	TI	[TI] State Tax Liability		119,869,746	50,058,998	276,368	1,671,983	2,536,972	10,842	36,986	4,356,445
113	TI	[TI] Prior Year Adjustment	TOTPLTNET	0	0	0	0	0	0	0	0
114	TI	**[TI] TOTAL STATE INCOME TAX LIABILITY**		119,869,746	50,058,998	276,368	1,671,983	2,536,972	10,842	36,986	4,356,445
115	TI										
116	TI	**[TI] TAXABLE NET INCOME - FEDERAL**		1,103,291,929	463,216,490	2,532,313	14,965,633	22,372,450	95,688	339,008	40,126,545
117	TI	[TI] Federal Tax Liability		231,691,305	97,275,463	531,786	3,142,783	4,698,215	20,094	71,192	8,426,575
118	TI	[Electric] Not Used_43	not_used	0	0	0	0	0	0	0	0
119	TI	[Electric] Not Used_44	not_used	0	0	0	0	0	0	0	0
120	TI	**[TI] TOTAL FEDERAL INCOME TAX LIABILITY**		231,691,305	97,275,463	531,786	3,142,783	4,698,215	20,094	71,192	8,426,575
121	TI										
122	TI	**[TI] TOTAL INCOME TAX EXPENSE**		351,561,051	147,334,461	808,154	4,814,766	7,235,187	30,937	108,177	12,783,020
123	TI										
124	TI										
125	TI										
126	TI										
127	TI	**[TI] TAX RATES**									
128	TI	[TI] FEDERAL TAX RATE - CURRENT		21.000%							
129	TI	[TI] NEW JERSEY CORP BUSINESS TAX RATE		9.000%							
130	TI	[TI] CUSTOMER ACCT UNCOLLECTIBLE RATE		0.0							
131	TI	[TI] EFFECTIVE TAX RATE		28.110%							
132	TI	[TI] COMPOSITE RATE		28.110%							
133	TI	[TI] 1 - EFFECTIVE TAX RATE		71.89000%							
134	TI										
135	TI	**[TI] DEVELOPMENT OF OPERATING INCOME ADJUSTED**									
136	TI	[TI] 410 + 411 - Additional Rental Income - NJ Properties	TOTPLT	-16,349	-6,435	-39	-293	-496	-2	-5	-593
137	TI	[TI] 410 + 411 - Amort of Def Gain on Sale of Services Assets	not_used	0	0	0	0	0	0	0	0
138	TI	[TI] 410 + 411 - Amort of Deferred Gain on Sale of Generation	not_used	0	0	0	0	0	0	0	0
139	TI	[TI] 410 + 411 - Bankruptcies and Accum Provision for Rent R	TOTPLT	53,745	21,154	129	964	1,632	7	17	1,950
140	TI	[TI] 410 + 411 - Casualty Loss Deferred O&M	TOTPLTNET	-1,120,547	-442,792	-2,579	-16,565	-25,742	-109	-349	-41,916
141	TI	[TI] 410 + 411 - CECL Reserve	not_used	0	0	0	0	0	0	0	0
142	TI	[TI] 410 + 411 - CEF- EC AMI	TOTPLT	20,866,765	8,213,195	50,216	374,115	633,590	2,694	6,560	757,205
143	TI	[TI] 410 + 411 - CEF- EV Deferral	TOTPLT	1,855,840	730,462	4,466	33,273	56,350	240	583	67,344
144	TI	[TI] 410 + 411 - Clause - Demographic Studies	not_used	0	0	0	0	0	0	0	0
145	TI	[TI] 410 + 411 - Clause - Navigant Studies	not_used	0	0	0	0	0	0	0	0
146	TI	[TI] 410 + 411 - Clause - RAC (Environmental Clean Up)	not_used	0	0	0	0	0	0	0	0
147	TI	[TI] 410 + 411 - Clause - Societal Benefits Clause (AAP)	not_used	0	0	0	0	0	0	0	0
148	TI	[TI] 410 + 411 - COVID Deferrals	not_used	0	0	0	0	0	0	0	0
149	TI	[TI] 410 + 411 - Current SHARE -- FT	DEPREXP	2,912,070	1,149,986	7,019	51,960	87,829	373	936	105,046
150	TI	[TI] 410 + 411 - Customer Advances	TOTPLTNET	-4,645,423	-1,835,670	-10,692	-68,675	-106,717	-454	-1,447	-173,769

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
101	TI	**[TI][Fed Tax Adj.] Miscellaneous**	TOTPLT							
102	TI	**[TI] TOTAL TAX ADJUSTMENTS - FEDERAL**		-23,754	-2,366,110	-27,673,028	-29,098,195	-5,152,208	-3,961,522	-865,589
103	TI									
104	TI	**[TI] TAX ADJUSTMENTS - STATE**								
105	TI	[TI] TEFA	TEFA_04	0	0	0	0	0	0	0
106	TI	[TI] Federal Depreciation Reversal	DEPREXP	14,327	1,004,184	15,441,144	16,085,732	2,929,970	1,821,677	32,708
107	TI	[TI] State Tax Depreciation	DEPREXP	7,295	511,295	7,862,084	8,190,285	1,491,837	927,533	16,654
108	TI	[Electric] Not Used_42	not_used	0	0	0	0	0	0	0
109	TI	**[TI] TOTAL TAX ADJUSTMENTS - STATE**		21,622	1,515,479	23,303,228	24,276,018	4,421,806	2,749,211	49,361
110	TI									
111	TI	**[TI] TAXABLE NET INCOME - STATE**		298,632	18,667,010	285,252,666	285,935,187	53,128,158	33,429,375	190,648
112	TI	[TI] State Tax Liability		26,877	1,680,031	25,672,740	25,734,167	4,781,534	3,008,644	17,158
113	TI	[TI] Prior Year Adjustment	TOTPLTNET	0	0	0	0	0	0	0
114	TI	**[TI] TOTAL STATE INCOME TAX LIABILITY**		26,877	1,680,031	25,672,740	25,734,167	4,781,534	3,008,644	17,158
115	TI									
116	TI	**[TI] TAXABLE NET INCOME - FEDERAL**		250,133	15,471,501	236,276,698	235,925,003	43,924,818	27,671,521	124,128
117	TI	[TI] Federal Tax Liability		52,528	3,249,015	49,618,107	49,544,251	9,224,212	5,811,019	26,067
118	TI	[Electric] Not Used_43	not_used	0	0	0	0	0	0	0
119	TI	[Electric] Not Used_44	not_used	0	0	0	0	0	0	0
120	TI	**[TI] TOTAL FEDERAL INCOME TAX LIABILITY**		52,528	3,249,015	49,618,107	49,544,251	9,224,212	5,811,019	26,067
121	TI									
122	TI	**[TI] TOTAL INCOME TAX EXPENSE**		79,405	4,929,046	75,290,847	75,278,417	14,005,746	8,819,663	43,225
123	TI									
124	TI									
125	TI									
126	TI									
127	TI	**[TI] TAX RATES**								
128	TI	[TI] FEDERAL TAX RATE - CURRENT								
129	TI	[TI] NEW JERSEY CORP BUSINESS TAX RATE								
130	TI	[TI] CUSTOMER ACCT UNCOLLECTIBLE RATE								
131	TI	[TI] EFFECTIVE TAX RATE								
132	TI	[TI] COMPOSITE RATE								
133	TI	[TI] 1 - EFFECTIVE TAX RATE								
134	TI									
135	TI	**[TI] DEVELOPMENT OF OPERATING INCOME ADJUSTED**								
136	TI	[TI] 410 + 411 - Additional Rental Income - NJ Properties	TOTPLT	-3	-229	-3,509	-3,661	-667	-411	-5
137	TI	[TI] 410 + 411 - Amort of Def Gain on Sale of Services Assets	not_used	0	0	0	0	0	0	0
138	TI	[TI] 410 + 411 - Amort of Deferred Gain on Sale of Generation	not_used	0	0	0	0	0	0	0
139	TI	[TI] 410 + 411 - Bankruptcies and Accum Provision for Rent R	TOTPLT	11	751	11,535	12,035	2,191	1,352	17
140	TI	[TI] 410 + 411 - Casualty Loss Deferred O&M	TOTPLTNET	-227	-16,109	-241,184	-255,650	-47,168	-29,961	-195
141	TI	[TI] 410 + 411 - CECL Reserve	not_used	0	0	0	0	0	0	0
142	TI	[TI] 410 + 411 - CEF- EC AMI	TOTPLT	4,153	291,723	4,478,562	4,672,579	850,789	524,885	6,499
143	TI	[TI] 410 + 411 - CEF- EV Deferral	TOTPLT	369	25,945	398,313	415,568	75,667	46,682	578
144	TI	[TI] 410 + 411 - Clause - Demographic Studies	not_used	0	0	0	0	0	0	0
145	TI	[TI] 410 + 411 - Clause - Navigant Studies	not_used	0	0	0	0	0	0	0
146	TI	[TI] 410 + 411 - Clause - RAC (Environmental Clean Up)	not_used	0	0	0	0	0	0	0
147	TI	[TI] 410 + 411 - Clause - Societal Benefits Clause (AAP)	not_used	0	0	0	0	0	0	0
148	TI	[TI] 410 + 411 - COVID Deferrals	not_used	0	0	0	0	0	0	0
149	TI	[TI] 410 + 411 - Current SHARE -- FT	DEPREXP	579	40,591	624,153	650,208	118,434	73,635	1,322
150	TI	[TI] 410 + 411 - Customer Advances	TOTPLTNET	-942	-66,782	-999,873	-1,059,841	-195,543	-124,209	-809

PUBLIC SERVICE ELECTRIC & GAS COMPANY
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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
151	TI	[TI] 410 + 411 - Deduction for Retention Payments (c)	LABOR	5,352	2,710	12	24	1	0	3	204
152	TI	[TI] 410 + 411 - Deferred Employer ER FICA	LABOR	7,086,760	3,589,129	16,367	32,139	1,863	18	4,550	269,707
153	TI	[TI] 410 + 411 - FAS 5 (ASC40) Reserve - Sales Tax	not_used	0	0	0	0	0	0	0	0
154	TI	[TI] 410 + 411 - Fed Amort of Deferred Gain on Sale of Gener	not_used	0	0	0	0	0	0	0	0
155	TI	[TI] 410 + 411 - Injuries & Damages - FT	TOTPLT	-328,505	-129,300	-791	-5,890	-9,975	-42	-103	-11,921
156	TI	[TI] 410 + 411 - Line Pack Adjustment	not_used	0	0	0	0	0	0	0	0
157	TI	[TI] 410 + 411 - Medicare Subsidy	not_used	0	0	0	0	0	0	0	0
158	TI	[TI] 410 + 411 - Partnership Income/Loss (nc)	TOTPLT	42,165	16,596	101	756	1,280	5	13	1,530
159	TI	[TI] 410 + 411 - Plant Related	DEPREXP	37,305,084	14,731,896	89,922	665,635	1,125,131	4,784	11,995	1,345,687
160	TI	[TI] 410 + 411 - Previously Deducted Amort - Reacquired Bon	not_used	0	0	0	0	0	0	0	0
161	TI	[TI] 410 + 411 - R & D Credits CF	TOTPLT	-15,263	-6,007	-37	-274	-463	-2	-5	-554
162	TI	[TI] 410 + 411 - RE - Lease Liability	TOTPLT	236,259	92,992	569	4,236	7,174	30	74	8,573
163	TI	[TI] 410 + 411 - RE - ROU Lease Asset	TOTPLT	-319,172	-125,627	-768	-5,722	-9,691	-41	-100	-11,582
164	TI	[TI] 410 + 411 - Real Estate Taxes (nc)	TOTPLT	-1,046,714	-411,988	-2,519	-18,766	-31,782	-135	-329	-37,983
165	TI	[TI] 410 + 411 - Reversal of Book Income from Partnerships	TOTPLT	-42,165	-16,596	-101	-756	-1,280	-5	-13	-1,530
166	TI	[TI] 410 + 411 - Severance Pay (nc)	LABOR	-154,681	-78,339	-357	-702	-41	0	-99	-5,887
167	TI	[TI] 410 + 411 - State NOL CF (c)	DEPREXP	-17,908,279	-7,072,036	-43,167	-319,538	-540,119	-2,296	-5,758	-645,996
168	TI	[TI] 410 + 411 - Unrealized G/L on Equity Securities	TOTPLT	-125,367	-49,345	-302	-2,248	-3,807	-16	-39	-4,549
169	TI	**[TI] E410 + E411- PROVISION FOR DEFERRED INCOME T**									
170	TI	[TI] E410 + E411 - Legal Reserves (c)	TOTPLTNET	0	0	0	0	0	0	0	0
171	TI	[TI] E410 + E411 - Tax Depreciation	DEPREXP	0	0	0	0	0	0	0	0
172	TI	[TI] 410 + 411 - Previously Ded Amort-Reacq Bonds	not_used	0	0	0	0	0	0	0	0
173	TI	[TI] E410 + E411 - Amortization of Power Gain	not_used	0	0	0	0	0	0	0	0
174	TI	[TI] E410 + E411 - Amort Def Gain - Sale of Gen Asset	not_used	0	0	0	0	0	0	0	0
175	TI	[TI] 410 + 411 - Gain on Sale of Services Corp Asset	not_used	0	0	0	0	0	0	0	0
176	TI	[TI] 410 + 411 - AFUDC / IDC - Debt	TOTPLT	1,076,666	423,778	2,591	19,303	32,691	139	338	39,070
177	TI	[TI] 410 + 411 - Capitalized Interest - Section 263A	TOTPLT	-3,363,340	-1,323,816	-8,094	-60,300	-102,123	-434	-1,057	-122,047
178	TI	[TI] 410 + 411 - Cost of removal	TOTPLT	0	0	0	0	0	0	0	0
179	TI	[TI] E410 + E411 - Utility Commodity Costs	not_used	0	0	0	0	0	0	0	0
180	TI	[TI] E410 + E411 - RAC-Environmental Cleanup Costs	not_used	0	0	0	0	0	0	0	0
181	TI	[TI] E410 + E411 - SBC-Societal Benefits Clause	not_used	0	0	0	0	0	0	0	0
182	TI	[TI] 410 + 411 - Def Comp - Off/Dir/NOC (c)	LABOR	-11,058	-5,600	-26	-50	-3	0	-7	-421
183	TI	[TI] 410 + 411 - Deduction of Securitizartion	not_used	0	0	0	0	0	0	0	0
184	TI	[TI] 410 + 411 - Additional Vacation Pay Adj (c)	LABOR	344,695	174,573	796	1,563	91	1	221	13,118
185	TI	[TI] 410 + 411 - Third Party Claims	TOTPLT	-87,346	-34,379	-210	-1,566	-2,652	-11	-27	-3,170
186	TI	[TI] E410 + E411 - Bankruptcies & Acc Prov-Rent Receivable	LABOR	0	0	0	0	0	0	0	0
187	TI	[TI] E410 + E411 - Deduction for New Network Meter Equipme	TOTPLT	0	0	0	0	0	0	0	0
188	TI	[TI] 410 + 411 - Gain/loss bond reacq	not_used	0	0	0	0	0	0	0	0
189	TI	[TI] 410 + 411 - Amortization of Call Option Sale	LABOR	0	0	0	0	0	0	0	0
190	TI	[TI] 410 + 411 - Defer Dividend Equivalents/Restricted Stock-T	LABOR	0	0	0	0	0	0	0	0
191	TI	[TI] E410 + E411 - Repair Allow Deferral Carrying Charges	TOTPLT	0	0	0	0	0	0	0	0
192	TI	[TI] 410 + 411 - CIAC Tax Gross Up	TOTPLTNET	-905,779	-357,925	-2,085	-13,390	-20,808	-88	-282	-33,882
193	TI	[TI] E410 + E411 - FIN48 Services Allocation	TOTPLT	0	0	0	0	0	0	0	0
194	TI	[TI] 410 + 411 - Pension	LABOR	3,671,962	1,859,686	8,480	16,653	965	9	2,358	139,747
195	TI	[TI] 410 + 411 - OPEB	LABOR	105,080,197	53,218,455	242,682	476,553	27,621	272	67,466	3,999,130
196	TI	[TI] 410 + 411 - Fin Def-Energy Competition Act Ct	TOTPLT	0	0	0	0	0	0	0	0
197	TI	[TI] E410 + E411 - Conditional Asset Retire Obligations	TOTPLTNET	0	0	0	0	0	0	0	0
198	TI	[TI] 410 + 411 - Rabbi Trust	LABOR	0	0	0	0	0	0	0	0
199	TI	[TI] E410 + E411 - FIN48 Reg Asset Reversal	LABOR	0	0	0	0	0	0	0	0
200	TI	[TI] 410 + 411 - Additional Expenses on Rental Property	TOTPLT	108,083	42,542	260	1,938	3,282	14	34	3,922

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
151	TI	[TI] 410 + 411 - Deduction for Retention Payments (c)	LABOR	1	88	947	1,001	176	145	39
152	TI	[TI] 410 + 411 - Deferred Employer ER FICA	LABOR	1,048	116,524	1,253,632	1,325,121	232,723	191,848	52,090
153	TI	[TI] 410 + 411 - FAS 5 (ASC40) Reserve - Sales Tax	not_used	0	0	0	0	0	0	0
154	TI	[TI] 410 + 411 - Fed Amort of Deferred Gain on Sale of Gener	not_used	0	0	0	0	0	0	0
155	TI	[TI] 410 + 411 - Injuries & Damages - FT	TOTPLT	-65	-4,593	-70,506	-73,560	-13,394	-8,263	-102
156	TI	[TI] 410 + 411 - Line Pack Adjustment	not_used	0	0	0	0	0	0	0
157	TI	[TI] 410 + 411 - Medicare Subsidy	not_used	0	0	0	0	0	0	0
158	TI	[TI] 410 + 411 - Partnership Income/Loss (nc)	TOTPLT	8	589	9,050	9,442	1,719	1,061	13
159	TI	[TI] 410 + 411 - Plant Related	DEPREXP	7,419	519,985	7,995,712	8,329,491	1,517,193	943,298	16,937
160	TI	[TI] 410 + 411 - Previously Deducted Amort - Reacquired Bon	not_used	0	0	0	0	0	0	0
161	TI	[TI] 410 + 411 - R & D Credits CF	TOTPLT	-3	-213	-3,276	-3,418	-622	-384	-5
162	TI	[TI] 410 + 411 - RE - Lease Liability	TOTPLT	47	3,303	50,708	52,904	9,633	5,943	74
163	TI	[TI] 410 + 411 - RE - ROU Lease Asset	TOTPLT	-64	-4,462	-68,503	-71,470	-13,013	-8,028	-99
164	TI	[TI] 410 + 411 - Real Estate Taxes (nc)	TOTPLT	-208	-14,633	-224,653	-234,385	-42,677	-26,329	-326
165	TI	[TI] 410 + 411 - Reversal of Book Income from Partnerships	TOTPLT	-8	-589	-9,050	-9,442	-1,719	-1,061	-13
166	TI	[TI] 410 + 411 - Severance Pay (nc)	LABOR	-23	-2,543	-27,363	-28,923	-5,080	-4,187	-1,137
167	TI	[TI] 410 + 411 - State NOL CF (c)	DEPREXP	-3,561	-249,619	-3,838,336	-3,998,567	-728,327	-452,830	-8,130
168	TI	[TI] 410 + 411 - Unrealized G/L on Equity Securities	TOTPLT	-25	-1,753	-26,907	-28,073	-5,112	-3,154	-39
169	TI	**[TI] E410 + E411- PROVISION FOR DEFERRED INCOME T/**								
170	TI	[TI] E410 + E411 - Legal Reserves (c)	TOTPLTNET	0	0	0	0	0	0	0
171	TI	[TI] E410 + E411 - Tax Depreciation	DEPREXP	0	0	0	0	0	0	0
172	TI	[TI] 410 + 411 - Previously Ded Amort-Reacq Bonds	not_used	0	0	0	0	0	0	0
173	TI	[TI] E410 + E411 - Amortization of Power Gain	not_used	0	0	0	0	0	0	0
174	TI	[TI] E410 + E411 - Amort Def Gain - Sale of Gen Asset	not_used	0	0	0	0	0	0	0
175	TI	[TI] 410 + 411 - Gain on Sale of Services Corp Asset	not_used	0	0	0	0	0	0	0
176	TI	[TI] 410 + 411 - AFUDC / IDC - Debt	TOTPLT	214	15,052	231,081	241,092	43,898	27,083	335
177	TI	[TI] 410 + 411 - Capitalized Interest - Section 263A	TOTPLT	-669	-47,020	-721,862	-753,134	-137,132	-84,602	-1,048
178	TI	[TI] 410 + 411 - Cost of removal	TOTPLT	0	0	0	0	0	0	0
179	TI	[TI] E410 + E411 - Utility Commodity Costs	not_used	0	0	0	0	0	0	0
180	TI	[TI] E410 + E411 - RAC-Environmental Cleanup Costs	not_used	0	0	0	0	0	0	0
181	TI	[TI] E410 + E411 - SBC-Societal Benefits Clause	not_used	0	0	0	0	0	0	0
182	TI	[TI] 410 + 411 - Def Comp - Off/Dir/NOC (c)	LABOR	-2	-182	-1,956	-2,068	-363	-299	-81
183	TI	[TI] 410 + 411 - Deduction of Securitizartion	not_used	0	0	0	0	0	0	0
184	TI	[TI] 410 + 411 - Additional Vacation Pay Adj (c)	LABOR	51	5,668	60,976	64,453	11,319	9,331	2,534
185	TI	[TI] 410 + 411 - Third Party Claims	TOTPLT	-17	-1,221	-18,747	-19,559	-3,561	-2,197	-27
186	TI	[TI] E410 + E411 - Bankruptcies & Acc Prov-Rent Receivable	LABOR	0	0	0	0	0	0	0
187	TI	[TI] E410 + E411 - Deduction for New Network Meter Equipme	TOTPLT	0	0	0	0	0	0	0
188	TI	[TI] 410 + 411 - Gain/loss bond reacq	not_used	0	0	0	0	0	0	0
189	TI	[TI] 410 + 411 - Amortization of Call Option Sale	LABOR	0	0	0	0	0	0	0
190	TI	[TI] 410 + 411 - Defer Dividend Equivalents/Restricted Stock-T	LABOR	0	0	0	0	0	0	0
191	TI	[TI] E410 + E411 - Repair Allow Deferral Carrying Charges	TOTPLT	0	0	0	0	0	0	0
192	TI	[TI] 410 + 411 - CIAC Tax Gross Up	TOTPLTNET	-184	-13,021	-194,958	-206,651	-38,128	-24,219	-158
193	TI	[TI] E410 + E411 - FIN48 Services Allocation	TOTPLT	0	0	0	0	0	0	0
194	TI	[TI] 410 + 411 - Pension	LABOR	543	60,376	649,562	686,604	120,584	99,405	26,990
195	TI	[TI] 410 + 411 - OPEB	LABOR	15,537	1,727,781	18,588,450	19,648,470	3,450,749	2,844,653	772,378
196	TI	[TI] 410 + 411 - Fin Def-Energy Competition Act Ct	TOTPLT	0	0	0	0	0	0	0
197	TI	[TI] E410 + E411 - Conditional Asset Retire Obligations	TOTPLTNET	0	0	0	0	0	0	0
198	TI	[TI] 410 + 411 - Rabbi Trust	LABOR	0	0	0	0	0	0	0
199	TI	[TI] E410 + E411 - FIN48 Reg Asset Reversal	LABOR	0	0	0	0	0	0	0
200	TI	[TI] 410 + 411 - Additional Expenses on Rental Property	TOTPLT	22	1,511	23,198	24,203	4,407	2,719	34

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
201	TI	[TI] 410 + 411 - Performance Incentive Plan Adj (c)	LABOR	1,045,327	529,412	2,414	4,741	275	3	671	39,783
202	TI	[TI] 410 + 411 - Deferred NJ Corp Bus Tax(Net of FIT)	TOTPLTNET	0	0	0	0	0	0	0	0
203	TI	[TI] 410 + 411 - Misc	TOTPLT	0	0	0	0	0	0	0	0
204	TI	[TI] 410 + 411 - Construction Period Interest	TOTPLTNET	0	0	0	0	0	0	0	0
205	TI	[TI] E410 + E411 - Clause - Deferred Return on CIP II	TOTPLT	-66,348	-26,115	-160	-1,190	-2,015	-9	-21	-2,408
206	TI	[TI] E410 + E411 - Clause - Deferred Depreciation on CIP II	TOTPLT	-52,458	-20,648	-126	-941	-1,593	-7	-16	-1,904
207	TI	[TI] 410 + 411 - Customer Connection Fees (Contributions in /	CUSTACCTS	-6,684,538	-3,868,705	-19,086	-32,542	-613	-9	-8,323	-23,891
208	TI	[TI] E410 + E411 - Decommissioning Costs	KWHMETER_04	0	0	0	0	0	0	0	0
209	TI	[TI] 410 + 411 - Investment Tax Credit	TOTPLT	0	0	0	0	0	0	0	0
210	TI	[TI] 410 + 411 - Assessment by Board of Public Utilities of the	TOTPLTNET	-91,151	-36,019	-210	-1,348	-2,094	-9	-28	-3,410
211	TI	[TI] E410 + E411 - Casualty Loss Deferred O&M & Ins Procee	TOTPLTNET	0	0	0	0	0	0	0	0
212	TI	[TI] E410 + E411 - GainState LILOAudit Refunds not yet recei	TOTPLTNET	0	0	0	0	0	0	0	0
213	TI	[TI] E410 + E411 - LCAPP	TOTPLTNET	0	0	0	0	0	0	0	0
214	TI	[TI] E410 + E411 - Audit Adjustment	not_used	0	0	0	0	0	0	0	0
215	TI	[TI] 410 + 411 - Stock-Based Compensation - Reverse Book -	TOTPLTNET	328,125	129,661	755	4,851	7,538	32	102	12,274
216	TI	[TI] 410 + 411 - Clause - Deferred Fuel	not_used	0	0	0	0	0	0	0	0
217	TI	[TI] 410 + 411 - Legal Reserves (nc)	TOTPLTNET	-401,853	-158,795	-925	-5,941	-9,232	-39	-125	-15,032
218	TI										
219	TI										
220	TI	**[TI] DEVELOPMENT OF OPERATING INCOME ADJ CONTI**									
221	TI	**[TI] E410 + E411- PROVISION FOR DEFER INC TAX CONT**									
222	TI	[TI] E410 + E411 - Material & Supplies Reserve (c)	TOTPLTNET	-107,143	-42,338	-247	-1,584	-2,461	-10	-33	-4,008
223	TI	[TI] E410 + E411 - Medicare Subsidy	TOTPLTNET								
224	TI	**[TI] TOTAL DEFERRED INCOME TAX**		144,525,616	68,877,750	334,262	1,130,425	1,113,608	4,900	77,753	5,657,838
225	TI										
226	TI	**[TI] TOTAL INC TAXES DEF IN PRIOR YEAR**	not_used	0	0	0	0	0	0	0	0
227	TI	**[TI] TOTAL INVEST TAX CRED ADJ (NET)**	not_used	0	0	0	0	0	0	0	0
228	TI	**[TI] TOTAL PRO FORMA OP INC ADJUSTMENTS**	not_used	0	0	0	0	0	0	0	0
229	TI										
230	TI	**[TI] OPERATING INCOME ADJUSTED**		738,814,468	314,528,771	1,699,160	9,824,611	14,541,804	62,276	232,263	26,498,998

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
201	TI	[TI] 410 + 411 - Performance Incentive Plan Adj (c)	LABOR	155	17,188	184,916	195,461	34,328	28,298	7,684
202	TI	[TI] 410 + 411 - Deferred NJ Corp Bus Tax(Net of FIT)	TOTPLTNET	0	0	0	0	0	0	0
203	TI	[TI] 410 + 411 - Misc	TOTPLT	0	0	0	0	0	0	0
204	TI	[TI] 410 + 411 - Construction Period Interest	TOTPLTNET	0	0	0	0	0	0	0
205	TI	[TI] E410 + E411 - Clause - Deferred Return on CIP II	TOTPLT	-13	-928	-14,240	-14,857	-2,705	-1,669	-21
206	TI	[TI] E410 + E411 - Clause - Deferred Depreciation on CIP II	TOTPLT	-10	-733	-11,259	-11,747	-2,139	-1,320	-16
207	TI	[TI] 410 + 411 - Customer Connection Fees (Contributions in /	CUSTACCTS	-1,025	-43,067	-1,309,422	-799,641	-175,856	-273,828	-128,530
208	TI	[TI] E410 + E411 - Decommissioning Costs	KWHMETER_04	0	0	0	0	0	0	0
209	TI	[TI] 410 + 411 - Investment Tax Credit	TOTPLT	0	0	0	0	0	0	0
210	TI	[TI] 410 + 411 - Assessment by Board of Public Utilities of the	TOTPLTNET	-18	-1,310	-19,619	-20,796	-3,837	-2,437	-16
211	TI	[TI] E410 + E411 - Casualty Loss Deferred O&M & Ins Procee	TOTPLTNET	0	0	0	0	0	0	0
212	TI	[TI] E410 + E411 - GainState LILOAudit Refunds not yet recei	TOTPLTNET	0	0	0	0	0	0	0
213	TI	[TI] E410 + E411 - LCAPP	TOTPLTNET	0	0	0	0	0	0	0
214	TI	[TI] E410 + E411 - Audit Adjustment	not_used	0	0	0	0	0	0	0
215	TI	[TI] 410 + 411 - Stock-Based Compensation - Reverse Book -	TOTPLTNET	67	4,717	70,625	74,861	13,812	8,773	57
216	TI	[TI] 410 + 411 - Clause - Deferred Fuel	not_used	0	0	0	0	0	0	0
217	TI	[TI] 410 + 411 - Legal Reserves (nc)	TOTPLTNET	-82	-5,777	-86,494	-91,682	-16,915	-10,745	-70
218	TI									
219	TI									
220	TI	**[TI] DEVELOPMENT OF OPERATING INCOME ADJ CONTI**								
221	TI	**[TI] E410 + E411- PROVISION FOR DEFER INC TAX CONT**								
222	TI	[TI] E410 + E411 - Material & Supplies Reserve (c)	TOTPLTNET	-22	-1,540	-23,061	-24,445	-4,510	-2,865	-19
223	TI	[TI] E410 + E411 - Medicare Subsidy	TOTPLTNET							
224	TI	**[TI] TOTAL DEFERRED INCOME TAX**		23,050	2,355,466	26,716,640	28,691,924	5,049,155	3,746,112	746,733
225	TI									
226	TI	**[TI] TOTAL INC TAXES DEF IN PRIOR YEAR**	not_used	0	0	0	0	0	0	0
227	TI	**[TI] TOTAL INVEST TAX CRED ADJ (NET)**	not_used	0	0	0	0	0	0	0
228	TI	**[TI] TOTAL PRO FORMA OP INC ADJUSTMENTS**	not_used	0	0	0	0	0	0	0
229	TI									
230	TI	**[TI] OPERATING INCOME ADJUSTED**		170,404	10,255,216	158,001,371	155,397,296	29,012,192	18,397,155	192,949

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	LR	**DEVELOPMENT OF LABOR ALLOCATION FACTOR**									
2	LR										
3	LR	**PRODUCTION LABOR EXPENSE**	not_used	0	0	0	0	0	0	0	0
4	LR										
5	LR	**TRANSMISSION LABOR EXPENSE**	not_used	0	0	0	0	0	0	0	0
6	LR										
7	LR	**DISTRIBUTION LABOR EXPENSE**									
8	LR	Operation									
9	LR	582-Station Equipment	E367PLT	280,636	121,848	602	1,539	27	0	96	1,683
10	LR	583-Overhead Lines	E367PLT	941,919	408,969	2,021	5,167	92	0	322	5,649
11	LR	584-Underground Lines	E367PLT	4,591,058	1,993,377	9,849	25,185	447	2	1,571	27,534
12	LR	586-Metering	MTROMMIN_07	4,311,826	2,160,954	7,507	12,543	2,057	32	853	
13	LR	587-Customer Installations	MTROMMIN_07	17,308,754	8,674,612	30,136	50,349	8,258	129	3,423	
14	LR	588-Miscellaneous	DISTEXPO	16,169,609	8,017,775	34,598	81,316	4,429	58	5,150	179,048
15	LR	Total Operation		43,603,802	21,377,534	84,714	176,100	15,310	222	11,416	213,914
16	LR	Maintenance									
17	LR	590-Supervision & Engineering	DISTEXPM	0	0	0	0	0	0	0	0
18	LR	591-Structures	E361PLT	2,559,859	1,010,552	5,066	12,747	21	0	800	10,392
19	LR	592-Station Equipment	E362PLT	8,699,368	3,434,239	17,216	43,320	73	1	2,718	35,315
20	LR	593-Overhead Lines	E365PLT	11,294,340	4,717,949	23,243	59,144	95	1	3,717	54,978
21	LR	594-Underground Lines	E367PLT	11,333,758	4,920,968	24,315	62,174	1,104	5	3,879	67,972
22	LR	595-Line Transformers	LNTRFRMR_04	2,457,581	1,754,504	13,306	11,147			2,347	7,614
23	LR	596-Street Lighting and Signal Systems	E373PLT	7,842,365	218,284	1,372	10,605	18,141	77	172	5,373,344
24	LR	597-Meters	MTROMMIN_07	700,642	351,140	1,220	2,038	334	5	139	
25	LR	598-Other Distribution Maintenance	DISTEXPM	529,302	199,108	983	2,489	13	0	156	37,370
26	LR	Total Maintenance		45,417,214	16,606,745	86,721	203,665	19,783	90	13,927	5,586,984
27	LR	TOTAL DISTRIBUTION LABOR EXPENSE		89,021,016	37,984,279	171,434	379,765	35,092	312	25,342	5,800,898
28	LR										
29	LR	**E901-E903,E905 CUST ACCOUNTS EXPENSE**	CUSTACCTS	58,697,026	33,971,151	167,594	285,748	5,380	82	73,088	209,786
30	LR	**E907-E910, xDSM CUST SERV & INFO EXP**	CUSTS_I	5,539,923	4,371,290	14,761	26,931	976	14	1,718	12,046
31	LR	**E911-E916 SALES EXPENSE**	SALESEXP								
32	LR	**ADMIN & GENERAL EXP ACCOUNTS xE926**	SALESEXP	5,748,870	4,203,182	13,436	28,675	349	3	1,940	28,733
33	LR	**Employee Pension/Benefits Acct E926**	LABOR								
34	LR										
35	LR	**TOTAL OPERATION & MAINT LABOR EXPENSE**		159,006,836	80,529,903	367,225	721,118	41,797	411	102,089	6,051,463

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
1	LR	**DEVELOPMENT OF LABOR ALLOCATION FACTOR**								
2	LR									
3	LR	**PRODUCTION LABOR EXPENSE**	not_used	0	0	0	0	0	0	0
4	LR									
5	LR	**TRANSMISSION LABOR EXPENSE**	not_used	0	0	0	0	0	0	0
6	LR									
7	LR	**DISTRIBUTION LABOR EXPENSE**								
8	LR	Operation								
9	LR	582-Station Equipment	E367PLT	65	763	65,653	73,364	11,548	3,446	
10	LR	583-Overhead Lines	E367PLT	218	2,561	220,357	246,237	38,759	11,567	
11	LR	584-Underground Lines	E367PLT	1,061	12,481	1,074,055	1,200,199	188,917	56,377	
12	LR	586-Metering	MTROMMIN_07			297,894	1,653,831	137,755	33,846	4,554
13	LR	587-Customer Installations	MTROMMIN_07			1,195,820	6,638,894	552,985	135,867	18,282
14	LR	588-Miscellaneous	DISTEXPO	2,790	55,243	3,366,985	3,310,466	706,641	389,142	15,969
15	LR	Total Operation		4,134	71,047	6,220,765	13,122,993	1,636,605	630,244	38,805
16	LR	Maintenance								
17	LR	590-Supervision & Engineering	DISTEXPM	0	0	0	0	0	0	0
18	LR	591-Structures	E361PLT	562	5,044	544,301	615,354	168,589	186,430	
19	LR	592-Station Equipment	E362PLT	1,909	17,143	1,849,739	2,091,205	572,930	633,561	
20	LR	593-Overhead Lines	E365PLT	2,496	47,866	2,542,050	2,835,825	738,051	268,926	
21	LR	594-Underground Lines	E367PLT	2,620	30,811	2,651,477	2,962,884	466,373	139,176	
22	LR	595-Line Transformers	LNTRFRMR_04	347	3,317	344,093	320,906			
23	LR	596-Street Lighting and Signal Systems	E373PLT	118	1,929,677	120,485	131,861	23,703	14,525	
24	LR	597-Meters	MTROMMIN_07			48,406	268,736	22,384	5,500	740
25	LR	598-Other Distribution Maintenance	DISTEXPM	1,567	17,501	107,234	118,988	27,799	16,090	3
26	LR	Total Maintenance		9,618	2,051,358	8,207,784	9,345,758	2,019,828	1,264,208	743
27	LR	TOTAL DISTRIBUTION LABOR EXPENSE		13,752	2,122,405	14,428,550	22,468,751	3,656,434	1,894,452	39,548
28	LR									
29	LR	**E901-E903,E905 CUST ACCOUNTS EXPENSE**	CUSTACCTS	9,002	378,175	11,498,057	7,021,662	1,544,190	2,404,487	1,128,624
30	LR	**E907-E910, xDSM CUST SERV & INFO EXP**	CUSTS_I	223	35,938	913,560	146,473	12,444	3,166	382
31	LR	**E911-E916 SALES EXPENSE**	SALESEXP							
32	LR	**ADMIN & GENERAL EXP ACCOUNTS xE926**	SALESEXP	534	77,950	1,287,784	95,083	8,588	2,409	204
33	LR	**Employee Pension/Benefits Acct E926**	LABOR							
34	LR									
35	LR	**TOTAL OPERATION & MAINT LABOR EXPENSE**		23,511	2,614,469	28,127,951	29,731,969	5,221,656	4,304,516	1,168,758

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	CA	**DEVELOPMENT OF CAPITAL ADDITIONS ALLOCATION F**									
2	CA										
3	CA	**INTANGIBLE PLANT**	not_used	0	0	0	0	0	0	0	0
4	CA	**PRODUCTION PLANT**	not_used	0	0	0	0	0	0	0	0
5	CA										
6	CA	**TRANSMISSION PLANT**									
7	CA	E352 Structure & Improvements	not_used	0	0	0	0	0	0	0	0
8	CA	E353 Station Equipment	not_used	0	0	0	0	0	0	0	0
9	CA	E354/355 Towers and Fixtures	not_used	0	0	0	0	0	0	0	0
10	CA	E356 OH Cond and Devices	not_used	0	0	0	0	0	0	0	0
11	CA	E357 UG Conduits	not_used	0	0	0	0	0	0	0	0
12	CA	E358 Underground Cond. and Devices	not_used	0	0	0	0	0	0	0	0
13	CA	E359 Roads and Trails	not_used	0	0	0	0	0	0	0	0
14	CA	Other Tangible Plant Unallocated	not_used	0	0	0	0	0	0	0	0
15	CA	TOTAL TRANSMISSION PLANT		0	0	0	0	0	0	0	0
16	CA										
17	CA	**DISTRIBUTION PLANT**									
18	CA	E360 Land and Land Rights	E360PLT	3,481,598	1,374,426	6,890	17,337	29	0	1,088	14,133
19	CA	E361 Structures and Improvements	E361PLT	1,433,350	565,842	2,837	7,138	12	0	448	5,819
20	CA	E362 Station Equipment	E362PLT	72,557,752	28,643,535	143,592	361,316	608	7	22,669	294,546
21	CA	E364 Poles Towers and Fixtures	E364PLT	86,501,520	36,503,668	181,672	459,269	759	9	28,834	1,050,922
22	CA	E365 OH Conductors and Dev.	E365PLT	235,018,380	98,173,497	483,650	1,230,697	1,983	24	77,336	1,144,003
23	CA	E366 Underground Conduits	E367PLT	3,221,386	1,398,683	6,911	17,672	314	2	1,102	19,320
24	CA	E367 Underground Cond. and Dev.	E367PLT	32,807,746	14,244,691	70,383	179,975	3,196	16	11,228	196,758
25	CA	E368 Line Transformers - Energy Related - Local	KWH_SEC_10	48,751,051	20,636,869	140,946	294,209	882	11	17,926	427,195
26	CA	E368 Line Transformers - Demand Related - Local	CP_SEC_04	44,108,093	22,014,084	70,880	242,003	0	0	15,745	0
27	CA	E369 Services	E369PLT	11,962,969	18,747	118,021	3,200,191	7,381,213	31,321	0	0
28	CA	E370 Meters	METERPLT	73,420,491	44,077,472	153,129	255,835	34,425	537	17,392	0
29	CA	E373 Street Lighting	E373PLT	39,887,684	1,110,233	6,979	53,941	92,270	392	876	27,329,799
30	CA	E374 Asset Retirement Obligations	TOTPLT								
31	CA	TOTAL DISTRIBUTION PLANT		653,152,020	268,761,746	1,385,889	6,319,583	7,515,690	32,319	194,644	30,482,494
32	CA										
33	CA	**TOTAL CAPITAL ADDITIONS**		653,152,020	268,761,746	1,385,889	6,319,583	7,515,690	32,319	194,644	30,482,494

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
1	CA	**DEVELOPMENT OF CAPITAL ADDITIONS ALLOCATION F**								
2	CA									
3	CA	**INTANGIBLE PLANT**	not_used	0	0	0	0	0	0	0
4	CA	**PRODUCTION PLANT**	not_used	0	0	0	0	0	0	0
5	CA									
6	CA	**TRANSMISSION PLANT**								
7	CA	E352 Structure & Improvements	not_used	0	0	0	0	0	0	0
8	CA	E353 Station Equipment	not_used	0	0	0	0	0	0	0
9	CA	E354/355 Towers and Fixtures	not_used	0	0	0	0	0	0	0
10	CA	E356 OH Cond and Devices	not_used	0	0	0	0	0	0	0
11	CA	E357 UG Conduits	not_used	0	0	0	0	0	0	0
12	CA	E358 Underground Cond. and Devices	not_used	0	0	0	0	0	0	0
13	CA	E359 Roads and Trails	not_used	0	0	0	0	0	0	0
14	CA	Other Tangible Plant Unallocated	not_used	0	0	0	0	0	0	0
15	CA	TOTAL TRANSMISSION PLANT		0	0	0	0	0	0	0
16	CA									
17	CA	**DISTRIBUTION PLANT**								
18	CA	E360 Land and Land Rights	E360PLT	764	6,861	740,289	836,927	229,294	253,559	0
19	CA	E361 Structures and Improvements	E361PLT	315	2,825	304,772	344,557	94,399	104,389	0
20	CA	E362 Station Equipment	E362PLT	15,921	142,980	15,427,894	17,441,855	4,778,566	5,284,262	0
21	CA	E364 Poles Towers and Fixtures	E364PLT	19,880	331,155	19,664,352	22,108,018	3,275,933	2,877,049	0
22	CA	E365 OH Conductors and Dev.	E365PLT	51,934	996,016	52,896,263	59,009,287	15,357,744	5,595,947	0
23	CA	E366 Underground Conduits	E367PLT	745	8,757	753,627	842,138	132,557	39,558	0
24	CA	E367 Underground Cond. and Dev.	E367PLT	7,585	89,188	7,675,211	8,576,638	1,350,005	402,871	0
25	CA	E368 Line Transformers - Energy Related - Local	KWH_SEC_10	23,092	207,372	11,034,433	15,968,117	0	0	0
26	CA	E368 Line Transformers - Demand Related - Local	CP_SEC_04	0	0	11,942,383	9,822,999	0	0	0
27	CA	E369 Services	E369PLT	0	0	1,185,393	22,642	5,432	9	0
28	CA	E370 Meters	METERPLT	0	0	23,017,806	3,559,858	1,674,542	568,888	60,608
29	CA	E373 Street Lighting	E373PLT	598	9,814,684	612,810	670,667	120,557	73,879	0
30	CA	E374 Asset Retirement Obligations	TOTPLT							
31	CA	TOTAL DISTRIBUTION PLANT		120,834	11,599,838	145,255,234	139,203,702	27,019,028	15,200,411	60,608
32	CA									
33	CA	**TOTAL CAPITAL ADDITIONS**		120,834	11,599,838	145,255,234	139,203,702	27,019,028	15,200,411	60,608

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	AF	**ALLOCATION FACTOR TABLE**									
2	AF	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**									
3	AF										
4	AF	**ALLOCATION FACTORS PART A**									
5	AF										
6	AF	Number of Customers x Aux &SL rates - local	CUSTNUMX_04	2,318,149	2,000,647	6,950	11,612	0	0	0	0
7	AF										
8	AF										
9	AF	CP @ secondary lines - local	CP_SEC_04	8,231,675	4,108,379	13,228	45,164	0	0	2,938	0
10	AF	CP @ 26 kV lines - switching station load -systems	CP_SUBT_05	3,519,017	1,384,625	4,458	15,221	0	0	990	0
11	AF	CP @ primary lines - systems	CP_PRI_05	8,928,659	4,218,210	13,582	46,371	0	0	3,017	0
12	AF	Sum Cust Peaks @ 26 kV lines - local	SUMPK_SUBT_04	21,256,013	12,306,251	68,333	102,324	0	0	31,834	67,596
13	AF	Sum Cust Peaks @ primary lines - local	SUMPK_PRI_04	19,856,464	12,146,933	67,448	100,999	0	0	31,422	66,721
14	AF	Sum Cust Peaks @ secondary lines - local	SUMPK_SEC_04	20,498,179	11,830,661	65,692	98,370	0	0	30,604	64,983
15	AF										
16	AF										
17	AF	CP @ primary lines - local	CP_PRI_04	8,928,659	4,218,210	13,582	46,371	0	0	3,017	0
18	AF	NCP @ meter - local	NCP_MTR_04	10,800,203	4,443,011	33,669	58,231	1,244	19	25,942	66,269
19	AF	NCP @ meter - measurement	NCP_MTR_07	10,800,203	4,443,011	33,669	58,231	1,244	19	25,942	66,269
20	AF	NCP @ meter - cust svs	NCP_MTR_06	10,800,203	4,443,011	33,669	58,231	1,244	19	25,942	66,269
21	AF	NCP x SL rates @ meter - measurement	NCPXSL_MTR_07	10,698,184	4,443,011	33,669	58,231	1,244	19	25,942	0
22	AF										
23	AF	**BILLING DETERMINANTS**									
24	AF										
25	AF	Number of Customers		2,348,219	2,000,647	6,950	11,612	662	10	789	4,938
26	AF	Delivered kWh @ Meter - annual (w/n net)		40,231,265,119	13,286,613,062	93,109,748	189,891,666	581,366	7,149	11,877,324	283,298,553
27	AF	Delivered Kw @ Meter - annual		0	0	0	0	0	0	0	0
28	AF										
29	AF										
30	AF	**ALLOCATION FACTORS PART B**									
31	AF										
32	AF	Delivery kWh @ meter	KWHMETER_04	40,816,033,564	13,685,554,460	93,469,833	195,107,964	584,797	7,149	11,887,502	283,298,553
33	AF	Delivery kWh @ meter x non-profiled rates	KWHMETERX_04	21,338,981,079	13,685,554,460	93,469,833	195,107,964	584,797	7,149	11,887,502	0
34	AF	Delivery kWh @ subtrans - System E	KWH_SUBT_09	12,282,908,123	2,946,792,247	20,126,052	42,010,913	125,919	1,539	2,559,633	61,000,231
35	AF	Delivery kWh @ primary - System E	KWH_PRI_09	36,303,573,183	14,051,414,693	95,968,591	200,323,847	600,430	7,341	12,205,294	290,872,062
36	AF	Delivery kWh @ primary - Local E	KWH_PRI_10	36,303,573,183	14,051,414,693	95,968,591	200,323,847	600,430	7,341	12,205,294	290,872,062
37	AF	Delivery kWh @ secondary - Local E	KWH_SEC_10	32,329,765,823	13,685,554,460	93,469,833	195,107,964	584,797	7,149	11,887,502	283,298,553
38	AF	Delivery kWh @ meter - measurement	KWHMETER_07	40,781,263,034	13,685,554,460	93,469,833	195,107,964	584,797	7,149	11,887,502	283,298,553
39	AF	Delivery kWh @ meter - cust svs	KWHMETER_06	40,781,263,034	13,685,554,460	93,469,833	195,107,964	584,797	7,149	11,887,502	283,298,553
40	AF										
41	AF										
42	AF	**ALLOCATION FACTORS PART C**									
43	AF										
44	AF	Draft EC Proforma	ECPRO_07	472,721,631	380,825,641	1,226,966	2,049,910	323,611	5,048	139,357	0
45	AF	E587 Customer Installation Expenses Local	CUSINT_04	112	100	1	1	1	1	1	1
46	AF	E587 Customer Installation Expenses System	CUSINT_05	112	100	1	1	1	1	1	1
47	AF	E369 minimum Service investment- access	SERVICESMIN_03	360,747,418	565,325	3,558,965	96,502,862	222,582,987	944,498	0	0
48	AF	E369 excess Service investment- local delivery	SERVICESEXC_04	709,786,184	312,686,346	245,199,879	1,436,410	2,399,832	12,866	0	0
49	AF	Avg Customer Bills - local	CUSTAVG_04	2,348,219	2,000,647	6,950	11,612	662	10	789	4,938
50	AF	Avg Customer Bills - cust svs	CUSTAVG_06	2,348,219	2,000,647	6,950	11,612	662	10	789	4,938

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
1	AF	**ALLOCATION FACTOR TABLE**								
2	AF	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**								
3	AF									
4	AF	**ALLOCATION FACTORS PART A**								
5	AF									
6	AF	Number of Customers x Aux &SL rates - local	CUSTNUMX_04	0	0	288,392	9,532	794	195	26
7	AF									
8	AF									
9	AF	CP @ secondary lines - local	CP_SEC_04	0	0	2,228,748	1,833,218	0	0	0
10	AF	CP @ 26 kV lines - switching station load -systems	CP_SUBT_05	0	0	751,143	617,840	156,550	588,188	0
11	AF	CP @ primary lines - systems	CP_PRI_05	0	0	2,288,330	1,882,226	476,925	0	0
12	AF	Sum Cust Peaks @ 26 kV lines - local	SUMPK_SUBT_04	3,223	33,220	3,731,290	3,009,831	762,998	1,139,114	0
13	AF	Sum Cust Peaks @ primary lines - local	SUMPK_PRI_04	3,181	32,790	3,682,984	2,970,865	753,120	0	0
14	AF	Sum Cust Peaks @ secondary lines - local	SUMPK_SEC_04	3,098	31,936	3,587,089	2,893,512	753,120	1,139,114	0
15	AF									
16	AF									
17	AF	CP @ primary lines - local	CP_PRI_04	0	0	2,288,330	1,882,226	476,925	0	0
18	AF	NCP @ meter - local	NCP_MTR_04	3,582	32,169	2,324,426	2,007,606	519,576	871,481	412,980
19	AF	NCP @ meter - measurement	NCP_MTR_07	3,582	32,169	2,324,426	2,007,606	519,576	871,481	412,980
20	AF	NCP @ meter - cust svs	NCP_MTR_06	3,582	32,169	2,324,426	2,007,606	519,576	871,481	412,980
21	AF	NCP x SL rates @ meter - measurement	NCPXSL_MTR_07	0	0	2,324,426	2,007,606	519,576	871,481	412,980
22	AF									
23	AF	**BILLING DETERMINANTS**								
24	AF									
25	AF	Number of Customers		90	23,580	288,392	9,532	794	195	26
26	AF	Delivered kWh @ Meter - annual (w/n net)		15,313,401	137,520,699	7,289,563,210	10,497,945,935	3,083,571,353	4,669,504,753	672,466,899
27	AF	Delivered Kw @ Meter - annual		0	0	0	0	0	0	0
28	AF									
29	AF									
30	AF	**ALLOCATION FACTORS PART B**								
31	AF									
32	AF	Delivery kWh @ meter	KWHMETER_04	15,313,401	137,520,699	7,352,369,374	10,589,422,620	3,109,525,559	4,669,504,753	672,466,899
33	AF	Delivery kWh @ meter x non-profiled rates	KWHMETERX_04	0	0	7,352,369,374	0	0	0	0
34	AF	Delivery kWh @ subtrans - System E	KWH_SUBT_09	3,297,302	29,611,145	1,575,635,361	2,280,128,917	652,114,111	4,669,504,753	0
35	AF	Delivery kWh @ primary - System E	KWH_PRI_09	15,722,779	141,197,084	7,513,222,517	10,872,512,987	3,109,525,559	0	0
36	AF	Delivery kWh @ primary - Local E	KWH_PRI_10	15,722,779	141,197,084	7,513,222,517	10,872,512,987	3,109,525,559	0	0
37	AF	Delivery kWh @ secondary - Local E	KWH_SEC_10	15,313,401	137,520,699	7,317,598,845	10,589,422,620	0	0	0
38	AF	Delivery kWh @ meter - measurement	KWHMETER_07	15,313,401	137,520,699	7,317,598,845	10,589,422,620	3,109,525,559	4,669,504,753	672,466,899
39	AF	Delivery kWh @ meter - cust svs	KWHMETER_06	15,313,401	137,520,699	7,317,598,845	10,589,422,620	3,109,525,559	4,669,504,753	672,466,899
40	AF									
41	AF									
42	AF	**ALLOCATION FACTORS PART C**								
43	AF									
44	AF	Draft EC Proforma	ECPRO_07	0	0	88,151,097	0	0	0	0
45	AF	E587 Customer Installation Expenses Local	CUSINT_04	1	1	1	1	1	0	1
46	AF	E587 Customer Installation Expenses System	CUSINT_05	1	1	1	1	1	0	1
47	AF	E369 minimum Service investment- access	SERVICESMIN_03	0	0	35,745,941	682,770	163,790	280	0
48	AF	E369 excess Service investment- local delivery	SERVICESEXC_04	0	0	138,224,973	9,042,819	366,892	416,167	0
49	AF	Avg Customer Bills - local	CUSTAVG_04	90	23,580	288,392	9,532	794	195	26
50	AF	Avg Customer Bills - cust svs	CUSTAVG_06	90	23,580	288,392	9,532	794	195	26

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
51	AF	E370 minimum meter investment - measurement	METERSMIN_07	191,661,323	110,732,227	384,693	642,713	430,290	6,712	43,693	0
52	AF	E368 Line Transfomers - local	LNTRFRMR_04	559,887,636	399,712,164	3,031,461	2,539,460	0	0	534,622	1,734,652
53	AF	Billing Function costs - cust svs	BILLING_06	130,951	94,645	329	549	6	0	7	397
54	AF	E370 excess mtr invst - measrmnt	METERSEXC_07	124,473,055	75,468,893	262,185	438,037	0	0	29,779	0
55	**AF**	**ALLOCATION FACTOR TABLE CONTINUED**									
56	**AF**	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**									
57	AF										
58	AF	Avg Customer Bills - measurement	CUSTAVG_07	2,335,622	2,000,647	6,950	11,612	662	10	789	4,938
59	AF	Account Maint - cust svs	ACCTMAINT_06	80,564,013	67,106,800	233,135	389,502	21,207	331	25,273	19,139
60	AF	Meter Reading Costs - measurement	MRCOST_07	20,538,511	16,168,305	56,170	93,844	1,071	17	1,276	0
61	AF	Sales	SALES_06	0	0	0	0	0	0	0	0
62	AF	Other Utility work by Cust Ops - local	UTILWORK_04	3,334,747	2,438,140	7,794	16,634	202	2	1,125	16,667
63	AF										
64	AF	E370 excess meter investment - local delivery - Demand	METERSEXC_04	124,473,055	75,468,893	262,185	438,037	0	0	29,779	0
65	AF	E370 excess meter investment - local delivery - Energy	METERSEXC_10	124,473,055	75,468,893	262,185	438,037	0	0	29,779	0
66	AF										
67	AF	Choice - local	CHOICE_04	0	0	0	0	0	0	0	0
68	AF										
69	AF	Direct - PSAL - streetlighting	DIR_PSAL_02	1	0	0	0	0	0	0	0
70	AF	Direct - BPL - streetlighting	DIR_BPL_02	1	0	0	0	0	0	0	1
71	AF	Direct - BPL-POF - streetlighting	DIR_BPLPOF_02	1	0	0	0	0	0	0	0
72	AF	Direct - HTS-HV - access	DIR_HTSHV_03	1	0	0	0	0	0	0	0
73	AF	Direct - HEP - access	DIR_HEP_03	0	0	0	0	0	0	0	0
74	**AF**	**ALLOCATION FACTOR TABLE CONTINUED**									
75	**AF**	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**									
76	AF	Direct - HTS-Sub - systems	DIR_HTSS_05	1	0	0	0	0	0	0	0
77	AF										
78	AF	Direct - HTS-Sub - local	DIR_HTSS_04	1	0	0	0	0	0	0	0
79	AF	Meter O&M - minimum - measurement	MTROMMIN_07	6,387,137	3,201,035	11,121	18,579	3,047	48	1,263	0
80	AF	Meter O&M - excess - measurement	MTROMEXC_07	0	0	0	0	0	0	0	0
81	AF	WN TEFA Responsibility	TEFA_04	0	0	0	0	0	0	0	0
82	AF	Meter O&M - measurement	METERPLT_07	456,573,728	380,825,641	1,226,966	2,049,910	323,611	5,048	139,357	0
83	AF										
84	AF	E370 excess meter investment - dummy	METERSEXC_08	5,064	0	0	0	0	0	0	0
85	AF	Meter O&M - excess - dummy	MTROMEXC_08	0	0	0	0	0	0	0	0
86	AF	E369 excess Service investment- dummy	SERVICESEXC_08	0	0	0	0	0	0	0	0
87	AF	E368 Line Transfomers - dummy	LNTRFRMR_08	0	0	0	0	0	0	0	0
88	AF	CP @ 26 kV lines - switching station load - dummy	CP@SUBT_08	0	0	0	0	0	0	0	0
89	AF	CP @ primary lines - dummy	CP@PRI_08	0	0	0	0	0	0	0	0
90	AF	Sum Cust Peaks @ secondary lines - local	SUMPK@SEC_08	0	0	0	0	0	0	0	0
91	AF										
92	AF										
93	AF	Dummy allocator for unused lines	not_used	0	0	0	0	0	0	0	0
94	AF										
95	AF										
96	AF	**Plant Related**									
97	AF	Distribution Plant Total	DISTPLT	10,773,828,418	4,210,219,934	25,847,331	195,170,040	331,843,556	1,410,730	3,235,061	395,999,604
98	AF	Distribution Plant x meters	DISTPLTXMTR	10,408,406,976	3,990,841,758	25,085,193	193,896,724	331,672,221	1,408,057	3,148,498	395,999,604
99	AF	Acct E360 - Land & Land Rights	E360PLT	51,314,168	20,257,231	101,551	255,529	430	5	16,032	208,308
100	AF	Acct E361 - Structures & Improvments	E361PLT	242,256,447	95,635,281	479,427	1,206,364	2,030	25	75,688	983,432

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
51	AF	E370 minimum meter investment - measurement	METERSMIN_07	0	0	66,256,263	7,189,292	1,876,806	3,341,065	757,571
52	AF	E368 Line Transfomers - local	LNTRFRMR_04	79,064	755,659	78,391,489	73,109,064	0	0	0
53	AF	Billing Function costs - cust svs	BILLING_06	7	1,896	23,193	8,966	747	183	25
54	AF	E370 excess mtr invst - measrmnt	METERSEXC_07	0	0	37,965,488	6,395,819	3,266,582	646,271	0
55	**AF**	**ALLOCATION FACTOR TABLE CONTINUED**								
56	**AF**	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**								
57	AF									
58	AF	Avg Customer Bills - measurement	CUSTAVG_07	90	23,580	275,795	9,532	794	195	26
59	AF	Account Maint - cust svs	ACCTMAINT_06	348	91,387	10,058,899	2,365,984	197,074	48,420	6,515
60	AF	Meter Reading Costs - measurement	MRCOST_07	0	0	3,962,103	231,110	19,250	4,730	636
61	AF	Sales	SALES_06	0	0	0	0	0	0	0
62	AF	Other Utility work by Cust Ops - local	UTILWORK_04	310	45,217	747,005	55,155	4,982	1,398	118
63	AF									
64	AF	E370 excess meter investment - local delivery - Demand	METERSEXC_04	0	0	37,965,488	6,395,819	3,266,582	646,271	0
65	AF	E370 excess meter investment - local delivery - Energy	METERSEXC_10	0	0	37,965,488	6,395,819	3,266,582	646,271	0
66	AF									
67	AF	Choice - local	CHOICE_04	0	0	0	0	0	0	0
68	AF									
69	AF	Direct - PSAL - streetlighting	DIR_PSAL_02	0	1	0	0	0	0	0
70	AF	Direct - BPL - streetlighting	DIR_BPL_02	0	0	0	0	0	0	0
71	AF	Direct - BPL-POF - streetlighting	DIR_BPLPOF_02	1	0	0	0	0	0	0
72	AF	Direct - HTS-HV - access	DIR_HTSHV_03	0	0	0	0	0	0	1
73	AF	Direct - HEP - access	DIR_HEP_03	0	0	0	0	0	0	0
74	**AF**	**ALLOCATION FACTOR TABLE CONTINUED**								
75	**AF**	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**								
76	AF	Direct - HTS-Sub - systems	DIR_HTSS_05	0	0	0	0	0	1	0
77	AF									
78	AF	Direct - HTS-Sub - local	DIR_HTSS_04	0	0	0	0	0	1	0
79	AF	Meter O&M - minimum - measurement	MTROMMIN_07	0	0	441,272	2,449,831	204,058	50,136	6,746
80	AF	Meter O&M - excess - measurement	MTROMEXC_07	0	0	0	0	0	0	0
81	AF	WN TEFA Responsibility	TEFA_04	0	0	0	0	0	0	0
82	AF	Meter O&M - measurement	METERPLT_07	0	0	61,413,169	5,406,906	1,411,504	2,512,740	1,258,876
83	AF									
84	AF	E370 excess meter investment - dummy	METERSEXC_08	0	0	0	0	5,064	0	0
85	AF	Meter O&M - excess - dummy	MTROMEXC_08	0	0	0	0	0	0	0
86	AF	E369 excess Service investment- dummy	SERVICESEXC_08	0	0	0	0	0	0	0
87	AF	E368 Line Transfomers - dummy	LNTRFRMR_08	0	0	0	0	0	0	0
88	AF	CP @ 26 kV lines - switching station load - dummy	CP@SUBT_08	0	0	0	0	0	0	0
89	AF	CP @ primary lines - dummy	CP@PRI_08	0	0	0	0	0	0	0
90	AF	Sum Cust Peaks @ secondary lines - local	SUMPK@SEC_08	0	0	0	0	0	0	0
91	AF									
92	AF									
93	AF	Dummy allocator for unused lines	not_used	0	0	0	0	0	0	0
94	AF									
95	AF									
96	AF	**Plant Related**								
97	AF	Distribution Plant Total	DISTPLT	2,149,976	151,697,776	2,317,368,080	2,428,498,049	441,689,675	268,396,952	301,654
98	AF	Distribution Plant x meters	DISTPLTXMTR	2,149,976	151,697,776	2,202,806,060	2,410,780,266	433,355,304	265,565,538	0
99	AF	Acct E360 - Land & Land Rights	E360PLT	11,260	101,118	10,910,889	12,335,199	3,379,489	3,737,127	0
100	AF	Acct E361 - Structures & Improvments	E361PLT	53,158	477,384	51,510,786	58,235,016	15,954,717	17,643,139	0

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
101	AF	Acct E362 - Station Equipment	E362PLT	1,565,418,169	617,978,217	3,097,969	7,795,309	13,118	160	489,085	6,354,762
102	AF	Acct E364 - Poles & Towers	E364PLT	1,027,443,483	433,581,460	2,157,854	5,455,077	9,018	110	342,481	12,482,595
103	AF	Acct E365 - OH Conductors & Devices x HTSHV	E365PLT	2,856,184,590	1,193,105,100	5,877,809	14,956,690	24,103	295	939,868	13,903,094
104	AF	Acct E366 - UG Conduit	E366PLT	512,107,003	222,350,106	1,098,632	2,809,297	49,885	248	175,262	3,071,260
105	AF	Acct E367 - UG Conductors & Devices x HEP	E367PLT	1,431,183,475	621,400,988	3,070,344	7,851,131	139,414	692	489,805	8,583,237
106	AF	Acct E369 Services	E369PLT	535,269,333	838,818	5,280,717	143,188,891	330,263,894	1,401,425	0	0
107	AF	Acct E370 Meters	METERPLT	365,421,442	219,378,176	762,138	1,273,316	171,335	2,673	86,562	0
108	AF										
109	AF	Acct E370 Meters x load profile meters	METERPLTXPR	365,421,442	219,378,176	762,138	1,273,316	171,335	2,673	86,562	0
110	AF	Acct E373 - Streetlights	E373PLT	499,027,153	13,889,907	87,308	674,847	1,154,367	4,901	10,958	341,917,862
111	AF	Subtrans Lines - HTS-S/Switching Station load	SUBTRANSLINES	1.0000	0.3104	0.0010	0.0034			0.0002	
112	AF	Primary Lines - 50 Sys CP/50 Loc Sum Cust Pks	PRIMARYLINES	1.0000	0.5421	0.0025	0.0051			0.0010	0.0017
113	AF										
114	AF	Acct E301-E303 Intangible Plt	INTANGPLT	40,584,928	15,974,298	97,668	727,637	1,232,304	5,239	12,759	1,472,729
115	AF	Acct E399.10-23 Oth Tangible Plt	TANGPLT	0	0	0	0	0	0	0	0
116	AF	E391-E398 General Plant	GENPLT	429,584,593	164,713,403	1,035,337	8,002,670	13,689,057	58,115	129,947	16,344,031
117	AF	Common Plant	COMPLT	126,654,044	67,736,462	345,628	1,081,945	1,086,672	4,711	121,195	1,611,631
118	AF	Accts C389-C399, E389-E399 Com & Gen Plt	COMGENPLT	556,238,637	232,449,865	1,380,965	9,084,615	14,775,729	62,826	251,142	17,955,662
119	AF										
120	AF	Total Plant	TOTPLT	11,456,990,950	4,509,491,507	27,571,490	205,409,461	347,875,461	1,478,986	3,601,770	415,746,553
121	AF										
122	AF	Total Distribution Plant Reserve	TOTDRESERVE	3,099,332,698	1,206,907,087	8,335,934	81,854,978	155,879,252	662,476	999,183	103,115,208
123	AF	Total Net Plant	TOTPLTNET	8,357,658,252	3,302,584,420	19,235,556	123,554,483	191,996,209	816,510	2,602,586	312,631,345
124	AF										
125	AF										
126	AF	**Revenue Related**									
127	AF	Total Operating Revenue	TOTREV	1,925,019,676	834,325,022	4,487,689	24,633,458	35,698,885	153,013	719,759	68,304,658
128	**AF**	**ALLOCATION PROPORTIONS TABLE CONTINUED**									
129	**AF**	**INTERNALLY DEVELOPED ALLOCATION FACTORS**									
130	AF										
131	AF	**Expense Related**									
132	AF	Distr Oper Exp	DISTEXPO	52,242,807	25,904,836	111,784	262,726	14,309	188	16,641	578,491
133	AF	Distr Maint Exp	DISTEXPM	123,204,777	46,346,183	228,789	579,365	3,121	25	36,357	8,698,609
134	AF	Cust Serv & Info Expense	CUSTS_I	5,318,001	4,196,182	14,170	25,852	936	14	1,649	11,564
135	AF	Acct E901-E903,E905 Cust Acct Exp Excl 904	CACCTEXP	94,394,062	54,630,961	269,518	459,527	8,652	132	117,538	337,369
136	AF	Accts E901-E910 Excl 904 - Cust Accts,Serv & Info	CUSTSVSX	99,712,063	58,827,143	283,687	485,379	9,588	146	119,187	348,932
137	AF	Sales Expense	SALESEXP	40,922	29,919	96	204	2	0	14	205
138	AF	Total O&M Expense Excl 904-Uncollectibles	TOTOMXAG	311,457,637	141,176,442	724,395	2,751,971	2,826,660	12,188	163,946	10,935,628
139	AF	Tot Admin & Genl Exp xPension/Ben	A_GEXP	111,662,106	48,571,975	274,626	1,748,000	2,779,133	11,857	41,043	4,140,799
140	AF	Accts E901-E905 Cust Accts Exp Excl 904-Uncol	CUSTACCTS	94,394,062	54,630,961	269,518	459,527	8,652	132	117,538	337,369
141	AF	O&M + Capital Additions	EXPENDITURES	964,609,657	409,938,188	2,110,284	9,071,554	10,342,350	44,508	358,590	41,418,122
142	AF										
143	AF	Depreciation Expense (total)	DEPREXP	286,771,855	113,247,114	691,247	5,116,873	8,649,117	36,772	92,204	10,344,570
144	AF										
145	AF	NJ State Income Tax (CBT)	STATEINCTAX	119,869,746	50,058,998	276,368	1,671,983	2,536,972	10,842	36,986	4,356,445
146	AF	NJ State Deferred Income Tax	DFSTATEINCTAX	1,034,603	525,191	2,388	4,548	-51	1	668	39,394
147	AF										
148	AF	**Labor Expense Related**									
149	AF	Total Distribution Exp (Oper) Labor	TLABDO	43,603,802	21,377,534	84,714	176,100	15,310	222	11,416	213,914
150	AF	Total Distribution Exp (Maint) Labor	TLABDM	45,417,214	16,606,745	86,721	203,665	19,783	90	13,927	5,586,984

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				(9)	(10)	(11)	(12)	(13)	(14)	(15)
101	AF	Acct E362 - Station Equipment	E362PLT	343,500	3,084,771	332,853,557	376,304,339	103,096,548	114,006,835	0
102	AF	Acct E364 - Poles & Towers	E364PLT	236,131	3,933,380	233,568,272	262,593,524	38,910,712	34,172,869	0
103	AF	Acct E365 - OH Conductors & Devices x HTSHV	E365PLT	631,159	12,104,603	642,849,684	717,141,426	186,643,064	68,007,696	0
104	AF	Acct E366 - UG Conduit	E366PLT	118,401	1,392,172	119,804,922	133,875,585	21,072,679	6,288,555	0
105	AF	Acct E367 - UG Conductors & Devices x HEP	E367PLT	330,894	3,890,698	334,818,356	374,141,583	58,891,734	17,574,600	0
106	AF	Acct E369 Services	E369PLT	0	0	53,039,066	1,013,079	243,028	415	0
107	AF	Acct E370 Meters	METERPLT	0	0	114,562,020	17,717,782	8,334,371	2,831,414	301,654
108	AF									
109	AF	Acct E370 Meters x load profile meters	METERPLTXPR	0	0	114,562,020	17,717,782	8,334,371	2,831,414	301,654
110	AF	Acct E373 - Streetlights	E373PLT	7,483	122,789,628	7,666,746	8,390,589	1,508,270	924,286	0
111	AF	Subtrans Lines - HTS-S/Switching Station load	SUBTRANSLINES			0.1684	0.1385	0.0351	0.3429	
112	AF	Primary Lines - 50 Sys CP/50 Loc Sum Cust Pks	PRIMARYLINES	0.0001	0.0008	0.2209	0.1802	0.0457		
113	AF									
114	AF	Acct E301-E303 Intangible Plt	INTANGPLT	8,077	567,388	8,710,604	9,087,957	1,654,747	1,020,878	12,641
115	AF	Acct E399.10-23 Oth Tangible Plt	TANGPLT	0	0	0	0	0	0	0
116	AF	E391-E398 General Plant	GENPLT	88,736	6,260,999	90,916,078	99,499,766	17,885,807	10,960,646	0
117	AF	Common Plant	COMPLT	20,663	1,091,256	25,189,287	18,477,440	3,731,250	4,465,781	1,690,125
118	AF	Accts C389-C399, E389-E399 Com & Gen Plt	COMGENPLT	109,399	7,352,255	116,105,365	117,977,206	21,617,058	15,426,426	1,690,125
119	AF									
120	AF	Total Plant	TOTPLT	2,280,224	160,171,869	2,458,974,623	2,565,500,323	467,129,611	288,190,559	3,568,514
121	AF									
122	AF	Total Distribution Plant Reserve	TOTDRESERVE	585,098	40,022,961	660,087,229	658,722,048	115,325,242	64,723,429	2,112,572
123	AF	Total Net Plant	TOTPLTNET	1,695,126	120,148,908	1,798,887,394	1,906,778,275	351,804,368	223,467,130	1,455,942
124	AF									
125	AF									
126	AF	**Revenue Related**								
127	AF	Total Operating Revenue	TOTREV	749,390	27,761,012	405,667,274	394,055,404	75,575,200	49,953,159	2,935,754
128	**AF**	**ALLOCATION PROPORTIONS TABLE CONTINUED**								
129	**AF**	**INTERNALLY DEVELOPED ALLOCATION FACTORS**								
130	AF									
131	AF	**Expense Related**								
132	AF	Distr Oper Exp	DISTEXPO	9,013	178,485	10,878,479	10,695,871	2,283,104	1,257,287	51,594
133	AF	Distr Maint Exp	DISTEXPM	364,664	4,073,681	24,960,676	27,696,698	6,470,625	3,745,275	709
134	AF	Cust Serv & Info Expense	CUSTS_I	214	34,498	876,964	140,606	11,945	3,040	367
135	AF	Acct E901-E903,E905 Cust Acct Exp Excl 904	CACCTEXP	14,476	608,165	18,490,686	11,291,938	2,483,301	3,866,794	1,815,005
136	AF	Accts E901-E910 Excl 904 - Cust Accts,Serv & Info	CUSTSVSX	14,690	642,664	19,367,650	11,432,543	2,495,247	3,869,834	1,815,372
137	AF	Sales Expense	SALESEXP	4	555	9,167	677	61	17	1
138	AF	Total O&M Expense Excl 904-Uncollectibles	TOTOMXAG	406,676	5,323,213	65,846,920	56,885,968	13,276,295	9,693,399	1,433,935
139	AF	Tot Admin & Genl Exp xPension/Ben	A_GEXP	25,922	1,650,347	23,887,478	21,062,147	4,468,411	2,861,069	139,298
140	AF	Accts E901-E905 Cust Accts Exp Excl 904-Uncol	CUSTACCTS	14,476	608,165	18,490,686	11,291,938	2,483,301	3,866,794	1,815,005
141	AF	O&M + Capital Additions	EXPENDITURES	527,510	16,923,051	211,102,155	196,089,670	40,295,323	24,893,810	1,494,543
142	AF									
143	AF	Depreciation Expense (total)	DEPREXP	57,030	3,997,233	61,464,680	64,030,515	11,662,973	7,251,328	130,196
144	AF									
145	AF	NJ State Income Tax (CBT)	STATEINCTAX	26,877	1,680,031	25,672,740	25,734,167	4,781,534	3,008,644	17,158
146	AF	NJ State Deferred Income Tax	DFSTATEINCTAX	152	17,038	182,614	193,060	33,890	28,029	7,680
147	AF									
148	AF	**Labor Expense Related**								
149	AF	Total Distribution Exp (Oper) Labor	TLABDO	4,134	71,047	6,220,765	13,122,993	1,636,605	630,244	38,805
150	AF	Total Distribution Exp (Maint) Labor	TLABDM	9,618	2,051,358	8,207,784	9,345,758	2,019,828	1,264,208	743

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
151	AF	Total Labor	LABOR	159,006,836	80,529,903	367,225	721,118	41,797	411	102,089	6,051,463
152	AF										
153	AF	**REVENUES AND BILLING DETERMINANTS**									
154	AF										
155	AF	Base Rate Sales Revenue	SALESREV	1,899,915,237	825,027,762	4,437,681	24,358,956	35,301,077	151,307	708,990	67,543,508
156	AF										
157	AF	Residential Service	REVRS	825,027,762	825,027,762	0	0	0	0	0	0
158	AF	Residential Heating Service	REVRHS	4,437,681	0	4,437,681	0	0	0	0	0
159	AF	Residential Load Management Service	REVRLM	24,358,956	0	0	24,358,956	0	0	0	0
160	AF	Water Heating Service	REVWH	35,301,077	0	0	0	35,301,077	0	0	0
161	AF	Water Heating Storage Service	REVWHS	151,307	0	0	0	0	151,307	0	0
162	AF	Building Heating Service	REVHS	708,990	0	0	0	0	0	708,990	0
163	AF	Body Police Lighting Service	REVBLP	67,543,508	0	0	0	0	0	0	67,543,508
164	AF	Body Police Lighting Service from Publicly Owned	REVBLPPOF	741,039	0	0	0	0	0	0	0
165	AF	Private Street and Area Lighting Service	REVPAL	27,345,651	0	0	0	0	0	0	0
166	AF	General Power and Lighting Service	REVGLP	399,597,683	0	0	0	0	0	0	0
167	AF	Large Power and Lighting Service - Secondary	REVLPLS	388,159,549	0	0	0	0	0	0	0
168	AF	Large Power and Lighting Service - Primary	REVLPLP	74,444,444	0	0	0	0	0	0	0
169	AF	High Tension Service - Subtransmission	REVHTSS	49,205,760	0	0	0	0	0	0	0
170	AF	High Tension Service - High Voltage	REVHTSHV	2,891,829	0	0	0	0	0	0	0
171	AF	HEP	REVHEP	0	0	0	0	0	0	0	0
172	AF										
173	AF										
174	AF	Total Rev Req @ desired ROR	REVREQ	1,899,915,237	825,027,762	4,437,681	24,358,956	35,301,077	151,307	708,990	67,543,508
175	AF										
176	AF										
177	AF	**PRESENT REVENUES FROM SALES INPUT**									
178	AF										
179	AF	Total Sales of Electricity Revenues		0	0	0	0	0	0	0	0
180	AF	Sales of Electricity Revenues - Rates		1,254,696,745	597,284,000	4,407,000	7,778,000	52,355	161	740,000	56,059,000
181	AF	Sales of Electricity Revenues - Other		0	0	0	0	0	0	0	0
182	AF										
183	AF	**RATE OF RETURN**									
184	AF	Rate of Return (Equalized)	CALCULATED	7.55%	7.55%	7.55%	7.55%	7.55%	7.55%	7.55%	7.55%
185	AF	Expense Reclassification Plus-local	ADJ_Plus_04	17,563	0	0	0	7,136	111	0	0
186	AF	Expense Reclassification-local	ADJEXP_04	-17,563	-10,963	-42	-77	0	0	-7	-674

PUBLIC SERVICE ELECTRIC & GAS COMPANY
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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
151	AF	Total Labor	LABOR	23,511	2,614,469	28,127,951	29,731,969	5,221,656	4,304,516	1,168,758
152	AF									
153	AF	**REVENUES AND BILLING DETERMINANTS**								
154	AF									
155	AF	Base Rate Sales Revenue	SALESREV	741,039	27,345,651	399,597,683	388,159,549	74,444,444	49,205,760	2,891,829
156	AF									
157	AF	Residential Service	REVRS	0	0	0	0	0	0	0
158	AF	Residential Heating Service	REVRHS	0	0	0	0	0	0	0
159	AF	Residential Load Management Service	REVRLM	0	0	0	0	0	0	0
160	AF	Water Heating Service	REVWH	0	0	0	0	0	0	0
161	AF	Water Heating Storage Service	REVWHS	0	0	0	0	0	0	0
162	AF	Building Heating Service	REVHS	0	0	0	0	0	0	0
163	AF	Body Police Lighting Service	REVBLP	0	0	0	0	0	0	0
164	AF	Body Police Lighting Service from Publicly Owned	REVBLPPOF	741,039	0	0	0	0	0	0
165	AF	Private Street and Area Lighting Service	REVPAL	0	27,345,651	0	0	0	0	0
166	AF	General Power and Lighting Service	REVGLP	0	0	399,597,683	0	0	0	0
167	AF	Large Power and Lighting Service - Secondary	REVLPLS	0	0	0	388,159,549	0	0	0
168	AF	Large Power and Lighting Service - Primary	REVLPLP	0	0	0	0	74,444,444	0	0
169	AF	High Tension Service - Subtransmission	REVHTSS	0	0	0	0	0	49,205,760	0
170	AF	High Tension Service - High Voltage	REVHTSHV	0	0	0	0	0	0	2,891,829
171	AF	HEP	REVHEP	0	0	0	0	0	0	0
172	AF									
173	AF									
174	AF	Total Rev Req @ desired ROR	REVREQ	741,039	27,345,651	399,597,683	388,159,549	74,444,444	49,205,760	2,891,829
175	AF									
176	AF									
177	AF	**PRESENT REVENUES FROM SALES INPUT**								
178	AF									
179	AF	Total Sales of Electricity Revenues		0	0	0	0	0	0	0
180	AF	Sales of Electricity Revenues - Rates		322,229	27,815,000	264,859,000	223,909,000	38,961,000	30,175,000	2,335,000
181	AF	Sales of Electricity Revenues - Other		0	0	0	0	0	0	0
182	AF									
183	AF	**RATE OF RETURN**								
184	AF	Rate of Return (Equalized)	CALCULATED	7.55%	7.55%	7.55%	7.55%	7.55%	7.55%	7.55%
185	AF	Expense Reclassification Plus-local	ADJ_Plus_04	0	0	0	0	0	0	10,316
186	AF	Expense Reclassification-local	ADJEXP_04	-1	-283	-2,947	-1,955	-350	-262	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	AP	**ALLOCATION PROPORTIONS TABLE**									
2	AP	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**									
3	AP										
4	AP	**ALLOCATION FACTORS PART A**									
5	AP										
6	AP	Number of Customers x Aux &SL rates - local	CUSTNUMX_04	1.000000	0.863036	0.002998	0.005009	0.000000	0.000000	0.000000	0.000000
7	AP										
8	AP										
9	AP	CP @ secondary lines - local	CP_SEC_04	1.000000	0.499094	0.001607	0.005487	0.000000	0.000000	0.000357	0.000000
10	AP	CP @ 26 kV lines - switching station load -systems	CP_SUBT_05	1.000000	0.393469	0.001267	0.004325	0.000000	0.000000	0.000281	0.000000
11	AP	CP @ primary lines - systems	CP_PRI_05	1.000000	0.472435	0.001521	0.005194	0.000000	0.000000	0.000338	0.000000
12	AP	Sum Cust Peaks @ 26 kV lines - local	SUMPK_SUBT_04	1.000000	0.578954	0.003215	0.004814	0.000000	0.000000	0.001498	0.003180
13	AP	Sum Cust Peaks @ primary lines - local	SUMPK_PRI_04	1.000000	0.611737	0.003397	0.005086	0.000000	0.000000	0.001582	0.003360
14	AP	Sum Cust Peaks @ secondary lines - local	SUMPK_SEC_04	1.000000	0.577157	0.003205	0.004799	0.000000	0.000000	0.001493	0.003170
15	AP										
16	AP	CP @ primary lines - local	CP_PRI_04	1.000000	0.472435	0.001521	0.005194	0.000000	0.000000	0.000338	0.000000
17	AP	NCP @ meter - local	NCP_MTR_04	1.000000	0.411382	0.003117	0.005392	0.000115	0.000002	0.002402	0.006136
18	AP	NCP @ meter - measurement	NCP_MTR_07	1.000000	0.411382	0.003117	0.005392	0.000115	0.000002	0.002402	0.006136
19	AP	NCP @ meter - cust svs	NCP_MTR_06	1.000000	0.411382	0.003117	0.005392	0.000115	0.000002	0.002402	0.006136
20	AP	NCP x SL rates @ meter - measurement	NCPXSL_MTR_07	1.000000	0.415305	0.003147	0.005443	0.000116	0.000002	0.002425	0.000000
21	AP	**BILLING DETERMINANTS**									
22	AP										
23	AP	Number of Customers									
24	AP	Delivered kWh @ Meter - annual (w/n net)									
25	AP	Delivered Kw @ Meter - annual									
26	AP										
27	AP	**ALLOCATION FACTORS PART B**									
28	AP										
29	AP	Delivery kWh @ meter	KWHMETER_04	1.000000	0.335298	0.002290	0.004780	0.000014	0.000000	0.000291	0.006941
30	AP	Delivery kWh @ meter x non-profiled rates	KWHMETERX_04	1.000000	0.641341	0.004380	0.009143	0.000027	0.000000	0.000557	0.000000
31	AP	Delivery kWh @ subtrans - System E	KWH_SUBT_09	1.000000	0.239910	0.001639	0.003420	0.000010	0.000000	0.000208	0.004966
32	AP	Delivery kWh @ primary - System E	KWH_PRI_09	1.000000	0.387053	0.002644	0.005518	0.000017	0.000000	0.000336	0.008012
33	AP	Delivery kWh @ primary - Local E	KWH_PRI_10	1.000000	0.387053	0.002644	0.005518	0.000017	0.000000	0.000336	0.008012
34	AP	Delivery kWh @ secondary - Local E	KWH_SEC_10	1.000000	0.423311	0.002891	0.006035	0.000018	0.000000	0.000368	0.008763
35	AP	Delivery kWh @ meter - measurement	KWHMETER_07	1.000000	0.335584	0.002292	0.004784	0.000014	0.000000	0.000291	0.006947
36	AP	Delivery kWh @ meter - cust svs	KWHMETER_06	1.000000	0.335584	0.002292	0.004784	0.000014	0.000000	0.000291	0.006947
37	AP										
38	AP										
39	AP	**ALLOCATION FACTORS PART C**									
40	AP										
41	AP	Draft EC Proforma	ECPRO_07	1.000000	0.805602	0.002596	0.004336	0.000685	0.000011	0.000295	0.000000
42	AP	E587 Customer Installation Expenses Local	CUSINT_04	1.000000	0.892857	0.008929	0.008929	0.008929	0.008929	0.008929	0.008929
43	AP	E587 Customer Installation Expenses System	CUSINT_05	1.000000	0.892857	0.008929	0.008929	0.008929	0.008929	0.008929	0.008929
44	AP	E369 minimum Service investment- access	SERVICESMIN_03	1.000000	0.001567	0.009866	0.267508	0.617005	0.002618	0.000000	0.000000
45	AP	E369 excess Service investment- local delivery	SERVICESEXC_04	1.000000	0.440536	0.345456	0.002024	0.003381	0.000018	0.000000	0.000000
46	AP	Avg Customer Bills - local	CUSTAVG_04	1.000000	0.851985	0.002960	0.004945	0.000282	0.000004	0.000336	0.002103
47	AP	Avg Customer Bills - cust svs	CUSTAVG_06	1.000000	0.851985	0.002960	0.004945	0.000282	0.000004	0.000336	0.002103
48	AP	E370 minimum meter investment - measurement	METERSMIN_07	1.000000	0.577749	0.002007	0.003353	0.002245	0.000035	0.000228	0.000000
49	AP	E368 Line Transfomers - local	LNTRFRMR_04	1.000000	0.713915	0.005414	0.004536	0.000000	0.000000	0.000955	0.003098
50	AP	Billing Function costs - cust svs	BILLING_06	1.000000	0.722749	0.002511	0.004195	0.000048	0.000001	0.000057	0.003033

PUBLIC SERVICE ELECTRIC & GAS COMPANY
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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
1	AP	**ALLOCATION PROPORTIONS TABLE**								
2	AP	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**								
3	AP									
4	AP	**ALLOCATION FACTORS PART A**								
5	AP									
6	AP	Number of Customers x Aux &SL rates - local	CUSTNUMX_04	0.000000	0.000000	0.124406	0.004112	0.000343	0.000084	0.000011
7	AP									
8	AP									
9	AP	CP @ secondary lines - local	CP_SEC_04	0.000000	0.000000	0.270753	0.222703	0.000000	0.000000	0.000000
10	AP	CP @ 26 kV lines - switching station load -systems	CP_SUBT_05	0.000000	0.000000	0.213453	0.175572	0.044487	0.167146	0.000000
11	AP	CP @ primary lines - systems	CP_PRI_05	0.000000	0.000000	0.256290	0.210807	0.053415	0.000000	0.000000
12	AP	Sum Cust Peaks @ 26 kV lines - local	SUMPK_SUBT_04	0.000152	0.001563	0.175540	0.141599	0.035896	0.053590	0.000000
13	AP	Sum Cust Peaks @ primary lines - local	SUMPK_PRI_04	0.000160	0.001651	0.185480	0.149617	0.037928	0.000000	0.000000
14	AP	Sum Cust Peaks @ secondary lines - local	SUMPK_SEC_04	0.000151	0.001558	0.174996	0.141159	0.036741	0.055571	0.000000
15	AP									
16	AP	CP @ primary lines - local	CP_PRI_04	0.000000	0.000000	0.256290	0.210807	0.053415	0.000000	0.000000
17	AP	NCP @ meter - local	NCP_MTR_04	0.000332	0.002979	0.215221	0.185886	0.048108	0.080691	0.038238
18	AP	NCP @ meter - measurement	NCP_MTR_07	0.000332	0.002979	0.215221	0.185886	0.048108	0.080691	0.038238
19	AP	NCP @ meter - cust svs	NCP_MTR_06	0.000332	0.002979	0.215221	0.185886	0.048108	0.080691	0.038238
20	AP	NCP x SL rates @ meter - measurement	NCPXSL_MTR_07	0.000000	0.000000	0.217273	0.187659	0.048567	0.081461	0.038603
21	AP	**BILLING DETERMINANTS**								
22	AP									
23	AP	Number of Customers								
24	AP	Delivered kWh @ Meter - annual (w/n net)								
25	AP	Delivered Kw @ Meter - annual								
26	AP									
27	AP	**ALLOCATION FACTORS PART B**								
28	AP									
29	AP	Delivery kWh @ meter	KWHMETER_04	0.000375	0.003369	0.180134	0.259443	0.076184	0.114404	0.016476
30	AP	Delivery kWh @ meter x non-profiled rates	KWHMETERX_04	0.000000	0.000000	0.344551	0.000000	0.000000	0.000000	0.000000
31	AP	Delivery kWh @ subtrans - System E	KWH_SUBT_09	0.000268	0.002411	0.128279	0.185634	0.053091	0.380163	0.000000
32	AP	Delivery kWh @ primary - System E	KWH_PRI_09	0.000433	0.003889	0.206955	0.299489	0.085653	0.000000	0.000000
33	AP	Delivery kWh @ primary - Local E	KWH_PRI_10	0.000433	0.003889	0.206955	0.299489	0.085653	0.000000	0.000000
34	AP	Delivery kWh @ secondary - Local E	KWH_SEC_10	0.000474	0.004254	0.226342	0.327544	0.000000	0.000000	0.000000
35	AP	Delivery kWh @ meter - measurement	KWHMETER_07	0.000376	0.003372	0.179435	0.259664	0.076249	0.114501	0.016490
36	AP	Delivery kWh @ meter - cust svs	KWHMETER_06	0.000376	0.003372	0.179435	0.259664	0.076249	0.114501	0.016490
37	AP									
38	AP									
39	AP	**ALLOCATION FACTORS PART C**								
40	AP									
41	AP	Draft EC Proforma	ECPRO_07	0.000000	0.000000	0.186476	0.000000	0.000000	0.000000	0.000000
42	AP	E587 Customer Installation Expenses Local	CUSINT_04	0.008929	0.008929	0.008929	0.008929	0.008929	0.000000	0.008929
43	AP	E587 Customer Installation Expenses System	CUSINT_05	0.008929	0.008929	0.008929	0.008929	0.008929	0.000000	0.008929
44	AP	E369 minimum Service investment- access	SERVICESMIN_03	0.000000	0.000000	0.099089	0.001893	0.000454	0.000001	0.000000
45	AP	E369 excess Service investment- local delivery	SERVICESEXC_04	0.000000	0.000000	0.194742	0.012740	0.000517	0.000586	0.000000
46	AP	Avg Customer Bills - local	CUSTAVG_04	0.000038	0.010042	0.122813	0.004059	0.000338	0.000083	0.000011
47	AP	Avg Customer Bills - cust svs	CUSTAVG_06	0.000038	0.010042	0.122813	0.004059	0.000338	0.000083	0.000011
48	AP	E370 minimum meter investment - measurement	METERSMIN_07	0.000000	0.000000	0.345694	0.037510	0.009792	0.017432	0.003953
49	AP	E368 Line Transfomers - local	LNTRFRMR_04	0.000141	0.001350	0.140013	0.130578	0.000000	0.000000	0.000000
50	AP	Billing Function costs - cust svs	BILLING_06	0.000055	0.014481	0.177112	0.068465	0.005703	0.001401	0.000189

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
51	AP	E370 excess mtr invst - measrmnt	METERSEXC_07	1.000000	0.606307	0.002106	0.003519	0.000000	0.000000	0.000239	0.000000
52	AP	Avg Customer Bills - measurement	CUSTAVG_07	1.000000	0.856580	0.002976	0.004972	0.000284	0.000004	0.000338	0.002114
53	AP	Account Maint - cust svs	ACCTMAINT_06	1.000000	0.832962	0.002894	0.004835	0.000263	0.000004	0.000314	0.000238
54	AP	Meter Reading Costs - measurement	MRCOST_07	1.000000	0.787219	0.002735	0.004569	0.000052	0.000001	0.000062	0.000000
55	AP										
56	AP	Sales	SALES_06	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
57	AP	Other Utility work by Cust Ops - local	UTILWORK_04	1.000000	0.731132	0.002337	0.004988	0.000061	0.000001	0.000337	0.004998
58	AP	E370 excess meter investment - local delivery - Demand	METERSEXC_04	1.000000	0.606307	0.002106	0.003519	0.000000	0.000000	0.000239	0.000000
59	AP	E370 excess meter investment - local delivery - Energy	METERSEXC_10	1.000000	0.606307	0.002106	0.003519	0.000000	0.000000	0.000239	0.000000
60	AP										
61	AP	Choice - local	CHOICE_04	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
62	AP										
63	AP	Direct - PSAL - streetlighting	DIR_PSAL_02	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
64	AP	Direct - BPL - streetlighting	DIR_BPL_02	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000
65	AP	Direct - BPL-POF - streetlighting	DIR_BPLPOF_02	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
66	AP	Direct - HTS-HV - access	DIR_HTSHV_03	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
67	AP	Direct - HEP - access	DIR_HEP_03	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
68	AP	Direct - HTS-Sub - systems	DIR_HTSS_05	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
69	AP										
70	**AP**	**ALLOCATION FACTOR TABLE CONTINUED**									
71	**AP**	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**									
72	AP										
73	AP	Direct - HTS-Sub - local	DIR_HTSS_04	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
74	AP	Meter O&M - minimum - measurement	MTROMMIN_07	1.000000	0.501169	0.001741	0.002909	0.000477	0.000007	0.000198	0.000000
75	AP	Meter O&M - excess - measurement	MTROMEXC_07	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
76	AP	WN TEFA Responsibility	TEFA_04	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
77	AP	Meter O&M - measurement	METERPLT_07	1.000000	0.834095	0.002687	0.004490	0.000709	0.000011	0.000305	0.000000
78	AP										
79	AP	E370 excess meter investment - dummy	METERSEXC_08	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
80	AP	Meter O&M - excess - dummy	MTROMEXC_08	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
81	AP	E369 excess Service investment- dummy	SERVICESEXC_08	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
82	AP	E368 Line Transfomers - dummy	LNTRFRMR_08	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
83	AP	CP @ 26 kV lines - switching station load - dummy	CP@SUBT_08	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
84	AP	CP @ primary lines - dummy	CP@PRI_08	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
85	AP	Sum Cust Peaks @ secondary lines - local	SUMPK@SEC_08	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
86	AP										
87	AP										
88	AP	Dummy allocator for unused lines	not_used	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
89	AP										
90	AP	**Plant Related**									
91	AP	Distribution Plant Total	DISTPLT	1.000000	0.390782	0.002399	0.018115	0.030801	0.000131	0.000300	0.036756
92	AP	Distribution Plant x meters	DISTPLTXMTR	1.000000	0.383425	0.002410	0.018629	0.031866	0.000135	0.000302	0.038046
93	AP	Acct E360 - Land & Land Rights	E360PLT	1.000000	0.394769	0.001979	0.004980	0.000008	0.000000	0.000312	0.004059
94	AP	Acct E361 - Structures & Improvments	E361PLT	1.000000	0.394769	0.001979	0.004980	0.000008	0.000000	0.000312	0.004059
95	AP	Acct E362 - Station Equipment	E362PLT	1.000000	0.394769	0.001979	0.004980	0.000008	0.000000	0.000312	0.004059
96	AP	Acct E364 - Poles & Towers	E364PLT	1.000000	0.422000	0.002100	0.005309	0.000009	0.000000	0.000333	0.012149
97	AP	Acct E365 - OH Conductors & Devices x HTSHV	E365PLT	1.000000	0.417727	0.002058	0.005237	0.000008	0.000000	0.000329	0.004868
98	AP	Acct E366 - UG Conduit	E366PLT	1.000000	0.434187	0.002145	0.005486	0.000097	0.000000	0.000342	0.005997
99	AP	Acct E367 - UG Conductors & Devices x HEP	E367PLT	1.000000	0.434187	0.002145	0.005486	0.000097	0.000000	0.000342	0.005997
100	AP	Acct E369 Services	E369PLT	1.000000	0.001567	0.009866	0.267508	0.617005	0.002618	0.000000	0.000000

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
51	AP	E370 excess mtr invst - measrmnt	METERSEXC_07	0.000000	0.000000	0.305010	0.051383	0.026243	0.005192	0.000000
52	AP	Avg Customer Bills - measurement	CUSTAVG_07	0.000038	0.010096	0.118082	0.004081	0.000340	0.000084	0.000011
53	AP	Account Maint - cust svs	ACCTMAINT_06	0.000004	0.001134	0.124856	0.029368	0.002446	0.000601	0.000081
54	AP	Meter Reading Costs - measurement	MRCOST_07	0.000000	0.000000	0.192911	0.011253	0.000937	0.000230	0.000031
55	AP									
56	AP	Sales	SALES_06	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
57	AP	Other Utility work by Cust Ops - local	UTILWORK_04	0.000093	0.013559	0.224006	0.016539	0.001494	0.000419	0.000035
58	AP	E370 excess meter investment - local delivery - Demand	METERSEXC_04	0.000000	0.000000	0.305010	0.051383	0.026243	0.005192	0.000000
59	AP	E370 excess meter investment - local delivery - Energy	METERSEXC_10	0.000000	0.000000	0.305010	0.051383	0.026243	0.005192	0.000000
60	AP									
61	AP	Choice - local	CHOICE_04	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
62	AP									
63	AP	Direct - PSAL - streetlighting	DIR_PSAL_02	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
64	AP	Direct - BPL - streetlighting	DIR_BPL_02	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
65	AP	Direct - BPL-POF - streetlighting	DIR_BPLPOF_02	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
66	AP	Direct - HTS-HV - access	DIR_HTSHV_03	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000
67	AP	Direct - HEP - access	DIR_HEP_03	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
68	AP	Direct - HTS-Sub - systems	DIR_HTSS_05	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000
69	AP									
70	**AP**	**ALLOCATION FACTOR TABLE CONTINUED**								
71	**AP**	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**								
72	AP									
73	AP	Direct - HTS-Sub - local	DIR_HTSS_04	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000
74	AP	Meter O&M - minimum - measurement	MTROMMIN_07	0.000000	0.000000	0.069088	0.383557	0.031948	0.007850	0.001056
75	AP	Meter O&M - excess - measurement	MTROMEXC_07	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
76	AP	WN TEFA Responsibility	TEFA_04	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
77	AP	Meter O&M - measurement	METERPLT_07	0.000000	0.000000	0.134509	0.011842	0.003092	0.005503	0.002757
78	AP									
79	AP	E370 excess meter investment - dummy	METERSEXC_08	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000
80	AP	Meter O&M - excess - dummy	MTROMEXC_08	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
81	AP	E369 excess Service investment- dummy	SERVICESEXC_08	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
82	AP	E368 Line Transfomers - dummy	LNTRFRMR_08	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
83	AP	CP @ 26 kV lines - switching station load - dummy	CP@SUBT_08	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
84	AP	CP @ primary lines - dummy	CP@PRI_08	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
85	AP	Sum Cust Peaks @ secondary lines - local	SUMPK@SEC_08	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
86	AP									
87	AP									
88	AP	Dummy allocator for unused lines	not_used	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
89	AP									
90	AP	**Plant Related**								
91	AP	Distribution Plant Total	DISTPLT	0.000200	0.014080	0.215092	0.225407	0.040997	0.024912	0.000028
92	AP	Distribution Plant x meters	DISTPLTXMTR	0.000207	0.014575	0.211637	0.231619	0.041635	0.025515	0.000000
93	AP	Acct E360 - Land & Land Rights	E360PLT	0.000219	0.001971	0.212629	0.240386	0.065859	0.072828	0.000000
94	AP	Acct E361 - Structures & Improvments	E361PLT	0.000219	0.001971	0.212629	0.240386	0.065859	0.072828	0.000000
95	AP	Acct E362 - Station Equipment	E362PLT	0.000219	0.001971	0.212629	0.240386	0.065859	0.072828	0.000000
96	AP	Acct E364 - Poles & Towers	E364PLT	0.000230	0.003828	0.227330	0.255580	0.037871	0.033260	0.000000
97	AP	Acct E365 - OH Conductors & Devices x HTSHV	E365PLT	0.000221	0.004238	0.225073	0.251084	0.065347	0.023811	0.000000
98	AP	Acct E366 - UG Conduit	E366PLT	0.000231	0.002719	0.233945	0.261421	0.041149	0.012280	0.000000
99	AP	Acct E367 - UG Conductors & Devices x HEP	E367PLT	0.000231	0.002719	0.233945	0.261421	0.041149	0.012280	0.000000
100	AP	Acct E369 Services	E369PLT	0.000000	0.000000	0.099089	0.001893	0.000454	0.000001	0.000000

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
101	AP	Acct E370 Meters	METERPLT	1.000000	0.600343	0.002086	0.003485	0.000469	0.000007	0.000237	0.000000
102	AP	Acct E370 Meters x load profile meters	METERPLTXPR	1.000000	0.600343	0.002086	0.003485	0.000469	0.000007	0.000237	0.000000
103	AP	Acct E373 - Streetlights	E373PLT	1.000000	0.027834	0.000175	0.001352	0.002313	0.000010	0.000022	0.685169
104	AP	Subtrans Lines - HTS-S/Switching Station load	SUBTRANSLINES	1.000000	0.310447	0.001000	0.003413	0.000000	0.000000	0.000222	0.000000
105	AP	Primary Lines - 50 Sys CP/50 Loc Sum Cust Pks	PRIMARYLINES	1.000000	0.542086	0.002459	0.005140	0.000000	0.000000	0.000960	0.001680
106	AP										
107	AP	Acct E301-E303 Intangible Plt	INTANGPLT	1.000000	0.393602	0.002407	0.017929	0.030364	0.000129	0.000314	0.036288
108	AP										
109	AP	Acct E399.10-23 Oth Tangible Plt	TANGPLT	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
110	AP	E391-E398 General Plant	GENPLT	1.000000	0.383425	0.002410	0.018629	0.031866	0.000135	0.000302	0.038046
111	AP	Common Plant	COMPLT	1.000000	0.534815	0.002729	0.008543	0.008580	0.000037	0.000957	0.012725
112	AP	Accts C389-C399, E389-E399 Com & Gen Plt	COMGENPLT	1.000000	0.417896	0.002483	0.016332	0.026564	0.000113	0.000452	0.032281
113	AP										
114	AP	Total Plant	TOTPLT	1.000000	0.393602	0.002407	0.017929	0.030364	0.000129	0.000314	0.036288
115	AP										
116	AP	Total Distribution Plant Reserve	TOTDRESERVE	1.000000	0.389409	0.002690	0.026411	0.050294	0.000214	0.000322	0.033270
117	AP	Total Net Plant	TOTPLTNET	1.000000	0.395157	0.002302	0.014783	0.022972	0.000098	0.000311	0.037407
118	AP										
119	AP										
120	AP	**Revenue Related**									
121	AP	Total Operating Revenue	TOTREV	1.000000	0.433411	0.002331	0.012796	0.018545	0.000079	0.000374	0.035483
122	AP										
123	AP										
124	**AP**	**ALLOCATION FACTOR TABLE CONTINUED**									
125	**AP**	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**									
126	AP										
127	AP	**Expense Related**									
128	AP	Distr Oper Exp	DISTEXPO	1.000000	0.495855	0.002140	0.005029	0.000274	0.000004	0.000319	0.011073
129	AP	Distr Maint Exp	DISTEXPM	1.000000	0.376172	0.001857	0.004702	0.000025	0.000000	0.000295	0.070603
130	AP	Cust Serv & Info Expense	CUSTS_I	1.000000	0.789053	0.002665	0.004861	0.000176	0.000003	0.000310	0.002174
131	AP	Acct E901-E903,E905 Cust Acct Exp Excl 904	CACCTEXP	1.000000	0.578754	0.002855	0.004868	0.000092	0.000001	0.001245	0.003574
132	AP	Accts E901-E910 Excl 904 - Cust Accts,Serv & Info	CUSTSVSX	1.000000	0.589970	0.002845	0.004868	0.000096	0.000001	0.001195	0.003499
133	AP	Sales Expense	SALESEXP	1.000000	0.731132	0.002337	0.004988	0.000061	0.000001	0.000337	0.004998
134	AP	Total O&M Expense Excl 904-Uncollectibles	TOTOMXAG	1.000000	0.453277	0.002326	0.008836	0.009076	0.000039	0.000526	0.035111
135	AP	Tot Admin & Genl Exp xPension/Ben	A_GEXP	1.000000	0.434991	0.002459	0.015654	0.024889	0.000106	0.000368	0.037083
136	AP	Accts E901-E905 Cust Accts Exp Excl 904-Uncol	CUSTACCTS	1.000000	0.578754	0.002855	0.004868	0.000092	0.000001	0.001245	0.003574
137	AP	O&M + Capital Additions	EXPENDITURES	1.000000	0.424978	0.002188	0.009404	0.010722	0.000046	0.000372	0.042938
138	AP										
139	AP	Depreciation Expense (total)	DEPREXP	1.000000	0.394903	0.002410	0.017843	0.030160	0.000128	0.000322	0.036072
140	AP										
141	AP	NJ State Income Tax (CBT)	STATEINCTAX	1.000000	0.417612	0.002306	0.013948	0.021164	0.000090	0.000309	0.036343
142	AP	NJ State Deferred Income Tax	DFSTATEINCTAX	1.000000	0.507625	0.002308	0.004396	-0.000049	0.000001	0.000645	0.038076
143	AP										
144	AP	**Labor Expense Related**									
145	AP	Total Distribution Exp (Oper) Labor	TLABDO	1.000000	0.490268	0.001943	0.004039	0.000351	0.000005	0.000262	0.004906
146	AP	Total Distribution Exp (Maint) Labor	TLABDM	1.000000	0.365649	0.001909	0.004484	0.000436	0.000002	0.000307	0.123015
147	AP	Total Labor	LABOR	1.000000	0.506456	0.002309	0.004535	0.000263	0.000003	0.000642	0.038058
148	AP										
149	AP	**REVENUES AND BILLING DETERMINANTS**									
150	AP										

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
101	AP	Acct E370 Meters	METERPLT	0.000000	0.000000	0.313507	0.048486	0.022808	0.007748	0.000825
102	AP	Acct E370 Meters x load profile meters	METERPLTXPR	0.000000	0.000000	0.313507	0.048486	0.022808	0.007748	0.000825
103	AP	Acct E373 - Streetlights	E373PLT	0.000015	0.246058	0.015363	0.016814	0.003022	0.001852	0.000000
104	AP	Subtrans Lines - HTS-S/Switching Station load	SUBTRANSLINES	0.000000	0.000000	0.168414	0.138526	0.035100	0.342878	0.000000
105	AP	Primary Lines - 50 Sys CP/50 Loc Sum Cust Pks	PRIMARYLINES	0.000080	0.000826	0.220885	0.180212	0.045672	0.000000	0.000000
106	AP									
107	AP	Acct E301-E303 Intangible Plt	INTANGPLT	0.000199	0.013980	0.214627	0.223924	0.040772	0.025154	0.000311
108	AP									
109	AP	Acct E399.10-23 Oth Tangible Plt	TANGPLT	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
110	AP	E391-E398 General Plant	GENPLT	0.000207	0.014575	0.211637	0.231619	0.041635	0.025515	0.000000
111	AP	Common Plant	COMPLT	0.000163	0.008616	0.198883	0.145889	0.029460	0.035260	0.013344
112	AP	Accts C389-C399, E389-E399 Com & Gen Plt	COMGENPLT	0.000197	0.013218	0.208733	0.212098	0.038863	0.027733	0.003038
113	AP									
114	AP	Total Plant	TOTPLT	0.000199	0.013980	0.214627	0.223924	0.040772	0.025154	0.000311
115	AP									
116	AP	Total Distribution Plant Reserve	TOTDRESERVE	0.000189	0.012913	0.212977	0.212537	0.037210	0.020883	0.000682
117	AP	Total Net Plant	TOTPLTNET	0.000203	0.014376	0.215238	0.228147	0.042094	0.026738	0.000174
118	AP									
119	AP									
120	AP	**Revenue Related**								
121	AP	Total Operating Revenue	TOTREV	0.000389	0.014421	0.210734	0.204702	0.039259	0.025949	0.001525
122	AP									
123	AP									
124	**AP**	**ALLOCATION FACTOR TABLE CONTINUED**								
125	**AP**	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**								
126	AP									
127	AP	**Expense Related**								
128	AP	Distr Oper Exp	DISTEXPO	0.000173	0.003416	0.208229	0.204734	0.043702	0.024066	0.000988
129	AP	Distr Maint Exp	DISTEXPM	0.002960	0.033064	0.202595	0.224802	0.052519	0.030399	0.000006
130	AP	Cust Serv & Info Expense	CUSTS_I	0.000040	0.006487	0.164905	0.026440	0.002246	0.000572	0.000069
131	AP	Acct E901-E903,E905 Cust Acct Exp Excl 904	CACCTEXP	0.000153	0.006443	0.195888	0.119626	0.026308	0.040964	0.019228
132	AP	Accts E901-E910 Excl 904 - Cust Accts,Serv & Info	CUSTSVSX	0.000147	0.006445	0.194236	0.114656	0.025025	0.038810	0.018206
133	AP	Sales Expense	SALESEXP	0.000093	0.013559	0.224006	0.016539	0.001494	0.000419	0.000035
134	AP	Total O&M Expense Excl 904-Uncollectibles	TOTOMXAG	0.001306	0.017091	0.211415	0.182644	0.042626	0.031123	0.004604
135	AP	Tot Admin & Genl Exp xPension/Ben	A_GEXP	0.000232	0.014780	0.213926	0.188624	0.040017	0.025623	0.001247
136	AP	Accts E901-E905 Cust Accts Exp Excl 904-Uncol	CUSTACCTS	0.000153	0.006443	0.195888	0.119626	0.026308	0.040964	0.019228
137	AP	O&M + Capital Additions	EXPENDITURES	0.000547	0.017544	0.218847	0.203284	0.041774	0.025807	0.001549
138	AP									
139	AP	Depreciation Expense (total)	DEPREXP	0.000199	0.013939	0.214333	0.223280	0.040670	0.025286	0.000454
140	AP									
141	AP	NJ State Income Tax (CBT)	STATEINCTAX	0.000224	0.014015	0.214172	0.214684	0.039889	0.025099	0.000143
142	AP	NJ State Deferred Income Tax	DFSTATEINCTAX	0.000147	0.016468	0.176507	0.186603	0.032757	0.027091	0.007423
143	AP									
144	AP	**Labor Expense Related**								
145	AP	Total Distribution Exp (Oper) Labor	TLABDO	0.000095	0.001629	0.142666	0.300960	0.037534	0.014454	0.000890
146	AP	Total Distribution Exp (Maint) Labor	TLABDM	0.000212	0.045167	0.180720	0.205776	0.044473	0.027835	0.000016
147	AP	Total Labor	LABOR	0.000148	0.016442	0.176898	0.186985	0.032839	0.027071	0.007350
148	AP									
149	AP	**REVENUES AND BILLING DETERMINANTS**								
150	AP									

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
151	AP	Base Rate Sales Revenue	SALESREV	1.000000	0.434245	0.002336	0.012821	0.018580	0.000080	0.000373	0.035551
152	AP										
153	AP	Residential Service	REVRS	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
154	AP	Residential Heating Service	REVRHS	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
155	AP	Residential Load Management Service	REVRLM	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000
156	AP	Water Heating Service	REVWH	1.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000
157	AP	Water Heating Storage Service	REVWHS	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000
158	AP	Building Heating Service	REVHS	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000
159	AP	Body Police Lighting Service	REVBLP	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000
160	AP	Body Police Lighting Service from Publicly Owned	REVBLPPOF	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
161	AP	Private Street and Area Lighting Service	REVPAL	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
162	AP										
163	AP	General Power and Lighting Service	REVGLP	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
164	AP	Large Power and Lighting Service - Secondary	REVLPLS	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
165	AP	Large Power and Lighting Service - Primary	REVLPLP	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
166	AP	High Tension Service - Subtransmission	REVHTSS	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
167	AP	High Tension Service - High Voltage	REVHTSHV	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
168	AP	HEP	REVHEP	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
169	AP										
170	AP	Total Rev Req @ desired ROR	REVREQ	1.000000	0.434245	0.002336	0.012821	0.018580	0.000080	0.000373	0.035551
171	AP										
172	AP	**PRESENT REVENUES FROM SALES INPUT**									
173	AP										
174	AP	Total Sales of Electricity Revenues		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
175	AP	Sales of Electricity Revenues - Rates		1.000000	0.476039	0.003512	0.006199	0.000042	0.000000	0.000590	0.044679
176	AP	Sales of Electricity Revenues - Other		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
177	AP	Expense Reclassification Plus-local	ADJ_Plus_04	1.000000	0.000000	0.000000	0.000000	0.406337	0.006306	0.000000	0.000000
178	AP	Expense Reclassification-local	ADJEXP_04	1.000000	0.624242	0.002413	0.004379	0.000000	0.000000	0.000423	0.038400

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
151	AP	Base Rate Sales Revenue	SALESREV	0.000390	0.014393	0.210324	0.204304	0.039183	0.025899	0.001522
152	AP									
153	AP	Residential Service	REVRS	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
154	AP	Residential Heating Service	REVRHS	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
155	AP	Residential Load Management Service	REVRLM	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
156	AP	Water Heating Service	REVWH	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
157	AP	Water Heating Storage Service	REVWHS	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
158	AP	Building Heating Service	REVHS	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
159	AP	Body Police Lighting Service	REVBLP	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
160	AP	Body Police Lighting Service from Publicly Owned	REVBLPPOF	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
161	AP	Private Street and Area Lighting Service	REVPAL	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
162	AP									
163	AP	General Power and Lighting Service	REVGLP	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000
164	AP	Large Power and Lighting Service - Secondary	REVLPLS	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000
165	AP	Large Power and Lighting Service - Primary	REVLPLP	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000
166	AP	High Tension Service - Subtransmission	REVHTSS	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000
167	AP	High Tension Service - High Voltage	REVHTSHV	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000
168	AP	HEP	REVHEP	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
169	AP									
170	AP	Total Rev Req @ desired ROR	REVREQ	0.000390	0.014393	0.210324	0.204304	0.039183	0.025899	0.001522
171	AP									
172	AP	**PRESENT REVENUES FROM SALES INPUT**								
173	AP									
174	AP	Total Sales of Electricity Revenues		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
175	AP	Sales of Electricity Revenues - Rates		0.000257	0.022169	0.211094	0.178457	0.031052	0.024050	0.001861
176	AP	Sales of Electricity Revenues - Other		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
177	AP	Expense Reclassification Plus-local	ADJ_Plus_04	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.587357
178	AP	Expense Reclassification-local	ADJEXP_04	0.000059	0.016095	0.167800	0.111337	0.019957	0.014895	0.000000

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	ADA	**ALLOCATED DIRECT ASSIGNMENTS**									
2	ADA	**DIRECT ASSIGN TO CLASSES W/SALES REV FUNCTIONS**									
3	ADA										
4	ADA	**Net Write-Offs**									
5	ADA	Residential Service	REVRS	0	0	0	0	0	0	0	0
6	ADA	Residential Heating Service	REVRHS	0	0	0	0	0	0	0	0
7	ADA	Residential Load Management Service	REVRLM	0	0	0	0	0	0	0	0
8	ADA	Water Heating Service	REVWH	0	0	0	0	0	0	0	0
9	ADA	Water Heating Storage Service	REVWHS	0	0	0	0	0	0	0	0
10	ADA	Building Heating Service	REVHS	0	0	0	0	0	0	0	0
11	ADA	Body Police Lighting Service	REVBLP	0	0	0	0	0	0	0	0
12	ADA	Body Police Lighting Service from Publicly Owned	REVBLPPOF	0	0	0	0	0	0	0	0
13	ADA	Private Street and Area Lighting Service	REVPAL	0	0	0	0	0	0	0	0
14	ADA	General Power and Lighting Service	REVGLP	0	0	0	0	0	0	0	0
15	ADA	Large Power and Lighting Service - Secondary	REVLPLS	0	0	0	0	0	0	0	0
16	ADA	Large Power and Lighting Service - Primary	REVLPLP	0	0	0	0	0	0	0	0
17	ADA	High Tension Service - Subtransmission	REVHTSS	0	0	0	0	0	0	0	0
18	ADA	High Tension Service - High Voltage	REVHTSHV	0	0	0	0	0	0	0	0
19	ADA	HEP	REVHEP	0	0	0	0	0	0	0	0
20	ADA										
21	ADA	Total Write-Offs	EXP_904	0	0	0	0	0	0	0	0
22	ADA										
23	ADA	Total Write-Offs	EXP_904	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
24	ADA										
25	ADA	Additional Net Write-Offs at Claimed Rate	EXP_904	0	0	0	0	0	0	0	0
26	ADA										
27	ADA										
28	ADA	**Rev to Customers w/Late Payment fees**									
29	ADA	Residential Service	REVRS	0	0	0	0	0	0	0	0
30	ADA	Residential Heating Service	REVRHS	0	0	0	0	0	0	0	0
31	ADA	Residential Load Management Service	REVRLM	0	0	0	0	0	0	0	0
32	ADA	Water Heating Service	REVWH	0	0	0	0	0	0	0	0
33	ADA	Water Heating Storage Service	REVWHS	0	0	0	0	0	0	0	0
34	ADA	Building Heating Service	REVHS	708,990	0	0	0	0	0	708,990	0
35	ADA	Body Police Lighting Service	REVBLP	0	0	0	0	0	0	0	0
36	ADA	Body Police Lighting Service from Publicly Owned	REVBLPPOF	0	0	0	0	0	0	0	0
37	ADA	Private Street and Area Lighting Service	REVPAL	27,345,651	0	0	0	0	0	0	0
38	ADA	General Power and Lighting Service	REVGLP	399,597,683	0	0	0	0	0	0	0
39	ADA	Large Power and Lighting Service - Secondary	REVLPLS	388,159,549	0	0	0	0	0	0	0
40	ADA	Large Power and Lighting Service - Primary	REVLPLP	74,444,444	0	0	0	0	0	0	0
41	ADA	High Tension Service - Subtransmission	REVHTSS	49,205,760	0	0	0	0	0	0	0
42	ADA	High Tension Service - High Voltage	REVHTSHV	2,891,829	0	0	0	0	0	0	0
43	ADA	HEP	REVHEP	0	0	0	0	0	0	0	0
44	ADA										
45	ADA	Total Late Payment Fees	REVLATEP	942,353,907	0	0	0	0	0	708,990	0
46	ADA	Total Late Payment Fees	REVLATEP	1.000000						0.000752	
47	ADA										
48	ADA	**ALLOCATED DIRECT ASSIGNMENTS**									
49	ADA	DIRECT ASSIGN TO CLASSES W/SALES REV FUNCTIONS									
50	ADA										

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
1	ADA	**ALLOCATED DIRECT ASSIGNMENTS**								
2	ADA	**DIRECT ASSIGN TO CLASSES W/SALES REV FUNCTIONS**								
3	ADA									
4	ADA	**Net Write-Offs**								
5	ADA	Residential Service	REVRS	0	0	0	0	0	0	0
6	ADA	Residential Heating Service	REVRHS	0	0	0	0	0	0	0
7	ADA	Residential Load Management Service	REVRLM	0	0	0	0	0	0	0
8	ADA	Water Heating Service	REVWH	0	0	0	0	0	0	0
9	ADA	Water Heating Storage Service	REVWHS	0	0	0	0	0	0	0
10	ADA	Building Heating Service	REVHS	0	0	0	0	0	0	0
11	ADA	Body Police Lighting Service	REVBLP	0	0	0	0	0	0	0
12	ADA	Body Police Lighting Service from Publicly Owned	REVBLPPOF	0	0	0	0	0	0	0
13	ADA	Private Street and Area Lighting Service	REVPAL	0	0	0	0	0	0	0
14	ADA	General Power and Lighting Service	REVGLP	0	0	0	0	0	0	0
15	ADA	Large Power and Lighting Service - Secondary	REVLPLS	0	0	0	0	0	0	0
16	ADA	Large Power and Lighting Service - Primary	REVLPLP	0	0	0	0	0	0	0
17	ADA	High Tension Service - Subtransmission	REVHTSS	0	0	0	0	0	0	0
18	ADA	High Tension Service - High Voltage	REVHTSHV	0	0	0	0	0	0	0
19	ADA	HEP	REVHEP	0	0	0	0	0	0	0
20	ADA									
21	ADA	Total Write-Offs	EXP_904	0	0	0	0	0	0	0
22	ADA									
23	ADA	Total Write-Offs	EXP_904	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
24	ADA									
25	ADA	Additional Net Write-Offs at Claimed Rate	EXP_904	0	0	0	0	0	0	0
26	ADA									
27	ADA									
28	ADA	**Rev to Customers w/Late Payment fees**								
29	ADA	Residential Service	REVRS	0	0	0	0	0	0	0
30	ADA	Residential Heating Service	REVRHS	0	0	0	0	0	0	0
31	ADA	Residential Load Management Service	REVRLM	0	0	0	0	0	0	0
32	ADA	Water Heating Service	REVWH	0	0	0	0	0	0	0
33	ADA	Water Heating Storage Service	REVWHS	0	0	0	0	0	0	0
34	ADA	Building Heating Service	REVHS	0	0	0	0	0	0	0
35	ADA	Body Police Lighting Service	REVBLP	0	0	0	0	0	0	0
36	ADA	Body Police Lighting Service from Publicly Owned	REVBLPPOF	0	0	0	0	0	0	0
37	ADA	Private Street and Area Lighting Service	REVPAL	0	27,345,651	0	0	0	0	0
38	ADA	General Power and Lighting Service	REVGLP	0	0	399,597,683	0	0	0	0
39	ADA	Large Power and Lighting Service - Secondary	REVLPLS	0	0	0	388,159,549	0	0	0
40	ADA	Large Power and Lighting Service - Primary	REVLPLP	0	0	0	0	74,444,444	0	0
41	ADA	High Tension Service - Subtransmission	REVHTSS	0	0	0	0	0	49,205,760	0
42	ADA	High Tension Service - High Voltage	REVHTSHV	0	0	0	0	0	0	2,891,829
43	ADA	HEP	REVHEP	0	0	0	0	0	0	0
44	ADA									
45	ADA	Total Late Payment Fees	REVLATEP	0	27,345,651	399,597,683	388,159,549	74,444,444	49,205,760	2,891,829
46	ADA	Total Late Payment Fees	REVLATEP		0.029018	0.424042	0.411904	0.078998	0.052216	0.003069
47	ADA									
48	ADA	**ALLOCATED DIRECT ASSIGNMENTS**								
49	ADA	DIRECT ASSIGN TO CLASSES W/SALES REV FUNCTIONS								
50	ADA									

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
51	ADA	**AVAILABLE**									
52	ADA	Residential Service	REVRS	0	0	0	0	0	0	0	0
53	ADA	Residential Heating Service	REVRHS	0	0	0	0	0	0	0	0
54	ADA	Residential Load Management Service	REVRLM	0	0	0	0	0	0	0	0
55	ADA	Water Heating Service	REVWH	0	0	0	0	0	0	0	0
56	ADA	Water Heating Storage Service	REVWHS	0	0	0	0	0	0	0	0
57	ADA	Building Heating Service	REVHS	0	0	0	0	0	0	0	0
58	ADA	Body Police Lighting Service	REVBLP	0	0	0	0	0	0	0	0
59	ADA	Body Police Lighting Service from Publicly Owned	REVBLPPOF	0	0	0	0	0	0	0	0
60	ADA	Private Street and Area Lighting Service	REVPAL	0	0	0	0	0	0	0	0
61	ADA	General Power and Lighting Service	REVGLP	0	0	0	0	0	0	0	0
62	ADA	Large Power and Lighting Service - Secondary	REVLPLS	0	0	0	0	0	0	0	0
63	ADA	Large Power and Lighting Service - Primary	REVLPLP	0	0	0	0	0	0	0	0
64	ADA	High Tension Service - Subtransmission	REVHTSS	0	0	0	0	0	0	0	0
65	ADA	High Tension Service - High Voltage	REVHTSHV	0	0	0	0	0	0	0	0
66	ADA	HEP	REVHEP	0	0	0	0	0	0	0	0
67	ADA										
68	ADA	Total Available	REVAVAIL	0	0	0	0	0	0	0	0
69	ADA	Total Available	REVAVAIL	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
51	ADA	**AVAILABLE**								
52	ADA	Residential Service	REVRS	0	0	0	0	0	0	0
53	ADA	Residential Heating Service	REVRHS	0	0	0	0	0	0	0
54	ADA	Residential Load Management Service	REVRLM	0	0	0	0	0	0	0
55	ADA	Water Heating Service	REVWH	0	0	0	0	0	0	0
56	ADA	Water Heating Storage Service	REVWHS	0	0	0	0	0	0	0
57	ADA	Building Heating Service	REVHS	0	0	0	0	0	0	0
58	ADA	Body Police Lighting Service	REVBLP	0	0	0	0	0	0	0
59	ADA	Body Police Lighting Service from Publicly Owned	REVBLPPOF	0	0	0	0	0	0	0
60	ADA	Private Street and Area Lighting Service	REVPAL	0	0	0	0	0	0	0
61	ADA	General Power and Lighting Service	REVGLP	0	0	0	0	0	0	0
62	ADA	Large Power and Lighting Service - Secondary	REVLPLS	0	0	0	0	0	0	0
63	ADA	Large Power and Lighting Service - Primary	REVLPLP	0	0	0	0	0	0	0
64	ADA	High Tension Service - Subtransmission	REVHTSS	0	0	0	0	0	0	0
65	ADA	High Tension Service - High Voltage	REVHTSHV	0	0	0	0	0	0	0
66	ADA	HEP	REVHEP	0	0	0	0	0	0	0
67	ADA									
68	ADA	Total Available	REVAVAIL	0	0	0	0	0	0	0
69	ADA	Total Available	REVAVAIL	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	RRW	**REVENUE REQUIREMENTS**									
2	RRW										
3	RRW	PRESENT RATES									
4	RRW	--									
5	RRW	RATE BASE		9,785,622,095	4,165,943,983	22,505,436	130,127,297	192,606,679	824,852	3,076,333	350,980,110
6	RRW	NET OPER INC (PRESENT RATES)		738,814,468	314,528,771	1,699,160	9,824,611	14,541,804	62,276	232,263	26,498,998
7	RRW	RATE OF RETURN (PRES RATES)		7.55%	7.55%	7.55%	7.55%	7.55%	7.55%	7.55%	7.55%
8	RRW	RELATIVE RATE OF RETURN		1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
9	RRW	SALES REVENUE (PRE RATES)		1,899,915,237	825,027,762	4,437,681	24,358,956	35,301,077	151,307	708,990	67,543,508
10	RRW	REVENUE PRES RATES $/KWH		$0.0465	$0.0603	$0.0475	$0.1248	$60.3647	$21.1634	$0.0596	$0.2384
11	RRW	REVENUE REQUIRED - $/MO/CUST		$67.42	$34.37	$53.21	$174.81	$4,440.95	$1,220.22	$74.84	$1,139.82
12	RRW	SALES REV REQUIRED $/KW		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	RRW										
14	RRW	CLAIMED RATE OF RETURN									
15	RRW	--									
16	RRW	CLAIMED RATE OF RETURN		7.55%	7.55%	7.55%	7.55%	7.55%	7.55%	7.55%	7.55%
17	RRW	RETURN REQ FOR CLAIMED ROR		738,814,468	314,528,771	1,699,160	9,824,611	14,541,804	62,276	232,263	26,498,998
18	RRW	SALES REVENUE REQ CLAIMED ROR		1,899,915,237	825,027,762	4,437,681	24,358,956	35,301,077	151,307	708,990	67,543,508
19	RRW	REVENUE DEFICIENCY SALES REV		0							
20	RRW	PERCENT INCREASE REQUIRED		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
21	RRW	ANNUAL BOOKED KWH SALES		40,816,033,564	13,685,554,460	93,469,833	195,107,964	584,797	7,149	11,887,502	283,298,553
22	RRW	SALES REV REQUIRED $/KWH		$0.0465	$0.0603	$0.0475	$0.1248	$60.3647	$21.1634	$0.0596	$0.2384
23	RRW	REVENUE DEFICIENCY $/KWH									

PUBLIC SERVICE ELECTRIC & GAS COMPANY
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12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
1	RRW	**REVENUE REQUIREMENTS**								
2	RRW									
3	RRW	PRESENT RATES								
4	RRW	--								
5	RRW	RATE BASE		2,257,009	135,830,682	2,092,733,396	2,058,242,336	384,267,442	243,670,921	2,555,619
6	RRW	NET OPER INC (PRESENT RATES)		170,404	10,255,216	158,001,371	155,397,296	29,012,192	18,397,155	192,949
7	RRW	RATE OF RETURN (PRES RATES)		7.55%	7.55%	7.55%	7.55%	7.55%	7.55%	7.55%
8	RRW	RELATIVE RATE OF RETURN		1.00	1.00	1.00	1.00	1.00	1.00	1.00
9	RRW	SALES REVENUE (PRE RATES)		741,039	27,345,651	399,597,683	388,159,549	74,444,444	49,205,760	2,891,829
10	RRW	REVENUE PRES RATES $/KWH		$0.0484	$0.1988	$0.0543	$0.0367	$0.0239	$0.0105	$0.0043
11	RRW	REVENUE REQUIRED - $/MO/CUST		$687.42	$96.64	$115.47	$3,393.33	$7,813.23	$21,019.12	$9,180.41
12	RRW	SALES REV REQUIRED $/KW		0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	RRW									
14	RRW	CLAIMED RATE OF RETURN								
15	RRW	--								
16	RRW	CLAIMED RATE OF RETURN		7.55%	7.55%	7.55%	7.55%	7.55%	7.55%	7.55%
17	RRW	RETURN REQ FOR CLAIMED ROR		170,404	10,255,216	158,001,371	155,397,296	29,012,192	18,397,155	192,949
18	RRW	SALES REVENUE REQ CLAIMED ROR		741,039	27,345,651	399,597,683	388,159,549	74,444,444	49,205,760	2,891,829
19	RRW	REVENUE DEFICIENCY SALES REV					0			
20	RRW	PERCENT INCREASE REQUIRED		0.0	0.0	0.0	0.0	0.0	0.0	0.0
21	RRW	ANNUAL BOOKED KWH SALES		15,313,401	137,520,699	7,352,369,374	10,589,422,620	3,109,525,559	4,669,504,753	672,466,899
22	RRW	SALES REV REQUIRED $/KWH		$0.0484	$0.1988	$0.0543	$0.0367	$0.0239	$0.0105	$0.0043
23	RRW	REVENUE DEFICIENCY $/KWH								

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PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 STAFF ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement	System Delivery Energy	Local Delivery Energy
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	S	**SUMMARY OF RESULTS**										
2	S	**DEVELOPMENT OF RETURN**										
3	S											
4	S	**RATE BASE**										
5	S	Plant in Service										
6	S	Production Plant E310-E346	CALCULATED	0	0	0	0	0	0	0	0	0
7	S	Transmission Plant E350-E359	CALCULATED	0	0	0	0	0	0	0	0	0
8	S	Distribution Plant										
9	S	Land & Structures E360-E361	CALCULATED	293,570,614	0	0	0	125,606,741	0	0	167,963,873	0
10	S	Station Equipment E362	CALCULATED	1,565,418,169	0	0	0	669,777,783	0	0	895,640,386	0
11	S	Poles, Towers, and Fixtures E364	CALCULATED	1,027,443,483	9,926,985	0	324,132,007	138,764,932	0	0	203,883,749	350,735,810
12	S	OH Conductors and Devices E365	CALCULATED	2,856,184,590	8,663,157	0	676,089,548	658,973,011	0	0	804,510,629	707,948,244
13	S	UG Conductors E366	CALCULATED	512,107,003	1,209,731	73,522	167,477,027	74,353,110	0	0	88,369,620	180,623,992
14	S	UG Conduits and Devices E367	CALCULATED	1,431,183,475	3,380,831	205,472	468,047,404	207,794,351	0	0	246,966,239	504,789,178
15	S	Line Transformers E368	CALCULATED	1,591,690,631	0	0	756,053,050	0	0	0	0	835,637,581
16	S	Services E369	CALCULATED	535,269,333	0	535,269,333	0	0	0	0	0	0
17	S	Meters E370	CALCULATED	365,421,442	0	0	122,177,671	0	0	76,316,914	0	166,926,857
18	S	Street Lighting E373	CALCULATED	499,027,153	464,501,858	1,870,457	8,459,940	6,595,096	0	0	8,474,749	9,125,053
19	S	Asset Retirement Obligations E374	CALCULATED	96,512,525	932,488	0	30,447,221	13,034,833	0	0	19,151,745	32,946,239
20	S	Other Distribution and Unallocated Plant	CALCULATED	0	0	0	0	0	0	0	0	0
21	S	Total Distribution Plant	CALCULATED	10,773,828,418	488,615,049	537,418,784	2,552,883,868	1,894,899,857	0	76,316,914	2,434,960,990	2,788,732,956
22	S	General Plant E389-E399	CALCULATED	429,584,593	20,166,534	22,180,803	100,322,166	78,207,913	0	0	100,497,773	108,209,403
23	S	Common Plant C389-C399	CALCULATED	126,654,044	1,587,719	1,746,304	11,272,300	6,157,341	72,130,276	17,328,503	7,912,231	8,519,370
24	S	Intangible Plant E301-E303, E399, C303-C390	CALCULATED	126,923,895	1,837,456	2,020,984	12,674,013	7,125,844	66,251,423	17,404,589	9,156,764	10,452,822
25	S	Total Plant in Service	CALCULATED	11,456,990,950	512,206,759	563,366,875	2,677,152,347	1,986,390,954	138,381,700	111,050,006	2,552,527,759	2,915,914,551
26	S											
27	S	Less: Reserve for Depreciation and Amorization	CALCULATED	3,099,332,698	126,416,094	252,481,133	742,150,688	455,781,716	84,778,006	49,872,573	577,895,582	809,956,907
28	S	Plus: Rate Base Additions										
29	S	Working Capital	CALCULATED	1,183,336,038	65,488,137	20,448,649	254,784,343	189,586,989	72,158,236	48,151,051	242,433,583	290,285,051
30	S	Plant Held for Future Use	CALCULATED	489,291	21,875	24,060	114,333	84,832	5,910	4,743	109,010	124,529
31	S	Capital Stimulus	CALCULATED	0	0	0	0	0	0	0	0	0
32	S	Other Rate Base Deductions		-40,898,861	-124,051	0	-9,681,199	-9,436,101	0	0	-11,520,113	-10,137,397
33	S	Other Rate Base Additions		2,066,897,171	64,136,153	65,591,953	330,675,480	249,461,926	4,588,649	670,733,041	320,840,127	360,869,842
34	S	Customer Advances	CALCULATED	-63,907,492	-2,850,605	-1,916,201	-12,647,114	-10,246,307	-3,995,924	-5,391,590	-13,153,291	-13,706,460
35	S	Unbilled Revenue	CALCULATED	0	0	0	0	0	0	0	0	0
36	S	Deferred Income Taxes and Credits	CALCULATED	-1,717,952,304	-76,273,908	-83,983,095	-398,479,399	-295,770,531	-31,604,346	-18,529,319	-380,061,189	-433,250,518
37	S											
38	S	Plus: Rate Base Deductions										
39	S	TOTAL RATE BASE		9,785,622,095	436,188,265	311,051,108	2,099,768,101	1,654,290,047	94,756,219	756,145,359	2,133,280,305	2,300,142,691
40	S											
41	S	**SUMMARY OF RESULTS**										
42	S	**DEVELOPMENT OF RETURN**	CALCULATED									
43	S											
44	S	**RATE BASE**	CALCULATED	9,785,622,095	436,188,265	311,051,108	2,099,768,101	1,654,290,047	94,756,219	756,145,359	2,133,280,305	2,300,142,691
45	S											
46	S	**OPERATING REVENUES**										
47	S	Rate Revenues from Customers	CALCULATED	1,899,915,237	84,746,048	56,967,015	375,987,929	304,613,976	118,795,402	160,287,388	391,036,114	407,481,364
48	S	Other Operating Revenues	CALCULATED	25,104,439	1,046,954	664,533	4,976,270	4,060,468	1,525,436	1,961,974	5,378,563	5,490,243
49	S	Revenues from Other Sources	CALCULATED	0	0	0	0	0	0	0	0	0
50	S	Less: Provisions for Rate Refunds	CALCULATED	0	0	0	0	0	0	0	0	0
51	S	TOTAL OPERATING REVENUES		1,925,019,676	85,793,001	57,631,548	380,964,199	308,674,444	120,320,838	162,249,361	396,414,677	412,971,607
52	S											
53	S	**OPERATING EXPENSES**										
54	S	Operation and Maintenance Expense										
55	S	Production Expense	CALCULATED	0	0	0	0	0	0	0	0	0
56	S	Transmission Expense	CALCULATED	0	0	0	0	0	0	0	0	0
57	S	Distribution Expense	CALCULATED	178,009,259	13,223,105	74,179	23,979,432	38,515,543	0	18,936,951	48,738,710	34,541,340
58	S	Customer Accounts Expense	CALCULATED	94,394,062	0	0	1,613,601	0	74,167,825	18,612,636	0	0
59	S	Customer Service & Information Expense	CALCULATED	5,318,001	0	0	2,010,317	0	3,307,684	0	0	0
60	S	Sales Expense	CALCULATED	40,922	0	0	40,922	0	0	0	0	0

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				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
61	S	Administrative and General Expense	CALCULATED	33,695,393	1,398,526	4,477,117	16,010,625	11,217,092	-18,654,913	-13,632,314	14,300,245	18,579,015
62	S	Total Operation and Maintenance Expense	CALCULATED	311,457,637	14,621,631	4,551,297	43,654,897	49,732,635	58,820,596	23,917,272	63,038,955	53,120,355
63	S	Depreciation Expense	CALCULATED	286,771,855	12,734,767	14,006,738	66,520,119	49,386,749	5,248,426	3,086,796	63,462,355	72,325,904
64	S	Amortization Expense	CALCULATED	21,391,564	285,087	313,561	1,957,050	1,105,595	11,519,706	3,260,152	1,420,698	1,529,715
65	S	Taxes Other Than Income Taxes	CALCULATED	-11,551,217	-552,284	-15,914	-1,497,165	-974,202	-3,518,188	-2,817,799	-1,234,195	-941,470
66	S	Proforma Expense Adjustments	CALCULATED	82,048,703	2,779,569	1,820,864	12,078,656	8,441,194	7,819,611	26,976,034	10,813,290	11,319,486
67	S	State Income Taxes	CALCULATED	119,869,746	5,407,751	4,100,306	26,349,476	20,673,847	596,678	7,268,777	26,653,389	28,819,521
68	S	Federal Income Taxes	CALCULATED	231,691,305	10,468,545	7,591,133	50,652,540	39,965,407	849,079	15,188,273	51,541,301	55,435,027
69	S	Provision for Deferred Income Taxes	CALCULATED	144,525,616	7,115,721	1,779,204	22,716,135	15,444,321	31,830,837	28,280,881	19,656,221	17,702,297
70	S	Income Taxes Deferred in Prior Years	CALCULATED	0	0	0	0	0	0	0	0	0
71	S	Investment Tax Credit Adjustement (Net)	CALCULATED	0	0	0	0	0	0	0	0	0
72	S	TOTAL OPERATING EXPENSES		1,186,205,208	52,860,787	34,147,190	222,431,707	183,775,546	113,166,744	105,160,387	235,352,014	239,310,834
73	S											
74	S	**OPERATING INCOME (RETURN)**		738,814,468	32,932,214	23,484,359	158,532,492	124,898,899	7,154,095	57,088,975	161,062,663	173,660,773
75	S	Plus Operating Income Adjustment	CALCULATED	0	0	0	0	0	0	0	0	0
76	S	TOTAL NET OPERATING INCOME		738,814,468	32,932,214	23,484,359	158,532,492	124,898,899	7,154,095	57,088,975	161,062,663	173,660,773
77	S											
78	S	**RATE OF RETURN ON RATE BASE (PRESENT)**		7.55%	7.55%	7.55%	7.55%	7.55%	7.55%	7.55%	7.55%	7.55%
79	S	**INDEX RATE OF RETURN (PRESENT)**		1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
80	S											
81	S	**EQUALIZED RETURN AT PROPOSED ROR**										
82	S											
83	S	**DEVELOPMENT OF RETURN (EQUALIZED RATE LEVELS**										
84	S											
85	S	**RATE BASE**	CALCULATED	9,785,622,095	436,188,265	311,051,108	2,099,768,101	1,654,290,047	94,756,219	756,145,359	2,133,280,305	2,300,142,691
86	S											
87	S	**RATE OF RETURN**		7.55%	7.55%	7.55%	7.55%	7.55%	7.55%	7.55%	7.55%	7.55%
88	S											
89	S	**RETURN (RATE BASE * 7.40% ROR)**		738,814,468	32,932,214	23,484,359	158,532,492	124,898,899	7,154,095	57,088,975	161,062,663	173,660,773
90	S											
91	S	**PLUS:**	CALCULATED									
92	S	**OPERATING EXPENSES**										
93	S	Total Operation and Maintenance Expense	CALCULATED	311,457,637	14,621,631	4,551,297	43,654,897	49,732,635	58,820,596	23,917,272	63,038,955	53,120,355
94	S	Depreciation Expense	CALCULATED	286,771,855	12,734,767	14,006,738	66,520,119	49,386,749	5,248,426	3,086,796	63,462,355	72,325,904
95	S	Amortization Expense	CALCULATED	21,391,564	285,087	313,561	1,957,050	1,105,595	11,519,706	3,260,152	1,420,698	1,529,715
96	S	Taxes Other Than Income Taxes	CALCULATED	-11,551,217	-552,284	-15,914	-1,497,165	-974,202	-3,518,188	-2,817,799	-1,234,195	-941,470
97	S	Proforma Expense Adjustments	CALCULATED	82,048,703	2,779,569	1,820,864	12,078,656	8,441,194	7,819,611	26,976,034	10,813,290	11,319,486
98	S	Income Taxes	CALCULATED	351,561,051	15,876,296	11,691,439	77,002,016	60,639,254	1,445,757	22,457,050	78,194,689	84,254,548
99	S	Provision for Deferred Income Taxes	CALCULATED	144,525,616	7,115,721	1,779,204	22,716,135	15,444,321	31,830,837	28,280,881	19,656,221	17,702,297
100	S	Income Taxes Deferred in Prior Years	CALCULATED	0	0	0	0	0	0	0	0	0
101	S	Investment Tax Credit Adjustement (Net)	CALCULATED	0	0	0	0	0	0	0	0	0
102	S	**TOTAL OPERATING EXPENSES**		1,186,205,208	52,860,787	34,147,190	222,431,707	183,775,546	113,166,744	105,160,387	235,352,014	239,310,834
103	S											
104	S	**EQUALS TOTAL COST OF SERVICE**		1,925,019,676	85,793,001	57,631,548	380,964,199	308,674,444	120,320,838	162,249,361	396,414,677	412,971,607
105	S											
106	S	**LESS:**										
107	S	Other Operating Revenues	CALCULATED	25,104,439	1,046,954	664,533	4,976,270	4,060,468	1,525,436	1,961,974	5,378,563	5,490,243
108	S	Revenues from Other Sources	CALCULATED	0	0	0	0	0	0	0	0	0
109	S	Plus: Provisions for Rate Refunds		0	0	0	0	0	0	0	0	0
110	S	**EQUALS:**										
111	S	**BASE RATE SALES @ EQUALIZED ROR 7.40%**		1,899,915,237	84,746,048	56,967,015	375,987,929	304,613,976	118,795,402	160,287,388	391,036,114	407,481,364
112	S											
113	S	**TOTAL COST OF SERVICE INCREASE/DECREASE**		0	0	0	0	0	0	0	0	0
114	S	**REVENUE INCREASE TO RETAIL REVENUES (%)**										

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				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	RBP	**DEVELOPMENT OF RATE BASE**										
2	RBP											
3	RBP	**ELECTRIC PLANT IN SERVICE**										
4	RBP											
5	RBP	PRODUCTION PLANT										
6	RBP	E304-E346 - Production Plant	not_used	0	0	0	0	0	0	0	0	0
7	RBP	Not Used	not_used	0	0	0	0	0	0	0	0	0
8	RBP	TOTAL PRODUCTION PLANT		0	0	0	0	0	0	0	0	0
9	RBP											
10	RBP	TRANSMISSION PLANT										
11	RBP	E350 Land & Land Rights	not_used	0	0	0	0	0	0	0	0	0
12	RBP	E352 Structures & Improvements	not_used	0	0	0	0	0	0	0	0	0
13	RBP	E353 Station Equipment	not_used	0	0	0	0	0	0	0	0	0
14	RBP	E354/E355 Towers and Fixtures	not_used	0	0	0	0	0	0	0	0	0
15	RBP	E356-E359 Transmission Plant - Others	not_used	0	0	0	0	0	0	0	0	0
16	RBP	TOTAL TRANSMISSION PLANT		0	0	0	0	0	0	0	0	0
17	RBP											
18	RBP	DISTRIBUTION PLANT										
19	RBP	E360-E361 Land & Structures										
20	RBP	E360 - Land and Land Rights										
21	RBP	- Headquarters related	E362PLT	14,080,608	0	0	0	6,024,510	0	0	8,056,097	0
22	RBP	- Direct - HTS-HV	E362PLT	0	0	0	0	0	0	0	0	0
23	RBP	- Direct - HEP	E362PLT	0	0	0	0	0	0	0	0	0
24	RBP	- Substation related	E362PLT	37,233,560	0	0	0	15,930,703	0	0	21,302,857	0
25	RBP	E361 - Structures and improvements										
26	RBP	- Headquarters related	E362PLT	124,204,880	0	0	0	53,142,139	0	0	71,062,742	0
27	RBP	- Substation related	E362PLT	118,051,566	0	0	0	50,509,390	0	0	67,542,177	0
28	RBP	Total Accounts E360-E361		293,570,614	0	0	0	125,606,741	0	0	167,963,873	0
29	RBP	E362 - Station Equipment										
30	RBP	Switching Stations - Energy Related - System		269,637,863	0	0	0	0	0	0	269,637,863	0
31	RBP	Switching Stations - Demand Related - System		68,805,545	0	0	0	68,805,545	0	0	0	0
32	RBP	H Class Substations - Energy Related - System		626,002,523	0	0	0	0	0	0	626,002,523	0
33	RBP	H Class Substations - Demand Related - System		600,972,238	0	0	0	600,972,238	0	0	0	0
34	RBP	4 kV Class Substations - Energy Related - System		0	0	0	0	0	0	0	0	0
35	RBP	4 kV Class Substations - Demand Related - System		0	0	0	0	0	0	0	0	0
36	RBP	Total Account E362		1,565,418,169	0	0	0	669,777,783	0	0	895,640,386	0
37	RBP	E364 - Poles Towers & Fixtures										
38	RBP	Streetlight poles - direct to BPL	DIR_BPL_02	8,114,160	8,114,160	0	0	0	0	0	0	0
39	RBP	Streetlight poles - direct to PSAL	DIR_PSAL_02	1,812,825	1,812,825	0	0	0	0	0	0	0
40	RBP	Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0	0	0
41	RBP	Subtransmission lines - Energy Related - System		80,822,343	0	0	0	0	0	0	80,822,343	0
42	RBP	Subtransmission lines - Demand Related - System		20,624,052	0	0	0	20,624,052	0	0	0	0
43	RBP	Primary Lines - Energy Related - Local		123,061,406	0	0	0	0	0	0	0	123,061,406
44	RBP	Primary Lines - Energy Related - System		123,061,406	0	0	0	0	0	0	123,061,406	0
45	RBP	Primary Lines - Demand Related - Local		118,140,880	0	0	118,140,880	0	0	0	0	0
46	RBP	Primary Lines - Demand Related - System		118,140,880	0	0	0	118,140,880	0	0	0	0
47	RBP	Secondary Lines - Energy Related - Local		227,674,404	0	0	0	0	0	0	0	227,674,404
48	RBP	Secondary Lines - Demand Related - Local		205,991,127	0	0	205,991,127	0	0	0	0	0
49	RBP	Total Account E364		1,027,443,483	9,926,985	0	324,132,007	138,764,932	0	0	203,883,749	350,735,810
50	RBP	**ELECTRIC PLANT IN SERVICE CONTINUED**										
51	RBD											
52	RBP	DISTRIBUTION PLANT CONTINUED										
53	RBP	E365 - OH Conductors and Devices										
54	RBP	Direct - BPL	DIR_BPL_02	2,226,625	2,226,625	0	0	0	0	0	0	0
55	RBP	Direct - PSAL	DIR_PSAL_02	6,436,532	6,436,532	0	0	0	0	0	0	0
56	RBP	Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0	0	0
57	RBP	Subtransmission lines - Energy Related - System		160,845,181	0	0	0	0	0	0	160,845,181	0
58	RBP	Subtransmission lines - Demand Related - System		41,044,089	0	0	0	41,044,089	0	0	0	0
59	RBP	Primary lines - Energy Related - Local		643,665,448	0	0	0	0	0	0	0	643,665,448
60	RBP	Primary lines - Energy Related - System		643,665,448	0	0	0	0	0	0	643,665,448	0

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				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
61	RBP	Primary lines - Demand Related - Local		617,928,923	0	0	617,928,923	0	0	0	0	0
62	RBP	Primary lines - Demand Related - System		617,928,923	0	0	0	617,928,923	0	0	0	0
63	RBP	Secondary lines -Energy Related - Local		64,282,796	0	0	0	0	0	0	0	64,282,796
64	RBP	Secondary lines -Demand Related - Local		58,160,625	0	0	58,160,625	0	0	0	0	0
65	RBP	Other	DISTPLT	0	0	0	0	0	0	0	0	0
66	RBP	Total Account E365		2,856,184,590	8,663,157	0	676,089,548	658,973,011	0	0	804,510,629	707,948,244
67	RBP											
68	RBP	E366 - Underground Conduit										
69	RBP	Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0	0	0
70	RBP	Direct - HEP	DIR_HEP_03	0	0	0	0	0	0	0	0	0
71	RBP	Underground Conduits	E367PLT	512,107,003	1,209,731	73,522	167,477,027	74,353,110	0	0	88,369,620	180,623,992
72	RBP	Not Used	not_used	0	0	0	0	0	0	0	0	0
73	RBP	Total Account E366		512,107,003	1,209,731	73,522	167,477,027	74,353,110	0	0	88,369,620	180,623,992
74	RBP											
75	RBP	E367 - Underground Conductors & Devices										
76	RBP	Direct - BPL	DIR_BPL_02	2,325,498	2,325,498	0	0	0	0	0	0	0
77	RBP	Direct - PSAL	DIR_PSAL_02	868,520	868,520	0	0	0	0	0	0	0
78	RBP	UG BPL Poles in UG areas	DISTPLTXMTR	3,979,461	186,813	205,472	929,335	724,480	0	0	930,962	1,002,399
79	RBP	Direct - HEP	DIR_HEP_03	0	0	0	0	0	0	0	0	0
80	RBP	367.1 - Conventional UG										
81	RBP	Subtransmission lines - Energy Related - System	KWH_SUBT_09	40,943,727	0	0	0	0	0	0	40,943,727	0
82	RBP	Subtransmission lines - Demand Related - System	CP_SUBT_05	10,447,922	0	0	0	10,447,922	0	0	0	0
83	RBP	Primary lines - Energy Related - Local	KWH_PRI_10	90,324,112	0	0	0	0	0	0	0	90,324,112
84	RBP	Primary lines - Energy Related - System	KWH_PRI_09	90,324,112	0	0	0	0	0	0	90,324,112	0
85	RBP	Primary lines - Demand Related - Local	CP_PRI_04	86,712,563	0	0	86,712,563	0	0	0	0	0
86	RBP	Primary lines - Demand Related - System	CP_PRI_05	86,712,563	0	0	0	86,712,563	0	0	0	0
87	RBP	Secondary lines -Energy Related - Local	KWH_SEC_10	283,098,081	0	0	0	0	0	0	0	283,098,081
88	RBP	Secondary lines -Demand Related - Local	CP_SEC_04	256,136,359	0	0	256,136,359	0	0	0	0	0
89	RBP	367.2 - BUD										
90	RBP	Subtransmission lines - Energy Related - System	KWH_SUBT_09	381,867	0	0	0	0	0	0	381,867	0
91	RBP	Subtransmission lines - Demand Related - System	CP_SUBT_05	97,444	0	0	0	97,444	0	0	0	0
92	RBP	Primary lines - Energy Related - Local	KWH_PRI_10	114,385,571	0	0	0	0	0	0	0	114,385,571
93	RBP	Primary lines - Energy Related - System	KWH_PRI_09	114,385,571	0	0	0	0	0	0	114,385,571	0
94	RBP	Primary lines - Demand Related - Local	CP_PRI_04	109,811,942	0	0	109,811,942	0	0	0	0	0
95	RBP	Primary lines - Demand Related - System	CP_PRI_05	109,811,942	0	0	0	109,811,942	0	0	0	0
96	RBP	Secondary lines -Energy Related - Local	KWH_SEC_10	15,979,016	0	0	0	0	0	0	0	15,979,016
97	RBP	Secondary lines -Demand Related - Local	CP_SEC_04	14,457,205	0	0	14,457,205	0	0	0	0	0
98	RBP	Other	E367PLT	0	0	0	0	0	0	0	0	0
99	RBP	Total Account E367		1,431,183,475	3,380,831	205,472	468,047,404	207,794,351	0	0	246,966,239	504,789,178
100	RBP											
101	RBP	E368 - Line Transformers										
102	RBP	Line Transformers - Energy Related - Local	KWH_SEC_10	835,637,581	0	0	0	0	0	0	0	835,637,581
103	RBP	Line Transformers - Demand Related - Local	CP_SEC_04	756,053,050	0	0	756,053,050	0	0	0	0	0
104	RBP	Not Used	not_used	0	0	0	0	0	0	0	0	0
105	RBP	Total Account E368		1,591,690,631	0	0	756,053,050	0	0	0	0	835,637,581
106	RBP	E369 - Services										
107	RBP	Basic portion (minimum size)	SERVICESMIN_03	535,269,333	0	535,269,333	0	0	0	0	0	0
108	RBP	E369 - Excess portion	SERVICESEXC_04	0	0	0	0	0	0	0	0	0
109	RBP	Total Account E369		535,269,333	0	535,269,333	0	0	0	0	0	0
110	RBP	**ELECTRIC PLANT IN SERVICE CONTINUED**										
111	RBP											
112	RBP	E370 - Meters										
113	RBP	Load profiling meters	KWHMETERX_04	0	0	0	0	0	0	0	0	0
114	RBP	Customer Component	METERSMIN_07	76,316,914	0	0	0	0	0	76,316,914	0	0
115	RBP	Excess portion - Demand (Commercial Customers)	METERSEXC_04	122,177,671	0	0	122,177,671	0	0	0	0	0
116	RBP	Excess portion - Demand (Residential Customers)	METERSEXC_10	166,926,857	0	0	0	0	0	0	0	166,926,857
117	RBP	Total Account E370		365,421,442	0	0	122,177,671	0	0	76,316,914	0	166,926,857
118	RBP											
119	RBP	E373 - Street Lighting & Signal Systems										
120	RBP	BPL luminaires & poles	DIR_BPL_02	340,539,607	340,539,607	0	0	0	0	0	0	0

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement	System Delivery Energy	Local Delivery Energy
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
121	RBP	PSAL luminaires & poles	DIR_PSAL_02	122,261,652	122,261,652	0	0	0	0	0	0	0
122	RBP	UG BPL Poles in UG areas	DISTPLTXMTR	36,225,893	1,700,598	1,870,457	8,459,940	6,595,096	0	0	8,474,749	9,125,053
123	RBP	Total Account E373		499,027,153	464,501,858	1,870,457	8,459,940	6,595,096	0	0	8,474,749	9,125,053
124	RBP											
125	RBP	E374 - Asset Retirement Obligations	E364PLT	96,512,525	932,488	0	30,447,221	13,034,833	0	0	19,151,745	32,946,239
126	RBP											
127	RBP	Other Distribution and Unallocated Plant										
128	RBP	Not Used	not_used	0	0	0	0	0	0	0	0	0
129	RBP	Total Other Plant and Unallocated Plant		0	0	0	0	0	0	0	0	0
130	RBP											
131	RBP	TOTAL DISTRIBUTION PLANT		10,773,828,418	488,615,049	537,418,784	2,552,883,868	1,894,899,857	0	76,316,914	2,434,960,990	2,788,732,956
132	RBP											
133	RBP	GENERAL AND COMMON PLANT										
134	RBP	E390-E398 GENERAL PLANT										
135	RBP	Meter Related	METERPLT	0	0	0	0	0	0	0	0	0
136	RBP	Customer Service Related	CUSTSVSX	0	0	0	0	0	0	0	0	0
137	RBP	Substation Related	E362PLT	0	0	0	0	0	0	0	0	0
138	RBP	Distribution Delivery	DISTPLTXMTR	429,584,593	20,166,534	22,180,803	100,322,166	78,207,913	0	0	100,497,773	108,209,403
139	RBP	Service & Support Related	UTILWORK_04	0	0	0	0	0	0	0	0	0
140	RBP	Unassigned	GENPLT	0	0	0	0	0	0	0	0	0
141	RBP	Total Accounts E390-E398		429,584,593	20,166,534	22,180,803	100,322,166	78,207,913	0	0	100,497,773	108,209,403
142	RBP											
143	RBP	C389-C399 COMMON PLANT										
144	RBP	Not Used	not_used	0	0	0	0	0	0	0	0	0
145	RBP	Meter Plant Related	METERPLT	0	0	0	0	0	0	0	0	0
146	RBP	Customer Related - Measurement	MRCOST_07	0	0	0	0	0	0	0	0	0
147	RBP	Demand Related - Measurement	NCP_MTR_07	0	0	0	0	0	0	0	0	0
148	RBP	Customer Service Related	CUSTSVSX	92,605,476	0	0	3,365,638	0	71,953,745	17,286,093	0	0
149	RBP	Distribution Delivery Related	DISTPLTXMTR	33,738,596	1,583,834	1,742,030	7,879,075	6,142,271			7,892,866	8,498,520
150	RBP	Service & Support Related	UTILWORK_04	0	0	0	0	0	0	0	0	0
151	RBP	Unassigned	COMPLT	309,972	3,886	4,274	27,588	15,069	176,531	42,410	19,364	20,850
152	RBP	Not Used	not_used	0	0	0	0	0	0	0	0	0
153	RBP	Total Accounts C389-C399		126,654,044	1,587,719	1,746,304	11,272,300	6,157,341	72,130,276	17,328,503	7,912,231	8,519,370
154	RBP											
155	RBP	TOTAL GENERAL AND COMMON PLANT		556,238,637	21,754,254	23,927,107	111,594,466	84,365,254	72,130,276	17,328,503	108,410,004	116,728,774
156	RBP											
157	RBP	**ELECTRIC PLANT IN SERVICE CONTINUED**										
158	RBP											
159	RBP	INTANGIBLE PLANT - E301-E303										
160	RBP	Customer Service Related	TOTPLT	40,584,928	1,814,427	1,995,655	9,483,470	7,036,536	490,200	393,380	9,042,004	10,329,255
161	RBP	Not Used	not_used	0	0	0	0	0	0	0	0	0
162	RBP	TOTAL INTANGIBLE PLANT		40,584,928	1,814,427	1,995,655	9,483,470	7,036,536	490,200	393,380	9,042,004	10,329,255
163	RBP											
164	RBP	C303 - INTANGIBLE PLANT										
165	RBP	- Customer Related - Measurement	MRCOST_07	606,400	0	0	0	0	0	606,400	0	0
166	RBP	- Demand Related - Measurement	NCP_MTR_07	606,400	0	0	0	0	0	606,400	0	0
167	RBP	Customer Service Related	CUSTSVSX	84,635,615	0	0	3,075,982	0	65,761,224	15,798,408	0	0
168	RBP	Distribution Related	INTANGPLT	0	0	0	0	0	0	0	0	0
169	RBP	C390.4 / C111.000 Capital Lease	TOTPLT	0	0	0	0	0	0	0	0	0
170	RBP	E399 Oth Tangible Plant	GENPLT	0	0	0	0	0	0	0	0	0
171	RBP	E399.1 Asset Retirement Obligations	GENPLT	490,552	23,029	25,329	114,560	89,307			114,761	123,567
172	RBP	TOTAL ACCOUNTS C303-C390.4,E399		86,338,967	23,029	25,329	3,190,542	89,307	65,761,224	17,011,208	114,761	123,567
173	RBP											
174	RBP	TOTAL INTANGIBLE PLANT		126,923,895	1,837,456	2,020,984	12,674,013	7,125,844	66,251,423	17,404,589	9,156,764	10,452,822
175	RBP											
176	RBP	**TOTAL ELECTRIC PLANT IN SERVICE**		11,456,990,950	512,206,759	563,366,875	2,677,152,347	1,986,390,954	138,381,700	111,050,006	2,552,527,759	2,915,914,551

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement	System Delivery Energy	Local Delivery Energy
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	RBD	**LESS: DEPRECIATION RESERVE & AMORT**										
2	RBD											
3	RBD	E301-E303 - INTANGILE PLANT - RESERVE										
4	RBD	Customer Service Related - Reserve	CUSTSVSX	15,757,979	0	0	572,705	0	12,243,829	2,941,445	0	0
5	RBD	Not Used	not_used	0	0	0	0	0	0	0	0	0
6	RBD	Not used	not_used	0	0	0	0	0	0	0	0	0
7	RBD	Total Accounts E301-E303 Reserve		15,757,979	0	0	572,705	0	12,243,829	2,941,445	0	0
8	RBD											
9	RBD	E304-E346 - PRODUCTION PLANT - RESERVE	not_used	0	0	0	0	0	0	0	0	0
10	RBD	E350-E359 - TRANSMISSION PLANT - RESERVE	not_used	0	0	0	0	0	0	0	0	0
11	RBD											
12	RBD	DISTRIBUTION PLANT RESERVE										
13	RBD	E360-E361 Land & Structures - Reserve										
14	RBD	E360 - Land and Land Rights										
15	RBD	- Headquarters Related	DISTPLT	0	0	0	0	0	0	0	0	0
16	RBD	- Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0	0	0
17	RBD	- Direct - HEP	DIR_HEP_03	0	0	0	0	0	0	0	0	0
18	RBD	- Substation Related	E362PLT	667,893	0	0	0	285,764	0	0	382,129	0
19	RBD	E361 - Structures and improvements										
20	RBD	- Headquarters Related	DISTPLT	40,449,681	1,834,475	2,017,706	9,584,647	7,114,286	0	286,527	9,141,912	10,470,128
21	RBD	- Substation Related	E362PLT	36,319,499	0	0	0	15,539,614	0	0	20,779,885	0
22	RBD	Total Accounts E360-E361		77,437,073	1,834,475	2,017,706	9,584,647	22,939,663	0	286,527	30,303,927	10,470,128
23	RBD	E362 Station Equipment - Rsrv	E362PLT	279,293,104	0	0	0	119,497,984	0	0	159,795,119	0
24	RBD	E364 Poles Towers and Fixtures Rsrv										
25	RBD	- Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0	0	0
26	RBD	- All Other	E364PLT	200,061,625	1,932,962	0	63,114,300	27,020,014	0	0	39,699,813	68,294,536
27	RBD	E365 OH Conductors and Devices - Rsrv										
28	RBD	- Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0	0	0
29	RBD	- All Other	E365PLT	609,997,837	1,850,198	0	144,393,035	140,737,441	0	0	171,820,038	151,197,125
30	RBD	E366 UG Conduit - Rsrv										
31	RBD	- Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0	0	0
32	RBD	- All Other	E366PLT	258,299,502	610,171	37,084	84,473,035	37,502,653	0	0	44,572,382	91,104,178
33	RBD	E367 UG Conductors and Devices - Rsrv										
34	RBD	- Direct - HTS-HV	DIR_HEP_03	0	0	0	0	0	0	0	0	0
35	RBD	- All Other	E367PLT	512,800,757	1,211,370	73,622	167,703,909	74,453,837	0	0	88,489,335	180,868,685
36	RBD	E368 Line Transformers - Rsrv Energy Related - Local	KWH_SEC_10	198,944,531	0	0	0	0	0	0	0	198,944,531
37	RBD	E368 Line Transformers - Rsrv Demand Related - Local	CP_SEC_04	179,997,433	0	0	179,997,433	0	0	0	0	0
38	RBD	E369 Services - Rsrv										
39	RBD	Services	E369PLT	240,814,772	0	240,814,772	0	0	0	0	0	0
40	RBD	Not used	not_used	0	0	0	0	0	0	0	0	0
41	RBD	Total Accounts E369 Rsrv		240,814,772	0	240,814,772	0	0	0	0	0	0
42	RBD	E370 Meters - Rsrv										
43	RBD	Load profile meters	KWHMETERX_04	0	0	0	0	0	0	0	0	0
44	RBD	All other Meters	METERPLTXPR	136,921,647	0	0	45,779,382	0	0	28,595,579	0	62,546,686
45	RBD	Total Account E370 Rsrv		136,921,647	0	0	45,779,382	0	0	28,595,579	0	62,546,686
46	RBD	E373 Street Lighting - Rsrv										
47	RBD	Streetlight fixtures	E373PLT	118,939,285	110,710,447	445,809	2,016,362	1,571,890	0	0	2,019,891	2,174,886
48	RBD	Not used	not_used	0	0	0	0	0	0	0	0	0
49	RBD	Total Account E373 Rsrv		118,939,285	110,710,447	445,809	2,016,362	1,571,890	0	0	2,019,891	2,174,886
50	RBD											
51	RBD	**DEPRECIATION RESERVE & AMORT CONTINUED**										
52	RBD	Other Plant Unallocated - Reserve										
53	RBD	Not Used	not_used	0	0	0	0	0	0	0	0	0
54	RBD	Not Used	not_used	0	0	0	0	0	0	0	0	0
55	RBD	Total Other Plant Unallocated - Reserve		0	0	0	0	0	0	0	0	0
56	RBD											
57	RBD	Not Used	not_used	0	0	0	0	0	0	0	0	0
58	RBD	Not Used	not_used	0	0	0	0	0	0	0	0	0
59	RBD	Not Used	not_used	0	0	0	0	0	0	0	0	0
60	RBD											

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement	System Delivery Energy	Local Delivery Energy
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
61	RBD	TOTAL DISTRIBUTION PLANT RESERVE		2,813,507,566	118,149,623	243,388,992	697,062,102	423,723,484		28,882,106	536,700,505	765,600,754
62	RBD											
63	RBD	GENERAL AND COMMON PLANT RESERVE										
64	RBD	E390-E398 GENERAL PLANT - RESERVE										
65	RBD	Meter Plant Related	METERPLT	0	0	0	0	0	0	0	0	0
66	RBD	Customer Service Related	CUSTSVSX	0	0	0	0	0	0	0	0	0
67	RBD	Substation Related	E362PLT	0	0	0	0	0	0	0	0	0
68	RBD	Distribution Delivery Related	DISTPLTXMTR	156,424,740	7,343,245	8,076,701	36,530,334	28,477,866	0	0	36,594,278	39,402,316
69	RBD	Service & Support Related	UTILWORK_04	0	0	0	0	0	0	0	0	0
70	RBD	Unassigned	GENPLT	0	0	0	0	0	0	0	0	0
71	RBD	Total Accounts E390-E398 Reserve		156,424,740	7,343,245	8,076,701	36,530,334	28,477,866	0	0	36,594,278	39,402,316
72	RBD											
73	RBD	C389-C399 COMMON PLANT RESERVE										
74	RBD	Not Used	not_used	0	0	0	0	0	0	0	0	0
75	RBD	Meter Plant Related	METERPLT	0	0	0	0	0	0	0	0	0
76	RBD	Meter Reading Related - Customer Related Measuremen	MRCOST_07	0	0	0	0	0	0	0	0	0
77	RBD	Meter Reading Related - Demand Related Measurement	NCP_MTR_07	0	0	0	0	0	0	0	0	0
78	RBD	Customer Service Related	CUSTSVSX	46,782,308	0	0	1,700,248	0	36,349,495	8,732,565	0	0
79	RBD	Distribution Delivery Related	DISTPLTXMTR	19,175,874	900,197	990,111	4,478,199	3,491,059	0	0	4,486,038	4,830,271
80	RBD	Sales and Service Dept. Related	UTILWORK_04	0	0	0	0	0	0	0	0	0
81	RBD	Unassigned	COMPLT	0	0	0	0	0	0	0	0	0
82	RBD	Not Used	not_used	0	0	0	0	0	0	0	0	0
83	RBD	Total Accounts C389-C399 Reserve		65,958,182	900,197	990,111	6,178,447	3,491,059	36,349,495	8,732,565	4,486,038	4,830,271
84	RBD											
85	RBD	C303 - INTANGIBLE PLANT										
86	RBD	- Customer Related - Measurement	MRCOST_07	311,743	0	0	0	0	0	311,743	0	0
87	RBD	- Demand Related - Measurement	NCP_MTR_07	311,743	0	0	0	0	0	311,743	0	0
88	RBD	Customer Service Related	CUSTSVSX	46,570,192	0	0	1,692,539	0	36,184,682	8,692,971	0	0
89	RBD	Distribution Related	INTANGPLT	0	0	0	0	0	0	0	0	0
90	RBD	C390.4 / C111.000 Capital Lease	TOTPLT	0	0	0	0	0	0	0	0	0
91	RBD	E399 Oth Tangible Plant	GENPLT	0	0	0	0	0	0	0	0	0
92	RBD	E399.1 Asset Retirement Obligations	GENPLT	490,552	23,029	25,329	114,560	89,307	0	0	114,761	123,567
93	RBD	Total Accounts C303-C390.4,E399		47,684,230	23,029	25,329	1,807,099	89,307	36,184,682	9,316,457	114,761	123,567
94	RBD											
95	RBD	**TOTAL DEPRECIATION RESERVE & AMORT.**		3,099,332,698	126,416,094	252,481,133	742,150,688	455,781,716	84,778,006	49,872,573	577,895,582	809,956,907
96	RBD	**NET ELECTRIC PLANT IN SERVICE**		8,357,658,252	385,790,665	310,885,742	1,935,001,659	1,530,609,238	53,603,694	61,177,433	1,974,632,177	2,105,957,644

Updated for 9 and 3

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 STAFF ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement	System Delivery Energy	Local Delivery Energy
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	RBO	**ADDITIONS AND DEDUCTIONS TO RATE BASE**										
2	RBO											
3	RBO	**PLUS: ADDITIONS TO RATE BASE**										
4	RBO											
5	RBO	Working Capital										
6	RBO	Cash (lead/lag)	EXPENDITURES	884,882,332	48,971,124	15,291,217	190,524,209	141,770,530	53,958,931	36,006,690	181,288,482	217,071,148
7	RBO	Materials and Supplies	EXPENDITURES	297,953,440	16,489,328	5,148,787	64,152,421	47,736,310	18,168,799	12,124,004	61,042,610	73,091,182
8	RBO	Prepayments	EXPENDITURES	500,266	27,686	8,645	107,712	80,150	30,506	20,356	102,491	122,721
9	RBO	Working Funds	EXPENDITURES	0	0	0	0	0	0	0	0	0
10	RBO	Total Working Capital		1,183,336,038	65,488,137	20,448,649	254,784,343	189,586,989	72,158,236	48,151,051	242,433,583	290,285,051
11	RBO	Net Plant Adds - Distribution	DISTPLT	1,061,820,806	48,155,735	52,965,615	251,600,926	186,752,936	0	7,521,457	239,978,969	274,845,167
12	RBO	Capital Lease Plant & Reserve Deduction	TOTPLT	489,291	21,875	24,060	114,333	84,832	5,910	4,743	109,010	124,529
13	RBO	Capital Stimulus Adjust	DISTPLT	0	0	0	0	0	0	0	0	0
14	RBO	Net Plant Adds - General & Other	TOTPLTNET	305,589,989	14,106,076	11,367,248	70,751,533	55,965,301	1,959,969	2,236,896	72,200,586	77,002,380
15	RBO	TOTAL ADDITIONS TO RATE BASE		3,250,722,500	129,646,164	86,064,662	585,574,155	439,133,747	76,752,794	718,888,835	563,382,720	651,279,422
16	RBO											
17	RBO											
18	RBO	**PLUS: DEDUCTIONS TO RATE BASE**										
19	RBO											
20	RBO	Customer Advances for Construction	REVREQ	-63,907,492	-2,850,605	-1,916,201	-12,647,114	-10,246,307	-3,995,924	-5,391,590	-13,153,291	-13,706,460
21	RBO	Unbilled Revenue	TOTREV	0	0	0	0	0	0	0	0	0
22	RBO	Deferred Income Taxes and Credits										
23	RBO	ADIT Test/Post year	TOTPLT	0	0	0	0	0	0	0	0	0
24	RBO	Liberalized Depreciation	TOTPLT	-2,247,763	-100,491	-110,528	-525,234	-389,713	-27,149	-21,787	-500,784	-572,077
25	RBO	Cost of Removal	TOTPLT	15,629,066	698,727	768,517	3,652,040	2,709,737	188,774	151,489	3,482,033	3,977,748
26	RBO	3% Investment Tax Credit	DISTPLT	0	0	0	0	0	0	0	0	0
27	RBO	Computer Software	INTANGPLT	0	0	0	0	0	0	0	0	0
28	RBO	Capitalized Interest	TOTPLTNET	312,066	14,405	11,608	72,251	57,151	2,002	2,284	73,731	78,634
29	RBO	NJ Corporate Business Tax	TOTPLTNET	6,378,736	294,443	237,274	1,476,833	1,168,192	40,911	46,692	1,507,080	1,607,310
30	RBO	Defrd Tax & Consolidated Tax Adjustment	DEPREXP	(1,738,024,409)	(77,180,993)	(84,889,967)	(403,155,289)	(299,315,899)	(31,808,883)	(18,707,997)	(384,623,248)	(438,342,132)
31	RBO	Total Deferred Income Taxes and Credits		-1,717,952,304	-76,273,908	-83,983,095	-398,479,399	-295,770,531	-31,604,346	-18,529,319	-380,061,189	-433,250,518
32	RBO											
33	RBO	TOTAL DEDUCTIONS TO RATE BASE		(1,822,758,657)	(79,248,564)	(85,899,296)	(420,807,713)	(315,452,939)	(35,600,270)	(23,920,909)	(404,734,592)	(457,094,374)
34	RBO											
35	RBO											
36	RBO	**TOTAL RATE BASE**		9,785,622,095	436,188,265	311,051,108	2,099,768,101	1,654,290,047	94,756,219	756,145,359	2,133,280,305	2,300,142,691
37	RBO	IAP Adjustment	E365PLT	-40,898,861	-124,051	0	-9,681,199	-9,436,101	0	0	-11,520,113	-10,137,397
38	RBO	CEF-EV Adjustment	TOTREV	42,056,391	1,874,341	1,259,091	8,323,021	6,743,689	2,628,680	3,544,703	8,660,572	9,022,295
39	RBO	CEF-EC Adjustment	ECPRO_07	657,429,985	0	0	0	0	0	657,429,985	0	0

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				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	REV	**OPERATING REVENUES**										
2	REV											
3	REV	**SALES REVENUES**										
4	REV	BASE RATE SALES @ EQUALIZED ROR 7.40%		1,899,915,237	84,746,048	56,967,015	375,987,929	304,613,976	118,795,402	160,287,388	391,036,114	407,481,364
5	REV	Not Used	not_used	0	0	0	0	0	0	0	0	0
6	REV	Not Used	not_used									
7	REV	TOTAL SALES OF ELECTRICITY		1,899,915,237	84,746,048	56,967,015	375,987,929	304,613,976	118,795,402	160,287,388	391,036,114	407,481,364
8	REV											
9	REV	**OTHER OPERATING REVENUES**										
10	REV	450-Forfeited Discounts	REVLATEP	3,653,078	90,924	22,319	731,014	620,769	184,647	153,956	961,136	888,315
11	REV	456-Other Electric Revenues	TOTREV	21,451,361	956,030	642,214	4,245,256	3,439,698	1,340,789	1,808,018	4,417,427	4,601,929
12	REV	Not Used	not_used	0	0	0	0	0	0	0	0	0
13	REV	Not Used	not_used									
14	REV	TOTAL OTHER OPERATING REV		25,104,439	1,046,954	664,533	4,976,270	4,060,468	1,525,436	1,961,974	5,378,563	5,490,243
15	REV											
16	REV	**OTHER REVENUE SOURCES**										
17	REV	Not Used	not_used	0	0	0	0	0	0	0	0	0
18	REV	Not Used	not_used	0	0	0	0	0	0	0	0	0
19	REV	TOTAL OTHER REVENUE SOURCES		0	0	0	0	0	0	0	0	0
20	REV											
21	REV	LESS: E496 Provision for Rate Refunds	TOTREV	0	0	0	0	0	0	0	0	0
22	REV											
23	REV	**TOTAL OPERATING REVENUES**		1,925,019,676	85,793,001	57,631,548	380,964,199	308,674,444	120,320,838	162,249,361	396,414,677	412,971,607

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement	System Delivery Energy	Local Delivery Energy
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	E	**OPERATION & MAINTENANCE EXPENSE**										
2	E	PRODUCTION EXPENSE										
3	E	E500-E557 Production Expenses										
4	E	Not Used	not_used	0	0	0	0	0	0	0	0	0
5	E	Total Production Expense		0	0	0	0	0	0	0	0	0
6	E	TOTAL PRODUCTION EXPENSE		0	0	0	0	0	0	0	0	0
7	E											
8	E	TRANSMISSION EXPENSES										
9	E	E560-E573 Transmission Exp	not_used	0	0	0	0	0	0	0	0	0
10	E	TOTAL TRANSMISSION EXPENSE		0	0	0	0	0	0	0	0	0
11	E											
12	E	DISTRIBUTION EXPENSES										
13	E	Operation										
14	E	E580 Operation Supervision & Eng'g	DISTEXPO	0	0	0	0	0	0	0	0	0
15	E	E581 Load Dispatching	CP_SUBT_05	0	0	0	0	0	0	0	0	0
16	E	E582 Station Expenses	E362PLT	2,539,578	0	0	0	1,086,581	0	0	1,452,997	0
17	E	E583 OH Line Expenses	E365PLT	4,195,894	12,727	0	993,213	968,068	0	0	1,181,871	1,040,015
18	E	E584 Underground Line Expenses	E367PLT	6,199,909	14,646	890	2,027,589	900,168	0	0	1,069,862	2,186,755
19	E	E585 Street Lighting and System Expenses	E373PLT	173,106	161,130	649	2,935	2,288			2,940	3,165
20	E	E586 Meter Expenses										
21	E	- Basic portion (minimum size)	METERPLT_07	5,865,310	0	0	0	0	0	5,865,310	0	0
22	E	- Excess portion	not_used	0	0	0	0	0	0	0	0	0
23	E	E587 Customer Installations Expenses	MTROMMIN_07	0	0	0	0	0	0	0	0	0
24	E	-E587 Customer Installation Expenses - System	CUSTAVG_04	-1,314,125	0	0	-1,314,125	0	0	0	0	0
25	E	-E587 Customer Installation Expenses - Local	CUSTAVG_04	-1,314,125	0	0	-1,314,125	0	0	0	0	0
26	E	E588 Miscellaneous Distribution Expenses	DISTEXPO	35,897,260	413,979	3,380	868,547	6,494,243	0	12,881,096	8,142,596	7,093,420
27	E	E589 Rents	DISTPLT	1,330,133	60,324	66,350	315,178	233,944	0	9,422	300,619	344,296
28	E	Total Distribution Operation		53,572,940	662,805	71,268	1,579,212	9,685,291	0	18,755,828	12,150,885	10,667,651
29	E	Maintenance										
30	E	E590 Maint. Supervision & Eng'g	DISTEXPM	0	0	0	0	0	0	0	0	0
31	E	E591 Maint of Structures	E360PLT	12,325,542	0	0	0	5,273,590	0	0	7,051,952	0
32	E	E592 Maint of Station Equipment	E362PLT	17,215,431	0	0	0	7,365,772	0	0	9,849,659	0
33	E	E593 Maint of Overhead Lines										
34	E	- Direct assigned - BPL poles	DIR_BPL_02	40,988	40,988	0	0	0	0	0	0	0
35	E	- Direct assigned - PSAL poles	DIR_PSAL_02	118,210	118,210	0	0	0	0	0	0	0
36	E	- all other O&M	E365PLT	56,305,216	170,781	0	13,328,049	12,990,623	0	0	15,859,670	13,956,093
37	E	E594.0 Maint of Underground Lines	E367PLT	20,076,605	47,426	2,882	6,565,757	2,914,934	0	0	3,464,436	7,081,170
38	E	Not used	not_used	0	0	0	0	0	0	0	0	0
39	E	E595 Maint of Line Transformers - Energy Related Local	KWH_SEC_10	2,207,903	0	0	0	0	0	0	0	2,207,903
40	E	E595 Maint of Line Transformers - Demand Related Local	CP_SEC_04	1,997,626	0	0	1,997,626	0	0	0	0	0
41	E	E596 Maint of Street Lighting & Signal Systems										
42	E	- BPL luminaires	DIR_BPL_02	8,123,869	8,123,869	0	0	0	0	0	0	0
43	E	- BPL-POF luminaires	DIR_BPLPOF_02	340,052	340,052	0	0	0	0	0	0	0
44	E	- PSAL luminaires	DIR_PSAL_02	3,594,664	3,594,664	0	0	0	0	0	0	0
45	E	E597 Maint of Meters										
46	E	- Load profiling meters O&M	KWHMETERX_04	0	0	0	0	0	0	0	0	0
47	E	- Basic portion (minimum size)	METERPLTXPR	858,670	0	0	287,094	0	0	179,330	0	392,246
48	E	- Excess portion	METERSEXC_04	0	0	0	0	0	0	0	0	0
49	E	E598 Other Dist Maint Exp	DISTEXPM	1,231,542	124,309	29	221,694	285,332	0	1,793	362,108	236,277
50	E	Total Distribution Maintenance		124,436,319	12,560,300	2,911	22,400,220	28,830,251	0	181,123	36,587,825	23,873,689
51	E											
52	E	TOTAL DISTRIBUTION PLANT O&M EXPENSES		178,009,259	13,223,105	74,179	23,979,432	38,515,543		18,936,951	48,738,710	34,541,340
53	E											
54	E	**OPERATION & MAINTENANCE EXPENSE CONTINUED**										
55	E											
56	E	TOTAL OPER & MAINT EXP (PROD,TRAN,& DIST)		178,009,259	13,223,105	74,179	23,979,432	38,515,543		18,936,951	48,738,710	34,541,340
57	E											
58	E											
59	E	CUSTOMER ACCOUNTS EXPENSES										
60	E	E901 Supervision	CUSTACCTS	0	0	0	0	0	0	0	0	0

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				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
61	E	E902 Meter Reading										
62	E	- Meter O&M - Customer Related - Cust Svs	METERPLT	0	0	0	0	0	0	0	0	0
63	E	- Meter O&M - Demand Related - Cust Svs	NCP_MTR_06	0	0	0	0	0	0	0	0	0
64	E	- Meter Reading - Customer Related Measurement	MRCOST_07	9,323,486	0	0	0	0	0	9,323,486	0	0
65	E	- Meter Reading - Demand Related Measurement	NCPXSL_MTR_07	9,323,486	0	0	0	0	0	9,323,486	0	0
66	E	- Billing - Customer Related - Cust Svs	BILLING_06	0	0	0	0	0	0	0	0	0
67	E	- Billing - Customer Related - Cust Svs	NCPXSL_MTR_07	0	0	0	0	0	0	0	0	0
68	E	- Remaining - Customer Related - Measurement	MRCOST_07	-283,695	0	0	0	0	0	-283,695	0	0
69	E	- Remaining - Demand Related - Measurement	NCPXSL_MTR_07	-283,695	0	0	0	0	0	-283,695	0	0
70	E	E903 Customer Records and Collection										
71	E	- SONP/RNP - Customer Related - Local D	CUSTAVG_04	275,332	0	0	275,332	0	0	0	0	0
72	E	- SONP/RNP - Demand Related - Local D	NCP_MTR_04	275,332	0	0	275,332	0	0	0	0	0
73	E	- Meter O&M - Customer Related - Cust Svs	METERPLT	0	0	0	0	0	0	0	0	0
74	E	- Meter O&M - Demand Related - Cust Svs	NCP_MTR_06	0	0	0	0	0	0	0	0	0
75	E	- Meter Reading - Customer Related Measurement	MRCOST_07	266,527	0	0	0	0	0	266,527	0	0
76	E	- Meter Reading - Demand Related Measurement	NCPXSL_MTR_07	266,527	0	0	0	0	0	266,527	0	0
77	E	- Billing - Customer Related - Cust Svs	BILLING_06	40,496	0	0	0	0	40,496	0	0	0
78	E	- Billing - Customer Related - Cust Svs	NCP_MTR_06	40,496	0	0	0	0	40,496	0	0	0
79	E	- Acct Maint Related - Customer Related - Cust Svs	ACCTMAINT_06	3,872,512	0	0	0	0	3,872,512	0	0	0
80	E	- Acct Maint Related - Demand Related - Cust Svs	NCP_MTR_06	3,872,512	0	0	0	0	3,872,512	0	0	0
81	E	- Utility Work Related -Customer related - Local D	UTILWORK_04	531,469	0	0	531,469	0	0	0	0	0
82	E	- Utility Work Related -Demand Related - Local D	NCP_MTR_04	531,469	0	0	531,469	0	0	0	0	0
83	E	- Remaining - Customer Related - Cust Svs	BILLING_06	33,170,904	0	0	0	0	33,170,904	0	0	0
84	E	- Remaining - Demand Related - Cust Svs	NCP_MTR_06	33,170,904	0	0	0	0	33,170,904	0	0	0
85	E	Not used	not_used	0	0	0	0	0	0	0	0	0
86	E	E904 Uncollectible Accounts	not_used	0	0	0	0	0	0	0	0	0
87	E	E905 Misc Customer Accounts	CUSTACCTS									
88	E	TOTAL CUSTOMER ACCTS EXPENSE		94,394,062	0	0	1,613,601	0	74,167,825	18,612,636	0	0
89	E											
90	E											
91	E	CUSTOMER SERVICE & INFO EXPENSES										
92	E	E907 & 908 - Cust Svs & Info										
93	E	- SONP/RNP	CUSTAVG_06	0	0	0	0	0	0	0	0	0
94	E	- Acct Maint related	ACCTMAINT_06	2,356,739	0	0	0	0	2,356,739	0	0	0
95	E	- Utility work related	UTILWORK_04	847,228	0	0	847,228	0	0	0	0	0
96	E	- Sales	SALES_06	0	0	0	0	0	0	0	0	0
97	E	- Billing	BILLING_06	41,297	0	0	0	0	41,297	0	0	0
98	E	- Remaining	ACCTMAINT_06	0	0	0	0	0	0	0	0	0
99	E	E909 Info & Instr Advertising	CUSTNUMX_04	0	0	0	0	0	0	0	0	0
100	E	E910 - Misc Cust Svs & Info										
101	E	- Utility work related	UTILWORK_04	1,163,089	0	0	1,163,089	0	0	0	0	0
102	E	- Acct Maint related	ACCTMAINT_06	689,620	0	0	0	0	689,620	0	0	0
103	E	- Not used	not_used	0	0	0	0	0	0	0	0	0
104	E	- Not used	not_used	0	0	0	0	0	0	0	0	0
105	E	- Not used	not_used	0	0	0	0	0	0	0	0	0
106	E	- Not used	not_used	0	0	0	0	0	0	0	0	0
107	E	- Remaining	BILLING_06	220,028					220,028			
108	E	TOTAL CUSTOMER SERVICE & INFO EXPENSES		5,318,001	0	0	2,010,317	0	3,307,684	0	0	0
109	E											
110	E	**OPERATION & MAINTENANCE EXPENSE CONTINUED**										
111	E											
112	E	SALES EXPENSES										
113	E	E911-E916 Sales Expenses										
114	E	- Sales	SALES_06	0	0	0	0	0	0	0	0	0
115	E	- Billing related	BILLING_06	0	0	0	0	0	0	0	0	0
116	E	- Acct Maint related	ACCTMAINT_06	0	0	0	0	0	0	0	0	0
117	E	- Utility work related	UTILWORK_04	40,922	0	0	40,922	0	0	0	0	0
118	E	- Remaining	UTILWORK_04	0	0	0	0	0	0	0	0	0
119	E	- Clause	not_used									
120	E	SALES EXPENSES TOTAL (ACCT 916)		40,922	0	0	40,922	0	0	0	0	0

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				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
121	E											
122	E	TOTAL OPER & MAINT EXCL A&G		277,762,244	13,223,105	74,179	27,644,272	38,515,543	77,475,509	37,549,587	48,738,710	34,541,340
123	E											
124	E	ADMINISTRATIVE & GENERAL EXPENSE										
125	E	E920 A&G Salaries	REVREQ	5,694,688	254,013	170,749	1,126,963	913,031	356,070	480,435	1,172,067	1,221,359
126	E	E921 Office Supplies & Exp	REVREQ	622,444	27,764	18,663	123,180	99,797	38,919	52,513	128,110	133,498
127	E	E923 Outside Services Employed	DISTPLT	68,020,983	3,084,890	3,393,014	16,117,731	11,963,524	0	481,830	15,373,221	17,606,774
128	E	E924 Property Insurance	TOTPLT	1,802,573	80,587	88,637	421,207	312,527	21,772	17,472	401,599	458,772
129	E	E925 Injuries & Damages	LABOR	14,161,029	678,137	2,974	1,799,423	1,163,501	4,414,263	3,535,479	1,472,926	1,094,324
130	E	E926 Employee Pension & Benefits	LABOR	-77,966,713	-3,733,637	-16,373	-9,907,129	-6,405,917	-24,303,713	-19,465,372	-8,109,524	-6,025,047
131	E	E928 Regulatory Comm Exp	REVREQ	15,042,373	670,968	451,030	2,976,844	2,411,748	940,550	1,269,058	3,095,986	3,226,190
132	E	E929 Duplicate Charges - credit	REVLPLS	-3,363,888	0	-922	-679,599	-543,401	-122,774	-56,179	-907,584	-1,053,430
133	E	E930.1 General Advertising Expenses	CUSTAVG_04	2,277,517	0	0	2,277,517	0	0	0	0	0
134	E	E930.2 Misc General Expenses	DISTPLT	2,932,568	132,998	146,282	694,879	515,780	0	20,773	662,781	759,075
135	E	E931 Rents	DISTPLT	4,471,819	202,806	223,063	1,059,608	786,503	0	31,676	1,010,663	1,157,500
136	E	E932 Maint of General Plant	COMGENPLT	0	0	0	0	0	0	0	0	0
137	E	E935 Other A&G Maint	COMGENPLT	0	0	0	0	0	0	0	0	0
138	E	Not Used	not_used									
139	E	TOTAL A&G EXPENSE		33,695,393	1,398,526	4,477,117	16,010,625	11,217,092	-18,654,913	-13,632,314	14,300,245	18,579,015
140	E											
141	E	**TOTAL OPERATION & MAINTENANCE EXPENSES**		311,457,637	14,621,631	4,551,297	43,654,897	49,732,635	58,820,596	23,917,272	63,038,955	53,120,355

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 STAFF ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement	System Delivery Energy	Local Delivery Energy
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	DE	**DEPRECIATION AND AMORTIZATION EXPENSES**										
2	DE											
3	DE	E403 DEPRECIATION EXPENSE										
4	DE	Production Plant	not_used	0	0	0	0	0	0	0	0	0
5	DE	Transmission Plant	not_used	0	0	0	0	0	0	0	0	0
6	DE	Distribution Plant	DISTPLT	257,769,144	11,690,355	12,858,009	61,079,002	45,336,411	0	1,825,920	58,257,639	66,721,808
7	DE	General Plant	GENPLT	19,786,964	928,885	1,021,663	4,620,908	3,602,311	0	0	4,628,997	4,984,200
8	DE	Common Plant	COMPLT	9,215,747	115,527	127,067	820,208	448,028	5,248,426	1,260,876	575,719	619,896
9	DE	Other Plant & Misc	DISTPLT	0	0	0	0	0	0	0	0	0
10	DE	TOTAL DEPRECIATION EXPENSE		286,771,855	12,734,767	14,006,738	66,520,119	49,386,749	5,248,426	3,086,796	63,462,355	72,325,904
11	DE											
12	DE	E404.3 AMORT OF OTHER LIMITED TERM PLANT										
13	DE	not used	not_used	0	0	0	0	0	0	0	0	0
14	DE	Distribution Delivery Related	DISTPLTXMTR	6,072,872	285,087	313,561	1,418,216	1,105,595	0	0	1,420,698	1,529,715
15	DE	Meter Reading	MRCOST_07	492,670	0	0	0	0	0	492,670	0	0
16	DE	Customer Service related	CUSTSVSX	14,826,022	0	0	538,834	0	11,519,706	2,767,482	0	0
17	DE	not used	not_used	0	0	0	0	0	0	0	0	0
18	DE	not used	not_used	0	0	0	0	0	0	0	0	0
19	DE	TOTAL AMORT OF OTHER LIMITED TERM PLT		21,391,564	285,087	313,561	1,957,050	1,105,595	11,519,706	3,260,152	1,420,698	1,529,715
20	DE											
21	DE	E407 AMORT OF PROPERTY LOSSES										
22	DE	Regulatory assets	KWHMETER_04	0	0	0	0	0	0	0	0	0
23	DE	Securitization amortization	not_used	0	0	0	0	0	0	0	0	0
24	DE	not used	not_used	0	0	0	0	0	0	0	0	0
25	DE	TOTAL AMORT OF PROPERTY LOSSES		0	0	0	0	0	0	0	0	0
26	DE											
27	DE	TOTAL AMORTIZATION EXPENSE		21,391,564	285,087	313,561	1,957,050	1,105,595	11,519,706	3,260,152	1,420,698	1,529,715
28	DE											
29	DE	**TOTAL DEPRECIATION AND AMORTIZATION EXPENSES**		308,163,419	13,019,854	14,320,300	68,477,169	50,492,344	16,768,132	6,346,948	64,883,053	73,855,618

Updated for 9 and 3

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 STAFF ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement	System Delivery Energy	Local Delivery Energy
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	EO	**OTHER OPERATING EXPENSES**										
2	EO	**E408 TAXES OTHER THAN INCOME TAXES**										
3	EO	TEFA	TEFA_04	0	0	0	0	0	0	0	0	0
4	EO	Real Estate Taxes	TOTPLT	0	0	0	0	0	0	0	0	0
5	EO	Miscellaneous State and Municipal Tax	TOTPLT	-275,485	-12,316	-13,546	-64,373	-47,763	-3,327	-2,670	-61,376	-70,114
6	EO	State Unemploy Insur (SUI) Tax	LABOR	0	0	0	0	0	0	0	0	0
7	EO	FICA & UnempTax	LABOR	-11,275,732	-539,968	-2,368	-1,432,793	-926,439	-3,514,861	-2,815,129	-1,172,819	-871,357
8	EO	Other Taxes	TOTPLT	0	0	0	0	0	0	0	0	0
9	EO	not used	not_used	0	0	0	0	0	0	0	0	0
10	EO	**TOTAL TAXES OTHER THAN INCOME**		-11,551,217	-552,284	-15,914	-1,497,165	-974,202	-3,518,188	-2,817,799	-1,234,195	-941,470
11	EO	**PROFORMA EXPENSE ADJUSTMENTS**										
12	EO	Wage Increases (Rate Year)	LABOR	7,691,360	368,321	1,615	977,331	631,939	2,397,544	1,920,245	799,999	594,367
13	EO	Payroll Taxes (Rate Year)	LABOR	541,904	25,950	114	68,859	44,524	168,922	135,293	56,365	41,877
14	EO	Interest Syncronization	TOTPLTNET	-459,649	-21,217	-17,098	-106,420	-84,179	-2,948	-3,365	-108,600	-115,822
15	EO	- add'l tax effects on rev req	TOTPLTNET	-179,729	-8,296	-6,686	-41,612	-32,915	-1,153	-1,316	-42,464	-45,288
16	EO	Pension & Fringe Benefit (Rate Year)	LABOR	11,745,951	562,485	2,467	1,492,543	965,073	3,661,437	2,932,525	1,221,727	907,694
17	EO	COLI Interest Expense Recovery	LABOR	2,434,135	116,565	511	309,302	199,994	758,766	607,712	253,181	188,103
18	EO	- add'l tax effects on rev req	LABOR	951,781	45,578	200	120,942	78,200	296,688	237,624	98,997	73,551
19	EO	ASB Margin	TOTPLT	0	0	0	0	0	0	0	0	0
20	EO	BPU / Rate Counsel Assessment	KWHMETER_04	377,877	0	0	377,877	0	0	0	0	0
21	EO	Adj #6 - Weather Normalization	not_used	0	0	0	0	0	0	0	0	0
22	EO	Gains / Losses Normalization	TOTPLT	-44,137	-1,973	-2,170	-10,314	-7,652	-533	-428	-9,833	-11,233
23	EO	- add'l tax effects on rev req	TOTPLT	-17,258	-772	-849	-4,033	-2,992	-208	-167	-3,845	-4,392
24	EO	Other Regulatory Asset / Liability Amortizations	TOTPLT	0	0	0	0	0	0	0	0	0
25	EO	Adj #15 - Excess COR Refund Recovery	TOTPLT	0	0	0	0	0	0	0	0	0
26	EO	Real Estate Tax Increases (Rate Year)	TOTPLT	700,231	31,305	34,432	163,623	121,405	8,458	6,787	156,006	178,215
27	EO	Test Year Amortization Adjustments	TOTPLT	-17,276,070	-772,360	-849,505	-4,036,895	-2,995,292	-208,667	-167,453	-3,848,973	-4,396,926
28	EO	Insurance Premium Increases (Rate Year)	TOTPLT	481,185	21,512	23,661	112,438	83,427	5,812	4,664	107,204	122,466
29	EO	Rate Case Expenses	TOTPLT	166,097	7,426	8,167	38,812	28,798	2,006	1,610	37,005	42,273
30	EO	Depreciation Rate Change	DEPREXP	50,211,393	2,229,753	2,452,465	11,647,126	8,647,214	918,956	540,473	11,111,737	12,663,671
31	EO	Adj #14 Post Rate Case Storm Cost Normalization	TOTPLT	0	0	0	0	0	0	0	0	0
32	EO	Adj #13 - Storm Cost Amortization	TOTPLTNET	0	0	0	0	0	0	0	0	0
33	EO	Adj #20 - Vacation Accrual	LABOR	0	0	0	0	0	0	0	0	0
34	EO	Energy Strong II / IAP Revenue Adjustment	TOTPLT	0	0	0	0	0	0	0	0	0
35	EO	Recovery of Credit Card Fees	CUSTSVSX	0	0	0	0	0	0	0	0	0
36	EO	Test Year Corrections	TOTPLT									
37	EO	TOTAL PROFORMA EXPENSE ADJUSTMENTS		82,048,703	2,779,569	1,820,864	12,078,656	8,441,194	7,819,611	26,976,034	10,813,290	11,319,486
38	EO											
39	EO	**TOTAL OTHER OPERATING EXPENSES**		70,497,486	2,227,285	1,804,950	10,581,490	7,466,992	4,301,422	24,158,235	9,579,095	10,378,016
40	EO	TOTAL OPERATING REVENUES	CALCULATED	1,925,019,676	85,793,001	57,631,548	380,964,199	308,674,444	120,320,838	162,249,361	396,414,677	412,971,607
41	EO	LESS:										
42	EO	OPERATION & MAINTAINENCE EXPENSE	CALCULATED	311,457,637	14,621,631	4,551,297	43,654,897	49,732,635	58,820,596	23,917,272	63,038,955	53,120,355
43	EO	DEPRECIATION & AMORTIZATION EXPENSE	CALCULATED	308,163,419	13,019,854	14,320,300	68,477,169	50,492,344	16,768,132	6,346,948	64,883,053	73,855,618
44	EO	OTHER OPERATING EXPENSES	CALCULATED	70,497,486	2,227,285	1,804,950	10,581,490	7,466,992	4,301,422	24,158,235	9,579,095	10,378,016
45	EO	NET OPERATING INCOME BEFORE TAXES		1,234,901,135	55,924,231	36,955,001	258,250,643	200,982,473	40,430,688	107,826,906	258,913,574	275,617,618
46	EO	LESS:										
47	EO	E427 - E432 INTEREST CHARGES	TOTPLTNET	(137,585,275)	(6,350,955)	(5,117,857)	(31,854,346)	(25,197,165)	(882,434)	(1,007,114)	(32,506,750)	(34,668,654)
48	EO	**TOTAL OPERATING INCOME BEFORE TAXES**		1,372,486,410	62,275,187	42,072,858	290,104,989	226,179,638	41,313,122	108,834,020	291,420,324	310,286,272
49	EO	TSG-NF Gas Margin Reset		0	0	0	0	0	0	0	0	0
50	EO	Adjustment Reclassification Minus	ADJEXP_04	-17,563	0	0	-17,563	0	0	0	0	0
51	EO	Adjustment Reclassification Plus	ADJ_Plus_04	17,563	0	0	17,563	0	0	0	0	0
52	EO	Tax Bad Debt Adjustment	not_used	0	0	0	0	0	0	0	0	0
53	EO	Deferred Compensation & Severance Expense	LABOR	-785,085	-37,596	-165	-99,760	-64,504	-244,726	-196,006	-81,659	-60,669
54	EO	TAC Revenue Accrual Adjustment	not_used	0	0	0	0	0	0	0	0	0
55	EO	CIP Revenue Accrual Adjustment	not_used	0	0	0	0	0	0	0	0	0
56	EO	Amortization of CEF-EV Program Regulatory Assets	TOTPLTNET	3,943,445	182,030	146,687	913,004	722,197	25,292	28,866	931,703	993,667
57	EO	Amortization of CEF-EC Program Regulatory Assets	ECPRO_07	20,893,898	0	0	0	0	0	20,893,898	0	0
58	EO	Gas Bad Debt Adjustment		0	0	0	0	0	0	0	0	0
59	EO	BGS Administrative Expense Adjustment	A_GEXP	671,374	30,857	27,017	155,832	105,959	33,964	35,072	134,740	147,933

PUBLIC SERVICE ELECTRIC & GAS COMPANY
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				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	TI	**DEVELOPMENT OF INCOME TAXES**										
2	TI	**TAX ADJUSTMENTS - FEDERAL**										
3	TI	Stock Based Compensation	TOTPLTNET	-328,125	-15,146	-12,206	-75,969	-60,092	-2,105	-2,402	-77,525	-82,681
4	TI	GainState LILOAudit Refunds not yet received	TOTPLTNET	0	0	0	0	0	0	0	0	0
5	TI	Repair Allowance	TOTPLT	0	0	0	0	0	0	0	0	0
6	TI	Uncollectible Accounts	REVREQ	0	0	0	0	0	0	0	0	0
7	TI	Injuries and Damages ;	TOTPLT	0	0	0	0	0	0	0	0	0
8	TI	Diesel Fuel Credit	not_used	0	0	0	0	0	0	0	0	0
9	TI	Partnership income/loss per K-1	TOTPLT	-42,165	-1,885	-2,073	-9,853	-7,310	-509	-409	-9,394	-10,731
10	TI	Meals & entertainment	LABOR	-417,376	-19,987	-88	-53,035	-34,293	-130,104	-104,203	-43,412	-32,254
11	TI	Company owned life insurance	LABOR	0	0	0	0	0	0	0	0	0
12	TI	ESOP/401(k) Cash Dividends	TOTPLTNET	-1,032,350	-47,653	-38,401	-239,014	-189,063	-6,621	-7,557	-243,909	-260,131
13	TI	Medicare Subsidy	LABOR	0	0	0	0	0	0	0	0	0
14	TI	Dividends Received Deduction	TOTPLTNET	0	0	0	0	0	0	0	0	0
15	TI	W-2 Earnings Exceeding $1,000,000	LABOR	1,841,683	88,194	387	234,020	151,317	574,088	459,799	191,558	142,320
16	TI	Allowable Depreciation	DEPREXP	0	0	0	0	0	0	0	0	0
17	TI	Previously Ded Amort-Reacq Bonds	not_used	0	0	0	0	0	0	0	0	0
18	TI	Amortization of Computer Software	INTANGPLT	0	0	0	0	0	0	0	0	0
19	TI	Amort Def Gain - Sale of Gen Asset	not_used	0	0	0	0	0	0	0	0	0
20	TI	Gain on Sale of Services Corp Asset	not_used	0	0	0	0	0	0	0	0	0
21	TI	AFUDC / IDC	TOTPLT	-1,076,666	-48,134	-52,942	-251,584	-186,670	-13,004	-10,436	-239,873	-274,022
22	TI	Capitalized interest-Section 263A	TOTPLT	3,363,340	150,365	165,383	785,911	583,129	40,624	32,600	749,326	856,002
23	TI	Cost of removal	TOTPLT	0	0	0	0	0	0	0	0	0
24	TI	Utility Commodity Costs	not_used	0	0	0	0	0	0	0	0	0
25	TI	RAC-Environmental Cleanup Costs	not_used	0	0	0	0	0	0	0	0	0
26	TI	SBC-Societal Benefits Clause	not_used	0	0	0	0	0	0	0	0	0
27	TI	Deferred Comp - officers	LABOR	11,058	530	2	1,405	909	3,447	2,761	1,150	855
28	TI	Deduction of Securitizartion	not_used	0	0	0	0	0	0	0	0	0
29	TI	Accrued vacation pay adjustment	LABOR	-344,695	-16,507	-72	-43,800	-28,321	-107,448	-86,057	-35,853	-26,637
30	TI	3rd Party Claims	TOTPLT	87,346	3,905	4,295	20,410	15,144	1,055	847	19,460	22,230
31	TI	Deduction for New Network Meter Equipment	TOTPLT	0	0	0	0	0	0	0	0	0
32	TI	Gain/loss bond reacq	not_used	0	0	0	0	0	0	0	0	0
33	TI	Amortization of Call Option Sale	LABOR	0	0	0	0	0	0	0	0	0
34	TI	Defer Dividend Equivalents/Restricted Stock-Temp.	LABOR	0	0	0	0	0	0	0	0	0
35	TI	Repair Allow Deferral Carrying Charges	TOTPLT	0	0	0	0	0	0	0	0	0
36	TI	Contribution in Aid of Construct	TOTPLTNET	905,779	41,811	33,693	209,710	165,883	5,809	6,630	214,005	228,238
37	TI	FIN48 Services Allocation	TOTPLT	0	0	0	0	0	0	0	0	0
38	TI	Pension Accrual Adjustment	LABOR	-3,671,962	-175,841	-771	-466,591	-301,697	-1,144,621	-916,752	-381,931	-283,759
39	TI	Unallowable OPEB Amortization	LABOR	-105,080,197	-5,032,036	-22,067	-13,352,404	-8,633,621	-32,755,504	-26,234,595	-10,929,669	-8,120,301
40	TI	Deferred Return on CIP II	TOTPLT	66,348	2,966	3,263	15,504	11,503	801	643	14,782	16,886
41	TI	Deferred Depreciation on CIP II	TOTPLT	52,458	2,345	2,580	12,258	9,095	634	508	11,687	13,351
42	TI	FIN48 Reg Asset Reversal	LABOR	0	0	0	0	0	0	0	0	0
43	TI	Assessment by Board of Public Utilities of the State of NJ	TOTPLTNET	91,151	4,208	3,391	21,104	16,693	585	667	21,536	22,968
44	TI	Misc Adj - Permanent	TOTPLTNET	0	0	0	0	0	0	0	0	0
45	TI	Casualty Loss Deferred O&M & Ins Proceeds	TOTPLTNET	1,120,547	51,725	41,682	259,434	205,215	7,187	8,202	264,747	282,355
46	TI	Performance Incentive Plan Adjustment	TOTPLTNET	-1,045,327	-48,252	-38,884	-242,019	-191,440	-6,704	-7,652	-246,975	-263,401
47	TI	**DEVELOPMENT OF INCOME TAXES CONTINUED**										
48	TI	**TAX ADJUSTMENTS - FEDERAL CONTINUED**										
49	TI	LCAPP	TOTPLTNET	0	0	0	0	0	0	0	0	0
50	TI	Clause - Deferred Fuel	not_used	0	0	0	0	0	0	0	0	0
51	TI	Penalties	not_used	0	0	0	0	0	0	0	0	0
52	TI	Restricted Stock - Permanent	TOTPLTNET	-82,615	-3,814	-3,073	-19,128	-15,130	-530	-605	-19,519	-20,817
53	TI	Environmental Accrual	TOTPLTNET	0	0	0	0	0	0	0	0	0
54	TI	Legal Reserves (c & nc)	TOTPLTNET	401,853	18,550	14,948	93,039	73,595	2,577	2,942	94,944	101,259
55	TI	Material Supplies & Reserves	TOTPLT	107,143	4,790	5,268	25,036	18,576	1,294	1,039	23,871	27,269
56	TI	Lobbying Expenses	LABOR	0	0	0	0	0	0	0	0	0
57	TI	Bankrupticies & Acc. Prov. For Rents Receivable	TOTPLTNET	62,834	2,900	2,337	14,548	11,507	403	460	14,846	15,833
58	TI	Real Estate Taxes	TOTPLTNET	1,046,714	48,316	38,935	242,340	191,694	6,713	7,662	247,303	263,750
59	TI	Credits & Adjustments	TOTPLTNET	0	0	0	0	0	0	0	0	0
60	TI	**Miscellaneous**	TOTPLT									

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				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
61	TI	**TOTAL TAX ADJUSTMENTS - FEDERAL**		-149,324,736	-7,017,220	-1,824,302	-22,552,940	-15,194,328	-36,673,211	-29,240,133	-19,332,171	-17,490,432
62	TI											
63	TI	**TAX ADJUSTMENTS - STATE**										
64	TI	TEFA	TEFA_04	0	0	0	0	0	0	0	0	0
65	TI	Federal Depreciation Reversal	DEPREXP	72,042,765	3,199,226	3,518,770	16,711,170	12,406,929	1,318,508	775,464	15,942,999	18,169,698
66	TI	State Tax Depreciation	DEPREXP	36,681,624	1,628,932	1,791,633	8,508,736	6,317,169	671,338	394,839	8,117,611	9,251,367
67	TI	not used	not_used	0	0	0	0	0	0	0	0	0
68	TI	**TOTAL TAX ADJUSTMENTS - STATE**		108,724,389	4,828,158	5,310,403	25,219,906	18,724,097	1,989,846	1,170,303	24,060,610	27,421,065
69	TI											
70	TI	**TAXABLE NET INCOME - STATE**		1,331,886,063	60,086,125	45,558,959	292,771,955	229,709,407	6,629,758	80,764,190	296,148,763	320,216,905
71	TI	State Tax Liability		119,869,746	5,407,751	4,100,306	26,349,476	20,673,847	596,678	7,268,777	26,653,389	28,819,521
72	TI	Prior Year Adjustment	TOTPLTNET	0	0	0	0	0	0	0	0	0
73	TI	**TOTAL STATE INCOME TAX LIABILITY**		119,869,746	5,407,751	4,100,306	26,349,476	20,673,847	596,678	7,268,777	26,653,389	28,819,521
74	TI											
75	TI	**TAXABLE NET INCOME - FEDERAL**		1,103,291,929	49,850,216	36,148,250	241,202,573	190,311,463	4,043,233	72,325,110	245,434,765	263,976,318
76	TI	Federal Tax Liability		231,691,305	10,468,545	7,591,133	50,652,540	39,965,407	849,079	15,188,273	51,541,301	55,435,027
77	TI	not used	not_used	0	0	0	0	0	0	0	0	0
78	TI	not used	not_used	0	0	0	0	0	0	0	0	0
79	TI	**TOTAL FEDERAL INCOME TAX LIABILITY**		231,691,305	10,468,545	7,591,133	50,652,540	39,965,407	849,079	15,188,273	51,541,301	55,435,027
80	TI											
81	TI	**TOTAL INCOME TAX EXPENSE**		351,561,051	15,876,296	11,691,439	77,002,016	60,639,254	1,445,757	22,457,050	78,194,689	84,254,548
82	TI											
83	TI											
84	TI											
85	TI	**TAX RATES**										
86	TI	FEDERAL TAX RATE - CURRENT		21.000%								
87	TI	NEW JERSEY CORP BUSINESS TAX RATE		9.000%								
88	TI	CUSTOMER ACCT UNCOLLECTIBLE RATE		0.000								
89	TI	EFFECTIVE TAX RATE		28.110%								
90	TI	COMPOSITE RATE		28.110%								
91	TI	1 - EFFECTIVE TAX RATE		71.89000%								
92	TI											
93	TI	**DEVELOPMENT OF OPERATING INCOME ADJUSTED**										
94	TI	**E410 + E411- PROVISION FOR DEFERRED INCOME TAX**										
95	TI	Legal Reserves (c)	TOTPLTNET	0	0	0	0	0	0	0	0	0
96	TI	Tax Depreciation	DEPREXP	0	0	0	0	0	0	0	0	0
97	TI	Previously Ded Amort-Reacq Bonds	not_used	0	0	0	0	0	0	0	0	0
98	TI	Amortization of Power Gain	not_used	0	0	0	0	0	0	0	0	0
99	TI	Amort Def Gain - Sale of Gen Asset	not_used	0	0	0	0	0	0	0	0	0
100	TI	Gain on Sale of Services Corp Asset	not_used	0	0	0	0	0	0	0	0	0
101	TI	AFUDC / IDC	TOTPLT	1,076,666	48,134	52,942	251,584	186,670	13,004	10,436	239,873	274,022
102	TI	Capitalized interest-Section 263A	TOTPLT	-3,363,340	-150,365	-165,383	-785,911	-583,129	-40,624	-32,600	-749,326	-856,002
103	TI	Cost of removal	TOTPLT	0	0	0	0	0	0	0	0	0
104	TI	Utility Commodity Costs	not_used	0	0	0	0	0	0	0	0	0
105	TI	RAC-Environmental Cleanup Costs	not_used	0	0	0	0	0	0	0	0	0
106	TI	SBC-Societal Benefits Clause	not_used	0	0	0	0	0	0	0	0	0
107	TI	Deferred Comp - officers	LABOR	-11,058	-530	-2	-1,405	-909	-3,447	-2,761	-1,150	-855
108	TI	Deduction of Securitizartion	not_used	0	0	0	0	0	0	0	0	0
109	TI	Accrued vacation pay adjustment	LABOR	344,695	16,507	72	43,800	28,321	107,448	86,057	35,853	26,637
110	TI	3rd Party Claims	TOTPLT	-87,346	-3,905	-4,295	-20,410	-15,144	-1,055	-847	-19,460	-22,230
111	TI	Bankruptcies & Acc Prov-Rent Receivable	LABOR	0	0	0	0	0	0	0	0	0
112	TI	Deduction for New Network Meter Equipment	TOTPLT	0	0	0	0	0	0	0	0	0
113	TI	Gain/loss bond reacq	not_used	0	0	0	0	0	0	0	0	0
114	TI	Amortization of Call Option Sale	LABOR	0	0	0	0	0	0	0	0	0
115	TI	Defer Dividend Equivalents/Restricted Stock-Temp.	LABOR	0	0	0	0	0	0	0	0	0
116	TI	Repair Allow Deferral Carrying Charges	TOTPLT	0	0	0	0	0	0	0	0	0
117	TI	Contribution in Aid of Construct	TOTPLTNET	-905,779	-41,811	-33,693	-209,710	-165,883	-5,809	-6,630	-214,005	-228,238
118	TI	FIN48 Services Allocation	TOTPLT	0	0	0	0	0	0	0	0	0
119	TI	Pension Accrual Adjustment	LABOR	3,671,962	175,841	771	466,591	301,697	1,144,621	916,752	381,931	283,759
120	TI	Unallowable OPEB Amortization	LABOR	105,080,197	5,032,036	22,067	13,352,404	8,633,621	32,755,504	26,234,595	10,929,669	8,120,301

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 STAFF ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement	System Delivery Energy	Local Delivery Energy
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
121	TI	Fin Def-Energy Competition Act Ct	TOTPLT	0	0	0	0	0	0	0	0	0
122	TI	Conditional Asset Retire Obligations	TOTPLTNET	0	0	0	0	0	0	0	0	0
123	TI	Rabbi Trust Unrealized Losses	LABOR	0	0	0	0	0	0	0	0	0
124	TI	FIN48 Reg Asset Reversal	LABOR	0	0	0	0	0	0	0	0	0
125	TI	Additional Real Estate Taxes	TOTPLT	108,083	4,832	5,315	25,256	18,739	1,305	1,048	24,080	27,508
126	TI	PIP Adjustment	LABOR	1,045,327	50,058	220	132,828	85,886	325,848	260,979	108,727	80,780
127	TI	Deferred NJ Corp Bus Tax(Net of FIT)	TOTPLTNET	0	0	0	0	0	0	0	0	0
128	TI	Misc	TOTPLT	0	0	0	0	0	0	0	0	0
129	TI	Construction Period Interest	TOTPLTNET	0	0	0	0	0	0	0	0	0
130	TI	Deferred Return on CIP II	TOTPLT	-66,348	-2,966	-3,263	-15,504	-11,503	-801	-643	-14,782	-16,886
131	TI	Deferred Depreciation on CIP II	TOTPLT	-52,458	-2,345	-2,580	-12,258	-9,095	-634	-508	-11,687	-13,351
132	TI	Customer Connections Fees	CUSTACCTS	-6,684,538	0	0	-114,268	0	-5,252,212	-1,318,058	0	0
133	TI	Decommissioning Costs	KWHMETER_04	0	0	0	0	0	0	0	0	0
134	TI	Investment Tax Credit	TOTPLT	0	0	0	0	0	0	0	0	0
135	TI	Assessment by Board of Public Utilities of the State of NJ	TOTPLTNET	-91,151	-4,208	-3,391	-21,104	-16,693	-585	-667	-21,536	-22,968
136	TI	Casualty Loss Deferred O&M & Ins Proceeds	TOTPLTNET	0	0	0	0	0	0	0	0	0
137	TI	GainState LILOAudit Refunds not yet received	TOTPLTNET	0	0	0	0	0	0	0	0	0
138	TI	LCAPP	TOTPLTNET	0	0	0	0	0	0	0	0	0
139	TI	Audit Adjustment	not_used	0	0	0	0	0	0	0	0	0
140	TI	Stock Based Compensation	TOTPLTNET	328,125	15,146	12,206	75,969	60,092	2,105	2,402	77,525	82,681
141	TI	Clause - Deferred Fuel	not_used	0	0	0	0	0	0	0	0	0
142	TI	Legal Reserves (nc)	TOTPLTNET	-401,853	-18,550	-14,948	-93,039	-73,595	-2,577	-2,942	-94,944	-101,259
143	TI											
144	TI											
145	TI	**DEVELOPMENT OF OPERATING INCOME ADJ CONTINUE**										
146	TI	**E410 + E411- PROVISION FOR DEFER INC TAX CONTINU**										
147	TI	Material Supplies & Reserves	TOTPLTNET	-107,143	-4,946	-3,985	-24,806	-19,622	-687	-784	-25,314	-26,998
148	TI	Medicare Subsidy	TOTPLTNET									
149	TI	**TOTAL DEFERRED INCOME TAX**		144,525,616	7,115,721	1,779,204	22,716,135	15,444,321	31,830,837	28,280,881	19,656,221	17,702,297
150	TI											
151	TI	**TOTAL INC TAXES DEF IN PRIOR YEAR**	not_used	0	0	0	0	0	0	0	0	0
152	TI	**TOTAL INVEST TAX CRED ADJ (NET)**	not_used	0	0	0	0	0	0	0	0	0
153	TI	**TOTAL PRO FORMA OP INC ADJUSTMENTS**	not_used	0	0	0	0	0	0	0	0	0
154	TI											
155	TI	**OPERATING INCOME ADJUSTED**		738,814,468	32,932,214	23,484,359	158,532,492	124,898,899	7,154,095	57,088,975	161,062,663	173,660,773
156	TI	Severance Pay (nc)	LABOR	154,681	7,407	32	19,655	12,709	48,217	38,618	16,089	11,953
157	TI	CEF- EV Deferral	TOTPLT	1,855,840	82,969	91,256	433,654	321,762	22,416	17,988	413,467	472,329
158	TI	CEF- EC AMI	TOTPLT	20,866,765	932,889	1,026,067	4,875,932	3,617,839	252,036	202,257	4,648,952	5,310,793
159	TI	Casualty Loss Deferred O&M	TOTPLTNET	-1,120,547	-51,725	-41,682	-259,434	-205,215	-7,187	-8,202	-264,747	-282,355
160	TI	Bankruptcies and Accum Provision for Rent Receivable	TOTPLT	53,745	2,403	2,643	12,559	9,318	649	521	11,974	13,679
161	TI	Amort of Def Gain on Sale of Services Assets	not_used	0	0	0	0	0	0	0	0	0
162	TI	Additional Rental Income - NJ Properties	TOTPLT	-16,349	-731	-804	-3,820	-2,835	-197	-158	-3,642	-4,161
163	TI	Amort of Deferred Gain on Sale of Generation Assets	not_used	0	0	0	0	0	0	0	0	0
164	TI	Amort of Def Gain on Sale of Services Assets	not_used	0	0	0	0	0	0	0	0	0
165	TI	Additional Rental Income - NJ Properties	TOTPLT	16,349	731	804	3,820	2,835	197	158	3,642	4,161
166	TI	Additional Expenses on Rental Property	TOTPLT	-108,083	-4,832	-5,315	-25,256	-18,739	-1,305	-1,048	-24,080	-27,508
167	TI	Unrealized G/L on Equity Securities	TOTPLT	-125,367	-5,605	-6,165	-29,295	-21,736	-1,514	-1,215	-27,931	-31,907
168	TI	Medicare Subsidy	not_used	0	0	0	0	0	0	0	0	0
169	TI	State NOL CF (c)	DEPREXP	-17,908,279	-795,259	-874,690	-4,154,037	-3,084,095	-327,753	-192,764	-3,963,086	-4,516,596
170	TI	Severance Pay (nc)	LABOR	-154,681	-7,407	-32	-19,655	-12,709	-48,217	-38,618	-16,089	-11,953
171	TI	Reversal of Book Income from Partnerships	TOTPLT	-42,165	-1,885	-2,073	-9,853	-7,310	-509	-409	-9,394	-10,731
172	TI	Line Pack Adjustment	not_used	0	0	0	0	0	0	0	0	0
173	TI	Real Estate Taxes (nc)	TOTPLT	-1,046,714	-46,795	-51,469	-244,585	-181,477	-12,643	-10,146	-233,200	-266,399
174	TI	RE - ROU Lease Asset	TOTPLT	-319,172	-14,269	-15,694	-74,581	-55,337	-3,855	-3,094	-71,109	-81,232
175	TI	RE - Lease Liability	TOTPLT	236,259	10,562	11,617	55,207	40,962	2,854	2,290	52,637	60,130
176	TI	R & D Credits CF	TOTPLT	-15,263	-682	-751	-3,566	-2,646	-184	-148	-3,400	-3,885
177	TI	Plant Related	DEPREXP	37,305,084	1,656,619	1,822,084	8,653,355	6,424,538	682,748	401,550	8,255,582	9,408,608
178	TI	Partnership Income/Loss (nc)	TOTPLT	42,165	1,885	2,073	9,853	7,310	509	409	9,394	10,731
179	TI	Injuries & Damages - FT	TOTPLT	-328,505	-14,686	-16,153	-76,762	-56,956	-3,968	-3,184	-73,188	-83,608
180	TI	FAS 5 (ASC40) Reserve - Sales Tax	not_used	0	0	0	0	0	0	0	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement	System Delivery Energy	Local Delivery Energy
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
181	TI	Deferred Employer ER FICA	LABOR	7,086,760	339,368	1,488	900,505	582,264	2,209,078	1,769,299	737,113	547,645
182	TI	Deduction for Retention Payments (c)	LABOR	5,352	256	1	680	440	1,668	1,336	557	414
183	TI	Clause - Navigant Studies	not_used	0	0	0	0	0	0	0	0	0
184	TI	Clause - Demographic Studies	not_used	0	0	0	0	0	0	0	0	0
185	TI	Clause - Societal Benefits Clause (AAP)	not_used	0	0	0	0	0	0	0	0	0
186	TI	Clause - RAC (Environmental Clean Up)	not_used	0	0	0	0	0	0	0	0	0
187	TI	Customer Advances	TOTPLTNET	-4,645,423	-214,433	-172,799	-1,075,529	-850,756	-29,794	-34,004	-1,097,556	-1,170,551
188	TI	Current SHARE -- FT	DEPREXP	2,912,070	129,317	142,234	675,489	501,506	53,296	31,345	644,439	734,445
189	TI	Fed Amort of Deferred Gain on Sale of Generation Assets	not_used	0	0	0	0	0	0	0	0	0
190	TI	Amort of Deferred Gain on Sale of Generation Assets	not_used	0	0	0	0	0	0	0	0	0
191	TI	Previously Deducted Amort - Reacquired Bonds	not_used	0	0	0	0	0	0	0	0	0
192	TI	COVID Deferrals	not_used	0	0	0	0	0	0	0	0	0
193	TI	CECL Reserve	not_used	0	0	0	0	0	0	0	0	0
194	TI	Reversal of Book Income from Partnerships	TOTPLT	42,165	1,885	2,073	9,853	7,310	509	409	9,394	10,731
195	TI	RE - ROU Lease Asset	TOTPLT	319,172	14,269	15,694	74,581	55,337	3,855	3,094	71,109	81,232
196	TI	RE - Lease Liability	TOTPLT	-236,259	-10,562	-11,617	-55,207	-40,962	-2,854	-2,290	-52,637	-60,130
197	TI	Rabbi Trust	not_used	0	0	0	0	0	0	0	0	0
198	TI	R & D Credits CF	not_used	0	0	0	0	0	0	0	0	0
199	TI	Previously Deducted Amort - Reacquired Bonds	not_used	0	0	0	0	0	0	0	0	0
200	TI	Plant Related	DEPREXP	-33,454,683	-1,485,633	-1,634,020	-7,760,209	-5,761,437	-612,279	-360,104	-7,403,492	-8,437,509
201	TI	R&D Expenditure	TOTPLT	-5,622	-251	-276	-1,314	-975	-68	-54	-1,253	-1,431
202	TI	Qualified Transportation Fringe	LABOR	162,269	7,771	34	20,619	13,332	50,582	40,512	16,878	12,540
203	TI	Entertainment (100%)	LABOR	38,419	1,840	8	4,882	3,157	11,976	9,592	3,996	2,969
204	TI	Diesel Fuel Tax Credit	TOTPLT	82	4	4	19	14	1	1	18	21
205	TI	Company Owned Life Insurance - Tax	LABOR	-58,279	-2,791	-12	-7,405	-4,788	-18,167	-14,550	-6,062	-4,504
206	TI	Company Owned Life Insurance - Book	LABOR	-1,117,127	-53,497	-235	-141,952	-91,786	-348,230	-278,905	-116,195	-86,328
207	TI	Amortization of Reacquisition of Pref Stock	TOTPLT	11,771	526	579	2,751	2,041	142	114	2,623	2,996
208	TI	Line Pack Adjustment	not_used	0	0	0	0	0	0	0	0	0
209	TI	Injuries & Damages - FT	TOTPLT	1,298,774	58,064	63,864	303,484	225,179	15,687	12,589	289,357	330,550
210	TI	Fed Amort of Deferred Gain on Sale of Generation Assets	not_used	0	0	0	0	0	0	0	0	0
211	TI	FAS 5 (ASC40) Reserve - Sales Tax	not_used	0	0	0	0	0	0	0	0	0
212	TI	Deferred Employer ER FICA	LABOR	-7,086,760	-339,368	-1,488	-900,505	-582,264	-2,209,078	-1,769,299	-737,113	-547,645
213	TI	Deduction for Retention Payments (c)	LABOR	-5,352	-256	-1	-680	-440	-1,668	-1,336	-557	-414
214	TI	Customer Connection Fees (Contributions in Aid of Constructi	TOTPLTNET	6,684,538	308,559	248,650	1,547,634	1,224,197	42,873	48,930	1,579,330	1,684,366
215	TI	Customer Advances	TOTPLTNET	4,645,423	214,433	172,799	1,075,529	850,756	29,794	34,004	1,097,556	1,170,551
216	TI	Current SHARE -- FT	DEPREXP	-11,513,122	-511,267	-562,333	-2,670,605	-1,982,746	-210,710	-123,927	-2,547,844	-2,903,691
217	TI	COVID Deferrals	not_used	0	0	0	0	0	0	0	0	0
218	TI	Clause - Societal Benefits Clause (AAP)	not_used	0	0	0	0	0	0	0	0	0
219	TI	Clause - RAC (Environmental Clean Up)	not_used	0	0	0	0	0	0	0	0	0
220	TI	Clause - Navigant Studies	not_used	0	0	0	0	0	0	0	0	0
221	TI	Clause - Demographic Studies	not_used	0	0	0	0	0	0	0	0	0
222	TI	CEF- EV Deferral	TOTPLT	-1,855,840	-82,969	-91,256	-433,654	-321,762	-22,416	-17,988	-413,467	-472,329
223	TI	CEF- EC AMI	TOTPLT	-20,866,765	-932,889	-1,026,067	-4,875,932	-3,617,839	-252,036	-202,257	-4,648,952	-5,310,793
224	TI	CECL Reserve	not_used	0	0	0	0	0	0	0	0	0
225	TI	Unrealized G/L on Equity Securities	TOTPLT	125,367	5,605	6,165	29,295	21,736	1,514	1,215	27,931	31,907
226	TI	Unicap book/tax inventory FS	not_used	0	0	0	0	0	0	0	0	0
227	TI	Tax Net Bad Debt Writeoffs - FT	TOTPLT	-460,907	-20,606	-22,664	-107,700	-79,911	-5,567	-4,467	-102,686	-117,305
228	TI	State NOL CF (c)	DEPREXP	17,908,279	795,259	874,690	4,154,037	3,084,095	327,753	192,764	3,963,086	4,516,596

Updated for 9 and 3

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement	System Delivery Energy	Local Delivery Energy
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	LR	**DEVELOPMENT OF LABOR ALLOCATION FACTOR**										
2	LR											
3	LR	**PRODUCTION LABOR EXPENSE**	not_used	0	0	0	0	0	0	0	0	0
4	LR											
5	LR	**TRANSMISSION LABOR EXPENSE**	not_used	0	0	0	0	0	0	0	0	0
6	LR											
7	LR	**DISTRIBUTION LABOR EXPENSE**										
8	LR	Operation										
9	LR	582-Station Equipment	E367PLT	280,636	663	40	91,778	40,746	0	0	48,427	98,982
10	LR	583-Overhead Lines	E367PLT	941,919	2,225	135	308,041	136,758	0	0	162,538	332,222
11	LR	584-Underground Lines	E367PLT	4,591,058	10,845	659	1,501,438	666,578	0	0	792,237	1,619,301
12	LR	586-Metering	MTROMMIN_07	4,311,826	0	0	0	0	0	4,311,826	0	0
13	LR	587-Customer Installations	MTROMMIN_07	17,308,754	0	0	0	0	0	17,308,754	0	0
14	LR	588-Miscellaneous	DISTEXPO	16,169,609	186,473	1,522	391,230	2,925,275	0	5,802,178	3,667,762	3,195,169
15	LR	Total Operation		43,603,802	200,206	2,357	2,292,485	3,769,357	0	27,422,758	4,670,963	5,245,674
16	LR	Maintenance										
17	LR	590-Supervision & Engineering	DISTEXPM	0	0	0	0	0	0	0	0	0
18	LR	591-Structures	E361PLT	2,559,859	0	0	0	1,095,258	0	0	1,464,601	0
19	LR	592-Station Equipment	E362PLT	8,699,368	0	0	0	3,722,100	0	0	4,977,268	0
20	LR	593-Overhead Lines	E365PLT	11,294,340	34,257	0	2,673,491	2,605,807	0	0	3,181,313	2,799,472
21	LR	594-Underground Lines	E367PLT	11,333,758	26,773	1,627	3,706,538	1,645,555	0	0	1,955,763	3,997,502
22	LR	595-Line Transformers	LNTRFRMR_04	2,457,581	0	0	2,457,581	0	0	0	0	0
23	LR	596-Street Lighting and Signal Systems	E373PLT	7,842,365	7,299,789	29,395	132,951	103,644	0	0	133,183	143,403
24	LR	597-Meters	MTROMMIN_07	700,642	0	0	0	0	0	700,642	0	0
25	LR	598-Other Distribution Maintenance	DISTEXPM	529,302	53,426	12	95,281	122,632	0	770	155,630	101,549
26	LR	Total Maintenance		45,417,214	7,414,246	31,034	9,065,842	9,294,996		701,413	11,867,757	7,041,925
27	LR	TOTAL DISTRIBUTION LABOR EXPENSE		89,021,016	7,614,452	33,391	11,358,327	13,064,353	0	28,124,171	16,538,721	12,287,599
28	LR											
29	LR	**E901-E903,E905 CUST ACCOUNTS EXPENSE**	CUSTACCTS	58,697,026	0	0	1,003,385	0	46,119,752	11,573,889	0	0
30	LR	**E907-E910, xDSM CUST SERV & INFO EXP**	CUSTS_I	5,539,923	0	0	2,094,208	0	3,445,715	0	0	0
31	LR	**E911-E916 SALES EXPENSE**	SALESEXP	0	0	0	0	0	0	0	0	0
32	LR	**ADMIN & GENERAL EXP ACCOUNTS xE926**	SALESEXP	5,748,870	0	0	5,748,870	0	0	0	0	0
33	LR	**Employee Pension/Benefits Acct E926**	LABOR	0	0	0	0	0	0	0	0	0
34	LR											
35	LR	**TOTAL OPERATION & MAINT LABOR EXPENSE**		159,006,836	7,614,452	33,391	20,204,791	13,064,353	49,565,467	39,698,060	16,538,721	12,287,599

PUBLIC SERVICE ELECTRIC & GAS COMPANY
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12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement	System Delivery Energy	Local Delivery Energy
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	CA	**DEVELOPMENT OF CAPITAL ADDITIONS ALLOCATION FACTOR**										
2	CA											
3	CA	**INTANGIBLE PLANT**	not_used	0	0	0	0	0	0	0	0	0
4	CA	**PRODUCTION PLANT**	not_used	0	0	0	0	0	0	0	0	0
5	CA											
6	CA	**TRANSMISSION PLANT**										
7	CA	E352 Structure & Improvements	not_used	0	0	0	0	0	0	0	0	0
8	CA	E353 Station Equipment	not_used	0	0	0	0	0	0	0	0	0
9	CA	E354/355 Towers and Fixtures	not_used	0	0	0	0	0	0	0	0	0
10	CA	E356 OH Cond and Devices	not_used	0	0	0	0	0	0	0	0	0
11	CA	E357 UG Conduits	not_used	0	0	0	0	0	0	0	0	0
12	CA	E358 Underground Cond. and Devices	not_used	0	0	0	0	0	0	0	0	0
13	CA	E359 Roads and Trails	not_used	0	0	0	0	0	0	0	0	0
14	CA	Other Tangible Plant Unallocated	not_used	0	0	0	0	0	0	0	0	0
15	CA	TOTAL TRANSMISSION PLANT		0	0	0	0	0	0	0	0	0
16	CA											
17	CA	**DISTRIBUTION PLANT**										
18	CA	E360 Land and Land Rights	E360PLT	3,481,598	0	0	0	1,489,632	0	0	1,991,966	0
19	CA	E361 Structures and Improvements	E361PLT	1,433,350	0	0	0	613,271	0	0	820,079	0
20	CA	E362 Station Equipment	E362PLT	72,557,752	0	0	0	31,044,465	0	0	41,513,287	0
21	CA	E364 Poles Towers and Fixtures	E364PLT	86,501,520	835,763	0	27,289,006	11,682,762	0	0	17,165,182	29,528,807
22	CA	E365 OH Conductors and Dev.	E365PLT	235,018,380	712,839	0	55,631,373	54,222,955	0	0	66,198,377	58,252,835
23	CA	E366 Underground Conduits	E367PLT	3,221,386	7,610	462	1,053,507	467,715	0	0	555,885	1,136,207
24	CA	E367 Underground Cond. and Dev.	E367PLT	32,807,746	77,501	4,710	10,729,288	4,763,375	0	0	5,661,333	11,571,539
25	CA	E368 Line Transformers - Energy Related - Local	KWH_SEC_10	48,751,051	0	0	0	0	0	0	0	48,751,051
26	CA	E368 Line Transformers - Demand Related - Local	CP_SEC_04	44,108,093	0	0	44,108,093	0	0	0	0	0
27	CA	E369 Services	E369PLT	11,962,969	0	11,962,969	0	0	0	0	0	0
28	CA	E370 Meters	METERPLT	73,420,491	0	0	24,547,943	0	0	15,333,598	0	33,538,951
29	CA	E373 Street Lighting	E373PLT	39,887,684	37,128,046	149,507	676,211	527,152	0	0	677,394	729,374
30	CA	E374 Asset Retirement Obligations	TOTPLT									
31	CA	TOTAL DISTRIBUTION PLANT		653,152,020	38,761,759	12,117,649	164,035,421	104,811,328	0	15,333,598	134,583,502	183,508,763
32	CA											
33	CA	**TOTAL CAPITAL ADDITIONS**		653,152,020	38,761,759	12,117,649	164,035,421	104,811,328	0	15,333,598	134,583,502	183,508,763

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement	System Delivery Energy	Local Delivery Energy
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	AF	**ALLOCATION FACTOR TABLE**										
2	AF	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**										
3	AF											
4	AF	**ALLOCATION FACTORS PART A**										
5	AF											
6	AF	Number of Customers x Aux &SL rates - local	CUSTNUMX_04	2,318,149	0	0	2,318,149	0	0	0	0	0
7	AF											
8	AF											
9	AF	CP @ 26 kV lines - switching station load -systems	CP_SUBT_05	3,519,017	0	0	0	3,519,017	0	0	0	0
10	AF	CP @ primary lines - systems	CP_PRI_05	8,928,659	0	0	0	8,928,659	0	0	0	0
11	AF	Sum Cust Peaks @ 26 kV lines - local	SUMPK_SUBT_04	21,256,013	0	0	21,256,013	0	0	0	0	0
12	AF	Sum Cust Peaks @ primary lines - local	SUMPK_PRI_04	19,856,464	0	0	19,856,464	0	0	0	0	0
13	AF	Sum Cust Peaks @ secondary lines - local	SUMPK_SEC_04	20,498,179	0	0	20,498,179	0	0	0	0	0
14	AF											
15	AF											
16	AF	CP @ secondary lines - local	CP_SEC_04	8,231,675	0	0	8,231,675	0	0	0	0	0
17	AF	CP @ primary lines - local	CP_PRI_04	8,928,659	0	0	8,928,659	0	0	0	0	0
18	AF	NCP @ meter - local	NCP_MTR_04	10,800,203	0	0	10,800,203	0	0	0	0	0
19	AF	NCP @ meter - measurement	NCP_MTR_07	10,800,203	0	0	0	0	0	10,800,203	0	0
20	AF	NCP @ meter - cust svs	NCP_MTR_06	10,800,203	0	0	0	0	10,800,203	0	0	0
21	AF	NCP x SL rates @ meter - measurement	NCPXSL_MTR_07	10,698,184	0	0	0	0	0	10,698,184	0	0
22	AF	**BILLING DETERMINANTS**										
23	AF											
24	AF	Number of Customers		2,348,219	2,348,219	2,348,219	2,348,219	2,348,219	2,348,219	2,348,219	2,348,219	2,348,219
25	AF	Delivered kWh @ Meter - annual (w/n net)		40,231,265,119	40,231,265,119	40,231,265,119	40,231,265,119	40,231,265,119	40,231,265,119	40,231,265,119	40,231,265,119	40,231,265,119
26	AF	Delivered Kw @ Meter - annual		0	0	0	0	0	0	0	0	0
27	AF											
28	AF											
29	AF	**ALLOCATION FACTORS PART B**										
30	AF											
31	AF	Delivery kWh @ meter	KWHMETER_04	40,816,033,564	0	0	40,816,033,564	0	0	0	0	0
32	AF	Delivery kWh @ meter x non-profiled rates	KWHMETERX_04	21,338,981,079	0	0	21,338,981,079	0	0	0	0	0
33	AF	Delivery kWh @ subtrans - System E	KWH_SUBT_09	12,282,908,123	0	0	0	0	0	0	12,282,908,123	0
34	AF	Delivery kWh @ primary - System E	KWH_PRI_09	36,303,573,183	0	0	0	0	0	0	36,303,573,183	0
35	AF	Delivery kWh @ primary - Local E	KWH_PRI_10	36,303,573,183	0	0	0	0	0	0	0	36,303,573,183
36	AF	Delivery kWh @ secondary - Local E	KWH_SEC_10	32,329,765,823	0	0	0	0	0	0	0	32,329,765,823
37	AF	Delivery kWh @ meter - measurement	KWHMETER_07	40,781,263,034	0	0	0	0	0	40,781,263,034	0	0
38	AF	Delivery kWh @ meter - cust svs	KWHMETER_06	40,781,263,034	0	0	0	0	40,781,263,034	0	0	0
39	AF											
40	AF											
41	AF	**ALLOCATION FACTORS PART C**										
42	AF											
43	AF	Avg Customer Bills - measurement	CUSTAVG_07	2,335,622	0	0	0	0	0	2,335,622	0	0
44	AF	E370 excess meter investment - local delivery - Demand	METERSEXC_04	124,473,055	0	0	124,473,055	0	0	0	0	0
45	AF	E370 excess meter investment - local delivery - Energy	METERSEXC_10	124,473,055	0	0	0	0	0	0	0	124,473,055
46	AF	Meter O&M - measurement	METERPLT_07	456,573,728	0	0	0	0	0	456,573,728	0	0
47	**AF**	**ALLOCATION FACTOR TABLE CONTINUED**										
48	**AF**	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**										
49	AF											
50	AF	E370 excess mtr invst - measrmnt	METERSEXC_07	124,473,055	0	0	0	0	0	124,473,055	0	0
51	AF	CP @ 26 kV lines - switching station load - dummy	CP@SUBT_08	0	0	0	0	0	0	0	0	0
52	AF	E587 Customer Installation Expenses Local	CUSINT_04	112	0	0	112	0	0	0	0	0
53	AF	E587 Customer Installation Expenses System	CUSINT_05	112	0	0	0	112	0	0	0	0
54	AF	Draft EC Proforma	ECPRO_07	472,721,631	0	0	0	0	0	472,721,631	0	0
55	AF	Expense Reclassification-local	ADJEXP_04	-17,563	0	0	-17,563	0	0	0	0	0
56	AF	Expense Reclassification Plus-local	ADJ_Plus_04	17,563	0	0	17,563	0	0	0	0	0
57	AF	E369 minimum Service investment- access	SERVICESMIN_03	360,747,418	0	360,747,418	0	0	0	0	0	0
58	AF	E369 excess Service investment- local delivery	SERVICESEXC_04	709,786,184	0	0	709,786,184	0	0	0	0	0
59	AF	Avg Customer Bills - local	CUSTAVG_04	2,348,219	0	0	2,348,219	0	0	0	0	0
60	AF	Avg Customer Bills - cust svs	CUSTAVG_06	2,348,219	0	0	0	0	2,348,219	0	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement	System Delivery Energy	Local Delivery Energy
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
61	AF	E370 minimum meter investment - measurement	METERSMIN_07	191,661,323	0	0	0	0	0	191,661,323	0	0
62	AF	E368 Line Transfomers - local	LNTRFRMR_04	559,887,636	0	0	559,887,636	0	0	0	0	0
63	AF	Billing Function costs - cust svs	BILLING_06	130,951	0	0	0	0	130,951	0	0	0
64	AF	Account Maint - cust svs	ACCTMAINT_06	80,564,013	0	0	0	0	80,564,013	0	0	0
65	AF	Meter Reading Costs - measurement	MRCOST_07	20,538,511	0	0	0	0	0	20,538,511	0	0
66	AF	Sales	SALES_06	0	0	0	0	0	0	0	0	0
67	AF	Other Utility work by Cust Ops - local	UTILWORK_04	3,334,747	0	0	3,334,747	0	0	0	0	0
68	AF											
69	AF											
70	**AF**	**ALLOCATION FACTOR TABLE CONTINUED**										
71	**AF**	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**										
72	AF											
73	AF	Choice - local	CHOICE_04	0	0	0	0	0	0	0	0	0
74	AF											
75	AF	Direct - PSAL - streetlighting	DIR_PSAL_02	1	1	0	0	0	0	0	0	0
76	AF	Direct - BPL - streetlighting	DIR_BPL_02	1	1	0	0	0	0	0	0	0
77	AF	Direct - BPL-POF - streetlighting	DIR_BPLPOF_02	1	1	0	0	0	0	0	0	0
78	AF	Direct - HTS-HV - access	DIR_HTSHV_03	1	0	1	0	0	0	0	0	0
79	AF	Direct - HEP - access	DIR_HEP_03	0	0	0	0	0	0	0	0	0
80	AF	Direct - HTS-Sub - systems	DIR_HTSS_05	1	0	0	0	1	0	0	0	0
81	AF											
82	AF	Direct - HTS-Sub - local	DIR_HTSS_04	1	0	0	1	0	0	0	0	0
83	AF	Meter O&M - minimum - measurement	MTROMMIN_07	6,387,137	0	0	0	0	0	6,387,137	0	0
84	AF	Meter O&M - excess - measurement	MTROMEXC_07	0	0	0	0	0	0	0	0	0
85	AF	WN TEFA Responsibility	TEFA_04	0	0	0	0	0	0	0	0	0
86	AF											
87	AF	E370 excess meter investment - dummy	METERSEXC_08	5,064	0	0	0	0	0	0	0	0
88	AF	Meter O&M - excess - dummy	MTROMEXC_08	0	0	0	0	0	0	0	0	0
89	AF	E369 excess Service investment- dummy	SERVICESEXC_08	0	0	0	0	0	0	0	0	0
90	AF	E368 Line Transfomers - dummy	LNTRFRMR_08	0	0	0	0	0	0	0	0	0
91	AF	CP @ primary lines - dummy	CP@PRI_08	0	0	0	0	0	0	0	0	0
92	AF	Sum Cust Peaks @ secondary lines - local	SUMPK@SEC_08	0	0	0	0	0	0	0	0	0
93	AF											
94	AF											
95	AF	Dummy allocator for unused lines	not_used	0	0	0	0	0	0	0	0	0
96	AF											
97	AF	**Plant Related**										
98	AF	Distribution Plant Total	DISTPLT	10,773,828,418	488,615,049	537,418,784	2,552,883,868	1,894,899,857	0	76,316,914	2,434,960,990	2,788,732,956
99	AF	Distribution Plant x meters	DISTPLTXMTR	10,408,406,976	488,615,049	537,418,784	2,430,706,197	1,894,899,857	0	0	2,434,960,990	2,621,806,099
100	AF	Acct E360 - Land & Land Rights	E360PLT	51,314,168	0	0	0	21,955,213	0	0	29,358,955	0
101	AF	Acct E361 - Structures & Improvments	E361PLT	242,256,447	0	0	0	103,651,528	0	0	138,604,918	0
102	AF	Acct E362 - Station Equipment	E362PLT	1,565,418,169	0	0	0	669,777,783	0	0	895,640,386	0
103	AF	Acct E364 - Poles & Towers	E364PLT	1,027,443,483	9,926,985	0	324,132,007	138,764,932	0	0	203,883,749	350,735,810
104	AF	Acct E365 - OH Conductors & Devices x HTSHV	E365PLT	2,856,184,590	8,663,157	0	676,089,548	658,973,011	0	0	804,510,629	707,948,244
105	AF	Acct E366 - UG Conduit	E366PLT	512,107,003	1,209,731	73,522	167,477,027	74,353,110	0	0	88,369,620	180,623,992
106	AF	Acct E367 - UG Conductors & Devices x HEP	E367PLT	1,431,183,475	3,380,831	205,472	468,047,404	207,794,351	0	0	246,966,239	504,789,178
107	AF	Acct E369 Services	E369PLT	535,269,333	0	535,269,333	0	0	0	0	0	0
108	AF	Acct E370 Meters	METERPLT	365,421,442	0	0	122,177,671	0	0	76,316,914	0	166,926,857
109	AF	Acct E370 Meters x load profile meters	METERPLTXPR	365,421,442	0	0	122,177,671	0	0	76,316,914	0	166,926,857
110	AF	Acct E373 - Streetlights	E373PLT	499,027,153	464,501,858	1,870,457	8,459,940	6,595,096	0	0	8,474,749	9,125,053
111	AF	Subtrans Lines - HTS-S/Switching Station load	SUBTRANSLINES	1.0000			0.2110	0.7890				
112	AF	Primary Lines - 50 Sys CP/50 Loc Sum Cust Pks	PRIMARYLINES	1.0000			0.5000	0.5000				
113	AF	Acct E301-E303 Intangible Plt	INTANGPLT	40,584,928	1,814,427	1,995,655	9,483,470	7,036,536	490,200	393,380	9,042,004	10,329,255
114	**AF**	**ALLOCATION FACTOR TABLE CONTINUED**										
115	AF											
116	AF	Acct E399.10-23 Oth Tangible Plt	TANGPLT	0	0	0	0	0	0	0	0	0
117	AF	E391-E398 General Plant	GENPLT	429,584,593	20,166,534	22,180,803	100,322,166	78,207,913	0	0	100,497,773	108,209,403
118	AF	Common Plant	COMPLT	126,654,044	1,587,719	1,746,304	11,272,300	6,157,341	72,130,276	17,328,503	7,912,231	8,519,370
119	AF	Accts C389-C399, E389-E399 Com & Gen Plt	COMGENPLT	556,238,637	21,754,254	23,927,107	111,594,466	84,365,254	72,130,276	17,328,503	108,410,004	116,728,774
120	AF											

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				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
121	AF	Total Plant	TOTPLT	11,456,990,950	512,206,759	563,366,875	2,677,152,347	1,986,390,954	138,381,700	111,050,006	2,552,527,759	2,915,914,551
122	AF											
123	AF	Total Distribution Plant Reserve	TOTDRESERVE	3,099,332,698	126,416,094	252,481,133	742,150,688	455,781,716	84,778,006	49,872,573	577,895,582	809,956,907
124	AF	Total Net Plant	TOTPLTNET	8,357,658,252	385,790,665	310,885,742	1,935,001,659	1,530,609,238	53,603,694	61,177,433	1,974,632,177	2,105,957,644
125	AF											
126	AF											
127	AF	**Revenue Related**										
128	AF	Total Operating Revenue	TOTREV	1,925,019,676	85,793,001	57,631,548	380,964,199	308,674,444	120,320,838	162,249,361	396,414,677	412,971,607
129	AF											
130	AF	**Expense Related**										
131	AF	Distr Oper Exp	DISTEXPO	52,242,807	602,481	4,919	1,264,034	9,451,348	0	18,746,406	11,850,265	10,323,355
132	AF	Distr Maint Exp	DISTEXPM	123,204,777	12,435,991	2,882	22,178,526	28,544,919	0	179,330	36,225,717	23,637,412
133	AF	Cust Serv & Info Expense	CUSTS_I	5,318,001	0	0	2,010,317	0	3,307,684	0	0	0
134	AF	Acct E901-E903,E905 Cust Acct Exp Excl 904	CACCTEXP	94,394,062	0	0	1,613,601	0	74,167,825	18,612,636	0	0
135	AF	Accts E901-E910 Excl 904 - Cust Accts,Serv & Info	CUSTSVSX	99,712,063	0	0	3,623,918	0	77,475,509	18,612,636	0	0
136	AF	Sales Expense	SALESEXP	40,922	0	0	40,922	0	0	0	0	0
137	AF	Total O&M Expense Excl 904-Uncollectibles	TOTOMXAG	311,457,637	14,621,631	4,551,297	43,654,897	49,732,635	58,820,596	23,917,272	63,038,955	53,120,355
138	AF	Tot Admin & Genl Exp xPension/Ben	A_GEXP	111,662,106	5,132,163	4,493,490	25,917,753	17,623,009	5,648,801	5,833,058	22,409,769	24,604,063
139	AF	Accts E901-E905 Cust Accts Exp Excl 904-Uncol	CUSTACCTS	94,394,062	0	0	1,613,601	0	74,167,825	18,612,636	0	0
140	AF	O&M + Capital Additions	EXPENDITURES	964,609,657	53,383,390	16,668,946	207,690,317	154,543,963	58,820,596	39,250,870	197,622,457	236,629,118
141	AF											
142	AF	Depreciation Expense (total)	DEPREXP	286,771,855	12,734,767	14,006,738	66,520,119	49,386,749	5,248,426	3,086,796	63,462,355	72,325,904
143	AF											
144	AF	NJ State Income Tax (CBT)	STATEINCTAX	119,869,746	5,407,751	4,100,306	26,349,476	20,673,847	596,678	7,268,777	26,653,389	28,819,521
145	AF	NJ State Deferred Income Tax	DFSTATEINCTAX	1,034,603	49,579	-308	130,323	84,027	325,719	260,875	106,338	78,051
146	AF											
147	AF	**Labor Expense Related**										
148	AF	Total Distribution Exp (Oper) Labor	TLABDO	43,603,802	200,206	2,357	2,292,485	3,769,357	0	27,422,758	4,670,963	5,245,674
149	AF	Total Distribution Exp (Maint) Labor	TLABDM	45,417,214	7,414,246	31,034	9,065,842	9,294,996	0	701,413	11,867,757	7,041,925
150	AF	Total Labor	LABOR	159,006,836	7,614,452	33,391	20,204,791	13,064,353	49,565,467	39,698,060	16,538,721	12,287,599
151	AF											
152	AF	**REVENUES AND BILLING DETERMINANTS**										
153	AF											
154	AF	Base Rate Sales Revenue	SALESREV	1,899,915,237	84,746,048	56,967,015	375,987,929	304,613,976	118,795,402	160,287,388	391,036,114	407,481,364
155	AF											
156	AF	Residential Service	REVRS	825,027,762	0	89,310	184,786,402	142,454,625	69,712,065	119,350,402	137,207,092	171,427,866
157	**AF**	**ALLOCATION FACTOR TABLE CONTINUED**										
158	AF											
159	AF	Residential Heating Service	REVRHS	4,437,681	0	562,242	601,198	458,667	337,783	415,740	937,099	1,124,951
160	AF	Residential Load Management Service	REVRLM	24,358,956	0	15,245,444	1,991,046	1,566,018	574,715	697,218	1,956,091	2,328,424
161	AF	Water Heating Service	REVWH	35,301,077	0	35,163,481	5,589	0	11,953	107,449	5,863	6,741
162	AF	Water Heating Storage Service	REVWHS	151,307	0	149,211	84	0	183	1,675	72	82
163	AF	Building Heating Service	REVHS	708,990	0	0	132,269	101,491	141,923	72,721	118,716	141,870
164	AF	Body Police Lighting Service	REVBLP	67,543,508	60,902,932	0	29,089	0	505,321	212	2,840,263	3,265,692
165	AF	Body Police Lighting Service from Publicly Owned	REVBLPPOF	741,039	388,331	0	993	0	21,652	11	153,527	176,524
166	AF	Private Street and Area Lighting Service	REVPAL	27,345,651	23,454,785	0	19,347	0	918,974	102	1,373,367	1,579,076
167	AF	General Power and Lighting Service	REVGLP	399,597,683	0	5,625,108	100,626,010	76,978,803	22,575,596	29,840,407	73,078,054	90,873,705
168	AF	Large Power and Lighting Service - Secondary	REVLPLS	388,159,549	0	106,400	78,418,990	62,703,126	14,166,885	6,482,454	104,726,264	121,555,429
169	AF	Large Power and Lighting Service - Primary	REVLPLP	74,444,444	0	25,775	9,084,095	16,043,615	3,031,704	1,129,763	30,245,088	14,884,405
170	AF	High Tension Service - Subtransmission	REVHTSS	49,205,760	0	44	229,267	4,307,630	4,629,395	1,528,208	38,394,617	116,599
171	AF	High Tension Service - High Voltage	REVHTSHV	2,891,829	0	0	63,550	0	2,167,253	661,026	0	0
172	AF	HEP	REVHEP	0	0	0	0	0	0	0	0	0
173	AF											
174	AF											
175	AF	Total Rev Req @ desired ROR	REVREQ	1,899,915,237	84,746,048	56,967,015	375,987,929	304,613,976	118,795,402	160,287,388	391,036,114	407,481,364
176	AF											
177	AF											
178	AF	**PRESENT REVENUES FROM SALES INPUT**										
179	AF											
180	AF	Total Sales of Electricity Revenues		0	0	0	0	0	0	0	0	0

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement	System Delivery Energy	Local Delivery Energy
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
181	AF	Sales of Electricity Revenues - Rates		1,254,696,745	1,254,696,745	1,254,696,745	1,254,696,745	1,254,696,745	1,254,696,745	1,254,696,745	1,254,696,745	1,254,696,745
182	AF	Sales of Electricity Revenues - Other		0	0	0	0	0	0	0	0	0
183	AF											
184	AF	**RATE OF RETURN**										
185	AF	Rate of Return (Equalized)	CALCULATED	7.55%	7.55%	7.55%	7.55%	7.55%	7.55%	7.55%	7.55%	7.55%

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				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	AP	**ALLOCATION PROPORTIONS TABLE**										
2	AP	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**										
3	AP											
4	AP	**ALLOCATION FACTORS PART A**										
5	AP											
6	AP	CP @ secondary lines - local	CP_SEC_04	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
7	AP	Number of Customers x Aux &SL rates - local	CUSTNUMX_04	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
8	AP											
9	AP											
10	AP	CP @ 26 kV lines - switching station load -systems	CP_SUBT_05	1.000000				1.000000				
11	AP	CP @ primary lines - systems	CP_PRI_05	1.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000
12	AP	Sum Cust Peaks @ 26 kV lines - local	SUMPK_SUBT_04	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
13	AP	Sum Cust Peaks @ primary lines - local	SUMPK_PRI_04	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
14	AP	Sum Cust Peaks @ secondary lines - local	SUMPK_SEC_04	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
15	AP	CP @ primary lines - local	CP_PRI_04	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
16	AP	NCP @ meter - local	NCP_MTR_04	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
17	AP	NCP @ meter - measurement	NCP_MTR_07	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000
18	AP	NCP @ meter - cust svs	NCP_MTR_06	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000
19	AP	NCP x SL rates @ meter - measurement	NCPXSL_MTR_07	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000
20	AP	**BILLING DETERMINANTS**										
21	AP											
22	AP	Number of Customers										
23	AP	Delivered kWh @ Meter - annual (w/n net)										
24	AP	Delivered Kw @ Meter - annual										
25	AP											
26	AP	**ALLOCATION FACTORS PART B**										
27	AP											
28	AP	Delivery kWh @ meter	KWHMETER_04	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
29	AP	Delivery kWh @ meter x non-profiled rates	KWHMETERX_04	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
30	AP											
31	AP	Delivery kWh @ subtrans - System E	KWH_SUBT_09	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000
32	AP	Delivery kWh @ primary - System E	KWH_PRI_09	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000
33	AP	Delivery kWh @ primary - Local E	KWH_PRI_10	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000
34	AP	Delivery kWh @ secondary - Local E	KWH_SEC_10	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000
35	AP	Delivery kWh @ meter - measurement	KWHMETER_07	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000
36	AP	Delivery kWh @ meter - cust svs	KWHMETER_06	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000
37	AP	**ALLOCATION PROPORTIONS TABLE CONTINUED**										
38	AP	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**										
39	AP											
40	AP	**ALLOCATION FACTORS PART C**										
41	AP											
42	AP	Avg Customer Bills - measurement	CUSTAVG_07	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000
43	AP	E370 excess meter investment - local delivery - Demand	METERSEXC_04	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
44	AP	E370 excess meter investment - local delivery - Energy	METERSEXC_10	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000
45	AP	Meter O&M - measurement	METERPLT_07	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000
46	AP	E370 excess mtr invst - measrmnt	METERSEXC_07	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000
47	AP	E587 Customer Installation Expenses Local	CUSINT_04	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
48	AP	E587 Customer Installation Expenses System	CUSINT_05	1.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000
49	AP	Draft EC Proforma	ECPRO_07	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000
50	AP	Expense Reclassification-local	ADJEXP_04	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
51	AP	Expense Reclassification Plus-local	ADJ_Plus_04	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
52	AP	E369 minimum Service investment- access	SERVICESMIN_03	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
53	AP	E369 excess Service investment- local delivery	SERVICESEXC_04	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
54	AP	Avg Customer Bills - local	CUSTAVG_04	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
55	AP	Avg Customer Bills - cust svs	CUSTAVG_06	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000
56	AP	E370 minimum meter investment - measurement	METERSMIN_07	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000
57	AP	E368 Line Transfomers - local	LNTRFRMR_04	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
58	AP	Billing Function costs - cust svs	BILLING_06	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000
59	AP	Account Maint - cust svs	ACCTMAINT_06	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000
60	AP	Meter Reading Costs - measurement	MRCOST_07	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000

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				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
61	AP	Sales	SALES_06	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
62	AP	Other Utility work by Cust Ops - local	UTILWORK_04	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
63	AP											
64	AP	Choice - local	CHOICE_04	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
65	AP											
66	AP	Direct - PSAL - streetlighting	DIR_PSAL_02	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
67	AP	Direct - BPL - streetlighting	DIR_BPL_02	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
68	AP	Direct - BPL-POF - streetlighting	DIR_BPLPOF_02	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
69	AP	Direct - HTS-HV - access	DIR_HTSHV_03	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
70	AP	Direct - HEP - access	DIR_HEP_03	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
71	AP	Direct - HTS-Sub - systems	DIR_HTSS_05	1.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000
72	AP											
73	AP	Direct - HTS-Sub - local	DIR_HTSS_04	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
74	AP	Meter O&M - minimum - measurement	MTROMMIN_07	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000
75	AP	Meter O&M - excess - measurement	MTROMEXC_07	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
76	AP	WN TEFA Responsibility	TEFA_04	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
77	AP											
78	AP	E370 excess meter investment - dummy	METERSEXC_08	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
79	AP	Meter O&M - excess - dummy	MTROMEXC_08	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
80	AP	E369 excess Service investment- dummy	SERVICESEXC_08	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
81	AP	E368 Line Transfomers - dummy	LNTRFRMR_08	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
82	AP	CP @ 26 kV lines - switching station load - dummy	CP@SUBT_08	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
83	AP	CP @ primary lines - dummy	CP@PRI_08	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
84	AP	Sum Cust Peaks @ secondary lines - local	SUMPK@SEC_08	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
85	AP											
86	AP	**ALLOCATION PROPORTIONS TABLE CONTINUED**										
87	AP	**INTERNALLY DEVELOPED ALLOCATION FACTORS**		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
88	AP											
89	AP	Dummy allocator for unused lines	not_used	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
90	AP											
91	AP	**Plant Related**										
92	AP	Distribution Plant Total	DISTPLT	1.000000	0.045352	0.049882	0.236952	0.175880	0.000000	0.007084	0.226007	0.258843
93	AP	Distribution Plant x meters	DISTPLTXMTR	1.000000	0.046944	0.051633	0.233533	0.182055	0.000000	0.000000	0.233942	0.251893
94	AP	Acct E360 - Land & Land Rights	E360PLT	1.000000	0.000000	0.000000	0.000000	0.427859	0.000000	0.000000	0.572141	0.000000
95	AP	Acct E361 - Structures & Improvments	E361PLT	1.000000	0.000000	0.000000	0.000000	0.427859	0.000000	0.000000	0.572141	0.000000
96	AP	Acct E362 - Station Equipment	E362PLT	1.000000	0.000000	0.000000	0.000000	0.427859	0.000000	0.000000	0.572141	0.000000
97	AP	Acct E364 - Poles & Towers	E364PLT	1.000000	0.009662	0.000000	0.315474	0.135058	0.000000	0.000000	0.198438	0.341367
98	AP	Acct E365 - OH Conductors & Devices x HTSHV	E365PLT	1.000000	0.003033	0.000000	0.236711	0.230718	0.000000	0.000000	0.281673	0.247865
99	AP	Acct E366 - UG Conduit	E366PLT	1.000000	0.002362	0.000144	0.327035	0.145191	0.000000	0.000000	0.172561	0.352708
100	AP	Acct E367 - UG Conductors & Devices x HEP	E367PLT	1.000000	0.002362	0.000144	0.327035	0.145191	0.000000	0.000000	0.172561	0.352708
101	AP	Acct E369 Services	E369PLT	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
102	AP	Acct E370 Meters	METERPLT	1.000000	0.000000	0.000000	0.334347	0.000000	0.000000	0.208846	0.000000	0.456806
103	AP	Acct E370 Meters x load profile meters	METERPLTXPR	1.000000	0.000000	0.000000	0.334347	0.000000	0.000000	0.208846	0.000000	0.456806
104	AP	Acct E373 - Streetlights	E373PLT	1.000000	0.930815	0.003748	0.016953	0.013216	0.000000	0.000000	0.016983	0.018286
105	AP	Subtrans Lines - HTS-S/Switching Station load	SUBTRANSLINES	1.000000	0.000000	0.000000	0.211000	0.789000	0.000000	0.000000	0.000000	0.000000
106	AP	Primary Lines - 50 Sys CP/50 Loc Sum Cust Pks	PRIMARYLINES	1.000000	0.000000	0.000000	0.500000	0.500000	0.000000	0.000000	0.000000	0.000000
107	AP											
108	AP	Acct E301-E303 Intangible Plt	INTANGPLT	1.000000	0.044707	0.049172	0.233670	0.173378	0.012078	0.009693	0.222792	0.254510
109	AP	Acct E399.10-23 Oth Tangible Plt	TANGPLT	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
110	AP	E391-E398 General Plant	GENPLT	1.000000	0.046944	0.051633	0.233533	0.182055	0.000000	0.000000	0.233942	0.251893
111	AP	Common Plant	COMPLT	1.000000	0.012536	0.013788	0.089001	0.048615	0.569506	0.136818	0.062471	0.067265
112	AP	Accts C389-C399, E389-E399 Com & Gen Plt	COMGENPLT	1.000000	0.039110	0.043016	0.200623	0.151671	0.129675	0.031153	0.194898	0.209854
113	AP											
114	AP	Total Plant	TOTPLT	1.000000	0.044707	0.049172	0.233670	0.173378	0.012078	0.009693	0.222792	0.254510
115	AP											
116	AP	Total Distribution Plant Reserve	TOTDRESERVE	1.000000	0.040788	0.081463	0.239455	0.147058	0.027354	0.016091	0.186458	0.261333
117	AP	Total Net Plant	TOTPLTNET	1.000000	0.046160	0.037198	0.231524	0.183139	0.006414	0.007320	0.236266	0.251979
118	AP											
119	AP	**ALLOCATION PROPORTIONS TABLE CONTINUED**		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
120	AP	**INTERNALLY DEVELOPED ALLOCATION FACTORS**		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000

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12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement	System Delivery Energy	Local Delivery Energy
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
121	AP											
122	AP	**Revenue Related**										
123	AP	Total Operating Revenue	TOTREV	1.000000	0.044567	0.029938	0.197901	0.160349	0.062504	0.084285	0.205928	0.214529
124	AP											
125	AP	**Expense Related**		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
126	AP	Distr Oper Exp	DISTEXPO	1.000000	0.011532	0.000094	0.024195	0.180912	0.000000	0.358832	0.226831	0.197603
127	AP	Distr Maint Exp	DISTEXPM	1.000000	0.100938	0.000023	0.180014	0.231687	0.000000	0.001456	0.294029	0.191855
128	AP	Cust Serv & Info Expense	CUSTS_I	1.000000	0.000000	0.000000	0.378021	0.000000	0.621979	0.000000	0.000000	0.000000
129	AP	Acct E901-E903,E905 Cust Acct Exp Excl 904	CACCTEXP	1.000000	0.000000	0.000000	0.017094	0.000000	0.785726	0.197180	0.000000	0.000000
130	AP	Accts E901-E910 Excl 904 - Cust Accts,Serv & Info	CUSTSVSX	1.000000	0.000000	0.000000	0.036344	0.000000	0.776992	0.186664	0.000000	0.000000
131	AP	Sales Expense	SALESEXP	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
132	AP	Total O&M Expense Excl 904-Uncollectibles	TOTOMXAG	1.000000	0.046946	0.014613	0.140163	0.159677	0.188856	0.076791	0.202400	0.170554
133	AP	Tot Admin & Genl Exp xPension/Ben	A_GEXP	1.000000	0.045962	0.040242	0.232109	0.157824	0.050588	0.052238	0.200693	0.220344
134	AP	Accts E901-E905 Cust Accts Exp Excl 904-Uncol	CUSTACCTS	1.000000	0.000000	0.000000	0.017094	0.000000	0.785726	0.197180	0.000000	0.000000
135	AP	O&M + Capital Additions	EXPENDITURES	1.000000	0.055342	0.017281	0.215310	0.160214	0.060979	0.040691	0.204873	0.245311
136	AP											
137	AP	Depreciation Expense (total)	DEPREXP	1.000000	0.044407	0.048843	0.231962	0.172216	0.018302	0.010764	0.221299	0.252207
138	AP											
139	AP	NJ State Income Tax (CBT)	STATEINCTAX	1.000000	0.045114	0.034206	0.219818	0.172469	0.004978	0.060639	0.222353	0.240424
140	AP	NJ State Deferred Income Tax	DFSTATEINCTAX	1.000000	0.047921	-0.000297	0.125964	0.081217	0.314825	0.252150	0.102782	0.075440
141	AP											
142	AP	**Labor Expense Related**										
143	AP	Total Distribution Exp (Oper) Labor	TLABDO	1.000000	0.004591	0.000054	0.052575	0.086446	0.000000	0.628908	0.107123	0.120303
144	AP	Total Distribution Exp (Maint) Labor	TLABDM	1.000000	0.163247	0.000683	0.199612	0.204658	0.000000	0.015444	0.261305	0.155050
145	AP	Total Labor	LABOR	1.000000	0.047888	0.000210	0.127069	0.082162	0.311719	0.249663	0.104013	0.077277
146	AP											
147	AP	REVENUES AND BILLING DETERMINANTS										
148	AP											
149	AP	Base Rate Sales Revenue	SALESREV	1.000000	0.044605	0.029984	0.197897	0.160330	0.062527	0.084366	0.205818	0.214473
150	AP											
151	AP	Residential Service	REVRS	1.000000	0.000000	0.000108	0.223976	0.172666	0.084497	0.144662	0.166306	0.207784
152	AP	Residential Heating Service	REVRHS	1.000000	0.000000	0.126697	0.135476	0.103357	0.076117	0.093684	0.211169	0.253500
153	AP	Residential Load Management Service	REVRLM	1.000000	0.000000	0.625866	0.081738	0.064289	0.023594	0.028623	0.080303	0.095588
154	AP	Water Heating Service	REVWH	1.000000	0.000000	0.996102	0.000158	0.000000	0.000339	0.003044	0.000166	0.000191
155	AP	Water Heating Storage Service	REVWHS	1.000000	0.000000	0.986144	0.000554	0.000000	0.001211	0.011072	0.000474	0.000545
156	AP	Building Heating Service	REVHS	1.000000	0.000000	0.000000	0.186560	0.143149	0.200176	0.102569	0.167444	0.200102
157	AP	Body Police Lighting Service	REVBLP	1.000000	0.901684	0.000000	0.000431	0.000000	0.007481	0.000003	0.042051	0.048349
158	AP	Body Police Lighting Service from Publicly Owned	REVBLPPOF	1.000000	0.524036	0.000000	0.001340	0.000000	0.029219	0.000015	0.207178	0.238211
159	AP	Private Street and Area Lighting Service	REVPAL	1.000000	0.857715	0.000000	0.000708	0.000000	0.033606	0.000004	0.050222	0.057745
160	AP	General Power and Lighting Service	REVGLP	1.000000	0.000000	0.014077	0.251818	0.192641	0.056496	0.074676	0.182879	0.227413
161	AP	Large Power and Lighting Service - Secondary	REVLPLS	1.000000	0.000000	0.000274	0.202028	0.161540	0.036498	0.016700	0.269802	0.313158
162	AP	Large Power and Lighting Service - Primary	REVLPLP	1.000000	0.000000	0.000346	0.122025	0.215511	0.040724	0.015176	0.406277	0.199940
163	AP	High Tension Service - Subtransmission	REVHTSS	1.000000	0.000000	0.000001	0.004659	0.087543	0.094082	0.031058	0.780287	0.002370
164	AP	High Tension Service - High Voltage	REVHTSHV	1.000000	0.000000	0.000000	0.021976	0.000000	0.749440	0.228584	0.000000	0.000000
165	AP	HEP	REVHEP	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
166	AP											
167	AP	Total Rev Req @ desired ROR	REVREQ	1.000000	0.044605	0.029984	0.197897	0.160330	0.062527	0.084366	0.205818	0.214473
168	AP											
169	AP	**PRESENT REVENUES FROM SALES INPUT**										
170	AP											
171	AP	Total Sales of Electricity Revenues		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
172	AP	Sales of Electricity Revenues - Rates		1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000
173	AP	Sales of Electricity Revenues - Other		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000

Updated for 9 and 3

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				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	ADA	**ALLOCATED DIRECT ASSIGNMENTS**										
2	ADA	**DIRECT ASSIGN TO CLASSES W/SALES REV FUNCTION!**										
3	ADA											
4	ADA	**Net Write-Offs**										
5	ADA	Residential Service	REVRS	0	0	0	0	0	0	0	0	0
6	ADA	Residential Heating Service	REVRHS	0	0	0	0	0	0	0	0	0
7	ADA	Residential Load Management Service	REVRLM	0	0	0	0	0	0	0	0	0
8	ADA	Water Heating Service	REVWH	0	0	0	0	0	0	0	0	0
9	ADA	Water Heating Storage Service	REVWHS	0	0	0	0	0	0	0	0	0
10	ADA	Building Heating Service	REVHS	0	0	0	0	0	0	0	0	0
11	ADA	Body Police Lighting Service	REVBLP	0	0	0	0	0	0	0	0	0
12	ADA	Body Police Lighting Service from Publicly Owned	REVBLPPOF	0	0	0	0	0	0	0	0	0
13	ADA	Private Street and Area Lighting Service	REVPAL	0	0	0	0	0	0	0	0	0
14	ADA	General Power and Lighting Service	REVGLP	0	0	0	0	0	0	0	0	0
15	ADA	Large Power and Lighting Service - Secondary	REVLPLS	0	0	0	0	0	0	0	0	0
16	ADA	Large Power and Lighting Service - Primary	REVLPLP	0	0	0	0	0	0	0	0	0
17	ADA	High Tension Service - Subtransmission	REVHTSS	0	0	0	0	0	0	0	0	0
18	ADA	High Tension Service - High Voltage	REVHTSHV	0	0	0	0	0	0	0	0	0
19	ADA	HEP	REVHEP	0	0	0	0	0	0	0	0	0
20	ADA											
21	ADA	Total Write-Offs	EXP_904	0	0	0	0	0	0	0	0	0
22	ADA											
23	ADA	Total Write-Offs	EXP_904									
24	ADA											
25	ADA	Additional Net Write-Offs at Claimed Rate	EXP_904	0	0	0	0	0	0	0	0	0
26	ADA											
27	ADA											
28	ADA	**Rev to Customers w/Late Payment fees**										
29	ADA	Residential Service	REVRS	0	0	0	0	0	0	0	0	0
30	ADA	Residential Heating Service	REVRHS	0	0	0	0	0	0	0	0	0
31	ADA	Residential Load Management Service	REVRLM	0	0	0	0	0	0	0	0	0
32	ADA	Water Heating Service	REVWH	0	0	0	0	0	0	0	0	0
33	ADA	Water Heating Storage Service	REVWHS	0	0	0	0	0	0	0	0	0
34	ADA	Building Heating Service	REVHS	708,990	0	0	132,269	101,491	141,923	72,721	118,716	141,870
35	ADA	Body Police Lighting Service	REVBLP	0	0	0	0	0	0	0	0	0
36	ADA	Body Police Lighting Service from Publicly Owned	REVBLPPOF	0	0	0	0	0	0	0	0	0
37	ADA	Private Street and Area Lighting Service	REVPAL	27,345,651	23,454,785	0	19,347	0	918,974	102	1,373,367	1,579,076
38	ADA	General Power and Lighting Service	REVGLP	399,597,683	0	5,625,108	100,626,010	76,978,803	22,575,596	29,840,407	73,078,054	90,873,705
39	ADA	Large Power and Lighting Service - Secondary	REVLPLS	388,159,549	0	106,400	78,418,990	62,703,126	14,166,885	6,482,454	104,726,264	121,555,429
40	ADA	Large Power and Lighting Service - Primary	REVLPLP	74,444,444	0	25,775	9,084,095	16,043,615	3,031,704	1,129,763	30,245,088	14,884,405
41	ADA	High Tension Service - Subtransmission	REVHTSS	49,205,760	0	44	229,267	4,307,630	4,629,395	1,528,208	38,394,617	116,599
42	ADA	High Tension Service - High Voltage	REVHTSHV	2,891,829	0	0	63,550	0	2,167,253	661,026	0	0
43	ADA	HEP	REVHEP	0	0	0	0	0	0	0	0	0
44	ADA											
45	ADA	Total Late Payment Fees	REVLATEP	942,353,907	23,454,785	5,757,327	188,573,528	160,134,666	47,631,730	39,714,681	247,936,106	229,151,084
46	ADA	Total Late Payment Fees	REVLATEP	1.000000	0.024890	0.006110	0.200109	0.169930	0.050545	0.042144	0.263103	0.243169
47	ADA											
48	ADA	**ALLOCATED DIRECT ASSIGNMENTS**										
49	ADA	DIRECT ASSIGN TO CLASSES W/SALES REV FUNCTIONS										
50	ADA											
51	ADA	**AVAILABLE**										
52	ADA	Residential Service	REVRS	0	0	0	0	0	0	0	0	0
53	ADA	Residential Heating Service	REVRHS	0	0	0	0	0	0	0	0	0
54	ADA	Residential Load Management Service	REVRLM	0	0	0	0	0	0	0	0	0
55	ADA	Water Heating Service	REVWH	0	0	0	0	0	0	0	0	0
56	ADA	Water Heating Storage Service	REVWHS	0	0	0	0	0	0	0	0	0
57	ADA	Building Heating Service	REVHS	0	0	0	0	0	0	0	0	0
58	ADA	Body Police Lighting Service	REVBLP	0	0	0	0	0	0	0	0	0
59	ADA	Body Police Lighting Service from Publicly Owned	REVBLPPOF	0	0	0	0	0	0	0	0	0
60	ADA	Private Street and Area Lighting Service	REVPAL	0	0	0	0	0	0	0	0	0

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				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
61	ADA	General Power and Lighting Service	REVGLP	0	0	0	0	0	0	0	0	0
62	ADA	Large Power and Lighting Service - Secondary	REVLPLS	0	0	0	0	0	0	0	0	0
63	ADA	Large Power and Lighting Service - Primary	REVLPLP	0	0	0	0	0	0	0	0	0
64	ADA	High Tension Service - Subtransmission	REVHTSS	0	0	0	0	0	0	0	0	0
65	ADA	High Tension Service - High Voltage	REVHTSHV	0	0	0	0	0	0	0	0	0
66	ADA	HEP	REVHEP	0	0	0	0	0	0	0	0	0
67	ADA											
68	ADA	Total Available	REVAVAIL	0	0	0	0	0	0	0	0	0
69	ADA	Total Available	REVAVAIL									

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement	System Delivery Energy	Local Delivery Energy
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	RRW	**REVENUE REQUIREMENTS**										
2	RRW											
3	RRW	PRESENT RATES										
4	RRW	--										
5	RRW	RATE BASE		9,785,622,095	436,188,265	311,051,108	2,099,768,101	1,654,290,047	94,756,219	756,145,359	2,133,280,305	2,300,142,691
6	RRW	NET OPER INC (PRESENT RATES)		738,814,468	32,932,214	23,484,359	158,532,492	124,898,899	7,154,095	57,088,975	161,062,663	173,660,773
7	RRW	RATE OF RETURN (PRES RATES)		7.55%	7.55%	7.55%	7.55%	7.55%	7.55%	7.55%	7.55%	7.55%
8	RRW	RELATIVE RATE OF RETURN		1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
9	RRW	SALES REVENUE (PRE RATES)		1,899,915,237	84,746,048	56,967,015	375,987,929	304,613,976	118,795,402	160,287,388	391,036,114	407,481,364
10	RRW	REVENUE PRES RATES $/KWH		$0.0465	$0.0021	$0.0014	$0.0092	$0.0075	$0.0029	$0.0039	$0.0096	$0.0100
11	RRW	REVENUE REQUIRED - $/MO/CUST		$67.42	$3.01	$2.02	$13.34	$10.81	$4.22	$5.69	$13.88	$14.46
12	RRW	SALES REV REQUIRED $/KW										
13	RRW											
14	RRW	CLAIMED RATE OF RETURN										
15	RRW	--										
16	RRW	CLAIMED RATE OF RETURN		7.55%	7.55%	7.55%	7.55%	7.55%	7.55%	7.55%	7.55%	7.55%
17	RRW	RETURN REQ FOR CLAIMED ROR		738,814,468	32,932,214	23,484,359	158,532,492	124,898,899	7,154,095	57,088,975	161,062,663	173,660,773
18	RRW	SALES REVENUE REQ CLAIMED ROR		1,899,915,237	84,746,048	56,967,015	375,987,929	304,613,976	118,795,402	160,287,388	391,036,114	407,481,364
19	RRW	REVENUE DEFICIENCY SALES REV		0						(0)	0	
20	RRW	PERCENT INCREASE REQUIRED										
21	RRW	ANNUAL BOOKED KWH SALES		40,816,033,564	40,816,033,564	40,816,033,564	40,816,033,564	40,816,033,564	40,816,033,564	40,816,033,564	40,816,033,564	40,816,033,564
22	RRW	SALES REV REQUIRED $/KWH		$0.0465	$0.0021	$0.0014	$0.0092	$0.0075	$0.0029	$0.0039	$0.0096	$0.0100
23	RRW	REVENUE DEFICIENCY $/KWH										

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Based on 12 months actual

line #	FUNCTIONAL SEGMENTS REV REQ	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Street Lighting	$84,746,048	0	0	0	0	0	0	$60,902,932
2	Access	$56,967,015	$89,310	$562,242	$15,245,444	$35,163,481	$149,211	0	0
3	Local Delivery Demand	$375,987,929	$184,786,402	$601,198	$1,991,046	$5,589	$84	$132,269	$29,089
4	Local Delivery Energy	$407,481,364	$171,427,866	$1,124,951	$2,328,424	$6,741	$82	$141,870	$3,265,692
5	System Delivery Demand	$304,613,976	$142,454,625	$458,667	$1,566,018	0	0	$101,491	0
6	System Delivery Energy	$391,036,114	$137,207,092	$937,099	$1,956,091	$5,863	$72	$118,716	$2,840,263
7	Customer Service	$118,795,402	$69,712,065	$337,783	$574,715	$11,953	$183	$141,923	$505,321
8	Measurement	160,287,388	119,350,402	415,740	697,218	107,449	1,675	72,721	212
9	Total	$1,899,915,237	$825,027,762	$4,437,681	$24,358,956	$35,301,077	$151,307	$708,990	$67,543,508

Based on 12 months actual

PUBLIC SERVICE ELECTRIC & GAS COMPANY
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12 MONTHS ENDING DECEMBER 31, 2022

line #	FUNCTIONAL SEGMENTS REV REQ	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Subtransmission	HTS-High Voltage
		(9)	(10)	(11)	(12)	(13)	(14)	(15)
1	Street Lighting	$388,331	$23,454,785	0	0	0	0	0
2	Access	0	0	$5,625,108	$106,400	$25,775	$44	0
3	Local Delivery Demand	$993	$19,347	$100,626,010	$78,418,990	$9,084,095	$229,267	$63,550
4	Local Delivery Energy	$176,524	$1,579,076	$90,873,705	$121,555,429	$14,884,405	$116,599	0
5	System Delivery Demand	0	0	$76,978,803	$62,703,126	$16,043,615	$4,307,630	0
6	System Delivery Energy	$153,527	$1,373,367	$73,078,054	$104,726,264	$30,245,088	$38,394,617	0
7	Customer Service	$21,652	$918,974	$22,575,596	$14,166,885	$3,031,704	$4,629,395	$2,167,253
8	Measurement	11	102	29,840,407	6,482,454	1,129,763	1,528,208	661,026
9	Total	$741,039	$27,345,651	$399,597,683	$388,159,549	$74,444,444	$49,205,760	$2,891,829

Service Charge Calculations

Service charges are comprised of revenue requirements for the Distribution Access and Measurement segments related to Minimum Size Facilities, plus the Revenue Requirements for the Customer Service segment.

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	
1	Average Distribution Increase =		41.964%							
line #	Rate Schedule	Access Segment Revenue Requirement From Synced COS Study	Measurement Segment Revenue Requirement From Synced COS Study	Customer Service Segment Revenue Requirements From Synced COS Study	Rev Req to be recovered through Service Charge	# of Customers	Cost Based Monthly Service Charge	Current Monthly Service Charge	Proposed Limited Monthly Service Charge	
								($/month)		
2	RS	$ 85,089	$ 113,709,895	$ 66,417,469	$ 180,212,452	1,981,089	$ 7.58	$ 4.64	$ 7.56	see Note 1
3	RHS	$ 535,671	$ 396,092	$ 321,819	$ 1,253,582	6,404	$ 16.31	$ 4.64	$ 7.56	see Note 1
4	RLM	$ 14,524,944	$ 664,267	$ 547,554	$ 15,736,765	11,197	$ 117.12	$ 13.07	$ 21.30	see Note 2
5	WH	no service charge								
6	WHS	$ 142,159	$ 1,596	$ 175	$ 143,930	11	$ 1,115.74	$ 0.64	$ 1.04	see Note 2
7	HS	$ -	$ 69,284	$ 135,215	$ 204,499	714	$ 23.87	$ 3.83	$ 6.24	see Note 2
8	BPL	no service charge								
9	BPL-POF	no service charge								
10	PSAL	no service charge								
11	GLP	$ 5,359,265	$ 28,430,147	$ 21,508,672		272,921				
12	GLP Metered					256,116	$ 17.32	$ 4.88	$ 7.95	see Note 3
13	GLP Unmetered					5,766	$ 10.32	$ 2.24	$ 3.65	see Note 4
14	GLP-NU					64			$ 347.77	set equal to LPL-S
15	LPL-S	$ 101,372	$ 6,176,093	$ 13,497,357	$ 19,774,822	9,379	$ 175.70	$ 347.77	$ 347.77	see Note 2
16	LPL-P	$ 24,556	$ 1,076,370	$ 2,888,426	$ 3,989,352	770	$ 431.79	$ 347.77	$ 431.79	see Note 2
17	LPL-P <100 kW						$ 322.95	$ 22.04	$ 35.91	see Note 5
18	HTS-S	$ 42	$ 1,455,985	$ 4,410,609	$ 5,866,636	189	$ 2,581.15	$ 1,911.39	$ 2,581.15	see Note 2
19	HTS-HV	$ -	$ 629,786	$ 2,064,829	$ 2,694,615	16	$ 13,761.50	$ 1,720.25	$ 2,803.08	see Note 2
Source:					= (2) + (3) + (4)		= (5) / (6) / 12	From Tariff		

Notes: 1 Move Toward Cost limited at no decrease from current service charge and no increase greater than 1.5 times the overall average distribution % increase.

2 Access and Customer Service Rev Req per total GLP Customer plus Measurement Rev Req divided by the number of metered customers divided by 12; limits the same as Note 1

3 Access and Customer Service Rev Req per total GLP Customer divided by 12; limits the same as Note 1

4 Calculated at the GLP Access Segment per customer plus the GLP Customer Service Segment Revenue Requirements per customer plus the LPL-P Measurement Segment per customer divided by 12; limits the same as Note 1

PSE&G 2024 Tax Adjustment Credit (TACs)
Proposed Rate Calculations

Actual results through: 2/29/2024

($'s Unless Specified)

SUT Rate 6.625%

Line	Date(s)		Electric	Gas	Total	Source/Description
1	Sept24 - Dec25	Net Revenue Requirements	(173,752,029)	(238,342,010)	(412,094,040)	SS-2E/G, Col 26
2	Aug-24	(Over) / Under Recovered Balance	11,539,842	(12,347,262)	(807,420)	- SS-3E/G, Col 5
3	Aug-24	Cumulative Interest Exp / (Credit)	342,718	(166,949)	175,769	- SS-3E/G, Col 10
4	Sept24 - Dec25	Total Target Rate Revenue	(161,869,469)	(250,856,221)	(412,725,691)	ln 1 + ln 2 + ln 3
5	Sept24 - Dec25	Revenue at Proposed 2024 TAC rates	(45,641,003)	(126,374,904)	(172,015,907)	SS-6E/G, ln 19
6	Sept24 - Dec25	Proposed TAC Increase / (Decrease)	(116,228,466)	(124,481,317)	(240,709,783)	Ln 4 - ln 5
7	Sep24 - Aug25	Annualized Target Rate Revenue	(122,965,082)	(196,974,806)	(319,939,887)	SS-6E/G, ln 15
8	Sep24 - Aug25	Annualized Revenue at Proposed 2024 TAC rates	(34,665,734)	(99,013,932)	(133,679,666)	SS-6E/G, ln 17
9	Sep24 - Aug25	Annualized TAC Increase / (Decrease)	(88,299,348)	(97,960,874)	(186,260,221)	Ln 7 - ln 8

PSE&G 2024 TAX ADJUSTMENT CREDIT
ETAC Net Revenue Requirement
$000

	1	2	3	4	5	6	1	2	3	4	5	6	7	8	9	10	11	12
							1. Return Historic ADIT											
	1. Return Excess Income Tax Expense						**Unprotected Excess**			**Protected Excess**			**SHARE**			**Mixed Service Cost**		
	Beginning Excess Income Tax Balance	Excess Income Tax	Excess Income Tax	Ending Excess Income Tax Balance	Short-Term Interest Rate	Interest On Excess Income Tax Balance	Beginning Balance	Amortization to Customers	Ending Balance	Beginning Balance	Amortization to Customers	Ending Balance	Beginning Balance	Amortization to Customers	Ending Balance	Beginning Balance	Amortization to Customers	Ending Balance
Jan-23	-	-	-	-	0.16%	-	71,138	(5,297)	65,841	351,198	(847)	350,351	95,414	(702)	94,713	-	-	-
Feb-23	-	-	-	-	4.64%	-	65,841	(5,297)	60,543	350,351	(847)	349,504	94,713	(702)	94,011	-	-	-
Mar-23	-	-	-	-	4.78%	-	60,543	(10,137)	50,407	349,504	(1,516)	347,988	94,011	(1,342)	92,669	-	-	-
Apr-23	-	-	-	-	5.32%	-	50,407	(3,694)	46,713	347,988	(572)	347,416	92,669	(489)	92,179	-	-	-
May-23	-	-	-	-	5.32%	-	46,713	(3,440)	43,273	347,416	(533)	346,883	92,179	(456)	91,724	-	-	-
Jun-23	-	-	-	-	5.54%	-	43,273	(5,387)	37,886	346,883	(834)	346,049	91,724	(713)	91,010	-	-	-
Jul-23	-	-	-	-	5.25%	-	37,886	(6,847)	31,039	346,049	(1,060)	344,988	91,010	(907)	90,104	-	-	-
Aug-23	-	-	-	-	5.21%	-	31,039	(6,091)	24,948	344,988	(943)	344,045	90,104	(807)	89,297	-	-	-
Sep-23	-	-	-	-	5.21%	-	24,948	(3,328)	21,620	344,045	(515)	343,530	89,297	(441)	88,856	-	-	-
Oct-23	-	-	-	-	5.49%	-	21,620	(3,737)	17,883	343,530	(501)	343,029	88,856	(495)	88,361	-	-	-
Nov-23	-	-	-	-	5.43%	-	17,883	(4,985)	12,898	343,029	(748)	342,281	88,361	(660)	87,701	-	-	-
Dec-23	-	-	-	-	5.49%	-	12,898	(5,329)	7,569	342,281	(953)	341,328	87,701	(706)	86,995	-	-	-
Jan-24	-	-	-	-	5.52%	-	7,569	(994)	6,575	341,328	(1,335)	339,993	86,995	(2,284)	84,711	-	-	-
Feb-24	-	-	-	-	5.49%	-	6,575	(880)	5,696	339,993	(1,182)	338,811	84,711	(2,022)	82,689	-	-	-
Mar-24	-	-	-	-	5.49%	-	5,696	(570)	5,125	338,811	(766)	338,045	82,689	(1,311)	81,378	-	-	-
Apr-24	-	-	-	-	5.49%	-	5,125	(504)	4,622	338,045	(677)	337,368	81,378	(1,158)	80,220	-	-	-
May-24	-	-	-	-	5.49%	-	4,622	(527)	4,094	337,368	(708)	336,660	80,220	(1,212)	79,008	-	-	-
Jun-24	-	-	-	-	5.49%	-	4,094	(641)	3,453	336,660	(861)	335,798	79,008	(1,474)	77,534	-	-	-
Jul-24	-	-	-	-	5.49%	-	3,453	(770)	2,683	335,798	(1,034)	334,764	77,534	(1,770)	75,764	-	-	-
Aug-24	-	-	-	-	5.49%	-	2,683	(712)	1,971	334,764	(957)	333,807	75,764	(1,637)	74,127	-	-	-
Sep-24	-	-	-	-	5.49%	-	1,971	(569)	1,402	333,807	(765)	333,043	74,127	(1,308)	72,819	-	-	-
Oct-24	-	-	-	-	5.49%	-	1,402	(404)	998	333,043	(543)	332,500	72,819	(929)	71,890	-	-	-
Nov-24	-	-	-	-	5.49%	-	998	(512)	486	332,500	(688)	331,812	71,890	(1,178)	70,712	-	-	-
Dec-24	-	-	-	-	5.49%	-	486	(486)	0	331,812	(652)	331,159	70,712	(1,116)	69,596	-	-	190,583
Jan-25	-	-	-	-	5.49%	-	0	-	0	331,159	(947)	330,212	69,596	(2,284)	67,312	190,583	(9,191)	181,393
Feb-25	-	-	-	-	5.49%	-	0	-	0	330,212	(838)	329,374	67,312	(2,022)	65,290	181,393	(8,135)	173,258
Mar-25	-	-	-	-	5.49%	-	0	-	0	329,374	(544)	328,830	65,290	(1,311)	63,979	173,258	(5,275)	167,983
Apr-25	-	-	-	-	5.49%	-	0	-	0	328,830	(480)	328,350	63,979	(1,158)	62,821	167,983	(4,659)	163,324
May-25	-	-	-	-	5.49%	-	0	-	0	328,350	(502)	327,848	62,821	(1,212)	61,609	163,324	(4,876)	158,448
Jun-25	-	-	-	-	5.49%	-	0	-	0	327,848	(611)	327,237	61,609	(1,474)	60,135	158,448	(5,929)	152,518
Jul-25	-	-	-	-	5.49%	-	0	-	0	327,237	(734)	326,503	60,135	(1,770)	58,365	152,518	(7,121)	145,398
Aug-25	-	-	-	-	5.49%	-	0	-	0	326,503	(679)	325,824	58,365	(1,637)	56,728	145,398	(6,586)	138,812
Sep-25	-	-	-	-	5.49%	-	0	-	0	325,824	(542)	325,282	56,728	(1,308)	55,420	138,812	(5,263)	133,549
Oct-25	-	-	-	-	5.49%	-	0	-	0	325,282	(385)	324,897	55,420	(929)	54,491	133,549	(3,737)	129,812
Nov-25	-	-	-	-	5.49%	-	0	-	0	324,897	(488)	324,408	54,491	(1,178)	53,314	129,812	(4,738)	125,074
Dec-25	-	-	-	-	5.49%	-	0	-	0	324,408	(463)	323,946	53,314	(1,116)	52,197	125,074	(4,491)	120,583
	= Prev Col 4	Input	Input	= Col 1 + Col 2 + Col 3	Input	= (Prev Col 4 + Col 4)/2 * Col 5 / 12	= Prev Col 3 + Col 1 & 2 of "Balances" Wkst	Input	= Col 1 + Col 2	= Prev Col 6 + Col 3 of "Balances" Wkst	Input	= Col 4 + Col 5	= Prev Col 9 + Col 4 of "Balances" Wkst	Input	= Col 7 + Col 8	= Prev Col 12 + Col 5 of "Balances" Wkst	Input	= Col 10 + Col 11
Annual																		
2023			-			-		(63,569)			(9,870)			(8,419)			-	
2024			-			-		(7,569)			(10,169)			(17,399)			-	
2025			-			-		-			(7,214)			(17,399)			(70,000)	
2026			-			-		-			(5,958)			(17,399)			(45,000)	
2027			-			-		-			(6,259)			(17,399)			(33,000)	
2028			-			-		-			(6,119)			(17,400)			(20,000)	
2029								-			(5,116)			-			(22,583)	

PSE&G 2024 TAX ADJUSTMENT CREDIT
ETAC Net Revenue Requirement
$000

Monthly After Tax WACC Post -2023 BRC: 0.587%
Monthly After Tax WACC Pre-2023 BRC: 0.540%

Monthly After Tax WACC Post -2023 BRC: 0.587%
Monthly After Tax WACC Pre-2023 BRC: 0.540%
Federal Tax Rate = 21.00%

Revenue Factor = 1.3947

	13	14	15	16	17	18	19	20`	21	22	23	24	25	26	27	28	29	30
	1. Return Historic ADIT (cont.)								**1a. Return Historic ADIT (cont.)**				**2. Current ESHARE Deduciton**	**2a. Current Mixed Srv & IDD**	**3. Other**			
	Return on Rate Base				**Corporate Alternative Minimum Tax (CAMT)**				**Return on Non Rate Base**									
	Unprotected Excess ADIT Rate Base Related %	Rate Base Related Portion of Unprotected Excess ADIT Amortizaiton to Customers	Cumulative Change in Rate Base	After-Tax Return on Cumulative Change in Rate Base	Beginning Balance	Amortization to Customers	Cumulative Change in Rate Base	After-Tax Return on Cumulative Change in Rate Base	Beginning Non-Rate Base Related Portion of Unprotected Excess	Non-Rate Base Related Portion of Unprotected Excess ADIT Amortizaiton to Customers	Ending Non-Rate Base Related Portion of Unprotected Excess	After-Tax Interest to Customers	Actual SHARE Deduction Flow-Through	Actual Mixed Service Cost Deduction Flow-Through	IRS ESHARE Deduction Audit Adjustments	Other Major Tax Adjustments	Net Tax Adjustment	**Net Revenue Requirement**
Jan-23	78%	(4,135)	247,378	1,302	-	-	-	-	13,947	(1,162)	12,785	(72)	(1,150)	-	-	-	(6,766)	**(9,437)**
Feb-23	78%	(4,135)	252,928	1,351	-	-	-	-	12,785	(1,162)	11,623	(66)	(1,150)	-	-	-	(6,711)	**(9,359)**
Mar-23	78%	(7,913)	258,344	1,381	-	-	-	-	11,623	(2,224)	9,399	(57)	(2,393)	-	-	(3)	(14,067)	**(19,619)**
Apr-23	78%	(2,883)	263,734	1,410	-	-	-	-	9,399	(810)	8,588	(49)	(836)	-	-	(5)	(4,234)	**(5,906)**
May-23	78%	(2,685)	269,054	1,439	-	-	-	-	8,588	(755)	7,834	(44)	(779)	-	-	(3)	(3,814)	**(5,320)**
Jun-23	78%	(4,205)	274,306	1,468	-	-	-	-	7,834	(1,182)	6,652	(39)	(1,219)	-	-	(2)	(6,727)	**(9,382)**
Jul-23	78%	(5,345)	279,489	1,496	-	-	-	-	6,652	(1,502)	5,149	(32)	(1,550)	-	-	(3)	(8,903)	**(12,417)**
Aug-23	78%	(4,755)	284,602	1,524	-	-	-	-	5,149	(1,336)	3,813	(24)	(1,379)	-	-	(4)	(7,725)	**(10,774)**
Sep-23	78%	(2,598)	289,648	1,551	-	-	-	-	3,813	(730)	3,083	(19)	(753)	-	-	(3)	(3,508)	**(4,893)**
Oct-23	78%	(2,917)	294,624	1,578	-	-	-	-	3,083	(820)	2,263	(14)	1,395	-	-	(1)	(1,775)	**(2,475)**
Nov-23	78%	(3,891)	299,533	1,605	-	-	-	-	2,263	(1,094)	1,169	(9)	(942)	-	-	(0)	(5,740)	**(8,006)**
Dec-23	78%	(4,160)	304,372	1,631	-	-	-	-	1,169	(1,169)	0.000014	(3)	(2,232)	-	-	0	(7,592)	**(10,588)**
Jan-24	100%	(994)	312,508	1,666	-	-	-	-	0	-	0.000014	(0)	(2,095)	-	-	0	(5,042)	**(7,033)**
Feb-24	100%	(880)	315,299	1,696	-	-	-	-	0	-	0.000014	(0)	(1,608)	-	-	0	(3,995)	**(5,572)**
Mar-24	100%	(570)	318,019	1,711	-	-	-	-	0	-	0.000014	(0)	(1,396)	-	-	0	(2,333)	**(3,254)**
Apr-24	100%	(504)	320,669	1,725	-	-	-	-	0	-	0.000014	(0)	(909)	-	-	0	(1,522)	**(2,123)**
May-24	100%	(527)	323,248	1,739	-	-	-	-	0	-	0.000014	(0)	(846)	-	-	0	(1,554)	**(2,168)**
Jun-24	100%	(641)	325,757	1,753	-	-	-	-	0	-	0.000014	(0)	(1,325)	-	-	0	(2,548)	**(3,554)**
Jul-24	100%	(770)	328,194	1,766	-	-	-	-	0	-	0.000014	(0)	(1,684)	-	-	0	(3,492)	**(4,870)**
Aug-24	100%	(712)	330,560	1,779	-	-	-	-	0	-	0.000014	(0)	(1,498)	-	-	0	(3,025)	**(4,218)**
Sep-24	100%	(569)	8,538	996	-	-	-	-	0	-	0.000014	(0)	(819)	-	-	0	(2,464)	**(3,437)**
Oct-24	100%	(404)	10,762	57	-	-	-	-	0	-	0.000014	(0)	(919)	-	-	0	(2,738)	**(3,819)**
Nov-24	100%	(512)	12,917	70	-	-	-	-	0	-	0.000014	(0)	(1,226)	-	-	0	(3,535)	**(4,930)**
Dec-24	100%	(486)	15,000	82	-	-	-	-	0	-	0.000014	(0)	(1,311)	-	-	0	(3,483)	**(4,858)**
Jan-25	0.0%	-	32,841	141	-	-	-	-	0	-	0	(0)	(1,805)	(1,182)	-	-	(15,268)	**(21,295)**
Feb-25	0%	-	43,702	225	-	-	-	-	0	-	0	(0)	(1,598)	(1,046)	-	-	(13,414)	**(18,708)**
Mar-25	0%	-	50,700	277	-	-	-	-	0	-	0	(0)	(1,036)	(678)	-	-	(8,567)	**(11,948)**
Apr-25	0%	-	56,841	316	-	-	-	-	0	-	0	(0)	(915)	(599)	-	-	(7,496)	**(10,455)**
May-25	0%	-	63,224	353	-	-	-	-	0	-	0	(0)	(958)	(627)	-	-	(7,822)	**(10,910)**
Jun-25	0%	-	70,937	394	-	-	-	-	0	-	0	(0)	(1,165)	(762)	-	-	(9,547)	**(13,315)**
Jul-25	0%	-	80,137	444	-	-	-	-	0	-	0	(0)	(1,399)	(916)	-	-	(11,495)	**(16,032)**
Aug-25	0%	-	88,589	496	-	-	-	-	0	-	0	(0)	(1,294)	(847)	-	-	(10,546)	**(14,709)**
Sep-25	0%	-	95,298	540	-	-	-	-	0	-	0	(0)	(1,034)	(677)	-	-	(8,284)	**(11,553)**
Oct-25	0%	-	100,030	574	-	-	-	-	0	-	0	(0)	(734)	(481)	-	-	(5,692)	**(7,939)**
Nov-25	0%	-	105,988	605	-	-	-	-	0	-	0	(0)	(931)	(609)	-	-	(7,338)	**(10,234)**
Dec-25	0%	-	111,596	639	-	-	-	-	0	-	0	(0)	(882)	(577)	-	-	(6,890)	**(9,610)**
	= Col 14 / Col 2	Input	See "RateBase-E", Col 9	= (Prev Col 15 + Col 15) / 2 * Monthly AT WACC	= Prev Col 19	Input	= Col 17 + Col 18	= (Prev Col 19 + Col 19) / 2 * Monthly AT WACC	Previous Col 23 + Col 1 of "Balances" Wkst	Input	= (Prev Col 21 - Col 22)	= (Prev Col 23 + Col 23) / 2 * Monthly AT WACC	= Input * Fed Tax Rate	= Input * Fed Tax Rate	Input	Input	= Col 2 + Col 5 + Col 8 + Col 11 + Col 16 + Col 18+ Col 20+ Col 25+ Col 25 + Col 26+ Col 28	= Col 29 * Rev Fct + Col 3 + Col 6
Annual																		
2023		(49,622)		17,737						(13,947)		(429)	(12,989)	-	-	(24)	(77,562)	**(108,176)**
2024		(7,569)		15,041						-		(0)	(15,636)	-	-	0	(35,732)	**(49,836)**
2025		-		5,003						-		(0)	(13,750)	(9,000)	-	-	(112,360)	**(156,708)**
2026		-		10,677						-		(0)	(13,750)	(9,000)	-	-	(80,430)	**(112,175)**
2027		-		15,040						-		(0)	(13,750)	(9,000)	-	-	(64,368)	**(89,774)**
2028		-		18,526						-		(0)	(13,750)	(9,000)	-	-	(47,743)	**(66,587)**
2029		-		20,994						-		(0)	(13,750)	(9,000)	-	-	(29,455)	**(41,081)**

Exhibit P-9 R-1

PSE&G 2024 TAX ADJUSTMENT CREDIT
Electric Over/(Under) Calculation

2/29/2024

Schedule SS-TAC-3E R-1

Reflects a tax rate of	28.11%

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Monthly Calculation	Over / (Under) Recovery Beginning Balance	Electric Revenues	Revenue Requirement Excluding WACC Cost	Over / (Under) Recovery	Over / (Under) Recovery Ending Balance	Over / (Under) Average Monthly Balance	Interest Rate (Annualized)	Interest On Over / (Under) Average Monthly Balance	Interest Roll-In	Cumulative Interest
Jan-23	(14,935,705)	(9,101,202)	(9,436,537)	335,334	(14,600,371)	(14,768,038)	0.16%	(1,416)	-	(11,231)
Feb-23	(14,600,371)	(8,073,880)	(9,359,172)	1,285,293	(13,315,078)	(13,957,725)	4.64%	(38,799)	-	(50,030)
Mar-23	(13,315,078)	(8,540,596)	(19,619,021)	11,078,425	(2,236,653)	(7,775,866)	4.78%	(22,267)	-	(72,297)
Apr-23	(2,236,653)	(6,993,582)	(5,905,692)	(1,087,890)	(3,324,543)	(2,780,598)	5.32%	(8,862)	-	(81,159)
May-23	(3,324,543)	(7,543,824)	(5,319,679)	(2,224,145)	(5,548,688)	(4,436,616)	5.32%	(14,140)	-	(95,299)
Jun-23	(5,548,688)	(9,671,729)	(9,381,900)	(289,830)	(5,838,518)	(5,693,603)	5.54%	(18,897)	-	(114,196)
Jul-23	(5,838,518)	(14,169,073)	(12,417,153)	(1,751,921)	(7,590,438)	(6,714,478)	5.25%	(21,118)	-	(135,314)
Aug-23	(7,725,752)	(10,458,907)	(10,773,659)	314,752	(7,411,000)	(7,568,376)	5.21%	(23,636)	(135,314)	(23,636)
Sep-23	(7,411,000)	(8,327,826)	(4,893,170)	(3,434,656)	(10,845,656)	(9,128,328)	5.21%	(28,508)	-	(52,144)
Oct-23	(10,845,656)	(6,663,048)	(2,475,453)	(4,187,595)	(15,033,251)	(12,939,454)	5.49%	(42,519)	-	(94,663)
Nov-23	(15,033,251)	(6,516,196)	(8,006,180)	1,489,984	(13,543,267)	(14,288,259)	5.43%	(46,446)	-	(141,109)
Dec-23	(13,543,267)	(7,701,790)	(10,588,089)	2,886,299	(10,656,968)	(12,100,118)	5.49%	(39,761)	-	(180,869)
Jan-24	(10,837,837)	(8,488,699)	(7,032,577)	(1,456,122)	(12,293,959)	(11,565,898)	5.52%	(38,234)	(180,869)	(38,234)
Feb-24	(12,293,959)	(7,183,072)	(5,572,054)	(1,611,018)	(13,904,977)	(13,099,468)	5.49%	(43,076)	-	(81,310)
Mar-24	(13,904,977)	(2,757,529)	(3,254,175)	496,646	(13,408,332)	(13,656,654)	5.49%	(44,908)	-	(126,218)
Apr-24	(13,408,332)	(2,369,771)	(2,122,907)	(246,864)	(13,655,195)	(13,531,763)	5.49%	(44,497)	-	(170,715)
May-24	(13,655,195)	(2,568,943)	(2,167,533)	(401,410)	(14,056,605)	(13,855,900)	5.49%	(45,563)	-	(216,279)
Jun-24	(14,056,605)	(2,925,404)	(3,553,903)	628,499	(13,428,106)	(13,742,356)	5.49%	(45,190)	-	(261,469)
Jul-24	(13,428,106)	(3,666,482)	(4,870,415)	1,203,933	(12,224,174)	(12,826,140)	5.49%	(42,177)	-	(303,646)
Aug-24	(12,224,174)	(3,534,148)	(4,218,480)	684,332	(11,539,842)	(11,882,008)	5.49%	(39,072)	-	(342,718)
Sep-24	(11,882,560)	(9,950,912)	(3,437,026)	(6,513,886)	(18,396,446)	(15,139,503)	5.49%	(49,784)	(342,718)	(49,784)
Oct-24	(18,396,446)	(9,573,411)	(3,819,137)	(5,754,274)	(24,150,720)	(21,273,583)	5.49%	(69,955)	-	(119,740)
Nov-24	(24,150,720)	(8,925,195)	(4,929,906)	(3,995,289)	(28,146,008)	(26,148,364)	5.49%	(85,985)	-	(205,725)
Dec-24	(28,146,008)	(10,382,417)	(4,857,675)	(5,524,743)	(33,670,751)	(30,908,380)	5.49%	(101,638)	-	(307,363)
Jan-25	(33,670,751)	(10,604,698)	(21,294,888)	10,690,190	(22,980,562)	(28,325,656)	5.49%	(93,145)	-	(400,508)
Feb-25	(22,980,562)	(9,365,611)	(18,708,289)	9,342,678	(13,637,884)	(18,309,223)	5.49%	(60,207)	-	(460,716)
Mar-25	(13,637,884)	(9,938,724)	(11,948,198)	2,009,474	(11,628,409)	(12,633,146)	5.49%	(41,542)	-	(502,258)
Apr-25	(11,628,409)	(8,541,159)	(10,454,641)	1,913,482	(9,714,928)	(10,671,668)	5.49%	(35,092)	-	(537,351)
May-25	(9,714,928)	(9,259,018)	(10,909,608)	1,650,591	(8,064,337)	(8,889,632)	5.49%	(29,232)	-	(566,583)
Jun-25	(8,064,337)	(10,543,781)	(13,315,307)	2,771,525	(5,292,812)	(6,678,574)	5.49%	(21,962)	-	(588,545)
Jul-25	(5,292,812)	(13,214,783)	(16,032,050)	2,817,267	(2,475,545)	(3,884,178)	5.49%	(12,773)	-	(601,317)
Aug-25	(2,475,545)	(12,737,825)	(14,708,855)	1,971,031	(504,514)	(1,490,030)	5.49%	(4,900)	-	(606,217)
Sep-25	(504,514)	(9,950,912)	(11,553,426)	1,602,514	1,098,000	296,743	5.49%	976	-	(605,241)
Oct-25	1,098,000	(9,573,411)	(7,938,876)	(1,634,535)	(536,536)	280,732	5.49%	923	-	(604,318)
Nov-25	(536,536)	(8,925,195)	(10,234,433)	1,309,238	772,703	118,084	5.49%	388	-	(603,930)
Dec-25	772,703	(10,382,417)	(9,609,715)	(772,703)	(0)	386,351	5.49%	1,270	-	(602,659)
	(Prior Col 5) + (Col 9)	Forecasted kWh * Proposed Rate	See Revenue Requirements Schedule for Details	Col 2 - Col 3	Col 1 + Col 4	(Col 1 + Col 5) / 2	Input	(Col 6 * (Col 7) / 12)*net of tax rate		Prior Month + Col 8 - Col 9

PSE&G 2024 TAX ADJUSTMENT CREDIT

Weighted Average Cost of Capital

	Percent	Embedded Cost	Weighted Cost	Pre-Tax Weighted Cost	After-Tax Weighted Cost
Long-Term Debt	45.53%	3.96%	1.80%	1.80%	1.30%
Customer Deposits	0.47%	0.87%	0.00%	0.00%	0.00%
Common Equity	54.00%	9.60%	5.18%	7.21%	5.18%
Total	100.00%		6.99%	9.02%	6.48%

Federal Tax Rate	21.00%
State Tax Rate	9.00%
Fed Benefit of State Tax Deduction	-1.89%
Effective Tax Rate	28.11%

Exhibit P-9 R-1

PSE&G 2024 TAX ADJUSTMENT CREDIT

Schedule SS-TAC-5 R-1

Revenue Factor

	ELECTRIC	GAS
Revenue Increase	100.0000	100.0000
Uncollectible Rate		0.0000
BPU Assessment Rate	0.2176	0.2176
Rate Counsel Assessment Rate	0.0455	0.0455
Income before State of NJ Bus. Tax	99.7369	99.7369
State of NJ Bus. Income Tax	8.9763	8.9763
Income Before Federal Income Taxes	90.7606	90.7606
Federal Income Taxes	19.0597	19.0597
Return	71.7008	71.7008
Revenue Factor	**1.3947**	**1.3947**

Exhibit P-9 R-1
Schedule SS-TAC-6E R-1

PSE&G 2024 TAX ADJUSTMENT CREDIT
Proposed ETAC Calculation
($'s Unless Specified)

Current SUT Rate 6.625%

Line		RS	RHS	RLM	WH	WHS	HS	GLP	LPL-S	LPL-P	HTS-S	HTS-HV	BPL	BPL-POF	PSAL	Total	Source/Description
								Electric									
1	2024 Sales (MWh)	13,108,453	81,419	176,712	492	10	9,630	6,816,613	10,257,891	2,792,604	4,404,888	464,483	287,195	14,795	139,211	38,554,397	Input
2	Rate Class Allocation[1]	71.15%	0.63%	0.90%	0.00%	0.00%	0.03%	12.26%	10.44%	1.82%	2.64%	0.11%	0.00%	0.02%	0.00%	100.00%	CreditCalc-E TAC 2023
3	Revenue Requirements	(24,289,116)	(213,548)	(307,373)	0	0	(11,887)	(4,186,254)	(3,563,230)	(620,689)	(900,890)	(37,360)	0	(6,793)	0	(34,137,139)	CreditCalc-E TAC 2023
4	Proposed Rate w/o SUT ($/kWh)	(0.001853)	(0.002623)	(0.001739)	0.000000	0.000000	(0.001234)	(0.000614)	(0.000347)	(0.000222)	(0.000205)	(0.000080)	0.000000	(0.000459)	0.000000		CreditCalc-E TAC 2023
5	Public Notice Rate w/o SUT ($/kWh)																CreditCalc-E TAC 2023
6	Proposed Rate w/ SUT ($/kWh)	(0.001976)	(0.002797)	(0.001854)	0.000000	0.000000	(0.001316)	(0.000655)	(0.000370)	(0.000237)	(0.000219)	(0.000085)	0.000000	(0.000489)	0.000000		CreditCalc-E TAC 2023
7	Sep-24 to Dec-25 Sales (MWh)	17,265,116	106,447	237,589	728	9	13,684	9,726,439	13,535,577	4,096,043	6,364,712	592,706	386,339	19,814	180,529	52,525,734	
8	Rate Class Allocation	71.19%	0.63%	0.90%				12.27%	10.44%	1.82%	2.64%	0.11%				100.00%	Line 2 / Sum Line 2
9	Revenue Requirements	(115,235,753)	(1,013,142)	(1,458,279)	0	0	0	(19,860,998)	(16,905,163)	(2,944,757)	(4,274,128)	(177,249)	0	0	0	(161,869,469)	(SS-TAC-1, ln 4 [Electric]) * Line 8 * 1000
10	Proposed Rate w/o SUT ($/kWh)	(0.006674)	(0.009518)	(0.006138)	0.000000	0.000000	0.000000	(0.002042)	(0.001249)	(0.000719)	(0.000672)	(0.000299)	0.000000	0.000000	0.000000		(Line 7 / (Line 9 * 1,000)) [Rnd 6]
11	Public Notice Rate w/o SUT ($/kWh)																
12	Proposed Rate w/ SUT ($/kWh)	(0.007116)	(0.010149)	(0.006545)	0.000000	0.000000	0.000000	(0.002177)	(0.001332)	(0.000767)	(0.000717)	(0.000319)	0.000000	0.000000	0.000000		(Line 10 * (1 + SUT Rate)) [Rnd 6]
13	Jun-23 to May 24 Sales (MWh)	13,166,714	82,189	180,730	551	7	10,674	7,325,083	10,174,460	3,056,341	4,757,020	454,332	283,276	14,352	132,104	39,637,832	Input
14	Annulization Factor	76.26%	77.21%	76.07%				75.31%	75.17%	74.62%	74.74%	76.65%					(Line 7) / (Line 13)
15	Annualized Revenue Requirements	(87,881,030)	(782,254)	(1,109,291)	0	0	0	(14,957,526)	(12,707,319)	(2,197,287)	(3,194,506)	(135,868)	0	0	0	(122,965,082)	(Line 9) * (Line 14)
16	Filed Rates 2024	(0.001853)	(0.002623)	(0.001739)	0.000000	0.000000	(0.001234)	(0.000614)	(0.000347)	(0.000222)	(0.000205)	(0.000080)	0.000000	(0.000459)	0.000000		Line 4
17	Test Year Revenue Requirements at Filed Rates 2024	(24,397,921)	(215,581)	(314,290)	0	0	(13,171)	(4,497,601)	(3,530,538)	(678,508)	(975,189)	(36,347)	0	(6,587)	0	(34,665,734)	(Line 13 * Line 16)*1000
18	Annualized Change	(63,483,108)	(566,673)	(795,001)	0	0	13,171	(10,459,925)	(9,176,782)	(1,518,779)	(2,219,317)	(99,522)	0	6,587	0	(88,299,348)	Line 15 - Line 17
19	16 Month Revenue Requiremnets at Filed 2024 Rates	(31,992,261)	(279,212)	(413,167)	0	0	(16,886)	(5,972,033)	(4,696,845)	(909,322)	(1,304,766)	(47,416)	0	(9,095)	0	(45,641,003)	(Line 7 * Line 16)*1000

[1] Rate Class Allocation remains the same and stays in effect until the conclusion of the Company's next Base Rate Case

PSE&G Electric - Storm Recovery Charge
SRC Electric Rate Calculation

($'s - Unless noted)

Line No.	Calculation	Description	
1		Deferred Storm Cost Balance as of 9/1/24	106,618,541
2		Estimated Interest Expenses	9,012,676
3	=(1+2)/3 Years	Estimated Annual Revenue Requirement	38,543,739
4		Forecasted Annual kWh	39,579,987,063
5	=3/4	Proposed SRC ($/kWh excluding Sales & Use Tax)	0.000973
6	=5*(1+SUT%)	Proposed SRC ($/kWh Including Sales and Use Tax)	0.001037
7		Existing SRC ($/kWh Including Sales & Use Tax)	0.000000
8	=(5-7)*4	Storm Recovery Charge Increase / (Decrease)	38,511,327

PSE&G Electric - Storm Recovery Charge
Over/(Under) Balance and Interest Calculation

($'s - Unless noted)

	(1)	(2)	(3)	(4)	(5)	(6)
	Input	Input	Prior Col 6 - Col 1 + Col 2	Input	(Prior Col 6 + Col 3) / 2 * (Col 4 / 12)	Col 3 + Col 5
Month	SRC Revenue	Incremental Deferred Major Storm Expenses	Prior Month (Over)/Under Balance + Monthly Activity)	Annual Interest Rate	Interest Expense	SRC Balance - (Over)/Under
Aug-24						106,618,541
Sep-24	3,305,467	-	103,313,073	5.43%	474,620	103,787,694
Oct-24	2,900,043	-	100,887,651	5.43%	462,737	101,350,388
Nov-24	2,939,466	-	98,410,921	5.43%	451,627	98,862,548
Dec-24	3,209,570	-	95,652,978	5.43%	439,767	96,092,746
Jan-25	3,290,489	-	92,802,256	5.43%	427,060	93,229,316
Feb-25	2,888,280	-	90,341,037	5.43%	415,022	90,756,059
Mar-25	3,095,303	-	87,660,756	5.43%	403,371	88,064,127
Apr-25	2,645,653	-	85,418,473	5.43%	392,215	85,810,689
May-25	2,867,419	-	82,943,269	5.43%	381,525	83,324,794
Jun-25	3,367,096	-	79,957,698	5.43%	369,155	80,326,853
Jul-25	4,087,316	-	76,239,537	5.43%	353,971	76,593,507
Aug-25	4,033,965	-	72,559,543	5.43%	337,210	72,896,753
Sep-25	3,304,195	-	69,592,557	5.43%	322,145	69,914,702
Oct-25	2,891,423	-	67,023,279	5.43%	309,594	67,332,873
Nov-25	2,915,716	-	64,417,157	5.43%	297,865	64,715,022
Dec-25	3,228,978	-	61,486,043	5.43%	285,320	61,771,363
Jan-26	3,285,448	-	58,485,915	5.43%	271,882	58,757,796
Feb-26	2,864,523	-	55,893,274	5.43%	259,207	56,152,480
Mar-26	3,065,884	-	53,086,597	5.43%	246,971	53,333,568
Apr-26	2,568,715	-	50,764,853	5.43%	235,349	51,000,202
May-26	2,906,674	-	48,093,529	5.43%	224,034	48,317,563
Jun-26	3,303,881	-	45,013,682	5.43%	211,006	45,224,688
Jul-26	4,074,721	-	41,149,967	5.43%	195,279	41,345,246
Aug-26	4,015,646	-	37,329,600	5.43%	177,871	37,507,471
Sep-26	3,284,385	-	34,223,086	5.43%	162,171	34,385,257
Oct-26	2,825,515	-	31,559,743	5.43%	149,091	31,708,833
Nov-26	2,908,091	-	28,800,742	5.43%	136,802	28,937,544
Dec-26	3,215,952	-	25,721,592	5.43%	123,575	25,845,167
Jan-27	3,360,775	-	22,484,392	5.43%	109,265	22,593,657
Feb-27	2,888,930	-	19,704,727	5.43%	95,630	19,800,357
Mar-27	3,055,216	-	16,745,141	5.43%	82,623	16,827,764
Apr-27	2,647,056	-	14,180,708	5.43%	70,105	14,250,813
May-27	2,937,048	-	11,313,765	5.43%	57,797	11,371,563
Jun-27	3,275,700	-	8,095,862	5.43%	44,013	8,139,875
Jul-27	4,098,514	-	4,041,361	5.43%	27,540	4,068,900
Aug-27	4,040,406	-	28,495	5.43%	9,264	37,758

PSE&G Electric - Storm Recovery Charge
Over/(Under) Balance and Interest Calculation

($'s - Unless noted)

(1)	(2)	(3)
Input	Input	[Schedule SS-SRC-1E R-1] Line 5 x Col 2
Rate Class	**Annual kWh**	**Annual Revenue**
RS	13,390,516,645	13,028,973
RHS	74,071,772	72,072
RLM	174,889,380	170,167
WH	554,008	539
WHS	7,013	7
HS	9,842,905	9,577
BPL	249,631,666	242,892
BPL-POF	13,978,769	13,601
PSAL	108,941,398	106,000
GLP	6,916,145,205	6,729,409
LPL-S	10,020,481,341	9,749,928
LPL-P	2,882,687,883	2,804,855
HTS-S	5,068,122,778	4,931,283
HTS-HV	670,116,301	652,023
Total	39,579,987,063	38,511,327

PSE&G Residential Electric Vehicle Cost of Service Study

System Peak	10,147,020	kW	
Peak Date	8/9/2022 Tuesday		
Peak Hour Ending	17	i.e. 4-5pm	

Customers		826			
Sum of Peaks		16,651	kW		
CP		34	kW		
Total Usage		2,921,627	kWh		
				9n3	
Local Delivery	$	481,937,668	Sum of Peaks	from 9n3 Cost of Service output	
System Delivery	$	308,233,692	Coincident Peaks	from 9n3 Cost of Service output	
				Scaled	
RS Customers		2,000,647		0.04%	
RS WN Sum of Peaks		11,830,661	kW	4,884	kW
RS WN Coincident Peak		4,362,852	kW	1,801	kW
RS Usage		13,286,613,062	kWh	5,485,597	kWh
		RS Cost Rate			
RS Local Delivery Rate		0.036272			
RS System Delivery Rate		0.023199			
Total		0.059471	$/kWh		
RS EV Sum of Peak Ratio		0.1407%			
RS EV Coincident Peak Ratio		0.0008%			
RS EV Sum of Peaks $	$	678,295		$ 198,976	
RS EV Coincident Peak $	$	2,404		$ 127,259	
Total $	$	680,699		$ 326,235	
		EV Cost Rate ($/kWh)			
RS EV Sum of Peaks Rate	$	0.232163			
RS EV Coincident Peak Rate	$	0.000823			
Total Rate	$	0.232986	w/o SUT	Sales Tax Factor	
Total Rate		0.248421	w/SUT	1.06625	
		Proposed Avg RS Rate			
proposed RS Dist kWh rev		761,469,000			
RS WN annual kWh		13,166,714	MWh		
RS Proposed avg kWh rate		0.057833	$/kWh		

PSE&G Commerical & Industial Electric Vehicle Cost of Service Study

System Peak	10,147,020	kW
Peak Date	8/9/2022 Tuesday	
Peak Hour Ending	17	i.e. 4-5pm

Customers		34				
Sum of Peaks		17,678	kW			
Coincident Peak		6,187	kW			
Total Usage		30,361,295	kWh			
				5n7		
Local Delivery	$	105,678,423	Sum of Peaks	from 5n7 Cost of Service output		
System Delivery	$	129,958,748	Coincident Peaks	from 5n7 Cost of Service output		
					Scaled	(for reference)
LPL-S Customers		9,532			0.36%	
LPL-S WN Sum of Peaks		2,893,512	kW		10,321	kW
LPL-S WN Coincident Peak		1,946,767	kW		6,944	kW
LPL-S Usage		10,497,945,935	kWh		37,443,827	kWh
LPL-S Local Delivery Rate		0.010067				
LPL-S System Delivery Rate		0.012379				
Total		0.022446				
LPL-S EV Sum of Peaks Ratio		0.6110%				
LPL-S EV Coincident Peak Ratio		0.3178%				
LPL-S EV Sum of Peaks $	$	645,660		$	376,931	
LPL-S EV Coincident Peak $	$	413,018		$	463,534	
Total $	$	1,058,678		$	840,465	
		EV Cost Rate				
LPL-S EV Coincident Peak Rate	$	0.021266				
LPL-S EV Sum of Peaks Rate	$	0.013603				
Total	$	0.034869				
Rate Revenue	$	219,900,000				
COS Rev	$	235,637,170				
Ratio of Rate Revenue to COS		0.93321				
		Proposed EV Rate - $/kWh				
DCFC Distribution kWh		0.032540	w/o SUT	Sales Tax Factor		
DCFC Distribution kWh		0.034696	w/SUT	1.06625		

PSE&G CEF Electric Vehicle Program **Exhibit P-9E R-1**
Rate Adjustment Calculation CEF-EV-1 R-1
Sample Calculation
in ($000)

	Rate Effective Date	**4/1/2025**	
	Plant In Service as of Date	12/31/2025	
	Rate Base Balance as of Date	3/31/2025	
	RATE BASE CALCULATION		
		Total	Notes
1	Gross Plant	$3,900	= ln 17
2	Regulatory Asset	$4,714	= ln 22 + ln 28 + ln 56
3	Accumulated Depreciation	($42)	= ln 28
4	Net Plant	$8,572	= ln 1 + ln 2 + ln 3
5	Accumulated Deferred Taxes	($1,177)	= ln 45
6	Rate Base	$7,395	= ln 4 + ln 5
7	Rate of Return - After Tax	7.55%	See Rate Case Schedule MPM-04 (WACC)
8	Return Requirement (After Tax)	$558	= ln 6 * ln 7
9	Depreciation Exp, net	$205	= ln 66
10	O&M Expense Regualtory Asset Amortization - After Tax	$563	= ln 70
11	Revenue Factor	1.3947	See Rate Case Schedule MPM-06 (Revenue Factor)
12	**Total Revenue Requirement**	**$1,850**	= (ln 8 + ln 9 + ln 10) * ln 11
	SUPPORT		
	Investment		
	Real Assets (Pole to Meter)		
13	Residential Smart Charging	$1,300	See "RevReq Detial Wkps
14	Mixed Use	$1,300	See "RevReq Detial Wkps
15	DCFC	$1,300	See "RevReq Detial Wkps
16	IT System Enhancements	$0	See "RevReq Detial Wkps
17	Total Real Assets	$3,900	= ln 13 + ln 14 + ln 15 + ln 16
	Regulatory Assets (Meter to Stub / Rebates)		
18	Residential Smart Charging	$1,300	See "RevReq Detial Wkps
19	Mixed Use	$1,300	See "RevReq Detial Wkps
20	DCFC	$1,560	See "RevReq Detial Wkps
21	IT System Enhancements	$0	See "RevReq Detial Wkps
22	Total Regulatory Assets	$4,160	= ln 18 + ln 19 + ln 20 + ln 21
23	**Total Investment**	**$8,060**	= ln 17 + ln 22
	Depreciation & Amortization		
	Real Assets (Pole to Meter)		
24	Residential Smart Charging	$14	See "RevReq Detial Wkps
25	Mixed Use	$14	See "RevReq Detial Wkps
26	DCFC	$14	See "RevReq Detial Wkps
27	IT System Enhancements	$0	See "RevReq Detial Wkps
28	Total Real Assets	$42	= ln 24 + ln 25 + ln 26 + ln 27
	Regulatory Assets (Meter to Stub / Rebates)		
29	Residential Smart Charging	$23	See "RevReq Detial Wkps
30	Mixed Use	$23	See "RevReq Detial Wkps
31	DCFC	$52	See "RevReq Detial Wkps
32	IT System Enhancements	$0	See "RevReq Detial Wkps
33	Total Regulatory Assets	$99	= ln 29 + ln 30 + ln 31 + ln 32
34	**Total Depreciation & Amortization**	**$141**	= ln 28 + ln 33

PSE&G CEF Electric Vehicle Program
Rate Adjustment Calculation
Sample Calculation
in ($000)

Exhibit P-9E
CEF-EV-1

ADIT

	Real Assets (Pole to Meter)		
35	Residential Smart Charging	$12	See "RevReq Detial Wkps
36	Mixed Use	$12	See "RevReq Detial Wkps
37	DCFC	$12	See "RevReq Detial Wkps
38	IT System Enhancements	$0	See "RevReq Detial Wkps
39	Total Real Assets	$35	= ln 35 + ln 36 + ln 37 + ln 38
	Regulatory Assets (Meter to Stub / Rebates)		
40	Residential Smart Charging	$359	See "RevReq Detial Wkps
41	Mixed Use	$359	See "RevReq Detial Wkps
42	DCFC	$424	See "RevReq Detial Wkps
43	IT System Enhancements	$0	See "RevReq Detial Wkps
44	Total Regulatory Assets	$1,142	= ln 40 + ln 41 + ln 42 + ln 43
45	**Total ADIT**	**$1,177**	= ln 39 + ln 44

Deferred Return / Carrying Charges

	Real Assets (Pole to Meter)		
46	Residential Smart Charging	$83	See "RevReq Detial Wkps
47	Mixed Use	$83	See "RevReq Detial Wkps
48	DCFC	$82	See "RevReq Detial Wkps
49	IT System Enhancements	$0	See "RevReq Detial Wkps
50	Total Real Assets	$248	= ln 46 + ln 47 + ln 48 + ln 49
	Regulatory Assets (Meter to Stub / Rebates)		
51	Residential Smart Charging	$83	See "RevReq Detial Wkps
52	Mixed Use	$83	See "RevReq Detial Wkps
53	DCFC	$98	See "RevReq Detial Wkps
54	IT System Enhancements	$0	See "RevReq Detial Wkps
55	Total Regulatory Assets	$264	= ln 51 + ln 52 + ln 53 + ln 54
56	**Total Deferred Return / Carrying Charges**	**$512**	= ln 50 + ln 55

Amortization Period

57	Residential Smart Charging	30	See Rate Case Schedule MPM-49 (Amort of CEF-EV Program)
58	Mixed Use	30	See Rate Case Schedule MPM-49 (Amort of CEF-EV Program)
59	DCFC	30	See Rate Case Schedule MPM-49 (Amort of CEF-EV Program)
60	IT System Enhancements	5	See Rate Case Schedule MPM-49 (Amort of CEF-EV Program)

Amortization Recovery

61	Residential Smart Charging	$92	= (ln 13 + ln 18 + ln 46 + ln 51) / ln 57
62	Mixed Use	$92	= (ln 14 + ln 19 + ln 47 + ln 52) / ln 58
63	DCFC	$101	= (ln 15 + ln 20 + ln 48 + ln 53) / ln 59
64	IT System Enhancements	$0	= (ln 16 + ln 21 + ln 49 + ln 54) / ln 60
65	Total D&A Recovery	$286	= ln 61 + ln 62 + ln 63 + ln 64
66	Total D&A (Net of Tax)	$205	= ln 65 * 1 - Tax Rate

O&M Expense Regualatory Asset Amortization

67	CEF-EV O&M Expenses	$3,913	See "RevReq Detial Wkps
68	Amortization Period (Years)	5	See Rate Case Schedule MPM-49 (Amort of CEF-EV Program)
69	Annaul CEF-EV O&M Expenses Amortization	$783	= ln 67 / ln 68
70	Total O&M Expense (Net of Tax)	$563	= ln 69 * 1 - Tax Rate

STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

In the Matter of the Petition of
Public Service Electric and Gas Company
for Approval of an Increase in Electric and Gas
Rates and for Changes in the Tariffs for
Electric and Gas Service, B.P.U.N.J.
No. 17 Electric and B.P.U.N.J. No. 17
Gas, and for Changes in Depreciation Rates,
Pursuant to N.J.S.A. 48:2-18,
N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1, and
for Other Appropriate Relief

BPU Docket Nos. ER23120924 & GR23120925

DIRECT TESTIMONY
OF

STEPHEN SWETZ

SENIOR DIRECTOR – CORPORATE RATES AND
REVENUE REQUIREMENTS
ON
GAS COST OF SERVICE AND RATE DESIGN

April 15, 2024
P-9G R-1

TABLE OF CONTENTS

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
DIRECT TESTIMONY
OF
STEPHEN SWETZ
SENIOR DIRECTOR – CORPORATE RATES AND REVENUE REQUIREMENTS
ON
GAS COST OF SERVICE AND RATE DESIGN

Q. Please state your name, affiliation and business address.

A. My name is Stephen Swetz, and I am the Senior Director – Corporate Rates and Revenue Requirements for PSEG Services Corporation. My principal place of business is 80 Park Plaza, Newark, New Jersey 07102. My credentials are set forth in the attached Schedule SS-G1 R-1.

Q. Please describe your responsibilities as Senior Director – Corporate Rates and Revenue Requirements.

A. In this position I have, among other things, responsibility for the development of rates and tariffs for Public Service Electric and Gas Company ("PSE&G" or "Company").

Q. Have you previously testified in proceedings before the New Jersey Board of Public Utilities ("Board" or "BPU")?

A. Yes. I have both submitted written testimony and testified live before the BPU in a number of proceedings that are identified in Schedule SS-G1 R-1.

<u>**SCOPE OF TESTIMONY**</u>

Q. What is the purpose of your direct testimony in this proceeding?

A. The purpose of my direct testimony is to support the Company's proposed changes to its rates for Gas Service, which are designed to recover the revenue requirements for the gas distribution business as presented in this filing. My testimony provides the Company's embedded cost of service study ("Company COSS") used as the basis for development of the new gas rates and the proposed rate design for each rate schedule in PSE&G's Gas Tariff. I also present an alternative embedded cost of service study ("the Staff COSS") as required under the 2018 Rate Case Order and explain why that COSS should not be used to set rates in this case.[1]

Additionally, I sponsor other studies and modifications to the Company's Tariff for Gas Service ("Tariff") including the following:

- Recovering Gas Bad Debt Costs consistent with method used in electric business; and
- The establishment of a Storm Recovery Charge ("SRC") to recover major storm costs as a component of a proposed Distribution Adjustment Charge ("DAC") that was previously proposed as part of the COVID-19 cost recovery proceeding;[2]
- Tax Adjustment Credit ("TAC") modifications.

I also sponsor the Company's proposed Tariff, which is attached to the Company's Petition in Exhibit P-1 as Schedule 3.

[1] *I/M/O the Petition of Public Service Electric and Gas Company for Approval of an Increase in Electric and Gas Rates and for Changes in Tariffs for Electric and Gas Service, B.P.U.N.J. No. 16 Electric and B.P.U.N.J. No. 16 Gas, and for Changes in Depreciation Rates, Pursuant to N.J.S.A. 48:2-18, N.J.S.A 48:2-21 and N.J.S.A. 48:2-21.1, and for Other Appropriate Relief*, BPU Docket Nos. ER18010029 & GR18010030; *I/M/O the New Jersey Board of Public Utilities' Consideration of the Tax Cuts and Jobs Act of 2017*; BPU Docket No. AX18010001; *I/M/O Public Service Electric and Gas Company for Approval of Revised Rates (Effective on an Interim Basis April 1, 2018) to Reflect the Reduction Under the Tax Cuts and Jobs Act of 2017*, BPU Docket No. ER18030231, Decision and Order Adopting Initial Decision and Stipulation (October 29, 2018) (the "2018 Rate Case Order"), paragraph 25.

[2] *I/M/O the New Jersey Board of Public Utilities Response to the COVID-19 Pandemic*, BPU Docket No. AO20060471, PSE&G filing titled *I/M/O the Petition of Public Service Electric and Gas Company for Approval of Incremental COVID-19 Costs for Recovery Through a New Special-Purpose Clause, and for Authorization to Recover Uncollectible Costs for Gas Through the Societal Benefits Charge* (July 17, 2023).

Q. Do you sponsor any schedules as part of your direct testimony?

A. Yes. I sponsor the following schedules that were prepared and/or compiled by me or under my direction and supervision:

SCHEDULE DESCRIPTION	NUMBER
Qualifications of Stephen Swetz	SS-G1 R-1
Basis of Calculations Schedules	
Actual and Weather Normalized Billing Determinants	SS-G2 R-1
COSS Adjustments	SS-G3 R-1
Cost of Service Schedules	
Details of Complete COSS	SS-G4 R-1
COSS Summary Report by Functional Segment	SS-G5 R-1
COSS Revenue Requirements by Rate and Function	SS-G6 R-1
Sync with Rate Design	SS-G7 R-1
Rate and Rate Design Schedules	
Inter Class Revenue Increase Allocations	SS-G8 R-1
Service Charge Calculations	SS-G9 R-1
BGSS Calculations	SS-G10 R-1
Proof of Revenue by Rate Schedule	SS-G11 R-1
Typical Customer Bill Impacts by Rate Schedule	SS-G12 R-1
Staff's Cost Allocation Methodology Related Schedules	
Details of Complete COSS – Staff's Method	SS-G13 R-1
Summary Report – by Functional Segment – Staff's Method	SS-G14 R-1
Functional Cost Summary – Staff's Method	SS-G15 R-1

<u>OVERVIEW OF THE COMPANY'S RATE FILING AND BASIS OF CALCULATIONS AND ANALYSIS</u>

Overview

Q. What terminology does your direct testimony use regarding revenue and rates?

A. Throughout this testimony, the revenue or percentage increase for "Distribution" is based only on revenue from the Service Charge and Distribution Charge(s) for the particular rate schedule. The term "Delivery" refers to revenue from the Service Charge and Distribution Charges as indicated on the particular rate schedule, plus the revenue from the Balancing Charge and all of the applicable adjustment clauses. The "Total Bill" equals the Delivery Charges plus gas supply, and is calculated as if all customers were supplied on Basic Gas Supply Service ("BGSS").

Q. Please describe the gas distribution services provided by the Company.

A. The Company provides gas distribution services under the following Rate Schedules:

(i) Rate Schedule RSG sets forth the terms at which the Company provides firm delivery service for residential purposes;

(ii) Rate Schedule GSG sets forth the terms at which the Company provides firm delivery service to customers that do not qualify for Rate Schedule RSG and whose usage does not exceed 3,000 therms in any month;

(iii) Rate Schedule LVG sets forth the terms at which the Company provides firm delivery service for general purposes;

(iv) Rate Schedule SLG sets forth the terms at which the Company provides firm delivery service for gas street lighting purposes as well as lamp posts and maintenance;

(v) Rate Schedule TSG-F is a closed service that was available to customers who purchased or committed to purchase service prior to December 1, 1994 and whose maximum request for firm gas is not less than 150 therms per hour;

(vi) Rate Schedule TSG-NF sets forth the terms at which the Company provides interruptible delivery service to customers whose maximum request for gas is not less than a 150 therms per hour; and

(vii) Rate Schedule CIG is a closed interruptible service that was available to cogeneration customers who purchased or committed to purchase service prior to January 9, 2002.

(viii) Rate Schedule CSG is a firm or interruptible delivery service for general purposes where the customer is requesting a discount rate from a Public Service Rate Schedule for delivery service based on an (a) Economically Viable Bypass alternative or (b) Other Considerations.

Q. Please provide an overview of the Company's filing in this proceeding.

A. As described more fully by Company witness Mr. Michael McFadden's, PSE&G is seeking to increase its base delivery rates effective September 1, 2024 by approximately $401 million annually for its gas distribution business. As discussed further by Mr. McFadden and Company witness Mr. Cliff Pardo, the Company further proposes to make certain modifications to the Company's TAC, including flowing back Mixed Service deductions to customers. This change will reduce gas rates by approximately $98 million annually. In addition, the Company is proposing the SRC to recover major storm costs, increasing gas rates by approximately $1 million annually. Finally, the Company is proposing to recover it gas bad debt costs through a new Social Programs component of the SBC for approximately $34 million. My testimony provides support on how these changes will impact rates.

Q. How have Gas distribution charges changed since the 2018 base rate case?

A. Gas distribution charges have increased at a compound annual growth rate ("CAGR") of 4.3% as shown in Figure 1. This increase is primarily driven by work to modernize the Gas system and replace cast iron and unprotected steel mains, which provide both a reliability and carbon emissions benefit to customers. Despite the considerable investment to modernize the gas system, the distribution charge CAGR for a residential customer using 1,000 therms per year is less than half of the statewide average of 10.6%. PSE&G's charges have increased considerably less than the New Jersey average because PSE&G has been able to control costs and maximize the value of its prior investments.

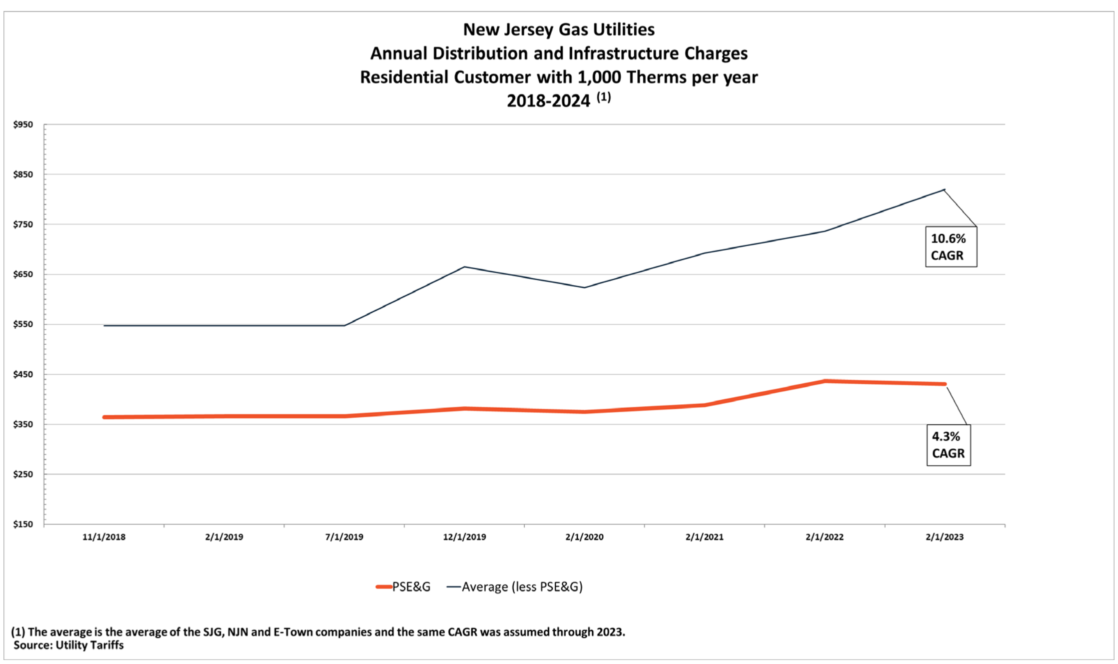

Figure 1

Q. That shows that PSE&G's Distribution charges are lower than average, but how does PSE&G compare on a total bill basis?

A. PSE&G continues to be lower than the average compared to its peers. In New Jersey, PSE&G remains on the lower cost side compared to of all of its peers in terms of the total gas and electric bill. Further, as shown in Figure 2 below, the Company has the lowest monthly gas bill amongst all of its peers – almost 27% lower than the average, as set forth in Figure 2 below.

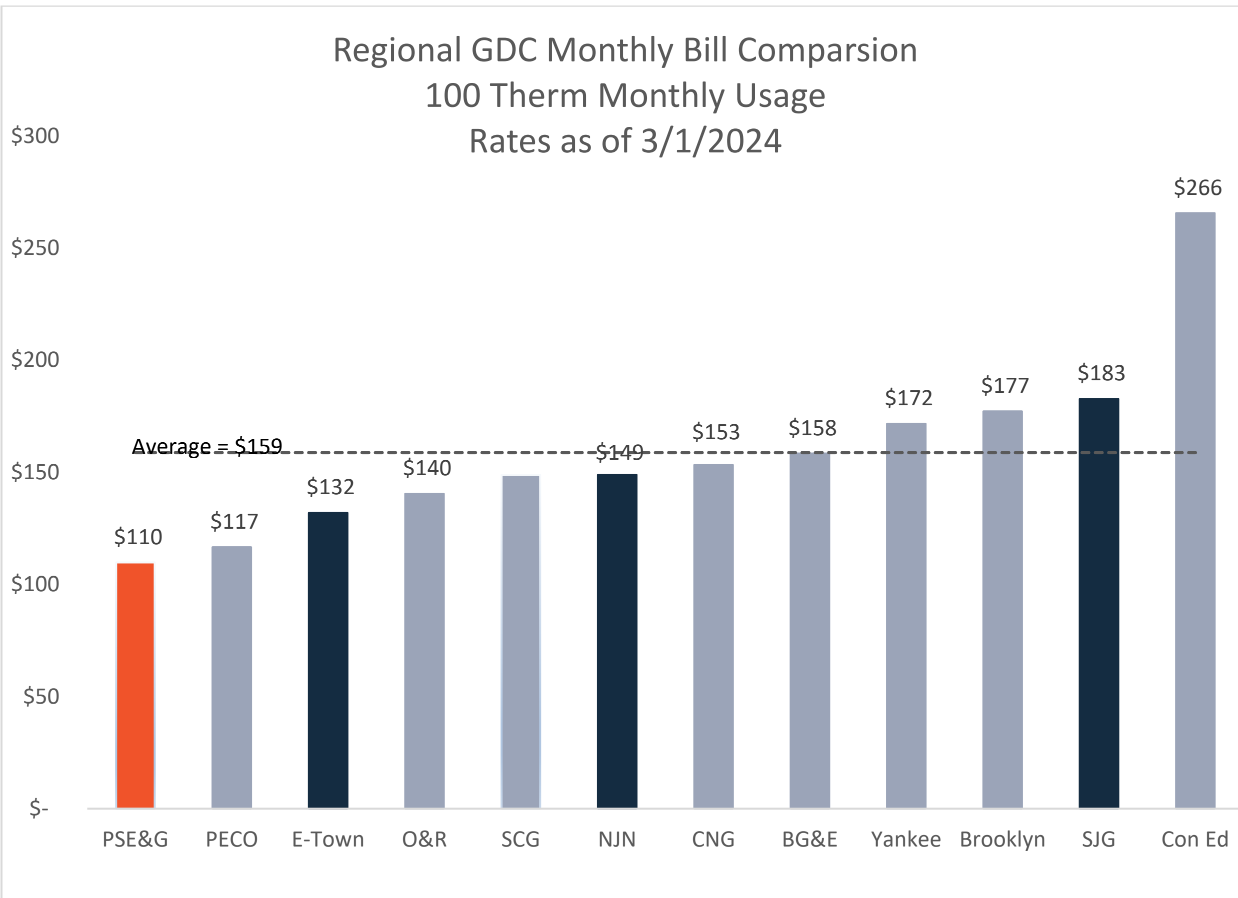

Figure 2

Q. How long has it been since PSE&G's last base rate case?

A. PSE&G filed its last base rate case on January 12, 2018, with new rates effective November 1, 2018. Since that time, every other NJ gas utility has filed at least two base rate cases.

Q. Why has PSE&G not filed a rate case until now?

A. As discussed in more detail below, this is primarily due to the Company's efforts to control costs. PSE&G takes very seriously its responsibility to customers to manage costs prudently and be good stewards of the gas distribution system and the customer funds needed to operate and maintain it effectively. This is achieved by regularly benchmarking Company costs and employee performance and creating appropriate employee incentives to continue to improve upon historic success.

Q. Please describe the efforts the Company has undertaken to protect lower-income customers from the impact of rate increases.

A. The Company is very focused on this vulnerable segment of our customer base. PSE&G's Energy Efficiency programs include incentives targeted to its lower income customers, with specific opportunities for both low and moderate income customers, who often face the highest energy burdens. The Company specifically seeks to provide energy savings opportunities to these customers in order to lower their energy burdens, as participants in the EE programs are expected to benefit from long term energy and bill savings, as well as health and safety improvements. The Company implements the State's Comfort Partners program to customers with incomes up to 250% of the Federal Poverty Level; that program provides free comprehensive energy savings solutions as well as upgrades to address health and safety problems in the home. PSE&G also recently filed its updated Clean Energy Future – Energy Efficiency II Program, which proposes to transfer administration of the Comfort Partners program to the Company in order further reduce market confusion and streamline the process for lower-income customers to take advantage of energy efficiency programs;[3] PSE&G believes this change in administration of the Comfort

[3] *I/M/O The Petition of Public Electric and Gas Company for Approval of its Clean Energy Future-Energy Efficiency II (CEF-EE I) Program on A Regulated Basis*, BPU Docket No. QO23120874 (filed December 1, 2023).

Partners program will significantly improve customer access to energy efficiency and allow the Company more flexibility in serving the needs of lower-income customers. Also as part of the Clean Energy Future – Energy Efficiency II Program, PSE&G proposed to continue to target low and moderate income customers by providing comprehensive energy assessments and free direct install of energy efficient measures and services to income qualified households with higher incentives and opportunities for no-interest financing for health and safety improvements to these customers (the Comfort Partners program does not include financing, as all measures are paid for by the program and free to eligible customers), and to continue to provide enhanced opportunities for customers in overburdened communities. PSE&G also offers higher incentives for high efficiency heating and cooling systems and continues to provide financial incentives to both property owners and tenants to install high efficiency equipment in apartments and other multifamily properties. The Company promotes the use of these programs to our customers through bill inserts and community outreach, conducting this communication in multiple languages where possible and appropriate.

Q. Are there other assistance programs for lower-income customers outside of PSE&G's energy efficiency programs, and if so, please describe those programs and who is eligible.

A. The Company also advocates at the State and Federal level for various grants provided to lower-income customers, including the Low-Income Home Energy Assistance Program ("LIHEAP"), Lifeline and Tenants Lifeline Program ("Lifeline"), and the Universal Service Fund ("USF"). LIHEAP is a Federal Block Grant program that helps low-income individuals and households pay for their winter heating bills, medically necessary cooling benefits, and weatherization. The Lifeline Program helps customers pay their utility bills with a $225 annual utility credit. To be eligible, a customer must be at least age 65, or at least age 18 and collecting

Social Security Disability. In addition, a single person must make less than $42,000, or a couple less than $49,000 annually. USF is a statewide program administered by the Department of Community Affairs that allows program recipients to pay no more than 3% of their income for electric and 3% for natural gas, or 6% for total electric, including electric heating for customers at or below 60% of the State median income. PAGE is a program for customers earning up to 500% of the Federal Poverty Limits and offers a grant of up to $700 per utility service. NJ SHARES is for customers earning up to 400% of the Federal Poverty Limit and is funded by customer donations which are matched by PSE&G.

PSE&G has more customers eligible for these low-income programs on a proportionate basis compared with other New Jersey utilities. This customer segment receives special focus.

Q. Are there steps PSE&G has taken during the COVID-19 pandemic to help these customers?

A. Yes. PSE&G, its customers, and New Jersey have faced unprecedented challenges as a result of the COVID-19 global pandemic that created difficult economic circumstances. In response to these challenges, PSE&G developed a comprehensive payment assistance outreach plan utilizing employees and contractors and conducted an external media campaign designed to provide customers opportunities to garner financial assistance and enter into deferred payment arrangements to avoid shut off.

Q. Has the Company considered the impact of gas rates on these customers?

A. Yes. As illustrated in the figure below, the relative cost of PSE&G's services to a typical combined (that is, electric and gas) residential lower-income customer has dropped significantly since 2009 and is essentially flat as compared with rates following the conclusion of the Company's 2018 base rate case.

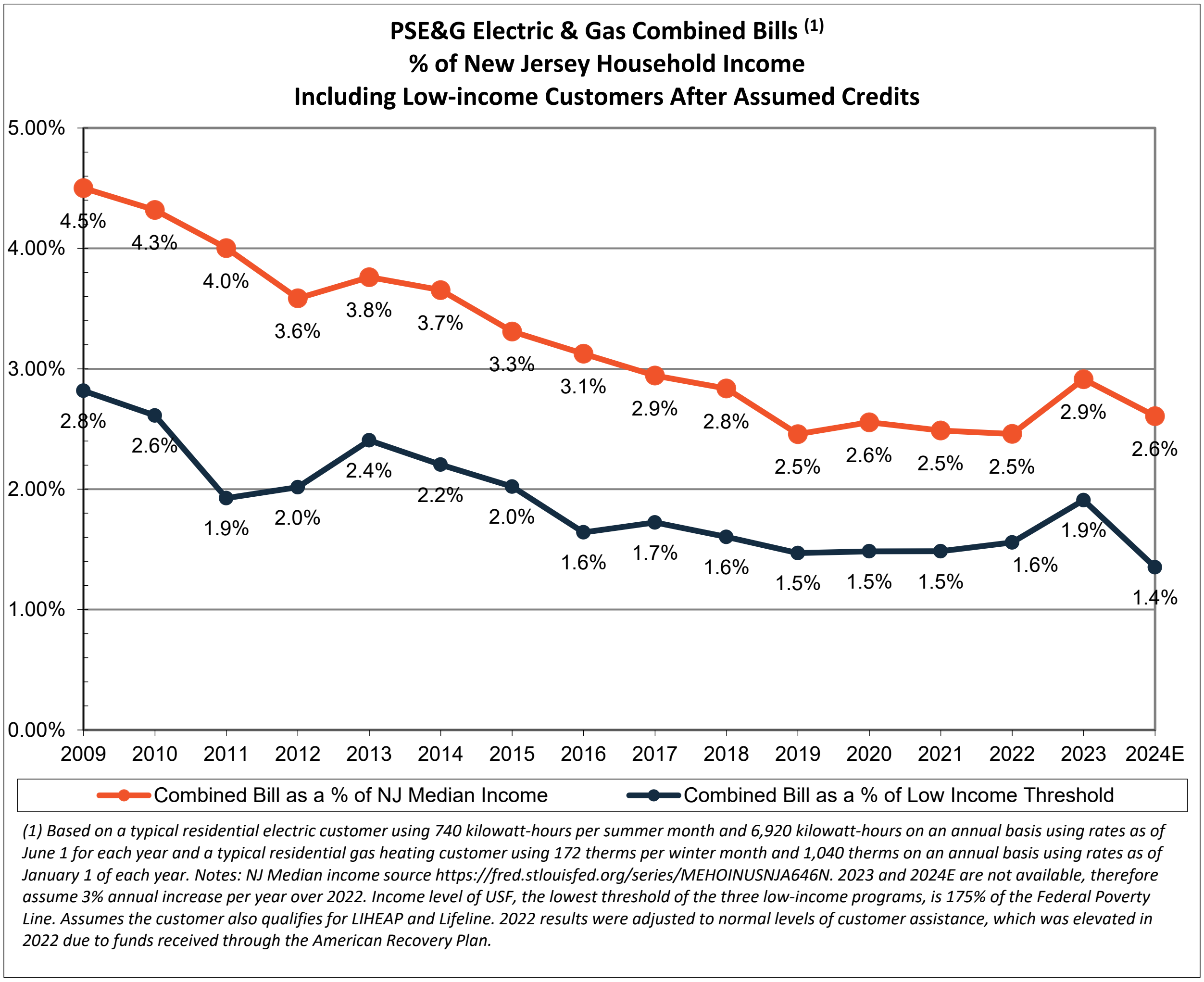

Figure 3

This chart compares the bill as a percentage of income for a typical combined electric and gas residential customer relative to New Jersey's median income and relative to the income threshold below which customers are considered low-income. As can be seen, for the average residential customer, the cost of service is less than 3% of median income. For lower-income customers, the cost of the bill after LIHEAP, USF, and Lifeline grants relative to an income level of 60% of State median income (the level at which a customer is eligible for these grants), is around 2% today. So, even with this proposed rate increase, the cost of electricity and gas for all of the Company's customers, including low-income customers, remains a very small portion of overall income for those able to take advantage of these programs.

Q. How does the current RSG Service Charge compare to other utilities?

A. As shown in the figure below, PSE&G's monthly RSG gas service charge is the lowest compared to similar gas utilities in the region.

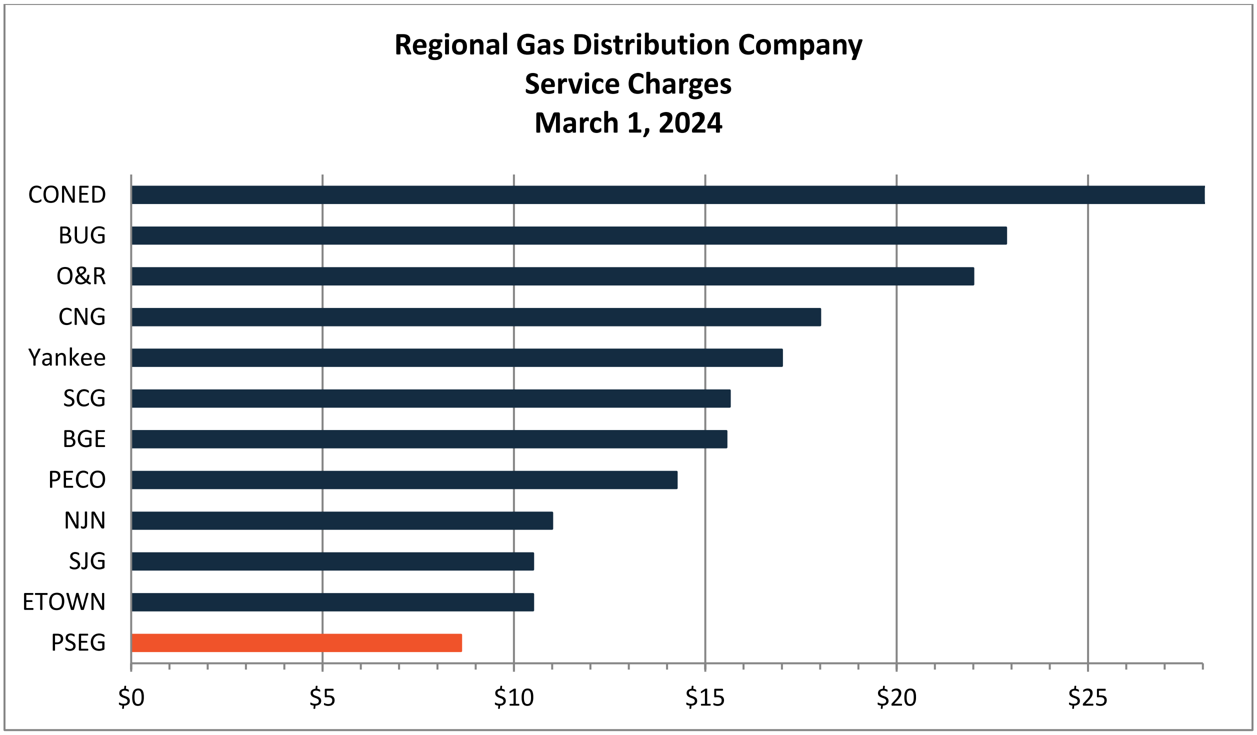

Figure 4

Q. What are the periods used for the COSSs and Rate Design that you are sponsoring in this proceeding?

A. The COSSs presented in this testimony are based upon the period of January 1 to December 31, 2022. The only variations from actual costs in the COSS period were the requested overall Rate of Return value, proposed rate base adjustments such as working capital requirements, and the proposed *pro forma* Adjustments. These adjustments, as well as the adjustments needed to synchronize the COSS results with the proposed rate design as discussed later in my testimony, and the rate design presented in this testimony are based upon the Test Year of June 1, 2023 through May 31, 2024 (hereafter "Test Year").

Q. What billing determinants will be used to determine the revenue requirement and rates that are being established in this proceeding?

A. The billing determinants used to establish rates and the revenue requirement in this proceeding will be the actual Test Year billing determinants as adjusted for normal weather. For the initial filing and any updates (prior to the final filing) with all actual data, the billing determinants will be a mix of weather normalized actual and forecasted billing determinants. Weather normalized billing determinants are calculated by adjusting actual recorded monthly gas sales to account for the effects of abnormal weather. A summary of the actual billing determinants, the weather normalized billing determinants, and the variation of each determinant from normal for the Test Year is shown in Schedule SS-G2 R-1.

Weather Normalization of Billing Determinants

Q. What weather pattern is used to weather normalize actual billing determinants?

A. The Company utilizes a twenty-year weather pattern as measured at Newark Liberty International Airport covering the period ended December 31, 2021.

Scope of the COSS

Q. Please describe the COSSs that the Company is presenting in this proceeding.

A. The Company is presenting two COSSs in this proceeding -- its recommended COSS is referred to as the "Company COSS" – and an additional COSS based on a methodology developed by BPU Staff. As discussed more fully below, the Company does not support the use of the Staff COSS to establish rates in this proceeding, but is submitting the study in compliance with the 2018 Rate Case Order. The COSSs discussed in this testimony are for the gas Distribution portion of the Company's operations. Thus the COSSs are generally "pipes only" analyses for the Company's regulated gas delivery business. They do not include the costs for the Company's Balancing Services or BGSS because rates for those services are set in another proceeding. The impact of changes in distribution margin revenues that flow to the BGSS provider, such as those associated with Rate Schedule TSG-F, will, however, be shown as a change in the BGSS charges to customers.

Adjustments to Accounting Data

Q. Did you make any adjustments to the accounting data used in the COSSs?

A. Several adjustments to the 2022 accounting data used in the COSSs were necessary prior to its use. These adjustments and FERC Accounts associated with each of these adjustments are shown on Page 1 of Schedule SS-G3 R-1.

In the rate design process, the unit charges associated with these adjustments will be added back as appropriate in each rate schedule to assure full recovery of these expenses. The Company COSS and the Staff COSS each include these adjustments to costs and billing determinants.

COSS OVERVIEW

Introduction

Q. What is the first step in developing new gas rates?

A. The first step in developing new gas rates is the preparation of an appropriate COSS. The Company COSS was used to both separate costs by functional segments and to allocate these segmented costs to the rate classes or sub-classes based upon each class's responsibility for that cost.

Q. What is the objective of a COSS?

A. The objective of a COSS is to measure the cost responsibility of each rate class and distribution function (functionalization).

Cost Allocation Concepts

Q. Please describe the cost allocation concepts used in the Company's COSS.

A. Inherent in any COSS is the allocation to rate classes of many costs which by their nature are difficult to relate precisely to cost causation. Cost causation describes the cause and effect relationship between customer requirements, load profile, and usage characteristics, and the costs incurred by the utility to serve those requirements. Experts will differ on the best way in which many costs should be allocated among customer classes. The key is to determine which approach makes the most sense in terms of best answering the question of what caused the cost, and then to apply the result in a reasoned, balanced manner. At all times, it is important to recognize that the COSS is intended to be a guide to appropriate ratemaking, and that one objective of ratemaking is that the end result should be a reasonable one.

As I will discuss later, I have used the results from the Company COSS as a direct guide in developing rates but tempered the final rate design to provide a reasonable balance between the goal of moving each rate schedule towards costs and the goal of achieving reasonable percentage increases based upon the resulting customer impacts.

General Cost Allocation and Functionalization Methodology

Q. What is the basis for the cost allocation and functionalization methodologies used in the Company COSS?

A. In the gas distribution business, the revenue requirements related to gas mains and services far exceed all other items. Together these facilities comprise the vast majority of rate base and are the basis for much of the operations and maintenance ("O&M") expenses. As previously stated, it is important to ensure that the allocation methods used in the COSS reflect the underlying cost causation principles. Gas mains have been, and continue to be, installed to bring gas service to the proximity of each customer's premise and are sized to handle the peak hourly gas flow at design conditions, without regard to the gas flow at any other time of day or season. These are the sole reasons and engineering basis for the design and cost of mains, and as such, the allocation of those costs should properly reflect each rate class's responsibility for the peak gas flow. Company witnesses Mike Schmid and Rick Fonseca discusses this in detail in the portion of their testimony entitled "Gas Capital Expenditures". In contrast to the cost of gas mains, the cost of a gas service (the pipe from the gas main to an individual building) is related to both the peak design loads of each building and the distance from the gas main (usually located in the street) to the structure itself. Because often one gas service serves more than one customer (or meter) in a building, the cost responsibility of a customer is a complex combination of site-specific conditions. The Company has relied on a study of actual installations of services and meters and employed that study to determine the allocation of gas service costs.

The methods of allocating the costs of mains and services used in the Company's COSS are based on sound cost causation principles and, as such, constitute a reasonable cost allocation methodology for the most significant categories of the Company's costs.

Functionalization into Five Segments

Q. What is the first step in the process to start a COSS?

A. As a first step in that process, the COSS unbundles total costs into five distinct functional segments – Distribution Access, Distribution Delivery, Street Lighting Fixtures, Customer Service, and Measurement.

Q. Once these functional segments are developed, how are they used?

A. These separate functions (or "segments") assist in the development of individual rate schedule components, such as the Service Charge. Once the plant and expenses are functionalized to the proper segment, the allocation process spreads the cost responsibility to the rate classes.

Q. What items are included in each of these segments?

A. The Distribution Access ("Access") segment includes the plant and O&M expenses related to gas services and regulators.

The Distribution Delivery ("Delivery") segment includes all equipment (plant and related O&M) from the city gate interconnections with upstream pipeline suppliers up to the point of connection with gas services, including all metering and regulation stations (the interface with the interstate gas pipelines), gas load dispatching operations, and gas mains. This segment also includes Appliance Services, recovery of regulatory assets, and the plant and non-commodity expenses related to gas production and storage facilities owned by PSE&G. Although these storage and production facilities are included in the Delivery segment, these costs are offset by the customer non-rate-related revenue received directly from the BGSS Supplier for whom these facilities are operated, as stipulated in the Gas Contracts Proceeding in Docket No. GM00080564, and thus do not affect the rates established in this proceeding.[4]

The Street Lighting segment is limited to gas street lighting lamps, posts and services.

The Customer Service segment includes all costs related to billing, inquiry, sales, service and collection activity.

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[4] *See In the Matter of the Petition of Public Service Electric and Gas Company's Proposal to Transfer its Rights and Obligations Under its Gas Supply and Capacity Contracts and Operating Agreements to an Unregulated Affiliate and Other Relief*, BPU Docket No. GM00080564.

The Measurement segment includes the costs for meter reading, customer-related meter plant and meter O&M.

Q. Are all costs included in these five segments?

A. Yes, all costs are included in one or more of these of five functional segments.

Access Segment

Q. Please discuss how the Access segment was allocated among the Company's customers classes.

A. The Access segment is the initial link between the shared or common distribution system and the customer's own gas facilities and is comprised of the gas service line from the main in the street to the meter and regulator at the customer's building. The embedded costs for this segment were allocated across the rate classes based on a study of actual installations of gas services.

Delivery Segment

Q. Please discuss how the Delivery segment was allocated among the Company's customer classes.

A. The Delivery segment consists of the portions of the distribution system that are used to serve multiple customers and are physically connected with individual customers' service lines. Basically, this segment includes all of the gas mains in the distribution system. The embedded costs of this segment were allocated across the rate classes through a variety of direct and indirect allocators which are discussed in greater detail in Appendix G-1.

Street Lighting Fixtures Segment

Q. Please discuss how the costs were allocated to the Street Lighting segment.

A. This segment is comprised of the investment for gas street lighting lamps and poles and all associated O&M expenses for this equipment. The gas service dedicated to supplying a gas streetlight is also segmented to this function. The costs of this segment are allocated solely to the Gas Streetlighting rate class.

Customer Service Segment

Q. Please discuss how the Customer Service costs were allocated to the Company's customer classes.

A. This segment encompasses all costs related to Customer Service type functions, such as costs related to billing, payment receipt and processing, collection activity, and other account maintenance type costs, with the exception of meter reading costs, which are included in the Measurement segment. These costs are allocated to the rate classes based upon a separate cost study of Customer Service functions.

Measurement Segment

Q. Please describe how the Measurement segment costs were allocated to the Company's customer classes.

A. This segment includes costs for meter reading and the investment and O&M expenses related to meters. Meter reading costs are allocated to the rate classes based upon a separate cost study of Customer Service functions, while the meter investment is allocated across the rate classes based upon the relative installed cost of new meters.

Modeling Procedure

Q. Please describe the Company COSS modeling procedure.

A. The Company COSS was developed based upon the weather normalized billing determinants and costs for each of the rate schedules. The revenues received by each rate class were calculated (or target balanced) such that the resulting rate of return ("ROR") for each rate class equals the Company's proposed overall ROR. Schedule SS-G4 R-1 contains the complete details of these final COSS results. Schedule SS-G5 R-1 presents a summary report of the revenue requirements by functional segment, while Schedule SS-G6 R-1 shows the revenue requirements by function (or segment) for each rate class.

Although Rate Schedule TSG-F and its associated costs are modeled in the COSS, all distribution revenue from Rate Schedule TSG-F flows to the BGSS provider as an offset to the "Non-Gulf Coast Cost of Gas." The revenue requirements associated with Rate Schedule TSG-F must therefore be recovered from the remaining firm customers. The allocation of these revenue requirements will be discussed in detail later in the section titled "Synchronizing the Cost of Service Study to the Rate Design".

After expenses or plant investment-related costs have been entered to the model, usually by FERC account or groups of accounts, a modeling allocator is also entered which performs two functions. The allocator shows:

1. Which of the five segments, or functions, the particular plant or expense item has been attributed to, and
2. The basis on which the particular plant or expense item has been allocated across the rate classes.

The Cost of Service model starts the calculation procedure by allocating the respective plant and expense items to rate classes using an allocator that reflects the reason the cost was incurred. Rate revenues received by each rate class are then target balanced such that the resulting ROR for each rate class equals the Company's proposed overall ROR. The model continues by separating all plant and expense items into appropriate functional segments by rate class, according to the modeling allocator assigned to the particular plant or expense item. The revenue requirement by segment for each rate class is then calculated to maintain, by rate class, the Company's proposed overall ROR used in the initial calculation.

The Direct and Indirect allocators used in the COSS and a detailed review of how all COSS items are segmented and functionalized are discussed in the Appendix G-1 to my testimony. In that Appendix, a description of how each of the major plant categories (gross plant), is segmented or functionalized is provided. The procedures used on Common and General plant, depreciation reserve, adjustments to rate base, operating revenues, O&M expenses for utility plant, administrative and general ("A&G") expenses, depreciation and amortization expenses, *pro forma* expense adjustments, and finally, taxes are also described.

Q. Please describe how the results of the Company COSS are presented in your schedules.

A. Schedule SS-G4 R-1 shows the details of how plant and expense items were separated into each of the five segments and allocated to each category of customers represented by the various rate classifications based upon the extent to which those groups of customers caused the costs. Schedule SS-G4 R-1 also shows the results of the allocation for each plant and expense item to each rate class. Schedule SS-G5 R-1 presents a high-level summary of expenses, plant, and revenue requirements for each of the five functional segments. Schedule SS-G6 R-1 is a summary report of the rate related revenue requirement, by functional segment, for each rate class in total.

The revenue requirements presented in the Company COSS do not include the revenue requirements associated with the SBC or other adjustment clauses or the revenue requirements associated with peaking plant and gas storage facilities. The costs related to the Adjustment Clauses will be collected from customers directly through the appropriate charges, and the revenue requirement associated with the peaking plant or gas storage facilities will be collected directly from the BGSS supplier.

Synchronizing the COSS to the Rate Design

Q. Please explain how the results of the Company COSS were synchronized with the proposed rate design.

A. Two adjustments are made to synchronize the results of the Company COSS to the proposed rate design. The first is an adjustment for the recovery of Rate Schedule TSG-F revenue requirements. The second is to synchronize costs because the COSS test period is different from the period used for the calculation of revenue requirements and rate design. With respect to the recovery of TSG-F revenue requirements, the Stipulation in the Gas Contracts Order, requires that all distribution revenues from Rate TSG-F must flow to the BGSS provider as an offset to BGSS gas costs, not to PSE&G. Thus, although the COSS can be used to determine the revenue requirements associated with Rate Schedule TSG-F, none of the revenue from these customers will flow to PSE&G. Instead, all distribution revenue requirements related to Rate Schedule TSG-F must be recovered from all other firm customers. The calculations to effectuate this requirement are set forth on Page 1 of Schedule SS-G7 R-1 (Cost of Service and Rate Design Sync). As indicated, the TSG-F revenue requirement is re-distributed to Rate Schedules RSG, GSG, LVG and SLG on an equal per therm of BGSS-supplied gas basis. The results of this re-distribution by functional segment are set forth on lines 15 to 20 of Page 1 of Schedule SS-G7 R-1.

In addition, as previously noted, the Company COSS is based on the period of January to December of 2022 while the Rate Design is based on the test year of June 2023 to May 2024. Thus, it is not possible to use the COSS results directly in the rate design process because the number of customers, therms transported, as well as plant and expenses are slightly different between the two time periods. To properly design rates, the COSS results must be adjusted slightly to correspond to the rate design test year period. The methodology used to synchronize the Cost of Service results is set forth on Page 2 of Schedule SS-G7 R-1. Because the primary difference is in the number of customers and amount of gas delivered, each functional segment's revenue requirement from Schedule SS-G6 R-1 was multiplied by the ratio of either the number of customers or gas delivered for the rate design test year to the same value during the COSS test year. The revenue requirements associated with the Distribution Delivery Segment (Row 2) were adjusted by the ratio of the gas delivered in these two periods. The revenue requirements associated with the Access Segment (Row 1), Customer Service Segment (Row 4) and Measurement Segment (Row 5) were adjusted by the ratio of the number of customers in these two periods. The revenue requirements associated with the Street Lighting Segment (Row 3) were adjusted by the ratio of the number of gas streetlights between these two periods. These steps are shown on lines 1 to 15 of page 2 of Schedule SS-G7 R-1. The resulting adjusted Company COSS functionalized revenue requirements are each then adjusted on an equal percentage basis so that the total equals the proposed rate related revenue requirements as set forth on lines 16 to 25 of Page 2 of Schedule SS-G7 R-1. The final adjusted functionalized revenue requirements are used in the rate design process.

<u>RATE DESIGN</u>

Introduction

Q. What are your objectives for developing the proposed gas rates?

A. The proposed gas rates have been developed to meet several objectives. The primary purpose is to recover revenues equal to the revenue requirement from customers. Additionally, this recovery should be effectuated on an equitable basis that provides the correct price signals to individual customers based on the cost to serve those customers. The final objective is that rates should be simple and understandable for the customer.

Q. Are the proposed rates based solely on the results of the Company COSS?

A. No. The COSS is a guide to appropriate ratemaking; its results are not applied in strict mathematical manner to design the proposed rates. While our goal is to move rates toward a full cost basis, that goal must be balanced against the need to achieve reasonable results.

Q. Do the rates included in your testimony include or exclude New Jersey Sales and Use Tax ("SUT")?

A. The proposed rates described in the next sections of my testimony and associated Schedules exclude SUT unless specifically indicated. However, the appropriate prices both without and with SUT are, included in the Proof of Revenue by Rate Schedule in Schedule SS-G11 R-1 as well as the proposed Tariff Sheets set forth in Schedule 3 of Exhibit P-1, and all other schedules that reference rates charged to customers.

Limitations on Rate Changes

Q. Did you develop and apply limits in designing proposed rates in this proceeding?

A. Yes. In order to achieve an overall goal of designing just and reasonable rates, I apply the principle of "gradualism" to temper the rate increases indicated by the Company COSS. To apply the principle of gradualism, I developed and employed a number of limits on the size of the rate increases that are proposed.

Q. Please describe the rate increase limits used in developing the proposed gas rates.

A. The first limit is that the proposed overall percentage revenue increase will be shared, within limits, among all customer classes. Although a primary goal is to move the delivery rates for each rate class toward the cost to serve as indicated by the Company COSS, no class will receive less than 50%, nor more than 150% of the overall average percentage Distribution increase. In addition, no class will receive more than 200% of the overall average percentage bill increase.

These rate increases limits were selected to provide a reasonable balance between the goal of moving towards the cost to serve, and the need to achieve equity among customer classes. The calculation and percentage values of these limits are shown on page 1 of Schedule SS-G8 R-1 (Inter Class Revenue Allocations). For Rates RSG, GSG and LVG, any shortfall in the revenue increase (or decrease) from these limitations was transferred to these other rates based upon the magnitude of the revenue increase (or decrease) received by those rates.

Q. Are there any exceptions to the proposed limits?

A. Yes. Because the prices charged for Rate Schedules TSG-NF and CIG are not cost-based but are based upon other considerations such as value of service, the distribution component for these rates was increased by the overall distribution percentage increase to maintain the current relationship in the level of distribution charges to the level of overall Company gas distribution revenue requirements, with the exception of Rate Schedule CSG. These customers have contracted distribution charges, so only the service charges were increased.

Inter Class Revenue Increase Allocations

Q. Please describe the process for allocating the proposed distribution increase to each rate class.

A. Page 1 of Schedule SS-G8 R-1 shows the calculation of the overall average percentage increase for Distribution and total bills, as well as the calculation of the upper and lower limits to be used in the inter class revenue increase allocation on Schedule SS-G8 R-1, page 2.

Page 2 of Schedule SS-G8 R-1 shows the development of the proposed inter-class allocation of the revenue increase. The Rate Schedules are indicated in Column 1, while Column 2 is the Proposed Distribution Revenue Requirement based upon the Company COSS results that were synchronized to the rate design test year. Column 3 is the Present Distribution Revenue, while Column 4 shows the increase that would occur if the synchronized Company COSS results were used directly, hence the use of the word "Unlimited" in the column heading. Column 5 is the present total bill revenue calculated as if all customers were supplied at BGSS rates. Column 6 is the percentage increase in distribution if the unlimited increase in dollars (from Column 4) were applied to the rates; that is, the percentage increase to each rate schedule if the COSS based increases were applied without constraints. Column 7 is the cost offsets from changes in the Margin Adjustment Clause and the BGSS charges resulting from distribution increases to Rate Schedules TSG-F, TSG-NF, CIG and CSG. The result of the proposed allocation of the Company's revenue requirement increase to the rate classes, consistent with the principles outlined in the previous section, Limitations on Rate Changes, is presented in Column 8 and Column 10. Specifically, Column 8 shows the percentage increase and Column 10 shows the proposed Distribution revenue increase by rate class. Column 9 shows the proposed total bill percentage increase if all customers were supplied at BGSS rates.

Application of these limits is somewhat complex due to the re-distribution of revenue from three sources. Rate Schedule TSG-NF distribution increases are flowed back to customers via the Margin Adjustment Charge (MAC), distribution increases applied to Rate Schedules TSG-F, CIG and CSG flow back to customers as a reduction in their BGSS rates and increases in the rates for gas supplied for pilot use for Rate Schedules TSG-NF and CIG also flow back to firm customers as a reduction in their BGSS rates. All of these credits are as shown in Column 7 of page 2 of Schedule SS-G8 R-1. In order to capture these revenue re-distributions correctly, a strict order of which calculations of the inter-class revenue increase allocations was followed.

The first step was the determination of the cost based charges for Rate Schedule TSG-F (as indicated on line 1 of page 2 of Schedule SS-G8 R-1). Because the value in Column 7 for Rate

Schedule TSG-F, the “Change in MAC and BGSS Credits” is based upon both the final outcome of the Rate Schedule TSG-F increase, as well as that for Rate Schedules TSG-NF and CIG, a value of zero was first utilized for the calculation. Once the upper and lower percentage distribution increase limits were applied (as shown in Column 8), an initial result for the Proposed Total Bill Increase Percentage (Column 9) and Proposed Distribution Revenue Increase (Column 10) was calculated.

The next step was to determine the increases for Rate Schedules TSG-NF and CIG. The Limited Final Distribution Charge Increase Percentage for Rate Schedule TSG-NF (Line 2, Column 8) was set equal to the overall average distribution charge percentage increase (Page 1, Line 8). For Rate Schedule CIG, the overall average distribution charge percentage increase was used as the Limited Final Distribution Charge Increase Percentage for Rate Schedule CIG (Line 3, Column 8).

Once the initial values for the increase to Rate Schedules TSG-NF, TSG-F and CIG were determined, the change in the MAC charge and BGSS credits could be calculated, and then applied to each of the rate schedules affected as indicated in Column 7. The change in the MAC charge used in this schedule relates only to the change in Rate Schedule TSG-NF margins, and does not include a change in the MAC charge due to current over/under recoveries.

The final step was to calculate the proposed distribution revenue increases for Rate Schedules RSG, GSG and LVG. These calculations were done in the same manner as performed for Rate Schedule TSG-F discussed above, although at this stage, the MAC and BGSS credits (in Column 7) had been calculated. These calculations and the application of the limits were performed in an Excel spreadsheet utilizing the “Goal Seek” function in order to meet all of the requirements of the limits and to properly allocate any revenue shortfall between these four rates, while recovering the full requested increase in distribution revenue.

Q. How should the rate design be affected if the Board approves an amount other than the Company's overall revenue increase request?

A. If the Board approves an amount other than the Company's overall revenue increase request, the increase to each of the classes should be allocated in proportion to the proposed revenue increase shown in Column 10, Page 2 of Schedule SS-G8 R-1.

General Rate Design Principles and Methodology

Q. Please describe the general rate design principles and methodology used in developing the proposed gas rates.

A. The rate design methodology presented in this testimony follows the philosophy of the cost allocation methodology used in the Company COSS. The rate design aligns, as close as practical, the rates (prices charged to customers) with the customers' underlying costs.

Changes in the distribution rates for Rate Schedules TSG-F, CIG, CSG and changes in the charges for pilot use for Rate Schedules TSG-NF, and CIG and CSG are cost offsets to the BGSS rates, and the resulting proposed BGSS tariff sheets have been modified appropriately (as indicated in Schedule 5 of the transmittal letter and in Schedule SS-G12 R-1).

The Service Charges for Rate Schedules RSG, GSG, LVG and TSG-F were set to move towards the revenue requirements indicated in the Company COSS for the sum of the Access, Customer Service, and Measurement segments. Except for the Residential Service Gas (RSG) Rate Class, which is discussed in the rate class specific changes portion of my testimony, the change in the Service Charges was limited to the same general inter rate class limits of no more than 150% of the overall average Distribution percentage increase. The proposed Service Charges on Rate Schedules TSG-NF and CSG were set equal to the Service Charge on Rate Schedule TSG-

F and the Service Charge for Rate Schedule CIG was increased in an amount equal to the overall average distribution percentage increase.

These limits were selected to provide a reasonable balance between the goal of moving each rate component towards costs, and the goal of achieving reasonable bill impacts. Any shortfall in Service Charge revenue resulting from these limitations was transferred to the remaining Distribution Charges of each rate schedule. In general, the Distribution Charges for each Rate Schedule were set to recover all the revenue requirements of the Distribution Delivery segment, plus any shortfall created from limitations in the proposed Service Charges. The calculations of the proposed Service Charges are found on Schedule SS-G10 R-1.

RATE SCHEDULE SPECIFIC CHANGES

Rate Schedule Residential Service Gas ("RSG")

Q. Please describe the rate design for Rate Schedule RSG.

A. Currently, Rate Schedule RSG is below its cost to serve. In addition, as indicated in Schedule SS-G9 R-1 Service Charge Calculations, (line 2), the Company COSS indicates that an increase in the monthly Service Charge is warranted, while the current Distribution Charge per Therm is above cost. Therefore, the Company proposes to increase the service charge corresponding to Service Charge limits discussed earlier. This will ensure that the Service Charge and Distribution Charge per Therm rate, will continue to move closer to the cost to serve.

The Distribution Charge for the Special Provision for Off-Peak use has been set at one-half the normal Distribution Charge. This is a continuation of the practice to provide a reasonable balance between providing the correct price signals to customers with gas air conditioning, while providing some contribution to offset winter peak period costs (and thus rates). No changes are proposed for qualification for this Off-Peak provision.

The results of the Rate Schedule RSG rate design appear on page 5 of the Proof of Revenue in Schedule SS-G11 R-1. The general format of the calculations is described on the first page of that Schedule. The calculation of the annual gas commodity cost utilized in the Proof of Revenues for this and all other rate schedules is based upon all customers purchasing gas on the appropriate BGSS service as presented in Schedule SS-G10 R-1. The magnitude of the BGSS values remain constant in both sides in the Proof of Revenue (Schedule SS-G11 R-1) and their inclusion allows the proposed rate changes to be viewed in the context of a customer's overall bill.

The calculation for the changes in the MAC clause resulting from the change in flow back from the TSG-NF rates is included in Schedule SS-G8 R-1. Typical residential customer bill impacts as a result of these changes are shown on page 1 and 2 of Schedule SS-G12 R-1.

Rate Schedule General Service Gas ("GSG")

Q. Please describe the rate design for Rate Schedule GSG.

A. The Service Charge was set to move towards the Company COSS results to recover the revenue requirements for the Access, Customer Service and Measurement segments utilizing the previously discussed limits as shown in Schedule SS-G9 R-1.

The Distribution Charge was set utilizing the balance of the Proposed GSG Distribution Revenue Increase from Schedule SS-G8 R-1.

As with Rate Schedule RSG, the Distribution Charge for the Special Provision for Off-Peak use has continued to be set at one-half of the normal Distribution Charge. This continues the practice of providing a reasonable balance between providing the correct price signals to customers with gas air conditioning, while providing some contribution to offset winter peak period costs (and thus rates). No changes are proposed for qualification for this Off-Peak provision.

The results of the Rate Schedule GSG rate design are shown on page 7 of Schedule SS-G11 R-1. The general format of the calculations is described on the first page of that Schedule. The typical customer bill impacts as a result of these changes are shown on page 3 and 4 of Schedule SS-G12 R-1.

Rate Schedule Large Volume Gas ("LVG")

Q. Please describe the rate design for Rate Schedule LVG.

A. Similar to what was done for Rate Schedule GSG, the LVG Service Charge was set to move towards the Company COSS results to recover the revenue requirements for the Access, Customer Service and Measurement segments utilizing the previously discussed limits as shown in Schedule SS-G9 R-1.

The Distribution Charges and Demand Charge were set to recover the balance of the revenue requirements. As I have previously discussed, the majority of gas distribution related costs are relatively fixed, and do not vary with the monthly volumes of gas transported.

In order to meet the rate design goals outlined at the start of this Section of my testimony, and to prevent unintended customer migration between Rate Schedules GSG and LVG, the Rate Schedule LVG rate maintains the existing rate design principle that a bill for a 12,000 therm per year customer be approximately the same for Rate Schedules GSG and LVG. With this in mind, the demand charge was set to recover the same percentage of the distribution revenue as currently. The block one and block two charges were then calculated to uniquely recover the balance of the Rate Schedule LVG revenue requirements and maintain LVG/GSG bill neutrality at 12,000 therms per year, distributed on the monthly usage pattern of the average GSG customer.

The results of the Rate Schedule LVG rate design are shown on page 9 of Schedule SS-G11 R-1. The general format of the calculations is described on the first page of that Schedule.

Information on the typical customer bill impacts as a result of these changes is indicated on page 5 and 6 of Schedule SS-G12 R-1.

Rate Schedule Street Lighting Gas ("SLG")

Q. Please describe the rate design for Rate Schedule SLG.

A. The Company proposes to increase the Distribution Charge per Therm to its cost to serve as determined by the COSS.

The balance of the revenue requirements will be recovered from the luminaire charge, and the prices for individual gas streetlights will be updated but limited by the overall rate impact limitations I have previously discussed.

The results of the Rate Schedule SLG rate design are shown on page 13 of Schedule SS-G11 R-1. The general format of the calculations is described on the first page of that Schedule.

Rate Schedule Transportation Service Gas – Firm ("TSG-F")

Q. Please describe the rate design for Rate Schedule TSG-F.

A. This rate remains closed except to existing customers. The Service Charge was set to move towards the Company COSS results to recover the revenue requirements for the Access, Customer Service and Measurement segments while applying the previously discussed limits as shown in Schedule SS-G9 R-1. The balance of the revenue increase is proposed to be recovered proportionally from the volumetric Distribution Charge and the Demand Charge. The results of the Rate Schedule TSG-F rate design are shown on page 15 of Schedule SS-G11 R-1. The general format of the calculations is described on the first page of that Schedule.

Rate Schedule Transportation Service Gas – Non Firm ("TSG-NF")

Q. Please describe the rate design for Rate Schedule TSG-NF.

A. The Service Charge for TSG-NF has been set equal to the new Service Charge proposed for Rate TSG-F, the calculation of which is shown on Schedule SS-G9 R-1. The charge for gas used for pilots during an interruption is proposed to be increased, based on the highest monthly price for gas service on Rate Schedule GSG, including balancing charges and gas supply service on BGSS-F, that occurred in the prior 36 month period.

Special Provision (a) has been modified to add penalty language if a customer does not provide an alternative fuel capability affidavit by November 1st.

The results of the Rate Schedule TSG-NF rate design are shown on page 17 of Schedule SS-G11 R-1. The general format of the calculations is described on the first page of that Schedule.

Rate Schedule Co-Generation Industrial Gas ("CIG")

Q. Please describe the rate design for Rate Schedule CIG.

A. This rate remains closed except to existing customers. Because the Service Charge was never based on cost, it was increased by the overall average Distribution percentage increase.

The Company proposes to modify the margin component of the rate so that the net of all of the adjustments to the Estimated Average Commodity Cost per therm that are used to determine the price paid by customers is increased by the overall average Distribution percentage increase. The differential charge for the two usage blocks of Rate Schedule CIG, usage less than 600,000 therms per month and usage in excess of this amount, has been kept at the same one cent per therm differential that currently exists.

The results of the rate design are shown on page 11 of Schedule SS-G11 R-1. The general format of the calculations is described on the first page of that Schedule.

Rate Schedule Contract Service Gas ("CSG")

Q. Please describe the rate design for Rate Schedule CSG.

A. The Service Charge for CSG has been set equal to the new Service Charge proposed for Rate TSG-F, the calculation of which is shown on Schedule SS-G9 R-1. Because the distribution charge for CSG customers is not based on cost the majority of customers on this rate class will receive no change in their per therm distribution rate with the exception of those that are contracted to have their charges adjusted during base rate proceedings.

<u>TARIFF CHANGES</u>

Q. Are you proposing any further changes to the proposed tariff?

A. Yes. Please refer to the Guide to Gas Tariff Changes, Exhibit P-1 Schedule 4.

<u>TAX ADJUSTMENT CREDIT ("TAC")</u>

Q. Please briefly describe the TAC Mechanism.

A. The TAC mechanism was established in the 2018 Rate Case Order, to flow back certain tax benefits to customers.

Q. Please briefly describe PSE&G's proposed TAC adjustments.

A. As described in more detail in the testimony of Mr. Pardo, the Company is proposing the following adjustments to the TAC:

1) In addition to continuing to flow back the benefit of the historic Safe Harbor Adjusted Repair Expense ("SHARE") deduction, the Company proposes to flow back to customers the net federal tax benefit associated with the historical Mixed Service accumulated deferred income taxes ("ADIT") balance over approximately five years.
2) The Company proposes to add the current Mixed Service deduction net benefit to the current SHARE deduction net benefit already included in the TAC, but both at a pre-

determined, fixed annual amount, with any excess to be flowed back to customers in a subsequent rate case; and

3) To better match the seasonal flow of Company pre-tax income, the Company began to amortize the monthly flow back of excess deferred income taxes ("EDIT") and SHARE on a seasonal basis in the 2023 TAC filing to match pre-tax income as described in the 2023 TAC cost recovery proceeding. In this proceeding, the Company is aligning the return calculation with the seasonal amortization methodology.

4) To anticipate additional guidance along with proposed and final regulations on the Inflation Reduction Act's newly enacted 15% corporate alternative minimum tax ("CAMT") and material changes to energy tax credit law, the Company may propose an adjustment to the TAC or other mechanism to capture the impact of further U.S. Treasury guidance on the CAMT, if such guidance is applicable to PSE&G. Any proposed amortizations would be included in columns 17-20 in worksheet 'RevReq-G' of WP-SS-TAC-1.xlsx.

Q. Does the Company have an amortization schedule for the proposed amortizations?

A. Yes, the proposed amortizations are included in summary format in rows 167-170 in worksheet 'RevReq-G' of WP-SS-TAC-1.xlsx for 2025 through 2028.

Q. How does the Company propose to modify the TAC revenue requirement formula based upon the changes discussed previously?

A. The TAC revenue requirement formula is calculated monthly and will be modified with the ***bolded items*** below:

TAC Revenue Requirement = (Amortization of Protected ADIT Balance +(Amortization of Historic SHARE ADIT) Balance + ***(Amortization of Historic MSC Deduction ADIT Balance*** *+ After-tax Return on Cumulative Historic SHARE Deduction ADIT Change +* ***After-tax Return on Cumulative Historic MSC***

Deduction ADIT Change *+* ***Pre-set*** *SHARE Deduction Flow-Through +* ***Pre-Set MSC Deduction Flow-Through*** *+ IRS Audit Electric Adjustments + Other Major Gas Tax Adjustments) + (****Amortization of CAMT*** *+ After-tax Return on CAMT)* Gas Revenue Factor*

See Schedule SS-TAC-2G R-1 for the monthly net revenue requirement calculations.

Q. What is the TAC amount for the initial period after base rates are projected to take effect in this proceeding?

A. The gas net revenue requirement for the initial 16-month period of September 1, 2024 through December 31, 2025 is a credit to gas customers of $250.9 million or $197.0 million on an annualized basis. See Schedule SS-TAC-1 R-1.

DISTRIBUTION ADJUSTMENT CHARGE AND STORM RECOVERY CHARGE ("SRC")

SRC Mechanism

Q. Please briefly describe the Company's proposed SRC.

A. As described in the testimony of Mr. McFadden, the Company is proposing a SRC to:

1. Recover the deferred major storm costs that have been incurred since 2018 with interest.
2. Defer and then recover future major storm costs, including interest, through subsequent true-up filings.

Q. Please describe the methodology used to calculate the SRC recovery.

A. The Company is proposing a new Distribution Adjustment Charge ("DAC") clause in its gas tariff with the SRC as a new component of the DAC. The DAC was proposed by the Company in its COVID-19 cost recovery filing where COVID-19 Recovery Charge would also be a component of the DAC. The details of the SRC and the recovery mechanism are described below. The following formula describes the SRC mechanism:

SRC Balance = Prior Month SRC Balance – SRC Revenue + Incremental Deferred Major Storm Costs + Interest Expense

Q. How will the SRC be charged or refunded to customers?

A. The Company proposes to charge or refund the SRC through a new component of the Company's proposed DAC in the Company's gas tariff. The charges will be applied to each therm of a customer's usage and will apply to all gas customers.

SRC Components

Q. What is the Initial SRC Balance?

A. The Initial SRC Balance is the total incremental deferred major storm costs associated with major storms since the Company's last Base Rate Case in 2018 prior to the implementation of the SRC rate.

Q. What are the "Incremental Deferred Major Storm Expenses?"

A. The Incremental Deferred Major Storm Costs are those monthly costs that occur after the implementation of the SRC rate.

Q. What is the "Interest Expense?"

A. The Interest Expense is the monthly carrying costs related to the SRC Balance. It is calculated as following ((Prior Month SRC Balance + (– SRC Revenue + Monthly Activity + Prior Month SRC Balance)) / 2) x (Annual Interest Rate / 12). In calculating the Interest Expense, the annual interest rate is based upon the Company's interest rate obtained on its commercial paper and/or bank credit lines utilized in the preceding month. If both commercial paper and bank credit lines have been utilized, the weighted average of both sources of capital shall be used. In the event that neither commercial paper nor bank credit lines were utilized in the preceding month, the last calculated rate will be used. The interest rate shall not exceed PSE&G's overall rate of return as authorized by the Board as utilized in calculating revenue requirements for the corresponding period. The calculation of the monthly interest can be found in Schedule SS-SRC-1G R-1, Page 1.

Q. How does the Company propose to calculate the initial SRC Rate?

A. The Company proposes to set the initial SRC Rate to recover these costs over a three- year period including interest. The rate will be a rate applied to all gas customers where applicable. See Schedule SS-SRC-1G R-1, Page 2 for the calculation.

Q. When does the Company propose to submit subsequent SRC filings to change the SRC?

A. The Company plans to submit a periodic SRC filing to change the SRC rate if warranted based upon the projected SRC over/under balance.

Q. When will storm costs be reviewed for prudency?

A. The Company proposes that all storm costs will be reviewed as part of subsequent SRC filings.

Q. When is the initial implementation of the SRC anticipated to occur?

A. The SRC is proposed to be effective September 1, 2024 corresponding to the change in base rates as a result of this proceeding. If the Board approves new base rates earlier or later than September 1, 2024, the initial rate period and corresponding rate will be adjusted accordingly from the effective date of the Board Order.

Q. What is the SRC amount for the initial period after base rates are projected to take effect in this proceeding?

A. The gas net revenue requirement for the initial annual period of September 1, 2024 through August 31, 2025 is a charge to gas customers of $1.3 million. See Schedule SS-SRC-1G R-1.

<u>GAS BAD DEBT RECOVERED VIA THE SBC</u>

Q. Is the Company proposing to change the recovery method of gas bad debt expenses currently recovered from customers?

A. Yes. As described in the testimony of Mr. McFadden, the Company is proposing to change the recovery method of its gas bad debt expenses.

Q. What is PSE&G's proposal in this proceeding?

A. Consistent with my testimony in the COVID-19 proceeding, the Company proposes that gas bad debt expenses be recovered through a new Social Programs component of the Gas SBC, consistent with the recovery of electric bad debt expense via the Social Programs component of the Electric SBC.

Q. Please describe the calculation method of Social Programs component of the Gas SBC and how it will be collected from customers?

A. The proposed Social Programs component of the Gas SBC will be calculated in a manner almost identical to the Social Programs component of the Company's Electric SBC. Schedule SS-SBC-1 R-1 contains the proposed rate calculation that will be effective concurrent with the effective date of the proposed base rates. This rate will be applicable to gas customers who currently pay the Gas SBC. Schedule SS-SBC-2 R-1 calculates the Over / (Under) Balances based upon the monthly revenue collected and gas bad debt expense. Interest calculated on the accumulated balance will be calculated identical to the method used to calculate interest for the Social Programs component of the Electric SBC, calculated monthly and added to the accumulated balance at end of each rate period. The interest rate will used will be the 2-year Treasury Bill rate plus 60 basis points, updated every August 1st each year. Schedule SS-SBC-3 R-1 calculates the annual forecasted revenue by rate schedule for the initial period commencing with the implementation of the proposed base rates.

STAFF COSS METHODOLOGY

Q. Please explain why you are submitting the Staff COSS.

A. As part of the 2018 Rate Case Order, the Company agreed to perform a COSS in the manner prescribed by Staff in the Company's next rate case. The Staff COSS and the summary of the resulting functional revenue requirements by rate class has been submitted herein with the Company's current proposed rate case filing.

Specifically, Schedule SS-G13 R-1 contains the Details of the complete Staff COSS, Schedule SS-G14 R-1 is the Summary Report by Functional Segment based on Staff's Method, and Schedule SS-G15 R-1 is the Functional Cost Summary of the COSS results based on Staff's Method.

In the Stipulation that resolved the 2018 Rate Case, the parties made it clear that they were not agreeing that the Staff COSS was appropriate, was consistent with cost causation principles, or would be a useful guide in determining just and reasonable rates. Specifically, the Stipulation stated (at 11-12):

> All parties will be free to submit any number of alternative cost of service methodologies for the Board's consideration in future cases. The Company and any Signatory to this agreement will have the right to file and support any COSS method it considers appropriate.[5]

Q. Does the Company believe that the Staff COSS provides a reasonable foundation for establishing just and reasonable rates in this proceeding?

A. No. The Staff COSS Methodology is not an appropriate methodology to use to establish just and reasonable rates because it does not achieve a result that is tied to cost causation. Instead, the Staff COSS goes to extraordinary and convoluted lengths to allocate and functionalize costs away from residential customers and onto the shoulders of commercial and industrial customers.

[5] 2018 Rate Case Order at Stipulation ¶ 25.

While it may be reasonable to moderate the level of increase to be borne by residential customers, the vehicle for doing so should not be an COSS that arbitrarily transfers costs to businesses operating in the Company's service territory. The Company has taken reasonable steps to moderate the level of increase in rates for Rate Schedules RSG and GSG customers with its gradualism-based recommendations that limit the amount of increases for those classes.

The "Average and Excess" methodology underlying the Staff COSS has existed for many years. Historically this method was used to allocate costs of electric generation plant and gas production facilities where, arguably, there is an energy investment component beyond that necessary to provide capacity at the time of peak load. However, there is no evidence that costs for Public Service's gas distribution service business are caused for such reasons. It is beyond dispute that the Company's existing design criteria is based solely on peak demand. Thus, the Staff COSS has no relationship to actual distribution plant costs or operations. As testified to by Mr. Schmid in this case, the distribution planners and designers plan and install facilities to meet the peak demands of customers – not based on the amount of energy (in therms) they consume.

The fundamental error in the Staff COSS is that there is no relationship at all between the amount of gas a pipe can carry, its diameter, and any split between a demand and energy cost classification. Determining an energy/peak classification based on the physical nature of natural gas and the pipe it flows within is unrelated to determining the cost of providing gas distribution service. Just because equipment such as gas main delivers energy, such as a gas main, it should not be classified as energy-related unless the amount of energy, other than peak energy, had some basis in the design. Gas mains have been, and continue to be, installed to bring gas service to the proximity of each customer's premise and are sized to handle the peak hourly gas flow at design conditions, without regard to the gas flow at any other time of day or season. These are the sole reasons and engineering basis for their design and cost, and as such, the allocation of these costs should properly reflect each rate class's responsibility for the peak gas flow.

Subsequent Base Case Requirements

Q. Do you believe that the Company should be required to complete the Staff COSS in subsequent base rate case filings?

A. No. The Company is requesting that this requirement not be included for the filing of its next base rate case.

Q. Does this conclude your direct testimony?

A. Yes. It does.

APPENDIX G-1 - DETAILED REVIEW OF COST OF SERVICE STUDY

Schedule SS-G4 R-1 shows the details of the Cost of Service Study used to develop distribution revenue requirements by rate schedule. This study was used in the development of the proposed rates and the following discussion is limited to this analysis. These results are summarized by revenue requirements for each rate schedule and by segment in Schedule SS-G6 R-1.

The study, as previously mentioned, is based on weather normalized costs and billing determinants for the 12 month period ending December 31, 2022, and is limited to the gas delivery business.

ALLOCATOR NAMING CONVENTION

For consistency and simplicity of bookkeeping, a naming convention has been developed for the modeling allocators.

Direct Allocators

All modeling allocators that end in a dash and a number (such as "PEAKHOUR-03") are direct allocators, meaning that:

1. The word portion of the direct allocator denotes the types of external constant or value used to allocate the plant or expense item as indicated by the name of the modeling allocator. For example, the "PEAKHOUR" denotes the Coincident Peak Hour demand of the entire system observed at the City Gate, and
2. The number portion of the direct allocator denotes the segment to which the plant or expense item is functionalized. For example, the "03" in "PEAKHOUR-03" denotes segment number 3. The business segment numbering method used in our analysis is as follows:

Segment #2 - Distribution Access

Segment #3 - Distribution Delivery

Segment #4 – Street Lighting Fixtures

Segment #5 - Customer Service

Segment #6 - Measurement

Note that labels for Segments #1 is not used.

Indirect Allocators

All modeling allocators that do not end in a dash and a number (such as A&GEXP) are indirect allocators, meaning that they will both segment and allocate costs in the same proportion as other individual or group of plant or expense items. The names of these modeling allocators are an indication of the basis upon which this allocation and functionalization process takes place.

ALLOCATION DETAILS

Intangible Plant

Gas intangible plant (Accounts G301 to G303) was not included in the study

Production Plant

All production plant (Accounts G304 to G320 on Schedule SS-G4 R-1, page 4, line 26) was determined to be related to wholesale balancing services and thus segmented to the Distribution Delivery segment and allocated on the basis of the total balancing therms for each rate schedule. This allocator (BALANCE-04) is the same allocator used throughout the Cost of Service model for all production plant assets and expenses, as well as the revenue received from the BGSS Supplier for the operation of these facilities.

Storage Plant

Storage plant (Schedule SS-G4 R-1, page 4, line 30 to 33) is treated in the same manner as production plant because it relates to balancing services. Therefore, Storage plant is segmented to Distribution Delivery and allocated on the basis of balancing therms.

Transmission Plant

All of transmission plant (Accounts G365 to G369 on Schedule SS-G4 R-1, page 4, lines 35 to 40) was determined to be related to the Distribution Delivery segment. A majority of this plant is for large gas pipes (transmission mains), which are classified as transmission mains rather than distribution mains in accordance with federal and state regulations generally due to the high operating pressure and larger size. Since these facilities perform the same type of function as distribution mains, the plant has been treated in an identical manner to that of distribution mains and allocated to the rates based upon each class's share of the amount of gas transported at the system design peak hour.

Distribution Plant

In the regulated gas distribution business determining cost causation for the revenue requirements related to gas mains and to gas services is one of the most important issues because together these facilities comprise the vast majority of rate base and are the basis for much of the operations and maintenance expenses. The majority of Distribution Plant (Accounts G374 to G388 as shown on Schedule SS-G4 R-1, page 5, line 46, to page 6, line 119) has been functionalized to four primary segments – Distribution Delivery, Distribution Access, Street Lighting Fixtures and Measurement. The plant related to Land and Structures (Accounts G374 and G375) is related to local Distribution operations field offices, and was functionalized and allocated in the same proportion as

Distribution plant in total. Gas mains have been functionalized to the Distribution Delivery segment, gas services and house regulators to the Distribution Access segment, meters to the Measurement segment, and all gas street lighting related equipment to the Street Lighting Fixtures segment.

After the functionalization was completed, each account was then examined to determine the proper allocation across rate classes. Investment for Gas Services (G380), Gas Meters (G381, G382, G385), and House Regulators (G383, G384) was then allocated to Rate Schedules RSG, GSG and LVG. This was based upon a study of actual customer installations and using the results as the basis for determining the relative investment for all customers. For the reasons that I have previously discussed, the investment for Gas Mains (Account G376) was allocated to all classes on the basis of each class's share of the amount of gas transported at the system design peak hour.

The investment in Compressor Station Equipment (Account G377) is generally determined to be related to the natural gas refueling stations located at several Public Service locations that are utilized to fuel the natural gas cars and trucks used by the Company. Any costs in this account shall be segmented to Distribution Delivery and allocated in the same manner as total Distribution Plant other than meters. All Street Lighting Facilities (G387) including the services, posts, and heads were directly assigned to Rate SLG.

Other Distribution Plant

The plant associated with Asset Retirement Obligations (booked in Account G388) relates almost exclusively to gas mains, and therefore was functionalized and allocated in the same proportion as gas mains.

General, Common and Other Plant

An accounting code, or Business Code, associated with the actual gross plant balances indicating the department to which the plant is assigned was used to segment both the general (Accounts G389 to G399) and common (Accounts C303, and C389 to C399) plant account items (Schedule SS-G4 R-1, page 4 for C303 and page 7 for general and common). Each Business Code was then grouped by function to be allocated based on cost causation. For example; a Description for office furniture and equipment was added to the Customer Service segment and allocated in the same proportion as all Customer Service activities. In other cases, where some of the facilities, such as vehicles, etc. used by the Customer Operations Department are shared between groups that are responsible for meter reading and those that provide general customer service (collections, phone inquiry, walk-in payment centers, etc.), these investments were further split in the Cost of Service Study between the Measurement segment and the Customer Service segment based on the proportion of work performed by each group. In general, all general and common investments were allocated to the rate schedules in the same proportion as the overall respective plant accounts for each segment. Items for which no reasonable functionalization could be determined were classified as "unassigned" and allocated in the same proportion as its associated plant account. In other words, unassigned general plant followed general plant and unassigned common plant followed common plant (general plant is shown on Schedule SS-G4 R-1, page 7 line 94 to line 102; while common plant is on Schedule SS-G4 R-1, page 7 line 105 to line 112).

Depreciation Reserve

The depreciation reserve associated with Accounts G300 to G399 was segmented and allocated in the same proportion as its associated plant account (Schedule SS-G4 R-1, page 8, line 1 to page 10, line 114).

Adjustments to Develop Rate Base

Adjustments to net plant used to develop Rate Base consist primarily of working capital and deferred taxes for the distribution utility. The underlying components of working capital were analyzed and segmented according to their individual use. Working capital requirements associated with Material and Supplies were allocated and segmented in proportion to the total plant, other than General and Common. Working capital requirements associated with Cash and Prepayments & Working Funds were allocated and segmented in the same proportion as the total of O&M and capital additions (essentially cash outlays) through the use of the allocator termed "EXPENDITURES". Deferred taxes were segmented and allocated in proportion to the related plant values. These adjustments are indicated in Schedule SS-G4 R-1, page 11, lines 1 to 37.

Operating Revenues

The values indicated in Schedule SS-G4 R-1, page 2, line 52 entitled "Rate Revenues from Customers" are the portion of the total target balanced revenue requirements that are necessary to be recovered from rate-related revenues (from service charges, distribution charges, minimum charges, etc.) at the proposed overall ROR, plus the increases in non rate-related revenues.

The effects of other non-rate-related revenues are booked to Accounts G487 to G495 and are shown in Schedule SS-G4 R-1, page 12, lines 9 to 19. The primary sources of these other revenues, booked in Account G488, are Competitive Services. These services have been segmented to the Distribution Delivery segment and allocated back to the customer rates from which the revenue was received, and Peaking Services (revenue from the BGSS Supplier for the operation of the peaking facilities), which constitutes the majority of the revenue booked in Account G495 and is segmented to Distribution Delivery and allocated based on balancing therms.

Production Expenses

Similar to the production plant items, all production expenses (Accounts G710 to G745 on Schedule SS-G4 R-1, page 13, lines 4 to 6) relate to wholesale balancing services and are segmented to Distribution Delivery and allocated on the basis of balancing therms, consistent with the methodology used for Production Plant.

Gas Supply Expenses

Although booked to Other Gas Supply Expenses - Account G813, any costs charged herein, relate to the operation of the Gas Systems Operations Center (GSOC) and thus are related to gas dispatching. Therefore, any costs in this Account shall be segmented to the Delivery segment and allocated on the basis of total therms delivered. This is shown on Schedule SS-G4 R-1, page 13, line 18.

Other Storage Expenses

The costs associated with the operation and maintenance of Company owned storage facilities (Account G840-G843 on Schedule SS-G4 R-1, page 13, lines 22 to 25) are treated in the same manner as production plant and segmented to Distribution Delivery and allocated on the basis of balancing therms.

Transmission and Distribution O&M Expenses

O&M expenses for transmission and distribution (Accounts G850 to G894 on Schedule SS-G4 R-1, page 13, line 28 to page 14, line 68) were generally segmented and allocated in the same proportion as their associated plant account(s) with the exception of Customer Installations expense (Account G879) which was allocated to the rates based upon an analysis of the customers for which that work was performed.

Customer Accounts, Service and Sales Expense

Expenses from a wide range of customer contact activities are booked to Accounts G901 to G916. A separate analysis was performed on the costs charged to each of these accounts to determine the best functionalization fit. The details of this account-by-account functionalization can be found on Schedule SS-G4 R-1, page 14, line 73 to page 15, line 108. The costs in each of these accounts related to meter reading were segmented to the Measurement segment and allocated on the basis of the costs to read meters for each rate class; the portion related to billing was segmented to the Customer Service segment and allocated on the relative costs of billing by rate class; the portion related to account maintenance activities (including answering general questions, setting up new accounts, remittance processing, and collection activities) was segmented to the Customer Service segment and allocated on the relative costs of performing these activities by rate class; and the portion of these expenses related to general regulated utility responsibilities was segmented to the Distribution Delivery segment and allocated on the relative costs of performing these activities by rate class. The portion of Customer Records and Collection costs (Account G903 and G905) associated with costs to disconnect customers for non-payment of bills (and their eventual reconnection) were segmented to the Customer Service segment and allocated based upon the number of customers.

Energy Efficiency and Renewable Energy expenses, a component of the SBC, normally recorded in Account G908 were not included in this analysis as discussed earlier in this testimony and as indicated on page 1 of Schedule SS-G3 R-1.

Administrative and General (A&G) Expenses

Administrative and General Expenses (Accounts G920-935) include a mix of expenditures, which were analyzed separately to determine the best functionalization fit. The details of this item-by-item functionalization can be found on Schedule SS-G4 R-1, page 15, lines 115 to 132.

An adjustment was made to the A&G expenses for G923 and G926 to separate those costs associated with the Gas Peaking Plants and to segment them to the Distribution Delivery segment. These costs were then allocated on the basis of balancing therms, similar to the method applied to other gas production related investment and expenses.

Depreciation and Amortization Expenses

All depreciation and amortization expenses were segmented and allocated in the same proportion as their associated plant accounts (Schedule SS-G4 R-1, page 17, lines 1 to 27).

Taxes Other Than Income Taxes

Other non-income type taxes were allocated based on their relationship to other plant and expenses, as indicated on Schedule SS-G4 R-1, page 18, lines 4 to 12.

Pro Forma Expense Adjustments

The pro forma adjustments the Company is proposing are summarized in Schedule MPM-29 R-1 and detailed as Adjustments #1 to #24 in Schedules MPM-30 R-1 through MPM-53 R-1 of Mr. McFaddens' direct testimony in this proceeding. Those adjustments are included in this section of the Cost of Service Study on Schedule SS-G4 R-1, page 18, lines 16 to page 19 lines 57, with the exception of the pro forma adjustments discussed below.

One specific adjustment, Pro Forma Adjustment #11 Schedule MPM-29 R-1 adjusts revenue related to the switching between Rate Schedules TSG-NF and LVG. The Company currently retains a portion of the margins from gas service to new TSG-NF customers that commenced after the Company's base rate cases in 2001 and 2005, in accordance with the Settlements and Board Orders in Docket Nos. GR01050297 and GR05100845. Also, the Company retains the margins (total revenue less commodity revenue, SUT, SBC, and GPRC) from customers who switch from Rate Schedule LVG to TSG-NF. Conversely, the margins from customers who switch from TSG-NF to LVG are credited to the Margin Adjustment Charge (MAC) in lieu of being retained by the Company. The balance of the margin is credited to the MAC. These retained amounts are reset to zero in each succeeding base rate case. Therefore, this adjustment decreased operating income in the amount of $764,221.

Each pro forma adjustment included in the Cost of Service Study was segmented and allocated in the same proportion as the associated plant or O&M account(s). The Cost of Service modeling of Pro Forma #3 associated with Interest Synchronization, Pro Forma #5 associated with Gas COLI Interest Expense, and Pro Forma #7 associated with Gains and Losses on Sales of Property all include the added tax effects on revenue requirements as an additional expense. Those pro forma adjustments excluded from the Cost of Service Study are as follows:

- Adjustment #6- Weather Normalization Adjustment (Schedule MPM-29 R-1) is a weather normalization of operating revenues. The Cost of Service Study is already based on weather normalized costs and usage, and no further adjustment is required.
- Adjustment #11 – TSG-NF Margin Sharing (Schedule MPM-29 R-1) is related to the elimination of margin sharing revenue associated with capital investment made for TSG-NF customers since the last base case. Because these investments are already included in the proposed Rate Base, the revenue requirements related to these investments are already included in the Cost of Service Study.

Taxes

All Taxes and Tax Deductions were segmented and allocated in the same proportion as their associated plant or O&M account(s). Details of these allocations are indicated from pages 20-25 of Schedule SS-G4 R-1.

CREDENTIALS
OF
STEPHEN SWETZ
SR. DIRECTOR-CORPORATE RATES AND REVENUE REQUIREMENTS

My name is Stephen Swetz and I am employed by PSEG Services Corporation. I am the Sr. Director - Corporate Rates and Revenue Requirements where my main responsibility is to contribute to the development and implementation of electric and gas rates for Public Service Electric and Gas Company (PSE&G, the Company).

WORK EXPERIENCE

I have over 30 years of experience in Rates, Financial Analysis and Operations for three Fortune 500 companies. Since 1991, I have worked in various positions within PSEG. I have spent most of my career contributing to the development and implementation of PSE&G electric and gas rates, revenue requirements, pricing and corporate planning with over 20 years of direct experience in Northeastern retail and wholesale electric and gas markets.

As Sr. Director of the Corporate Rates and Revenue Requirements department, I have submitted pre-filed direct cost recovery testimony as well as oral testimony to the New Jersey Board of Public Utilities and the New Jersey Office of Administrative Law for base rate cases, as well as a number of clauses including infrastructure investments, renewable energy, and energy efficiency programs. A list of my prior testimonies can be found on pages 3 and 4 of this document. I have also contributed to other filings including unbundling electric rates and Off-Tariff Rate Agreements. I have had a leadership role in various economic analyses, asset valuations, rate design, pricing efforts and cost of service studies.

I am an active member of the American Gas Association's Rate and Strategic Issues Committee, the Edison Electric Institute's Rates and Regulatory Affairs Committee and the New Jersey Utility Association (NJUA) Finance and Regulatory Committee.

EDUCATIONAL BACKGROUND

I hold a B.S. in Mechanical Engineering from Worcester Polytechnic Institute and an MBA from Fairleigh Dickinson University.

LIST OF PRIOR TESTIMONIES

Company	Utility	Docket	Testimony	Date	Case / Topic
Public Service Electric & Gas Company	E	ER24020073	written	Feb-24	Elecric Conservation Incentive Program (ECIP)
Public Service Electric & Gas Company	E/G	ER23120924 & GR23120925	written	Dec-23	Base Rate Proceeding / Cost of Service & Rate Design
Public Service Electric & Gas Company	E/G	QO23120874	written	Dec-23	Clean Energy Future - Energy Efficiency II Program
Public Service Electric & Gas Company	E/G	G018101112 and EO18101113	written	Nov-23	Clean Energy Future - Energy Efficiency Extension 2 Program
Public Service Electric & Gas Company	E	ER23110783	written	Nov-23	Infrastructure Advancement Program (IAP) - First Roll-In
Public Service Electric & Gas Company	E/G	ER23050273	written	Nov-23	Energy Strong II Program (Energy Strong II) - Fifth Roll-In
Public Service Electric & Gas Company	E/G	ER - 23090634 & GR - 23090635	written	Sep-23	Tax Adjustment Clauses (TACs)
Public Service Electric & Gas Company	E/G	GR23070448	written	Jul-23	COVID-19 Filing
Public Service Electric & Gas Company	E/G	ER23070423 & GR23070424	written	Jul-23	Green Programs Recovery Charge (GPRC)-Including CA, EEE, EEE Ext, S4A, SLII, S4AE, SLIII, EEE Ext 2, S4AEII, EE2017, and CEF-EE
Public Service Electric & Gas Company	E	ER - ER23060412	written	Jul-23	SPRC 2023
Public Service Electric & Gas Company	G	GR23060330	written	Jun-23	Margin Adjustment Charge (MAC) / Cost Recovery
Public Service Electric & Gas Company	G	GR23060332	written	Jun-23	Conservation Incentive Program (GCIP)
Public Service Electric & Gas Company	E	ER23050273	written	May-23	Energy Strong II Program (Energy Strong II) - Fourth Roll-In
Public Service Electric & Gas Company	G	GR23030102	written	Mar-23	Gas System Modernization Program III (GSMPIII)
Public Service Electric & Gas Company	E	ER23020061	written	Feb-23	Elecric Conservation Incentive Program (ECIP)
Public Service Electric & Gas Company	E/G	GR23010050	written	Jan-23	Remediation Adjustment Charge-RAC 30
Public Service Electric & Gas Company	E/G	GR23010009 and ER23010010	written	Jan-23	Societal Benefits Charge (SBC) / Cost Recovery
Public Service Electric & Gas Company	G	GR22120749	written	Dec-22	Gas System Modernization Program II (GSMPII) - Eighth Roll-In
Public Service Electric & Gas Company	E/G	ER22110669 & GR22110670	written	Nov-22	Energy Strong II Program (Energy Strong II) - Third Roll-In
Public Service Electric & Gas Company	E/G	ER22100667 & GR22100668	written	Oct-22	Tax Adjustment Clauses (TACs)
Public Service Electric & Gas Company	E/G	EO18101113 & GO18101112	written	Sep-22	Clean Energy Future - Energy Efficiency Extension Program
Public Service Electric & Gas Company	E/G	ER22070413 & GR22070414	written	Jul-22	Green Programs Recovery Charge (GPRC)-Including CA, DR, EEE, EEE Ext, EE17, S4AII, S4AEXT, S4AEXT II, SLII, SLIII / Cost Recovery
Public Service Electric & Gas Company	E	ER22060408	written	Jul-22	SPRC 2022
Public Service Electric & Gas Company	G	GR22060409	written	Jun-22	Gas System Modernization Program II (GSMPII) - Seventh Roll-In
Public Service Electric & Gas Company	G	GR22060367	written	Jun-22	Margin Adjustment Charge (MAC) / Cost Recovery
Public Service Electric & Gas Company	G	GR22060362	written	Jun-22	Conservation Incentive Program (GCIP)
Public Service Electric & Gas Company	E/G	GR22030152	written	Mar-22	Remediation Adjustment Charge-RAC 29
Public Service Electric & Gas Company	E	ER22020035	written	Feb-22	Elecric Conservation Incentive Program (ECIP)
Public Service Electric & Gas Company	G	GR21121256	written	Dec-21	Gas System Modernization Program II (GSMPII) - Sixth Roll-In
Public Service Electric & Gas Company	E	ER21121242	written	Dec-21	Solar Successor Incentive Program (SuSI)
Public Service Electric & Gas Company	E/G	EO21111211 & GO21111212	written	Nov-21	Infrastructure Advancement Program (IAP)
Public Service Electric & Gas Company	E/G	ER21111209 & GR21111210	written	Nov-21	Energy Strong II Program (Energy Strong II) - Second Roll-In
Public Service Electric & Gas Company	E/G	ER21101201 & GR21101202	written	Oct-21	Tax Adjustment Clauses (TACs)
Public Service Electric & Gas Company	E/G	ER21070965 & GR21070966	written	Jul-21	Green Programs Recovery Charge (GPRC)-Including CA, DR, EEE, EEE Ext, EE17, S4AII, S4AEXT, S4AEXT II, SLII, SLIII / Cost Recovery
Public Service Electric & Gas Company	G	ER21060952	written	Jun-21	Weather Normalization Charge / Cost Recovery
Public Service Electric & Gas Company	G	GR21060949	written	Jun-21	Gas System Modernization Program II (GSMPII) - Fifth Roll-In
Public Service Electric & Gas Company	E	ER21060948	written	Jun-21	SPRC 2021
PSEG New Haven LLC	PSEG New Haven LLC	21-06-40	written	Jun-21	PSEG 2022 AFRR
Public Service Electric & Gas Company	G	GR21060882	written	Jun-21	Margin Adjustment Charge (MAC) / Cost Recovery
Public Service Electric & Gas Company	E	ER21050859	written	May-21	Community Solar Cost Recovery
Public Service Electric & Gas Company	G	GR20120771	written	Dec-20	Gas System Modernization Program II (GSMPII) - Forth Roll-In
Public Service Electric & Gas Company	E/G	GR20120763	written	Dec-20	Remediation Adjustment Charge-RAC 28
Public Service Electric & Gas Company	E	ER20120736	written	Nov-20	Energy Strong II Program (Energy Strong II) - First Roll-In
Public Service Electric & Gas Company	E/G	ER20100685 & GR20100686	written	Oct-20	Tax Adjustment Clauses (TACs)
Public Service Electric & Gas Company	E	ER20100658	written	Oct-20	Non-Utility Generation Charge (NGC) / Cost Recovery
Public Service Electric & Gas Company	E/G	ER20060467 & GR20060468	written	Jun-20	Green Programs Recovery Charge (GPRC)-Including CA, DR, EEE, EEE Ext, EE17, S4AII, S4AEXT, S4AEXT II, SLII, SLIII / Cost Recovery
Public Service Electric & Gas Company	G	GR20060464	written	Jun-20	Gas System Modernization Program II (GSMPII) - Third Roll-In
Public Service Electric & Gas Company	E	ER20060454	written	Jun-20	Solar Pilot Recovery Charge (SPRC-Solar Loan I) / Cost Recovery
Public Service Electric & Gas Company	G	GR20060470	written	Jun-20	Weather Normalization Charge / Cost Recovery
Public Service Electric & Gas Company	G	GR20060384	written	Jun-20	Margin Adjustment Charge (MAC) / Cost Recovery
Public Service Electric & Gas Company	E	ER20040324	written	Apr-20	Transitional Renewable Energy Certificate Program (TREC)
Public Service Electric & Gas Company	E/G	GR20010073	written	Jan-20	Remediation Adjustment Charge-RAC 27
Public Service Electric & Gas Company	G	GR19120002	written	Dec-19	Gas System Modernization Program II (GSMPII) - Second Roll-In
Public Service Electric & Gas Company	E/G	ER19091302 & GR19091303	written	Aug-19	Tax Adjustment Clauses (TACs)
Public Service Electric & Gas Company	E/G	ER19070850	written	Jul-19	Societal Benefits Charge (SBC) / Cost Recovery
Public Service Electric & Gas Company	E/G	ER19060764 & GR19060765	written	Jun-19	Green Programs Recovery Charge (GPRC)-Including CA, DR, EEE, EEE Ext, S4AII, S4AEXT, S4AEXT II, SLII, SLIII / Cost Recovery
Public Service Electric & Gas Company	G	GR19060766	written	Jun-19	Gas System Modernization Program II (GSMPII) - First Roll-In
Public Service Electric & Gas Company	G	GR19060761	written	Jun-19	Weather Normalization Charge / Cost Recovery
Public Service Electric & Gas Company	E	ER19060741	written	Jun-19	Solar Pilot Recovery Charge (SPRC-Solar Loan I) / Cost Recovery
Public Service Electric & Gas Company	E/G	EO18060629 & GO18060630	oral	Jun-19	Energy Strong II / Revenue Requirements & Rate Design
Public Service Electric & Gas Company	G	GR19060698	written	May-19	Margin Adjustment Charge (MAC) / Cost Recovery
Public Service Electric & Gas Company	E	ER19040523	written	May-19	Non-Utility Generation Charge (NGC) / Cost Recovery
Public Service Electric & Gas Company	E/G	EO18101113 & GO18101112	oral	May-19	Clean Energy Future - Energy Efficiency Program Approval
Public Service Electric & Gas Company	E	ER19040530	written	Apr-19	Madison 4kV Substation Project (Madison & Marshall)
Public Service Electric & Gas Company	E/G	EO18101113 & GO18101112	written	Dec-18	Clean Energy Future - Energy Efficiency Program Approval
Public Service Electric & Gas Company	E/G	GR18121258	written	Nov-18	Remediation Adjustment Charge-RAC 26
Public Service Electric & Gas Company	E	EO18101115	written	Oct-18	Clean Energy Future - Energy Cloud Program (EC)
Public Service Electric & Gas Company	E	EO18101111	written	Oct-18	Clean Energy Future-Electric Vehicle And Energy Storage Programs (EVES)
Public Service Electric & Gas Company	G	GR18070831	written	Jul-18	Gas System Modernization Program (GSMP) - Third Roll-In

LIST OF PRIOR TESTIMONIES

Company	Utility	Docket	Testimony	Date	Case / Topic
Public Service Electric & Gas Company	E/G	ER18070688 & GR18070689	written	Jun-18	Green Programs Recovery Charge (GPRC)-Including CA, DR, EEE, EEE Ext, S4All, S4AEXT, S4AEXT II, SLII, SLIII / Cost Recovery
Public Service Electric & Gas Company	E	ER18060681	written	Jun-18	Solar Pilot Recovery Charge (SPRC-Solar Loan I) / Cost Recovery
Public Service Electric & Gas Company	G	GR18060675	written	Jun-18	Weather Normalization Charge / Cost Recovery
Public Service Electric & Gas Company	E/G	EO18060629 & GO18060630	written	Jun-18	Energy Strong II / Revenue Requirements & Rate Design
Public Service Electric & Gas Company	G	GR18060605	written	Jun-18	Margin Adjustment Charge (MAC) / Cost Recovery
Public Service Electric & Gas Company	E/G	ER18040358 & GR18040359	written	Mar-18	Energy Strong / Revenue Requirements & Rate Design - Eighth Roll-in
Public Service Electric & Gas Company	E/G	ER18030231	written	Mar-18	Tax Cuts and Job Acts of 2017
Public Service Electric & Gas Company	E/G	GR18020093	written	Feb-18	Remediation Adjustment Charge-RAC 25
Public Service Electric & Gas Company	E/G	ER18010029 & GR18010030	written	Jan-18	Base Rate Proceeding / Cost of Service & Rate Design
Public Service Electric & Gas Company	E	ER17101027	written	Sep-17	Energy Strong / Revenue Requirements & Rate Design - Seventh Roll-in
Public Service Electric & Gas Company	G	GR17070776	written	Jul-17	Gas System Modernization Program II (GSMP II)
Public Service Electric & Gas Company	G	GR17070775	written	Jul-17	Gas System Modernization Program (GSMP) - Second Roll-In
Public Service Electric & Gas Company	G	GR17060720	written	Jul-17	Weather Normalization Charge / Cost Recovery
Public Service Electric & Gas Company	E/G	ER17070724 & GR17070725	written	Jul-17	Green Programs Recovery Charge (GPRC)-Including CA, DR, EEE, EEE Ext, S4All, S4AEXT, S4AEXT II, SLII, SLIII / Cost Recovery
Public Service Electric & Gas Company	E	ER17070723	written	Jul-17	Solar Pilot Recovery Charge (SPRC-Solar Loan I) / Cost Recovery
Public Service Electric & Gas Company	G	GR17060593	written	Jun-17	Margin Adjustment Charge (MAC) / Cost Recovery
Public Service Electric & Gas Company	E/G	ER17030324 & GR17030325	written	Mar-17	Energy Strong / Revenue Requirements & Rate Design - Sixth Roll-in
Public Service Electric & Gas Company	E/G	EO14080897	written	Mar-17	Energy Efficiency 2017 Program
Public Service Electric & Gas Company	E/G	ER17020136	written	Feb-17	Societal Benefits Charge (SBC) / Cost Recovery
Public Service Electric & Gas Company	E/G	GR16111064	written	Nov-16	Remediation Adjustment Charge-RAC 24
Public Service Electric & Gas Company	E	ER16090918	written	Sep-16	Energy Strong / Revenue Requirements & Rate Design - Fifth Roll-in
Public Service Electric & Gas Company	E	EO16080788	written	Aug-16	Construction of Mason St Substation
Public Service Electric & Gas Company	E	ER16080785	written	Aug-16	Non-Utility Generation Charge (NGC) / Cost Recovery
Public Service Electric & Gas Company	G	GR16070711	written	Jul-16	Gas System Modernization Program (GSMP) - First Roll-In
Public Service Electric & Gas Company	G	GR16070617	written	Jul-16	Weather Normalization Charge / Cost Recovery
Public Service Electric & Gas Company	E/G	ER16070613 & GR16070614	written	Jul-16	Green Programs Recovery Charge (GPRC)-Including CA, DR, EEE, EEE Ext, S4All, S4AEXT, SLII, SLIII / Cost Recovery
Public Service Electric & Gas Company	E	ER16070616	written	Jul-16	Solar Pilot Recovery Charge (SPRC-Solar Loan I) / Cost Recovery
Public Service Electric & Gas Company	G	GR16060484	written	Jun-16	Margin Adjustment Charge (MAC) / Cost Recovery
Public Service Electric & Gas Company	E	EO16050412	written	May-16	Solar 4 All Extension II (S4Allext II) / Revenue Requirements & Rate Design
Public Service Electric & Gas Company	E/G	ER16030272 & GR16030273	written	Mar-16	Energy Strong / Revenue Requirements & Rate Design - Fourth Roll-in
Public Service Electric & Gas Company	E/G	GR15111294	written	Nov-15	Remediation Adjustment Charge-RAC 23
Public Service Electric & Gas Company	E	ER15101180	written	Sep-15	Energy Strong / Revenue Requirements & Rate Design - Third Roll-in
Public Service Electric & Gas Company	E/G	ER15070757 & GR15070758	written	Jul-15	Green Programs Recovery Charge (GPRC)-Including CA, DR, EEE, EEE Ext, S4All, S4AEXT, SLII, SLIII / Cost Recovery
Public Service Electric & Gas Company	E	ER15060754	written	Jul-15	Solar Pilot Recovery Charge (SPRC-Solar Loan I) / Cost Recovery
Public Service Electric & Gas Company	G	GR15060748	written	Jul-15	Weather Normalization Charge / Cost Recovery
Public Service Electric & Gas Company	G	GR15060646	written	Jun-15	Margin Adjustment Charge (MAC) / Cost Recovery
Public Service Electric & Gas Company	E/G	ER15050558	written	May-15	Societal Benefits Charge (SBC) / Cost Recovery
Public Service Electric & Gas Company	E	ER15050558	written	May-15	Non-Utility Generation Charge (NGC) / Cost Recovery
Public Service Electric & Gas Company	E/G	ER15030389 & GR15030390	written	Mar-15	Energy Strong / Revenue Requirements & Rate Design - Second Roll-in
Public Service Electric & Gas Company	G	GR15030272	written	Feb-15	Gas System Modernization Program (GSMP)
Public Service Electric & Gas Company	E/G	GR14121411	written	Dec-14	Remediation Adjustment Charge-RAC 22
Public Service Electric & Gas Company	E/G	ER14091074	written	Sep-14	Energy Strong / Revenue Requirements & Rate Design - First Roll-in
Public Service Electric & Gas Company	E/G	EO14080897	written	Aug-14	EEE Ext II

Actual & Weather Normalized
Billing Determinants
Filing "9 and 3"

	Rate		Actual Determinants	Weather Normalized (WN) Determinants	Variation from WN
1	RSG	**Delivery**			
2		Service Charge	20,576.897	20,576.897	0.000
3		Distribution Therms	1,440,366	1,584,457	144,091
4		Off-Peak Dist. Therms	41	41	0
5		Balancing Therms	1,041,528	1,185,618	144,091
6					
7		**Supply**			
8		BGSS Therms	1,411,532	1,552,805	141,274
9		BGSS Off-Peak Therms	41	41	0
10		Emergency Sales Srvc. Therms	0	0	0
11					
12					
13	GSG	**Delivery**			
14		Service Charge	1,681.703	1,681.703	0.000
15		Distribution Therms	275,933	302,101	26,168
16		Off-Peak Dist. Therms	12	12	0
17		Balancing Therms	187,599	213,767	26,168
18					
19		**Supply**			
20		BGSS Therms	224,759	246,245	21,486
21		Emergency Sales Srvc. Therms	0	0	0

Actual & Weather Normalized
Billing Determinants
Filing "9 and 3"

	Rate		Actual Determinants	Weather Normalized (WN) Determinants	Variation from WN
1	LVG	**Delivery**			
2		Service Charge	235.304	235.304	0.000
3		Demand Therms	18,912	20,258	1,346
4		Distribution Therms 0 -1,000	138,980	147,721	8,741
5		Distribution Therms over 1,000	592,149	631,192	39,043
6		Balancing Therms	422,124	469,908	47,784
7					
8		**Supply**			
9		BGSS Therms	273,926	292,980	19,054
10		Emergency Sales Srvc. Therms	0	0	0
11					
12					
13	SLG	**Delivery**			
14		Lamp Chgs:			
15		Single	11.276	11.276	0.000
16		Double	0.727	0.727	0.000
17		Triple Prior to 1/1/93	18.168	18.168	0.000
18		Triple on & after 1/1/93	0.432	0.432	0.000
19		Distribution Therms	695.404	695.404	0.000
20					
21		**Supply**			
22		BGSS Therms	286.411	286.411	0.000
23		Emergency Sales Srvc. Therms	0.000	0.000	0

Actual & Weather Normalized
Billing Determinants
Filing "9 and 3"

	Rate		Actual Determinants	Weather Normalized (WN) Determinants	Variation from WN
1	TSG-F	**Delivery**			
2		Service Charge	0.371	0.371	0.000
3		Demand Therms	812	812	0
4		Demand Therms - Agreements	0	0	0
5		Distribution Therms	22,584	22,584	0
6		Distribution Therms - Agreements	0	0	0
7					
8		**Supply**			
9		Emergency Sales Srvc. Therms	581	581	0
10					
11					
12	TSG-NF	**Delivery**			
13		Service Charge	1.677	1.677	0.000
14		Distribution Therms 0 - 50,000	49,749	49,749	0
15		Distribution Therms 0 - 50,000 - Agreements	0	0	0
16		Distribution Therms over 50,000	75,197	75,197	0
17		Distribution Therms over 50,000 - Agreements	0	0	0
18		Pilot & Penalty Therms	0	0	0
19					
20		**Supply**			
21		BGSS Therms	6,488	6,488	0
22		Emergency Sales Srvc. Therms	0	0	0
23		Pilot & Penalty Therms	0	0	0

Actual & Weather Normalized
Billing Determinants
Filing "9 and 3"

	Rate		Actual Determinants	Weather Normalized (WN) Determinants	Variation from WN
1	CIG	**Delivery**			
2		Service Charge	0.110	0.110	0.000
3		Distribution Therms 0 - 600,000	26,259	26,259	0
4		Distribution Therms over 600,000	1,615	1,615	0
5		Extended Sales Srvc. Therms	0	0	0
6					
7		**Supply**			
8		BGSS Therms	26,596	26,596	0
9		Extended Sales Srvc. Therms	1,278	1,278	0
10		Pilot & Penalty Therms	0	0	0
11					
12					
13	CSG	**Delivery**			
14		Service Charge - Power	0.000	0.000	0.000
15		Service Charge - Power- Non Firm	0.000	0.000	0.000
16		Service Charge - Other	0.232	0.232	0.000
17		Distribution Charge - Power	0	0	0
18		Distribution Charge - Power- Non Firm	0	0	0
19		Distribution Charge - Other	702,392	702,392	0
20					
21					
22		**Supply:**			
23		BGSS-Firm - Power	0	0	0
24		BGSS-Firm - Power- Non Firm	0	0	0
25		BGSS-Firm - Other	0	0	0
26					
27		BGSS-Interruptible - Power	0	0	0
28		BGSS-Interruptible - Power- Non Firm	0	0	0
29		BGSS-Interruptible - Other	0	0	0
30					
31		Emergency Sales Svc. - Power	0	0	0
32		Emergency Sales Svc. - Power- Non Firm	0	0	0
33		Emergency Sales Svc - Other	0	0	0
34		Pilot & Penalty Therms	0	0	0

COS Adjustments

Listing of plant and expense items listed in the BPU Report but not included
in the COS modeling for reasons as indicated

line	FERC Account		Amount	Related to:
1	Expenses			
2	G905 MAC Adjustment Clause	$	(364,271)	MAC Adjustment Clause
3	G908 DSM Amortization		$46,805,034.86	SBC
4	G908 USF/LifelineAmortization		$53,360,246.70	SBC
5	G908 E-BRC Amortization		$7,819,110.66	Rate Case
6	Amortizations			
7	G407 & G407.3 - RAC Amortization		$30,048,016.75	RAC
8	Interest Charges			
9	G427-G431 Interest Charges	$	(1,138,521)	Interest Expense on Clauses
10	Manufactured Gas Production Expenses			
11	G729 BGSS Deferral	$	29,792,635	BGSS
12	804 & 805 Gas Purchase	$	1,244,109,804	BGSS
13	Current Tax Adjustments & Deductions			
14	Amort of Def Gain on Sale of Services Assets	$	35,437	Non Regulated Business
15	CECL Reserve	$	937,429	CECL
16	COVID Deferrals	$	(3,801,014)	COVID
17	Previously Deducted Amort - Reacquired Bonds	$	352,147	Incl'd in ROR calc.
18	Clause - Deferred Fuel	$	(3,385,475)	BGSS
19	Clause - RAC (Environmental Clean Up)	$	4,598,075	RAC
20	Clause - Societal Benefits Clause (AAP)	$	(4,643,306)	SBC
21	Clause - Demographic Studies	$	6,633	GPRC
22	Clause - Navigant Studies	$	(41,588)	GPRC
23	Deferred Taxes			
24	Amort of Def Gain on Sale of Services Assets	$	(35,437)	Non Regulated Business

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
1	S	**SUMMARY OF RESULTS**							
2	S	**DEVELOPMENT OF RETURN**							
3	S								
4	S	**RATE BASE**							
5	S	Plant in Service							
6	S	Production Plant 304-320	CALCULATED	52,043,670	39,041,892	4,021,862	8,979,916	0	0
7	S	Storage Plant 360-363	CALCULATED	19,575,233	14,684,863	1,512,747	3,377,624	0	0
8	S	Transmission Plant 365-371	CALCULATED	103,544,395	64,642,269	12,838,857	24,898,729	0	1,164,539
9	S	Distribution Plant							
10	S	Land & Structures 374-375	CALCULATED	96,512,525	70,215,496	12,449,888	13,347,431	14,144	485,566
11	S	Mains 376	CALCULATED	3,775,184,891	2,356,717,833	468,062,797	907,951,391	747	42,452,124
12	S	Compressor Station Equipment 377	CALCULATED	0	0	0	0	0	0
13	S	Meas & Regulating Station Equip 378-379	CALCULATED	285,986,290	178,539,869	35,460,510	68,769,490	0	3,216,420
14	S	Services 380	CALCULATED	5,447,179,699	4,488,006,097	641,086,199	314,336,599	1,381	3,749,423
15	S	Meters 381	CALCULATED	477,048,047	317,953,337	110,271,175	48,821,975	1	1,559
16	S	Meter Installations 382	CALCULATED	52,631,537	47,983,374	4,209,056	439,073	0	33
17	S	House Regulators & Install 383-384	CALCULATED	151,182,537	135,567,948	12,123,371	3,487,303	3	3,912
18	S	Industrial Meas & Reg Station Equip 385	CALCULATED	145,614,455	1,941,847	62,478,553	79,018,841	479	2,174,735
19	S	Other Property on Cust Premises 386	CALCULATED	0	0	0	0	0	0
20	S	Other Equipment (Street Lighting) 387	CALCULATED	1,521,717	0	0	0	1,521,717	0
21	S	Asset Retirement Obligation 388	CALCULATED	65,215,073	40,711,523	8,085,630	15,684,561	13	733,346
22	S	Total Distribution Plant	CALCULATED	10,498,076,770	7,637,637,323	1,354,227,179	1,451,856,664	1,538,485	52,817,119
23	S	General Plant E389-E399	CALCULATED	200,812,197	147,554,738	23,925,192	28,267,180	31,216	1,033,872
24	S	Common Plant C389-C399	CALCULATED	102,234,955	84,260,302	9,479,747	7,064,405	6,518	1,423,983
25	S	Intangible Plant E301-E303, E399, C303-C390	CALCULATED	16,791,854	14,306,794	1,416,896	787,996	597	279,572
26	S	Total Plant in Service	CALCULATED	10,993,079,074	8,002,128,180	1,407,422,480	1,525,232,514	1,576,816	56,719,085
27	S								
28	S	Less: Reserve for Depreciation and Amorization	CALCULATED	2,718,471,978	1,987,170,038	327,714,788	387,006,388	19,576	16,561,188
29	S								
30	S	Plus: Rate Base Additions							
31	S	Working Capital	CALCULATED	645,513,843	477,426,168	81,132,278	83,360,874	168,377	3,426,145
32	S	Capital Stimulas Adjust (Pro Forma #13)	CALCULATED	0	0	0	0	0	0
33	S	Capital Lease Plt & Reserve Deduct	CALCULATED	96,280	70,085	12,327	13,358	14	497
34	S	Other Rate Base Additions		1,727,003,584	1,256,348,704	223,007,510	238,726,427	259,481	8,661,462
35	S	Plus: Rate Base Deductions							
36	S	Customer Advances	CALCULATED	-24,909,672	-18,486,626	-2,995,654	-3,301,226	-1,383	-124,784
37	S	Unbilled Revenue	CALCULATED	-256,132,009	-186,444,685	-32,792,082	-35,536,983	-36,739	-1,321,520
38	S	Deferred Income Taxes and Credits	CALCULATED	-1,684,560,542	-1,226,274,710	-215,563,675	-233,798,494	-241,148	-8,682,514
39	S								
40	S	Other Rate Base Deductions		0	0	0	0	0	0
41	S	TOTAL RATE BASE		8,681,618,581	6,317,597,079	1,132,508,397	1,187,690,081	1,705,842	42,117,183
42	S								
43	S								
44	S								

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
45	S								
46	S	**SUMMARY OF RESULTS**							
47	S	**DEVELOPMENT OF RETURN**							
48	S								
49	S	**RATE BASE**	CALCULATED	8,681,618,581	6,317,597,079	1,132,508,397	1,187,690,081	1,705,842	42,117,183
50	S								
51	S	**OPERATING REVENUES**							
52	S	Rate Revenues from Customers	CALCULATED	1,401,350,320	1,015,564,742	181,736,301	195,384,067	470,352	8,194,858
53	S	Other Operating Revenues	CALCULATED	67,687,036	59,547,442	3,609,242	4,413,942	6,319	110,091
54	S	Revenues from Other Sources	CALCULATED	0	0	0	0	0	0
55	S	Less: Provisions for Rate Refunds	CALCULATED	0	0	0	0	0	0
56	S	TOTAL OPERATING REVENUES		1,469,037,356	1,075,112,184	185,345,543	199,798,009	476,671	8,304,949
57	S								
58	S	**OPERATING EXPENSES**							
59	S	Operation and Maintenance Expense							
60	S	Gas Production and Supply Expense	CALCULATED	31,906,945	23,935,800	2,465,727	5,505,418	0	1
61	S	Storage Expense	CALCULATED	2,714,605	2,036,430	209,781	468,394	0	0
62	S	Transmission Expense	CALCULATED	2,593,507	1,619,114	321,579	623,646	0	29,169
63	S	Distribution Expense	CALCULATED	102,873,398	78,462,609	11,507,363	12,288,348	202,974	412,103
64	S	Customer Accounts Expense	CALCULATED	98,759,541	81,184,487	9,284,074	6,836,701	2,373	1,451,905
65	S	Customer Service & Information Expense	CALCULATED	4,034,218	3,357,834	490,597	180,904	79	4,804
66	S	Sales Expense	CALCULATED	88,423	70,127	12,936	5,339	2	19
67	S	Administrative and General Expense	CALCULATED	38,752,071	22,991,576	5,699,198	9,490,616	63,765	506,916
68	S	Total Operation and Maintenance Expense	CALCULATED	281,722,708	213,657,978	29,991,254	35,399,366	269,194	2,404,917
69	S	Depreciation Expense	CALCULATED	203,691,216	148,803,241	25,897,310	27,869,800	29,232	1,091,633
70	S	Amortization Expense	CALCULATED	2,351,634	1,860,221	253,627	211,519	203	26,064
71	S	Taxes Other Than Income Taxes	CALCULATED	-24,480,722	-19,202,614	-2,516,697	-2,610,848	-7,347	-143,216
72	S	Proforma Expense Adjustments	CALCULATED	100,619,236	75,257,620	11,938,428	12,839,517	20,350	563,321
73	S	State Income Taxes	CALCULATED	77,634,124	56,530,606	10,095,876	10,612,856	14,966	379,821
74	S	Federal Income Taxes	CALCULATED	143,331,440	104,353,756	18,689,851	19,565,230	28,691	693,912
75	S	Provision for Deferred Income Taxes	CALCULATED	28,705,516	16,872,797	5,491,510	6,239,968	-7,409	108,650
76	S	Income Taxes Deferred in Prior Years	CALCULATED	0	0	0	0	0	0
77	S	Investment Tax Credit Adjustement (Net)	CALCULATED	0	0	0	0	0	0
78	S	TOTAL OPERATING EXPENSES		813,575,153	598,133,604	99,841,159	110,127,408	347,880	5,125,102
79	S								
80	S	**OPERATING INCOME (RETURN)**		655,462,203	476,978,579	85,504,384	89,670,601	128,791	3,179,847
81	S	Plus Operating Income Adjustment	CALCULATED						
82	S	TOTAL NET OPERATING INCOME		655,462,203	476,978,579	85,504,384	89,670,601	128,791	3,179,847
83	S								
84	S	**RATE OF RETURN ON RATE BASE (PRESENT)**		7.55%	7.55%	7.55%	7.55%	7.55%	7.55%
85	S	**INDEX RATE OF RETURN (PRESENT)**		1	1	1	1	1	1
86	S								
87	S								
88	S	**EQUALIZED RETURN AT PROPOSED ROR**							

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
89	S	**DEVELOPMENT OF RETURN (EQUALIZED RATE LEVELS)**							
90	S								
91	S	**RATE BASE**	CALCULATED	8,681,618,581	6,317,597,079	1,132,508,397	1,187,690,081	1,705,842	42,117,183
92	S								
93	S	**RATE OF RETURN**		7.55%	7.55%	7.55%	7.55%	7.55%	7.55%
94	S								
95	S	**RETURN (RATE BASE * 7.40% ROR)**		655,462,203	476,978,579	85,504,384	89,670,601	128,791	3,179,847
96	S								
97	S	**PLUS:**							
98	S	**OPERATING EXPENSES**							
99	S	Total Operation and Maintenance Expense	CALCULATED	281,722,708	213,657,978	29,991,254	35,399,366	269,194	2,404,917
100	S	Depreciation Expense	CALCULATED	203,691,216	148,803,241	25,897,310	27,869,800	29,232	1,091,633
101	S	Amortization Expense	CALCULATED	2,351,634	1,860,221	253,627	211,519	203	26,064
102	S	Taxes Other Than Income Taxes	CALCULATED	-24,480,722	-19,202,614	-2,516,697	-2,610,848	-7,347	-143,216
103	S	Proforma Expense Adjustments	CALCULATED	100,619,236	75,257,620	11,938,428	12,839,517	20,350	563,321
104	S	Income Taxes	CALCULATED	220,965,564	160,884,362	28,785,727	30,178,086	43,657	1,073,733
105	S	Provision for Deferred Income Taxes	CALCULATED	28,705,516	16,872,797	5,491,510	6,239,968	-7,409	108,650
106	S	Income Taxes Deferred in Prior Years	CALCULATED	0	0	0	0	0	0
107	S	Investment Tax Credit Adjustement (Net)	CALCULATED	0	0	0	0	0	0
108	S	**TOTAL OPERATING EXPENSES**		813,575,153	598,133,604	99,841,159	110,127,408	347,880	5,125,102
109	S								
110	S	**EQUALS TOTAL COST OF SERVICE**		1,469,037,356	1,075,112,184	185,345,543	199,798,009	476,671	8,304,949
111	S								
112	S	**LESS:**							
113	S	Other Operating Revenues	CALCULATED	67,687,036	59,547,442	3,609,242	4,413,942	6,319	110,091
114	S	Revenues from Other Sources	CALCULATED	0	0	0	0	0	0
115	S	Plus: Provisions for Rate Refunds	CALCULATED	0	0	0	0	0	0
116	S	**EQUALS:**							
117	S	**BASE RATE SALES @ EQUALIZED ROR 7.40%**		1,401,350,320	1,015,564,742	181,736,301	195,384,067	470,352	8,194,858
118	S								
119	S	**TOTAL COST OF SERVICE INCREASE/DECREASE**		0	0	0	0	0	0
120	S	**REVENUE INCREASE TO RETAIL REVENUES (%)**		0.0	0.0	0.0	0.0	0.0	0.0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
1	RBP	**DEVELOPMENT OF RATE BASE**							
2	RBP								
3	RBP	**GAS PLANT IN SERVICE**							
4	RBP								
5	RBP	INTANGIBLE PLANT - G301-G303							
6	RBP	General - AWMS & Misc.	TOTPLT	0	0	0	0	0	0
7	RBP	Choice Progect	not_used	0	0	0	0	0	0
8	RBP	GSMIS - meter related	not_used	0	0	0	0	0	0
9	RBP	- regulator related	not_used	0	0	0	0	0	0
10	RBP	- appliance safety related	not_used	0	0	0	0	0	0
11	RBP	- Comp Svs related	not_used	0	0	0	0	0	0
12	RBP	- Cust Svs related	not_used	0	0	0	0	0	0
13	RBP	TOTAL INTANGIBLE PLANT		0	0	0	0	0	0
14	RBP								
15	RBP	C303 - INTANGIBLE PLANT - CUST SERVICE							
16	RBP	Customer Service	CUSTSVSX	16,301,302	13,946,341	1,358,451	718,943	521	277,046
17	RBP	Measurement	MRCOST_07	0	0	0	0	0	0
18	RBP	Not Used	not_used	0	0	0	0	0	0
19	RBP	G399.1 Asset Retirement Costs of General Plt	GENPLT	490,552	360,453	58,445	69,052	76	2,526
20	RBP	Not Used	not_used	0	0	0	0	0	0
21	RBP	TOTAL ACCOUNTS C303-C390.4,G399		16,791,854	14,306,794	1,416,896	787,996	597	279,572
22	RBP								
23	RBP	TOTAL INTANGIBLE PLANT		16,791,854	14,306,794	1,416,896	787,996	597	279,572
24	RBP								
25	RBP	PRODUCTION PLANT							
26	RBP	G304-G320 - All Land & Equipment	BALANCE_04	52,043,670	39,041,892	4,021,862	8,979,916	0	0
27	RBP	Not Used	not_used	0	0	0	0	0	0
28	RBP	TOTAL PRODUCTION PLANT		52,043,670	39,041,892	4,021,862	8,979,916	0	0
29	RBP								
30	RBP	STORAGE PLANT							
31	RBP	G360-G363 - All Land & Equipment	BALANCE_04	19,575,233	14,684,863	1,512,747	3,377,624	0	0
32	RBP	Not Used	not_used	0	0	0	0	0	0
33	RBP	TOTAL STORAGE PLANT		19,575,233	14,684,863	1,512,747	3,377,624	0	0
34	RBP								
35	RBP	TRANSMISSION PLANT							
36	RBP	G365 Land & Land Rights	PEAKHOUR_04	5,421,128	3,384,384	672,186	1,303,588	0	60,970
37	RBP	G366 Structures & Improvements	PEAKHOUR_04	0	0	0	0	0	0
38	RBP	G367 Mains	PEAKHOUR_04	93,786,847	58,550,679	11,628,982	22,552,388	0	1,054,798
39	RBP	G369 Meas. & Reg. Station Equipment	PEAKHOUR_04	4,336,420	2,707,207	537,689	1,042,754		48,771
40	RBP	TOTAL TRANSMISSION PLANT		103,544,395	64,642,269	12,838,857	24,898,729	0	1,164,539
41	RBP								
42	RBP								
43	RBP								
44	RBP	**GAS PLANT IN SERVICE CONTINUED**							

PUBLIC SERVICE ELECTRIC & GAS COMPANY
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12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
45	RBP								
46	RBP	DISTRIBUTION PLANT							
47	RBP	G374-G375 Land & Structures							
48	RBP	General	DISTPLT	96,512,525	70,215,496	12,449,888	13,347,431	14,144	485,566
49	RBP	Not Used	not_used	0	0	0	0	0	0
50	RBP	Total Accounts G374-G375		96,512,525	70,215,496	12,449,888	13,347,431	14,144	485,566
51	RBP								
52	RBP	G376 Mains							
53	RBP	Firm Allocation	PEAKHOUR_04	3,772,391,917	2,355,086,185	467,752,988	907,125,544	0	42,427,200
54	RBP	CIG, TSG-NF & CSG Redistribution	TRANSPORT_04	2,792,974	1,631,647	309,809	825,847	747	24,924
55	RBP	Not Used	not_used	0	0	0	0	0	0
56	RBP	Total Account G376		3,775,184,891	2,356,717,833	468,062,797	907,951,391	747	42,452,124
57	RBP								
58	RBP	G377 Compressor Station Equip	DISTPLTXMTR	0	0	0	0	0	0
59	RBP								
60	RBP	G378-G379 Meas & Regulatory Equipment							
61	RBP	Firm Investment	PEAKHOUR_04	285,986,290	178,539,869	35,460,510	68,769,490	0	3,216,420
62	RBP	Not Used	not_used	0	0	0	0	0	0
63	RBP	Total Account G378-G379		285,986,290	178,539,869	35,460,510	68,769,490	0	3,216,420
64	RBP								
65	RBP	G380 Services							
66	RBP	Firm Allocation	SERVICES_03	5,442,013,091	4,484,987,779	640,513,095	312,808,899	0	3,703,317
67	RBP	CIG, TSG-NF & CSG Redistribution	TRANSPORT_03	5,166,608	3,018,317	573,103	1,527,700	1,381	46,106
68	RBP	Not Used	not_used	0	0	0	0	0	0
69	RBP	Total Account G380		5,447,179,699	4,488,006,097	641,086,199	314,336,599	1,381	3,749,423
70	RBP								
71	RBP	G381 Meters							
72	RBP	Firm Allocation	SMMETERS_07	477,045,042	317,951,581	110,270,842	48,821,087	0	1,532
73	RBP	CIG, TSG-NF & CSG Redistribution	TRANSPORT_07	3,005	1,755	333	888	1	27
74	RBP	Not Used	not_used	0	0	0	0	0	0
75	RBP	Total Account G381		477,048,047	317,953,337	110,271,175	48,821,975	1	1,559
76	RBP								
77	RBP	G382 Meter Installations							
78	RBP	Firm Allocation	MTRINSTAL_07	52,630,927	47,983,018	4,208,988	438,893	0	27
79	RBP	CIG, TSG-NF & CSG Redistribution	TRANSPORT_07	609	356	68	180	0	5
80	RBP	Not Used	not_used	0	0	0	0	0	0
81	RBP	Total Account G382		52,631,537	47,983,374	4,209,056	439,073	0	33
82	RBP								
83	RBP								
84	RBP								
85	RBP								
86	RBP								
87	RBP								
88	RBP	**GAS PLANT IN SERVICE CONTINUED**							

PUBLIC SERVICE ELECTRIC & GAS COMPANY
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12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
89	RBP								
90	RBP	DISTRIBUTION PLANT CONTINUED							
91	RBP								
92	RBP	G383 House Regulators & Installation							
93	RBP	Firm Allocation - Regulators - G383	HOUSEREG_03	38,488,025	32,605,191	3,994,393	1,885,454	0	2,986
94	RBP	CIG, TSG-NF & CSG Redistribution	TRANSPORT_03	11,098	6,483	1,231	3,282	3	99
95	RBP	Not Used	not_used	0	0	0	0	0	0
96	RBP	Total Account G383		38,499,123	32,611,675	3,995,624	1,888,736	3	3,085
97	RBP								
98	RBP	G384 House Regulators & Installation		0	0	0	0	0	0
99	RBP	Firm Allocation - Installation - G384	HSEREGINST_03	112,681,544	102,955,181	8,127,539	1,598,014	0	810
100	RBP	G384 CIG. TSG-NF & CSG Redistribution	TRANSPORT_03	1,870	1,092	207	553	0	17
101	RBP	Total Account G384		112,683,414	102,956,273	8,127,747	1,598,567	0	827
102	RBP	G385 Industrial Meas and Regul Station Equip							
103	RBP	Firm Allocation - Regulators	LRGREG_03	71,912,204	896,108	1,613,951	69,103,946	0	298,200
104	RBP	Firm Allocation - Meters	LRGMTR_07	71,912,204	0	60,666,042	9,385,601	0	1,860,561
105	RBP	CIG, TSG-NF & CSG Redistribution - Regulators	TRANSPORT_03	895,023	522,870	99,280	264,647	239	7,987
106	RBP	CIG, TSG-NF & CSG Redistribution - Meters	TRANSPORT_07	895,023	522,870	99,280	264,647	239	7,987
107	RBP	Not Used	not_used	0	0	0	0	0	0
108	RBP	Total Account G385		145,614,455	1,941,847	62,478,553	79,018,841	479	2,174,735
109	RBP								
110	RBP	G386 Other Prop on Cust Prem	TRANSPORT_04	0	0	0	0	0	0
111	RBP								
112	RBP	G387-Other Equipment							
113	RBP	G387.1 Other Eqmt - Street Ltg Posts	DIRSLG_05	1,011,930	0	0	0	1,011,930	0
114	RBP	G387.2 Other Eqmt - Street Ltg Services	DIRSLG_03	509,787	0	0	0	509,787	0
115	RBP	Total Accounts G387		1,521,717	0	0	0	1,521,717	0
116	RBP								
117	RBP	G388 - Asset Retirement Obligations	PLT_376	65,215,073	40,711,523	8,085,630	15,684,561	13	733,346
118	RBP								
119	RBP	TOTAL DISTRIBUTION PLANT		10,498,076,770	7,637,637,323	1,354,227,179	1,451,856,664	1,538,485	52,817,119
120	RBP								
121	RBP								
122	RBP								
123	RBP								
124	RBP								
125	RBP								
126	RBP								
127	RBP								
128	RBP								
129	RBP								
130	RBP								
131	RBP								
132	RBP								

PUBLIC SERVICE ELECTRIC & GAS COMPANY
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12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
133	RBP								
134	RBP								
135	RBP	**GAS PLANT IN SERVICE CONTINUED**							
136	RBP								
137	RBP	GENERAL AND COMMON PLANT							
138	RBP	E390-E398 GENERAL PLANT							
139	RBP	Meter Related	METERPLT	0	0	0	0	0	0
140	RBP	Regulator Plant Related	PLT_3834	0	0	0	0	0	0
141	RBP	Appliance Safety Related	CINST_04	0	0	0	0	0	0
142	RBP	Distribution Delivery	DISTPLTXMTR	200,812,197	147,554,738	23,925,192	28,267,180	31,216	1,033,872
143	RBP	Competitive Service	COMPSVSWK_04	0	0	0	0	0	0
144	RBP	SONP/RNP Related	CUSTAVG_04	0	0	0	0	0	0
145	RBP	Gas Peaking Plant Related	BALANCE_04	0	0	0	0	0	0
146	RBP	Total Accounts E390-E398		200,812,197	147,554,738	23,925,192	28,267,180	31,216	1,033,872
147	RBP								
148	RBP	C389-C399 COMMON PLANT							
149	RBP	ASB Work Related	CINST_04	0	0	0	0	0	0
150	RBP	Meter Plant Related	METERPLT	0	0	0	0	0	0
151	RBP	Meter Reading Related	MRCOST_07	0	0	0	0	0	0
152	RBP	Not Used	not_used	0	0	0	0	0	0
153	RBP	Customer Service Related	CUSTSVSX	75,768,117	64,822,307	6,314,050	3,341,634	2,421	1,287,704
154	RBP	Distribution Delivery Related	DISTPLTXMTR	25,073,523	18,423,767	2,987,313	3,529,456	3,898	129,090
155	RBP	Service & Support Related	UTILWORK_04	0	0	0	0	0	0
156	RBP	Unassigned	TOTPLT	1,393,316	1,014,228	178,384	193,315	200	7,189
157	RBP	Total Accounts C389-C399		102,234,955	84,260,302	9,479,747	7,064,405	6,518	1,423,983
158	RBP								
159	RBP	TOTAL GENERAL AND COMMON PLANT		303,047,153	231,815,040	33,404,939	35,331,585	37,734	2,457,855
160	RBP								
161	RBP								
162	RBP	**TOTAL GAS PLANT IN SERVICE (101)**		10,993,079,074	8,002,128,180	1,407,422,480	1,525,232,514	1,576,816	56,719,085

PUBLIC SERVICE ELECTRIC & GAS COMPANY
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12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
1	RBD	**LESS: DEPRECIATION RESERVE & AMORT**							
2	RBD								
3	RBD	G301-G303 - INTANGILE PLANT - RESERVE							
4	RBD	General - AWMS & Misc.	TOTPLT	0	0	0	0	0	0
5	RBD	Choice Progect	not_used	0	0	0	0	0	0
6	RBD	GSMIS - meter related	not_used	0	0	0	0	0	0
7	RBD	- regulator related	not_used	0	0	0	0	0	0
8	RBD	- appliance safety related	not_used	0	0	0	0	0	0
9	RBD	- Comp Svs related	not_used	0	0	0	0	0	0
10	RBD	- Cust Svs related	not_used	0	0	0	0	0	0
11	RBD	Total Accounts E301-E303 Reserve		0	0	0	0	0	0
12	RBD								
13	RBD	C303 - INTANGIBLE PLANT - CUST SERVICE							
14	RBD	Customer Service	CUSTSVSX	9,821,603	8,402,729	818,472	433,166	314	166,921
15	RBD	Measurement	MRCOST_07	0	0	0	0	0	0
16	RBD	Not Used	not_used	0	0	0	0	0	0
17	RBD	G399.1 Asset Retirement Costs of General Plt	GENPLT	0	0	0	0	0	0
18	RBD	Not Used	not_used	0	0	0	0	0	0
19	RBD	TOTAL ACCOUNTS C303-C390.4,G399		9,821,603	8,402,729	818,472	433,166	314	166,921
20	RBD								
21	RBD	TOTAL INTANGIBLE PLANT		9,821,603	8,402,729	818,472	433,166	314	166,921
22	RBD								
23	RBD	PRODUCTION PLANT G304-G320 RESERVE	BALANCE_04	56,077,402	42,067,900	4,333,584	9,675,919	0	0
24	RBD								
25	RBD	STORAGE PLANT G360-G363 RESERVE	BALANCE_04	9,476,790	7,109,257	732,353	1,635,180	0	0
26	RBD								
27	RBD	TRANSMISSION PLANT G365-G369 RESERVE	TRANPLT	50,246,121	31,368,412	6,230,204	12,082,398	0	565,106
28	RBD								
29	RBD	DISTRIBUTION PLANT RESERVE							
30	RBD	G374-G375 Land & Structures Reserve	PLT_3745	432,406	314,587	55,779	59,801	63	2,175
31	RBD								
32	RBD	G376 Mains Reserve							
33	RBD	Firm Allocation	PEAKHOUR_04	1,017,890,245	635,463,999	126,212,020	244,766,255	0	11,447,971
34	RBD	CIG, TSG-NF & CSG Redistribution	TRANSPORT_04	759,994	443,986	84,302	224,720	203	6,782
35	RBD	Not Used	not_used	0	0	0	0	0	0
36	RBD	Total Account G376		1,018,650,239	635,907,986	126,296,322	244,990,976	203	11,454,753
37	RBD								
38	RBD	G377 Compressor Station Equip Reserve	DISTPLTXMTR						
39	RBD								
40	RBD	G378-G379 Meas & Regulatory Equip Reserve							
41	RBD	Firm Investment	PEAKHOUR_04	93,669,010	58,477,114	11,614,371	22,524,052	0	1,053,473
42	RBD	Not Used	not_used	0	0	0	0	0	0
43	RBD	Total Account G378-G379		93,669,010	58,477,114	11,614,371	22,524,052	0	1,053,473
44	RBD	**DEPRECIATION RESERVE & AMORT CONTINUED**							

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12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
45	RBD								
46	RBD	**DISTRIBUTION PLANT CONTINUED**							
47	RBD								
48	RBD	G380 Services Reserve							
49	RBD	Firm Allocation	SERVICESR_03	1,126,944,013	941,879,849	127,667,704	56,085,079	0	1,311,381
50	RBD	CIG, TSG-NF & CSG Redistribution	TRANSPORT_03	2,349,910	1,372,810	260,663	694,838	628	20,970
51	RBD	Not Used	not_used	0	0	0	0	0	0
52	RBD	Total Account G380		1,129,293,923	943,252,660	127,928,367	56,779,917	628	1,332,351
53	RBD								
54	RBD	G381 Meters Reserve							
55	RBD	Firm Allocation	SMMETERSR_07	61,006,069	41,220,681	13,639,927	6,145,259	0	202
56	RBD	CIG, TSG-NF & CSG Redistribution	TRANSPORT_07	1,948	1,138	216	576	1	17
57	RBD	Not Used	not_used	0	0	0	0	0	0
58	RBD	Total Account G381		61,008,018	41,221,819	13,640,143	6,145,836	1	219
59	RBD								
60	RBD	G382 Meter Installations Reserve							
61	RBD	Firm Allocation	MTRINSTALR_07	33,652,945	31,062,601	2,354,621	235,711	0	11
62	RBD	CIG, TSG-NF & CSG Redistribution	TRANSPORT_07	279	163	31	83	0	2
63	RBD	Not Used	not_used	0	0	0	0	0	0
64	RBD	Total Account G382		33,653,224	31,062,764	2,354,652	235,794	0	14
65	RBD								
66	RBD	G383 House Regulators & Installation Reserve							
67	RBD	Firm Allocation - Regulators - G383	HOUSEREGR_03	25,030,964	21,059,419	2,653,835	1,312,627	0	5,082
68	RBD	CIG, TSG-NF & CSG Redistribution	TRANSPORT_03	4,827	2,820	535	1,427	1	43
69	RBD	Not Used	not_used	0	0	0	0	0	0
70	RBD	Total Account G383		25,035,791	21,062,240	2,654,371	1,314,054	1	5,125
71	RBD								
72	RBD	G384 House Regulators & Installation Reserve		0	0	0	0	0	0
73	RBD	Firm Allocation - Installation - G384	HSEREGINSTR_03	58,406,745	53,459,006	4,125,696	820,870	0	1,173
74	RBD	G384 CIG. TSG-NF & CSG Redistribution	TRANSPORT_03	1,006	588	112	298	0	9
75	RBD	Total Account G384		58,407,752	53,459,594	4,125,808	821,168	0	1,182
76	RBD	G385 Industrial Meas and Regul Sta Equip Reserve							
77	RBD	Firm Allocation - Regulators	LRGREGR_03	12,236,618	23,869	289,692	11,817,896	0	105,161
78	RBD	Firm Allocation - Meters	LRGMTRR_07	12,236,618	0	10,344,813	1,235,941	0	655,864
79	RBD	CIG, TSG-NF & CSG Redistribution - Regulators	TRANSPORT_03	295,977	172,909	32,831	87,517	79	2,641
80	RBD	CIG, TSG-NF & CSG Redistribution - Meters	TRANSPORT_07	295,977	172,909	32,831	87,517	79	2,641
81	RBD	Not Used	not_used	0	0	0	0	0	0
82	RBD	Total Account G385		25,065,190	369,687	10,700,167	13,228,870	158	766,307
83	RBD								
84	RBD	G386 Other Prop on Cust Prem	TRANSPORT_04	0	0	0	0	0	0
85	RBD	G387.1 Other Eqmt - Street Ltg Posts	DIRSLG_05	0	0	0	0	0	0
86	RBD	G387.2 Other Eqmt - Street Ltg Services	DIRSLG_03	0	0	0	0	0	0
87	RBD								
88	RBD	TOTAL DISTRIBUTION PLANT RESERVE		2,445,215,554	1,785,128,451	299,369,981	346,100,467	1,055	14,615,600

PUBLIC SERVICE ELECTRIC & GAS COMPANY
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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
89	RBD								
90	RBD	**DEPRECIATION RESERVE & AMORT CONTINUED**							
91	RBD								
92	RBD	GENERAL AND COMMON PLANT RESERVE							
93	RBD								
94	RBD	E390-E398 GENERAL PLANT - RESERVE							
95	RBD	Meter Related	METERPLT	0	0	0	0	0	0
96	RBD	Regulator Plant Related	PLT_3834	0	0	0	0	0	0
97	RBD	Appliance Safety Related	CINST_04	0	0	0	0	0	0
98	RBD	Distribution Delivery	DISTPLTXMTR	94,949,830	69,768,158	11,312,525	13,365,542	14,760	488,845
99	RBD	Competitive Service	COMPSVSWK_04	0	0	0	0	0	0
100	RBD	SONP/RNP Related	CUSTAVG_04	0	0	0	0	0	0
101	RBD	Gas Peaking Plant Related	BALANCE_04	0	0	0	0	0	0
102	RBD	Total Accounts E390-E398		94,949,830	69,768,158	11,312,525	13,365,542	14,760	488,845
103	RBD								
104	RBD	C389-C399 COMMON PLANT							
105	RBD	ASB Work Related	CINST_04	0	0	0	0	0	0
106	RBD	Meter Reading Related	MRCOST_07	0	0	0	0	0	0
107	RBD	Not Used	not_used	0	0	0	0	0	0
108	RBD	Customer Service Related	CUSTSVSX	38,276,434	32,746,845	3,189,723	1,688,122	1,223	650,521
109	RBD	Distribution Delivery Related	DISTPLTXMTR	13,134,595	9,651,165	1,564,884	1,848,882	2,042	67,623
110	RBD	Service & Support Related	UTILWORK_04	0	0	0	0	0	0
111	RBD	Unassigned	TOTPLT	1,273,650	927,121	163,063	176,712	183	6,571
112	RBD	Total Accounts C389-C399 Reserve		52,684,679	43,325,131	4,917,670	3,713,716	3,447	724,715
113	RBD								
114	RBD	**TOTAL DEPRECIATION RESERVE & AMORT.**		2,718,471,978	1,987,170,038	327,714,788	387,006,388	19,576	16,561,188
115	RBD								
116	RBD								
117	RBD	**NET GAS PLANT IN SERVICE**		8,274,607,096	6,014,958,143	1,079,707,691	1,138,226,125	1,557,240	40,157,897
118	RBD	Meter Plant Related	METERPLT	0	0	0	0	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
1	RBO	**ADDITIONS AND DEDUCTIONS TO RATE BASE**							
2	RBO								
3	RBO	**PLUS: ADDITIONS TO RATE BASE**							
4	RBO								
5	RBO	Working Capital							
6	RBO	Materials and Supplies Excl Fuel Stock	PSTDPLT	59,382,049	43,151,615	7,636,654	8,284,886	8,560	300,334
7	RBO	Fuel Stock & Fuel Stock Expense	not_used	0	0	0	0	0	0
8	RBO	Gas Stored Underground	not_used	0	0	0	0	0	0
9	RBO	Cash (lead/lag)	EXPENDITURES	586,016,094	434,188,829	73,481,117	75,061,168	159,786	3,125,193
10	RBO	Prepayments/Working Funds	EXPENDITURES	115,700	85,724	14,508	14,820	32	617
11	RBO	Total Working Capital		645,513,843	477,426,168	81,132,278	83,360,874	168,377	3,426,145
12	RBO	CEF-EC Adjustment	not_used						
13	RBO	CEF-EV Adjustment	not_used						
14	RBO	Net Plant Adds - Distribution	DISTPLT	1,573,578,886	1,144,821,580	202,987,970	217,621,860	230,607	7,916,869
15	RBO	Capital Stimulas Adjust	DISTPLT	0	0	0	0	0	0
16	RBO	Plant Held for Future Use	TOTPLT	96,280	70,085	12,327	13,358	14	497
17	RBO	Net Plant Adds - General & Other	TOTPLTNET	153,424,698	111,527,125	20,019,540	21,104,567	28,874	744,593
18	RBO	TOTAL ADDITIONS TO RATE BASE		2,372,613,708	1,733,844,958	304,152,115	322,100,660	427,872	12,088,104
19	RBO								
20	RBO	**PLUS: DEDUCTIONS TO RATE BASE**							
21	RBO								
22	RBO	Customer Advances for Construction	MAIN_SERV	(24,909,672)	(18,486,626)	(2,995,654)	(3,301,226)	(1,383)	(124,784)
23	RBO	IAP Adjustment	not_used						
24	RBO	GSMP II EXT Adjustment	TOTPLT	(256,132,009)	(186,444,685)	(32,792,082)	(35,536,983)	(36,739)	(1,321,520)
25	RBO	Deferred Income Taxes and Credits							
26	RBO	ADIT Test/Post year	TOTPLT						
27	RBO	Liberalized Depreciation	TOTPLT	35,377,684	25,752,272	4,529,336	4,908,470	5,074	182,532
28	RBO	Liberalized Depreciation - Production	BALANCE_04	(1,955,963)	(1,467,315)	(151,154)	(337,493)		
29	RBO	Cost of Removal	TOTPLT	9,569,770	6,966,067	1,225,199	1,327,756	1,373	49,375
30	RBO	3% Investment Tax Credit	DISTPLT	0	0	0	0	0	0
31	RBO	Computer Software	TOTPLT	0	0	0	0	0	0
32	RBO	Capitalized Interest	TOTPLTNET	(160,793)	(116,883)	(20,981)	(22,118)	(30)	(780)
33	RBO	NJ Corporate Business Tax	STATEINCTAX	4,194,912	3,054,596	545,524	573,459	809	20,523
34	RBO	Defrd Tax & Consolidated Tax Adjustment	TOTPLT	(1,731,586,152)	(1,260,463,447)	(221,691,599)	(240,248,568)	(248,374)	(8,934,165)
35	RBO	Total Deferred Income Taxes and Credits		(1,684,560,542)	(1,226,274,710)	(215,563,675)	(233,798,494)	(241,148)	(8,682,514)
36	RBO								
37	RBO	TOTAL DEDUCTIONS TO RATE BASE		(1,965,602,222)	(1,431,206,021)	(251,351,410)	(272,636,704)	(279,270)	(10,128,818)
38	RBO								
39	RBO								
40	RBO	**TOTAL RATE BASE**		8,681,618,581	6,317,597,079	1,132,508,397	1,187,690,081	1,705,842	42,117,183

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
1	REV	**OPERATING REVENUES**							
2	REV								
3	REV	**SALES REVENUES**							
4	REV	BASE RATE SALES @ EQUALIZED ROR 7.40%		1,401,350,320	1,015,564,742	181,736,301	195,384,067	470,352	8,194,858
5	REV	Revenue Requirement - Other #1	not_used	0	0	0	0	0	0
6	REV	Revenue Requirement - Other #2	not_used	0	0	0	0	0	0
7	REV	TOTAL SALES OF GAS		1,401,350,320	1,015,564,742	181,736,301	195,384,067	470,352	8,194,858
8	REV								
9	REV	**OTHER OPERATING REVENUES**							
10	REV	G487-Forfeited Discounts	REVLATEP	1,447,215	0	697,421	749,794	0	0
11	REV	G488-Miscellaneous Service Revenues	COMPSVSWK_04	40,880,111	40,880,111	0	0	0	0
12	REV	G489-Revenues from Transmission from Others	not_used	0	0	0	0	0	0
13	REV	G493-Rent from Gas Property	TOTPLT	0	0	0	0	0	0
14	REV	G495-Other Gas Revenues							
15	REV	Miscellaneous Gas Revenues	TOTREV	19,473,704	14,251,793	2,456,959	2,648,542	6,319	110,091
16	REV	Peak Shaving Revenues	BALANCE_04	5,886,006	4,415,538	454,862	1,015,606	0	0
17	REV	Not Used	not_used	0	0	0	0	0	0
18	REV	Not Used	not_used	0	0	0	0	0	0
19	REV	TOTAL OTHER OPERATING REV		67,687,036	59,547,442	3,609,242	4,413,942	6,319	110,091
20	REV								
21	REV	**OTHER REVENUE SOURCES**							
22	REV	Not Used	not_used	0	0	0	0	0	0
23	REV	Not Used	not_used	0	0	0	0	0	0
24	REV	TOTAL OTHER REVENUE SOURCES		0	0	0	0	0	0
25	REV								
26	REV	LESS: E496 Provision for Rate Refunds	TOTREV	0	0	0	0	0	0
27	REV								
28	REV	**TOTAL OPERATING REVENUES**		1,469,037,356	1,075,112,184	185,345,543	199,798,009	476,671	8,304,949

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
1	E	**OPERATION & MAINTENANCE EXPENSE**							
2	E								
3	E	MANUFACTURED GAS PRODUCTION EXPENSE							
4	E	G710-G718 Production Expenses Incl Labor	BALANCE_04	281,982	211,536	21,791	48,655	0	0
5	E	G722-G736 Gas Raw Materials	BALANCE_04	29,792,635	22,349,708	2,302,333	5,140,593	0	0
6	E	G739-G745 Operation & Maintenance Exp	BALANCE_04	1,832,256	1,374,514	141,594	316,148	0	0
7	E	Not Used	not_used	0	0	0	0	0	0
8	E	TOTAL MANUFACTURED GAS PRODUCTION EXP		31,906,873	23,935,758	2,465,719	5,505,396	0	0
9	E								
10	E	OTHER GAS SUPPLY EXPENSE							
11	E	G801 Natural Gas Field Line Purchases	not_used	0	0	0	0	0	0
12	E	G804 Natural Gas City Gate Purchases	not_used	0	0	0	0	0	0
13	E	G805 Other Gas Purchases	not_used	0	0	0	0	0	0
14	E	G808.1,.2 GasInject & W/D from Storage	not_used	0	0	0	0	0	0
15	E	G812 Gas Used for Other Util Oper	not_used	0	0	0	0	0	0
16	E	G813 Other Gas Supply Expenses							
17	E	Supply Related	not_used	0	0	0	0	0	0
18	E	Distribution Related	TRANSPORT_04	72	42	8	21	0	1
19	E	TOTAL OTHER GAS SUPPLY EXPENSE		72	42	8	21	0	1
20	E	TOTAL GAS PRODUCTION AND SUPPLY		31,906,945	23,935,800	2,465,727	5,505,418	0	1
21	E								
22	E	OTHER STORAGE EXPENSE							
23	E	G840-G842 Operation	BALANCE_04	8,906	6,681	688	1,537	0	0
24	E	G843 Maintenance	BALANCE_04	2,705,699	2,029,749	209,093	466,857		
25	E	TOTAL OTHER STORAGE EXPENSE		2,714,605	2,036,430	209,781	468,394	0	0
26	E								
27	E	TRANSMISSION EXPENSES							
28	E	G850-G867 Transmission Exp	TRANPLT	2,593,507	1,619,114	321,579	623,646		29,169
29	E	TOTAL TRANSMISSION EXPENSE		2,593,507	1,619,114	321,579	623,646	0	29,169
30	E								
31	E	DISTRIBUTION EXPENSES							
32	E	Operation							
33	E	G870 Operation Supervision & Engineering	TLABDO	0	0	0	0	0	0
34	E	G871 Load Dispatching	TRANSPORT_04	5,839,316	3,411,311	647,723	1,726,611	1,561	52,109
35	E	G872 Compressor Station Labor & Expenses	TRANSPORT_04	0	0	0	0	0	0
36	E	G874 Mains & Services	MAIN_SERV	20,733,577	15,387,352	2,493,434	2,747,777	1,151	103,864
37	E	G875 Meas & Reg Station - General	PLT_3789	2,497,019	1,558,877	309,615	600,444	0	28,083
38	E	G876 Meas & Reg Station - Industrial	PLT_3789	7,594	4,741	942	1,826	0	85
39	E	G877 Meas & Reg Station - City Gate	PLT_3789	514,539	321,224	63,800	123,728	0	5,787
40	E	G878 Meter & House Reg	PLT_3814	11,492,061	8,464,742	2,136,903	890,323	0	93
41	E	G879 Customer Installations							
42	E	- Customer Installations	CINST_04	17,355,157	17,355,157	0	0	0	0
43	E	- Competitive Services by ASB	COMPSVSWK_04	0	0	0	0	0	0
44	**E**	**OPERATION & MAINTENANCE EXPENSE CONTINUED**							

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
45	E								
46	E	G880.0,.1,.2 Other Expenses	DISTEXPO	14,050,188	11,236,945	1,355,188	1,413,289	593	44,173
47	E	G880.3 Operation of Street Lighting	DIRSLG_05	0	0	0	0	0	0
48	E	G881 Rents	TRANSPORT_04	-1,088,602	-635,958	-120,753	-321,886	-291	-9,715
49	E	Total Distribution Operation		71,400,849	57,104,391	6,886,851	7,182,113	3,014	224,480
50	E								
51	E	DISTRIBUTION EXPENSES CONTINUED							
52	E	Maintenance							
53	E	G885 Maint. Supervision & Engineering	TLABDM	0	0	0	0	0	0
54	E	G886 Structures & Improvements	PLT_3745	8,016,449	5,832,185	1,034,103	1,108,654	1,175	40,332
55	E	G887 Mains	PLT_376	8,706,285	5,435,034	1,079,441	2,093,906	2	97,903
56	E	G888 Compressor Station Equip	PLT_377	0	0	0	0	0	0
57	E	G889 Meas & Reg Station - General	PLT_3789	1,007,898	629,226	124,973	242,363	0	11,336
58	E	G891 Meas & Reg Station - City Gate	PLT_3789	3,155,564	1,970,003	391,270	758,800	0	35,490
59	E	G892 Services	SERVICES	3,610,466	2,974,434	424,881	208,327	339	2,485
60	E	G893 Meters & House Reg							
61	E	G893.1 - Meters	SMMETERS_07	6,767,990	4,510,880	1,564,448	692,640	0	22
62	E	G893.4 - House Regulators	PLT_3834	0	0	0	0	0	0
63	E	Not Used	not_used	0	0	0	0	0	0
64	E	G894 Maint of Other Equipment							
65	E	G894.0 - Maint of Other Equip	DISTEXPM	9,513	6,456	1,397	1,543	60	57
66	E	G894.1 - Maint of Gas Streetlights	DIRSLG_05	198,384	0	0	0	198,384	0
67	E	Total Distribution Maintenance		31,472,549	21,358,219	4,620,512	5,106,235	199,960	187,623
68	E	TOTAL DISTRIBUTION PLANT O&M EXPENSES		102,873,398	78,462,609	11,507,363	12,288,348	202,974	412,103
69	E								
70	E	TOTAL OPER & MAINT EXP (PROD,STOR, TRAN,& DIST)		140,088,455	106,053,954	14,504,449	18,885,805	202,975	441,273
71	E								
72	E	CUSTOMER ACCOUNTS EXPENSES							
73	E	G901 Supervision	CUSTACCTS	0	0	0	0	0	0
74	E	G902 Meter Reading							
75	E	- Meter Reading Related	MRCOST_07	12,907,838	11,695,648	984,362	227,828	0	0
76	E	- Meter O&M Related	METERPLT	38,249	23,265	11,125	3,740	0	119
77	E	- Remaining	MRCOST_07	0	0	0	0	0	0
78	E	G903 Customer Records and Collection							
79	E	- SONP/RNP	CUSTAVG_06	526,534	477,008	40,157	9,334	8	27
80	E	- Meter O&M Related	METERPLT	0	0	0	0	0	0
81	E	- Meter Reading Related	MRCOST_07	63,202	57,267	4,820	1,116	0	0
82	E	- Billing Related	BILLING_06	16,558,655	13,225,534	1,341,715	1,310,000	1,164	680,242
83	E	- Acct Maint Related	ACCTMAINT_06	26,073,286	23,623,844	2,005,203	393,770	159	50,309
84	E	- Utility Work Related	UTILWORK_04	2,712,621	2,151,329	396,835	163,794	70	592
85	E	- Remaining	BILLING_06	13,832,442	11,048,085	1,120,815	1,094,322	972	568,247
86	E	Not used	not_used	0	0	0	0	0	0
87	**E**	**OPERATION & MAINTENANCE EXPENSE CONTINUED**							
88	E								

PUBLIC SERVICE ELECTRIC & GAS COMPANY
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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
89	E	G904 Uncollectible Accounts	EXP_904	26,046,715	18,882,507	3,379,043	3,632,797	0	152,368
90	E	G905 Misc Customer Accounts	CUSTACCTS	0	0	0	0	0	0
91	E	TOTAL CUSTOMER ACCTS EXPENSE		98,759,541	81,184,487	9,284,074	6,836,701	2,373	1,451,905
92	E								
93	E	CUSTOMER SERVICE & INFO EXPENSES							
94	E	G907 & 908 - Customer Service & Information							
95	E	- Billing	BILLING_06	37,379	29,855	3,029	2,957	3	1,536
96	E	- Acct Maint related	ACCTMAINT_06	746,413	676,291	57,404	11,273	5	1,440
97	E	- Utility work related	UTILWORK_04	1,684,915	1,336,275	246,490	101,739	44	368
98	E	- Remaining	ACCTMAINT_06	0	0	0	0	0	0
99	E	G909 Info & Instr Advertising	TRANSPORT_04	0	0	0	0	0	0
100	E	G910 - Misc Cust Service & Info							
101	E	- Utility work related	UTILWORK_04	911,953	723,253	133,412	55,066	24	199
102	E	- Remaining	ACCTMAINT_06	653,558	592,160	50,263	9,870	4	1,261
103	E	TOTAL CUSTOMER SERVICE & INFO EXPENSES		4,034,218	3,357,834	490,597	180,904	79	4,804
104	E								
105	E	SALES EXPENSES							
106	E	G912 - Demonstrating and Selling	UTILWORK_04	88,423	70,127	12,936	5,339	2	19
107	E	G913 - Advertising	UTILWORK_04	0	0	0	0	0	0
108	E	G916 - Miscellaneous	UTILWORK_04	0	0	0	0	0	0
109	E								
110	E	SALES EXPENSES TOTAL (ACCT 916)		88,423	70,127	12,936	5,339	2	19
111	E								
112	E	TOTAL OPER & MAINT EXCL A&G		242,970,637	190,666,402	24,292,056	25,908,750	205,429	1,898,001
113	E								
114	E	ADMINISTRATIVE & GENERAL EXPENSE							
115	E	G920 A&G Salaries	LABOR	6,954,680	5,942,289	497,411	464,900	3,438	46,642
116	E	G921 Office Supplies & Exp	LABOR	652,569	557,575	46,673	43,622	323	4,376
117	E	G923 Outside Services Employed							
118	E	- Gas Peaking Plant Related	BALANCE_04	0	0	0	0	0	0
119	E	- Remaining	TOMXFUEL904	61,043,177	46,604,280	6,587,051	7,163,926	73,435	614,485
120	E	G924 Property Insurance	TOTPLT	296,480	215,815	37,958	41,135	43	1,530
121	E	G925 Injuries & Damages	LABOR	15,351,785	13,117,029	1,097,986	1,026,222	7,590	102,958
122	E	G926 Employee Pension & Benefits							
123	E	- Gas Peaking Plant Related	BALANCE_04	0	0	0	0	0	0
124	E	- Remaining	LABOR	-60,778,346	-51,930,855	-4,346,972	-4,062,857	-30,048	-407,614
125	E	G928 Regulatory Comm Exp	TRANSPORT_04	5,147,284	3,007,028	570,960	1,521,986	1,376	45,934
126	E	G929 Duplicate Charges - credit	INTRAREV	764,611	0	40,127	724,484	0	0
127	E	G930.1 General Advertising Expenses	TRANSPORT_04	1,968,152	1,149,789	218,316	581,957	526	17,564
128	E	G930.2 Misc General Expenses	TRANSPORT_04	3,638,524	2,125,615	403,601	1,075,865	973	32,470
129	E	G931 Rents	AGEXP	3,713,155	2,203,012	546,087	909,374	6,110	48,572
130	E	G932 Maint of General Plant	COMGENPLT	0	0	0	0	0	0
131	E	G935 Other A&G Maint	COMGENPLT	0	0	0	0	0	0
132	E	Not Used	not_used	0	0	0	0	0	0

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				(1)	(2)	(3)	(4)	(5)	(6)
133	E	TOTAL A&G EXPENSE		38,752,071	22,991,576	5,699,198	9,490,616	63,765	506,916
134	E								
135	E	**TOTAL OPERATION & MAINTENANCE EXPENSES**		281,722,708	213,657,978	29,991,254	35,399,366	269,194	2,404,917
136	E	G890 Meas & Reg Station - Industrial	PLT_3789	0	0	0	0	0	0

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
1	DE	**DEPRECIATION AND AMORTIZATION EXPENSES**							
2	DE								
3	DE	G403 DEPRECIATION EXPENSE							
4	DE	Production Plant	BALANCE_04	1,670	1,253	129	288	0	0
5	DE	Storage Plant	BALANCE_04	114,612	85,979	8,857	19,776	0	0
6	DE	Transmission Plant	TRANPLT	1,172,631	732,068	145,399	281,976	0	13,188
7	DE	Distribution Plant	DISTPLT	182,874,076	133,045,881	23,590,325	25,291,008	26,800	920,062
8	DE	General and Common Plant	COMGENPLT	19,528,227	14,938,061	2,152,600	2,276,752	2,432	158,383
9	DE	Not Used	not_used	0	0	0	0	0	0
10	DE	TOTAL DEPRECIATION EXPENSE		203,691,216	148,803,241	25,897,310	27,869,800	29,232	1,091,633
11	DE								
12	DE	G404.3 AMORT OF OTHER LIMITED TERM PLANT							
13	DE	Customer Service related	CUSTSVSX	1,194,362	1,021,819	99,531	52,675	38	20,299
14	DE	AWMS	DISTPLT	0	0	0	0	0	0
15	DE	Distribution	DISTPLT	1,127,553	820,326	145,452	155,938	165	5,673
16	DE	Metering	METERPLT	29,719	18,076	8,644	2,906	0	92
17	DE	All Other	PSTDPLT	0	0	0	0	0	0
18	DE	TOTAL AMORT OF OTHER LIMITED TERM PLT		2,351,634	1,860,221	253,627	211,519	203	26,064
19	DE								
20	DE	G407 AMORT OF PROPERTY LOSSES							
21	DE	Remediation Adjustment Clause	not_used	0	0	0	0	0	0
22	DE	Excess Cost of Removal	TOTPLT						
23	DE	TOTAL AMORT OF PROPERTY LOSSES		0	0	0	0	0	0
24	DE								
25	DE	TOTAL AMORTIZATION EXPENSE		2,351,634	1,860,221	253,627	211,519	203	26,064
26	DE								
27	DE	**TOTAL DEPRECIATION AND AMORTIZATION EXPENSES**		206,042,850	150,663,462	26,150,937	28,081,319	29,435	1,117,697

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
1	EO	**OTHER OPERATING EXPENSES**							
2	EO								
3	EO	**G408 TAXES OTHER THAN INCOME TAXES**							
4	EO	Payroll	LABOR	-2,034	-1,738	-145	-136	-1	-14
5	EO	TEFA	TEFA_04	0	0	0	0	0	0
6	EO	Real Estate Taxes	TOTPLT	-13,552,354	-9,865,086	-1,735,081	-1,880,319	-1,944	-69,924
7	EO	State Unemploy Insur (SUI) Tax	LABOR	0	0	0	0	0	0
8	EO	Fed Insur Contr & UnempTax	LABOR	-60,481	-51,677	-4,326	-4,043	-30	-406
9	EO	Fed Insur Contr & UnempTax - Gas Peaking Plts	BALANCE_04	0	0	0	0	0	0
10	EO	FICA	LABOR	-10,865,853	-9,284,113	-777,144	-726,351	-5,372	-72,873
11	EO	Miscellaneous State and Municipal Tax	TOTPLT	0	0	0	0	0	0
12	EO	Federal Environmental Tax	PSTDPLT	0.0	0.0	0.0	0.0	0.0	0.0
13	EO	**TOTAL TAXES OTHER THAN INCOME**		-24,480,722	-19,202,614	-2,516,697	-2,610,848	-7,347	-143,216
14	EO								
15	EO	**PROFORMA EXPENSE ADJUSTMENTS**							
16	EO	Amortization of CEF-EC Program Regulatory Assets		0	0	0	0	0	0
17	EO	Amortization of CEF-EV Program Regulatory Assets		0	0	0	0	0	0
18	EO	BGS Administrative Expense Adjustment		0	0	0	0	0	0
19	EO	CIP Revenue Accrual Adjustment	not_used	0	0	0	0	0	0
20	EO	Deferred Compensation & Severance Expense	LABOR	-361,345	-308,744	-25,844	-24,155	-179	-2,423
21	EO	Gas Bad Debt Adjustment	not_used	0	0	0	0	0	0
22	EO	TAC Revenue Accrual Adjustment	not_used	0	0	0	0	0	0
23	EO	Tax Bad Debt Adjustment	SALESREV	2,990,017	2,166,878	387,765	416,885	1,004	17,485
24	EO	TSG-NF Gas Margin Reset	not_used	0	0	0	0	0	0
25	EO	Wage Increases (Rate Year)	LABOR	7,223,753	6,172,193	516,655	482,887	3,571	48,447
26	EO	Payroll Taxes (Rate Year)	LABOR	508,958	434,869	36,402	34,022	252	3,413
27	EO	Interest Syncronization	TOTPLTNET	-1,864,683	-1,355,471	-243,312	-256,499	-351	-9,050
28	EO	- add'l tax effects on rev req	TOTPLTNET	-729,117	-530,008	-95,138	-100,295	-137	-3,539
29	EO	Pension & Fringe Benefit (Rate Year)	LABOR	7,091,402	6,059,108	507,189	474,040	3,506	47,559
30	EO	Adj #5 - Gas COLI Interest Expense	LABOR	0	0	0	0	0	0
31	EO	- add'l tax effects on rev req	LABOR	0	0	0	0	0	0
32	EO	Postage	CUSTACCTS	0	0	0	0	0	0
33	EO	BPU / Rate Counsel Assessment	TRANSPORT_04	738,301	431,313	81,896	218,306	197	6,589
34	EO	Adj #6 - Weather Normalization	not_used	0	0	0	0	0	0
35	EO	Gains / Losses Normalization	TOTPLT	-207,450	-151,008	-26,559	-28,783	-30	-1,070
36	EO	- add'l tax effects on rev req	TOTPLT	-81,116	-59,046	-10,385	-11,254	-12	-419
37	EO	Test Year Corrections	TOTPLT	0	0	0	0	0	0
38	EO	Customer Information System Amort	CUSTSVSX	0	0	0	0	0	0
39	EO	Real Estate Tax Increases (Rate Year)	TOTPLT	158,827	115,614	20,334	22,036	23	819
40	EO	Capital Stimulus (Depreciation)	DISTPLT	0	0	0	0	0	0
41	EO	Insurance Premium Increases (Rate Year)	TOTPLT	237,517	172,894	30,409	32,954	34	1,225
42	EO	Adj #15 - Excess COR Refund Recovery	TOTPLT	0	0	0	0	0	0
43	EO	Test Year Amortization Adjustments	TOTPLT	-5,932,749	-4,318,591	-759,558	-823,138	-851	-30,610
44	EO	Adj #11 - TSGNF Margin Sharing	not_used	0	0	0	0	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
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12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
45	EO	Adj #12 - Depreciation Rate Change/Annualization	DEPREXP	0	0	0	0	0	0
46	EO	Capital Stimulus Revenue	DISTPLT	0	0	0	0	0	0
47	EO	ASB Margin	TOTPLT	15,265,290	11,111,974	1,954,385	2,117,980	2,190	78,762
48	EO	Adj #13 - Storm Cost Amortization	TOTPLTNET	0	0	0	0	0	0
49	EO	Other Regulatory Asset / Liability Amortizations	TOTPLT	0	0	0	0	0	0
50	EO	Rate Case Expenses	TOTPLT	141,376	102,911	18,100	19,615	20	729
51	EO	Tax - Repair Allowance	DISTPLT	0	0	0	0	0	0
52	EO	Tax - Flow Through Items	DISTPLT	0	0	0	0	0	0
53	EO	Adj #14 Post Rate Case Storm Cost Normalization	TOTPLT	0	0	0	0	0	0
54	EO	Recovery of Credit Card Fees	CUSTSVSX	0	0	0	0	0	0
55	EO	Adj #20 - Vacation Accrual	LABOR	0	0	0	0	0	0
56	EO	Energy Strong II / IAP Revenue Adjustment	TOTPLT						
57	EO	Depreciation Rate Change	DEPREXP	74,624,206	54,515,477	9,487,725	10,210,365	10,709	399,930
58	EO	TOTAL PROFORMA EXPENSE ADJUSTMENTS		100,619,236	75,257,620	11,938,428	12,839,517	20,350	563,321
59	EO								
60	EO	**TOTAL OTHER OPERATING EXPENSES**		76,138,514	56,055,006	9,421,731	10,228,669	13,003	420,106
61	EO	COLI Interest Expense Recovery	LABOR	816,048	697,256	58,365	54,550	403	5,473

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PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
1	TI	**DEVELOPMENT OF INCOME TAXES**							
2	TI								
3	TI	TOTAL OPERATING REVENUES	CALCULATED	1,469,037,356	1,075,112,184	185,345,543	199,798,009	476,671	8,304,949
4	TI	LESS:							
5	TI	OPERATION & MAINTAINENCE EXPENSE	CALCULATED	281,722,708	213,657,978	29,991,254	35,399,366	269,194	2,404,917
6	TI	DEPRECIATION & AMORTIZATION EXPENSE	CALCULATED	206,042,850	150,663,462	26,150,937	28,081,319	29,435	1,117,697
7	TI	OTHER OPERATING EXPENSES	CALCULATED	76,138,514	56,055,006	9,421,731	10,228,669	13,003	420,106
8	TI	NET OPERATING INCOME BEFORE TAXES		905,133,284	654,735,739	119,781,621	126,088,655	165,039	4,362,230
9	TI	LESS:							
10	TI	G427 - G431 INTEREST CHARGES	TOTPLTNET	100,820,068	73,287,889	13,155,453	13,868,457	18,974	489,295
11	TI	**TOTAL OPERATING INCOME BEFORE TAXES**		804,313,216	581,447,849	106,626,168	112,220,198	146,065	3,872,935
12	TI								
13	TI	**TAX ADJUSTMENTS - FEDERAL**							
14	TI								
15	TI	Assessment by Board of Public Utilities of the State of NJ	TOTPLTNET	56,782	41,276	7,409	7,811	11	276
16	TI	Injuries and Damages ;		0	0	0	0	0	0
17	TI	Bankrupticies & Acc. Prov. For Rents Receivable	TOTPLTNET	52,256	37,986	6,819	7,188	10	254
18	TI	Capitalized interest-Section 263A	TOTPLT	416,892	303,465	53,374	57,842	60	2,151
19	TI	Casualty Loss Deferred O&M & Ins Proceeds	TOTPLTNET	-1,095,802	-796,557	-142,985	-150,735	-206	-5,318
20	TI	Deduction for New Network Meter Equipment		0	0	0	0	0	0
21	TI	Defer Dividend Equivalents/Restricted Stock-Temp.		0	0	0	0	0	0
22	TI	Deferred Depreciation on CIP ll	TOTPLT	8,262	6,014	1,058	1,146	1	43
23	TI	Deferred Return on CIP ll	TOTPLT	18,055	13,143	2,312	2,505	3	93
24	TI	Diesel Fuel Credit		0	0	0	0	0	0
25	TI	Environmental Accrual		0	0	0	0	0	0
26	TI	FIN48 Reg Asset Reversal		0	0	0	0	0	0
27	TI	FIN48 Services Allocation		0	0	0	0	0	0
28	TI	GainState LILOAudit Refunds not yet received		0	0	0	0	0	0
29	TI	LCAPP		0	0	0	0	0	0
30	TI	Legal Reserves (c & nc)	TOTPLTNET	-418,012	-303,860	-54,544	-57,500	-79	-2,029
31	TI	Material Supplies & Reserves	TOTPLT	78,535	57,168	10,055	10,896	11	405
32	TI	Misc Adj - Permanent		0	0	0	0	0	0
33	TI	Miscellaneous		0	0	0	0	0	0
34	TI	Partnership income/loss per K-1		0	0	0	0	0	0
35	TI	Performance Incentive Plan Adjustment	TOTPLTNET	-455,695	-331,253	-59,461	-62,684	-86	-2,212
36	TI	RAC-Environmental Cleanup Costs		0	0	0	0	0	0
37	TI	Repair Allow Deferral Carrying Charges		0	0	0	0	0	0
38	TI	SBC-Societal Benefits Clause		0	0	0	0	0	0
39	TI	Stock Based Compensation	TOTPLTNET	-325,229	-236,415	-42,437	-44,737	-61	-1,578
40	TI	TAX ADJUSTMENTS - FEDERAL CONTINUED		0	0	0	0	0	0
41	TI	Uncollectible Accounts		0	0	0	0	0	0
42	TI	Utility Commodity Costs		0	0	0	0	0	0
43	TI	Additional Expenses on Rental Property	TOTPLT	0	0	0	0	0	0
44	TI	Additional Rental Income - NJ Properties	TOTPLT	0	0	0	0	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
45	TI	Amort of Def Gain on Sale of Services Assets	not_used	0	0	0	0	0	0
46	TI	Amort of Deferred Gain on Sale of Generation Assets	not_used	0	0	0	0	0	0
47	TI	Amortization of Limited-Term Utility Plant	TOTPLT	-14	-10	-2	-2	0	0
48	TI	Amortization of Reacquisition of Pref Stock	TOTPLT	7,787	5,668	997	1,080	1	40
49	TI	CECL Reserve	not_used	0	0	0	0	0	0
50	TI	CEF- EC AMI	TOTPLT	0	0	0	0	0	0
51	TI	CEF- EV Deferral	TOTPLT	0	0	0	0	0	0
52	TI	Clause - Demographic Studies	not_used	0	0	0	0	0	0
53	TI	Clause - Navigant Studies	not_used	0	0	0	0	0	0
54	TI	Clause - RAC (Environmental Clean Up)	not_used	0	0	0	0	0	0
55	TI	Clause - Societal Benefits Clause (AAP)	not_used	0	0	0	0	0	0
56	TI	Company Owned Life Insurance - Book	LABOR	-352,245	-300,969	-25,193	-23,547	-174	-2,362
57	TI	Company Owned Life Insurance - Tax	LABOR	-14,570	-12,449	-1,042	-974	-7	-98
58	TI	COVID Deferrals	not_used	0	0	0	0	0	0
59	TI	Current SHARE -- FT	DEPREXP	-21,771,486	-15,904,798	-2,768,028	-2,978,857	-3,124	-116,679
60	TI	Customer Advances	TOTPLTNET	294,687	214,213	38,452	40,536	55	1,430
61	TI	Customer Connection Fees (Contributions in Aid of Constructi	TOTPLTNET	0	0	0	0	0	0
62	TI	Deduction for Retention Payments (c)	LABOR	-4,379	-3,741	-313	-293	-2	-29
63	TI	Deferred Employer ER FICA	LABOR	-5,798,258	-4,954,207	-414,701	-387,597	-2,867	-38,886
64	TI	Diesel Fuel Tax Credit	TOTPLT	928	676	119	129	0	5
65	TI	Entertainment (100%)	LABOR	36,298	31,014	2,596	2,426	18	243
66	TI	FAS 5 (ASC40) Reserve - Sales Tax	not_used	0	0	0	0	0	0
67	TI	Fed Amort of Deferred Gain on Sale of Generation Assets	not_used	0	0	0	0	0	0
68	TI	Injuries & Damages - FT	TOTPLT	1,044,758	760,505	133,758	144,955	150	5,390
69	TI	Line Pack Adjustment	not_used	0	0	0	0	0	0
70	TI	Plant Related	DEPREXP	-61,904,159	-45,223,057	-7,870,497	-8,469,960	-8,884	-331,760
71	TI	Previously Deducted Amort - Reacquired Bonds	not_used	0	0	0	0	0	0
72	TI	Qualified Transportation Fringe	LABOR	139,386	119,096	9,969	9,318	69	935
73	TI	R & D Credits CF	not_used	0	0	0	0	0	0
74	TI	R&D Credit - Fed	TOTPLT	-75,718	-55,117	-9,694	-10,505	-11	-391
75	TI	R&D Expenditure	TOTPLT	-16,866	-12,277	-2,159	-2,340	-2	-87
76	TI	Rabbi Trust	not_used	0	0	0	0	0	0
77	TI	RE - Lease Liability	TOTPLT	-519,350	-378,047	-66,491	-72,057	-74	-2,680
78	TI	RE - ROU Lease Asset	TOTPLT	594,984	433,103	76,175	82,551	85	3,070
79	TI	Reversal of Book Income from Partnerships	TOTPLT	0	0	0	0	0	0
80	TI	Severance Pay (nc)	LABOR	121,791	104,062	8,711	8,141	60	817
81	TI	State NOL CF (c)	DEPREXP	7,732,062	5,648,530	983,055	1,057,930	1,110	41,438
82	TI	Tax Net Bad Debt Writeoffs - FT	TOTPLT	-81,087	-59,025	-10,381	-11,250	-12	-418
83	TI	Unicap book/tax inventory FS	not_used	0	0	0	0	0	0
84	TI	Unrealized G/L on Equity Securities	TOTPLT	142,148	103,473	18,199	19,722	20	733
85	TI	Credits & Adjustments	TOTPLT	0	0	0	0	0	0
86	TI	Repair Allowance	TOTPLT	0	0	0	0	0	0
87	TI	Uncollectible Accounts - Writeoff	EXP_904	0	0	0	0	0	0
88	TI	Injuries and Damages	TOTPLT	0	0	0	0	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
89	TI	Meals & entertainment	LABOR	-459,207	-392,360	-32,843	-30,697	-227	-3,080
90	TI	Company owned life insurance	LABOR	0	0	0	0	0	0
91	TI	ESOP/401(k) Cash Dividends	TOTPLTNET	-844,650	-613,991	-110,214	-116,187	-159	-4,099
92	TI	Medicare Subsidy		0	0	0	0	0	0
93	TI	Allowable Depreciation	DEPREXP	0	0	0	0	0	0
94	TI	Book Depreciation	DEPREXP	0	0	0	0	0	0
95	TI	Previously Ded Amort-Reacq Bonds	not_used	0	0	0	0	0	0
96	TI	Amortization of Computer Software	INTANGPLT	0	0	0	0	0	0
97	TI	Amort Def Gain - Sale of Gen Asset	not_used	0	0	0	0	0	0
98	TI	Gain on Sale of Services Corp Asset	not_used	0	0	0	0	0	0
99	TI	AFUDC / IDC	TOTPLT	-345,079	-251,191	-44,180	-47,878	-49	-1,780
100	TI	Cost of removal	TOTPLT	0	0	0	0	0	0
101	TI	*Utility Commodity Costs-Non-Taxable Income	not_used	0	0	0	0	0	0
102	TI	*RAC-Environmental Cleanup Costs - Debit	not_used	0	0	0	0	0	0
103	TI	*SBC-Societal Benefits Clause - Unallow Deductions	not_used	0	0	0	0	0	0
104	TI	Deferred Comp - officers	LABOR	-15,155	-12,949	-1,084	-1,013	-7	-102
105	TI	Deduction of Securitizartion	not_used	0	0	0	0	0	0
106	TI	Accrued vacation pay adjustment	LABOR	-257,985	-220,431	-18,452	-17,246	-128	-1,730
107	TI	3rd Party Claims	TOTPLT	-975	-709	-125	-135	0	-5
108	TI	Gain/loss bond reacq	not_used	0	0	0	0	0	0
109	TI	Amortization of Call Option Sale	LABOR	0	0	0	0	0	0
110	TI	Contribution in Aid of Construct	TOTPLTNET	0	0	0	0	0	0
111	TI	Pension Accrual Adjustment	LABOR	-7,780,352	-6,647,768	-556,464	-520,094	-3,847	-52,179
112	TI	Unallowable OPEB Amortization	LABOR	47,224,310	40,349,877	3,377,564	3,156,808	23,347	316,713
113	TI	NJ BPU assessment	TOTPLTNET	0	0	0	0	0	0
114	TI	Unicap book/tax inventory	TOTPLTNET	0	0	0	0	0	0
115	TI	W-2 Earnings Exceeding $1,000,000	LABOR	1,506,831	1,287,482	107,771	100,727	745	10,106
116	TI	Diesel Fuel Tax Credit	not_used	0	0	0	0	0	0
117	TI	Deferred Depreciation & Return on CIP II	TOTPLTNET	0	0	0	0	0	0
118	TI	Capitalized Interest - Section 263A	TOTPLT	0	0	0	0	0	0
119	TI	Clause - Deferred Fuel	not_used	0	0	0	0	0	0
120	TI	Restricted Stock - Permanent	LABOR	-67,594	-57,755	-4,834	-4,518	-33	-453
121	TI	Materials & Supplies Reserve	TOTPLT	0	0	0	0	0	0
122	TI	Amortization of Reacquisition of Pref Stock	TOTPLTNET	0	0	0	0	0	0
123	TI	Lobbying Expenses	LABOR	0	0	0	0	0	0
124	TI	Penalties	not_used	0	0	0	0	0	0
125	TI	Dividends Received Deduction	TOTPLTNET	0	0	0	0	0	0
126	TI	Real Estate Taxes	TOTPLTNET	-1,021,308	-742,407	-133,265	-140,488	-192	-4,957
127	TI	Line Pack Adjustment	TOTPLTNET	0	0	0	0	0	0
128	TI	Legal Reserves	TOTPLTNET	0	0	0	0	0	0
129	TI	Casualty Insurance Proceeds	TOTPLT	0	0	0	0	0	0
130	TI	Miscellaneous (R&D Exp., Limit Term Util Plant, ARO Fin 47, F	TOTPLT	0	0	0	0	0	0
131	TI	**TOTAL TAX ADJUSTMENTS - FEDERAL**		-44,148,425	-27,994,596	-7,531,000	-8,439,582	5,524	-188,771
132	TI								

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				(1)	(2)	(3)	(4)	(5)	(6)
133	TI								
134	TI	**DEVELOPMENT OF INCOME TAXES CONTINUED**							
135	TI								
136	TI	**TAX ADJUSTMENTS - STATE**							
137	TI	Reverse TEFA	TEFA_04	0	0	0	0	0	0
138	TI	Federal Depreciation Reversal	TOTPLT	64,677,176	47,080,081	8,280,493	8,973,622	9,277	333,704
139	TI	State Tax Depreciation	DEPREXP	37,759,415	27,584,515	4,800,734	5,166,385	5,419	202,362
140	TI	Amortization of Service's Asset Sale	TOTPLTNET	0	0	0	0	0	0
141	TI	NOL Utilization	TOTPLTNET	0	0	0	0	0	0
142	TI	**TOTAL TAX ADJUSTMENTS - STATE**		102,436,591	74,664,595	13,081,226	14,140,007	14,696	536,066
143	TI								
144	TI	**TAXABLE NET INCOME - STATE**		862,601,382	628,117,849	112,176,395	117,920,623	166,285	4,220,230
145	TI	State Tax Liability		77,634,124	56,530,606	10,095,876	10,612,856	14,966	379,821
146	TI	Prior Year Adjustment & State Credit	TOTPLTNET	0	0	0	0	0	0
147	TI	**TOTAL STATE INCOME TAX LIABILITY**		77,634,124	56,530,606	10,095,876	10,612,856	14,966	379,821
148	TI								
149	TI	**TAXABLE NET INCOME - FEDERAL**		682,530,667	496,922,647	88,999,293	93,167,760	136,624	3,304,343
150	TI	Federal Tax Liability		143,331,440	104,353,756	18,689,851	19,565,230	28,691	693,912
151	TI	Prior Yr & Oth Adjustments	TOTPLTNET	0	0	0	0	0	0
152	TI	Not Used	not_used	0	0	0	0	0	0
153	TI	**TOTAL FEDERAL INCOME TAX LIABILITY**		143,331,440	104,353,756	18,689,851	19,565,230	28,691	693,912
154	TI								
155	TI	**TOTAL INCOME TAX EXPENSE**		220,965,564	160,884,362	28,785,727	30,178,086	43,657	1,073,733
156	TI								
157	TI	**<u>TAX RATES</u>**							
158	TI	FEDERAL TAX RATE - CURRENT		21.000%					
159	TI	NEW JERSEY CORP BUSINESS TAX RATE		9.000%					
160	TI	CUSTOMER ACCT UNCOLLECTIBLE RATE		0.0					
161	TI	EFFECTIVE TAX RATE		28.110%					
162	TI	COMPOSITE RATE		28.110%					
163	TI	1 - EFFECTIVE TAX RATE		71.89000%					
164	TI								
165	TI	**DEVELOPMENT OF OPERATING INCOME ADJUSTED**							
166	TI								
167	TI	**G410 + G411- PROVISION FOR DEFERRED INCOME TAX**							
168	TI	Additional Rental Income - NJ Properties	TOTPLT	0	0	0	0	0	0
169	TI	Amort of Def Gain on Sale of Services Assets	not_used	0	0	0	0	0	0
170	TI	Amort of Deferred Gain on Sale of Generation Assets	not_used	0	0	0	0	0	0
171	TI	Amortization of Limited-Term Utility Plant	TOTPLT	14	10	2	2	0	0
172	TI	Bankruptcies and Accum Provision for Rent Receivable	TOTPLT	-31,746	-23,109	-4,064	-4,405	-5	-164
173	TI	Casualty Loss Deferred O&M	TOTPLTNET	1,095,802	796,558	142,985	150,735	206	5,318
174	TI	CECL Reserve	not_used	0	0	0	0	0	0
175	TI	CEF- EC AMI	TOTPLT	0	0	0	0	0	0
176	TI	CEF- EV Deferral	TOTPLT	0	0	0	0	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
177	TI	Clause - Demographic Studies	not_used	0	0	0	0	0	0
178	TI	Clause - Navigant Studies	not_used	0	0	0	0	0	0
179	TI	Clause - RAC (Environmental Clean Up)	not_used	0	0	0	0	0	0
180	TI	Clause - Societal Benefits Clause (AAP)	not_used	0	0	0	0	0	0
181	TI	COVID Deferrals	not_used	0	0	0	0	0	0
182	TI	Current SHARE -- FT	DEPREXP	5,506,769	4,022,879	700,131	753,457	790	29,512
183	TI	Customer Advances	TOTPLTNET	-294,687	-214,213	-38,452	-40,536	-55	-1,430
184	TI	Deduction for Retention Payments (c)	LABOR	4,379	3,741	313	293	2	29
185	TI	Deferred Employer ER FICA	LABOR	5,798,258	4,954,207	414,701	387,597	2,867	38,886
186	TI	FAS 5 (ASC40) Reserve - Sales Tax	not_used	0	0	0	0	0	0
187	TI	Fed Amort of Deferred Gain on Sale of Generation Assets	not_used	0	0	0	0	0	0
188	TI	Injuries & Damages - FT	TOTPLT	-264,256	-192,358	-33,832	-36,664	-38	-1,363
189	TI	Line Pack Adjustment	not_used	0	0	0	0	0	0
190	TI	Medicare Subsidy	not_used	0	0	0	0	0	0
191	TI	Partnership Income/Loss (nc)	TOTPLT	0	0	0	0	0	0
192	TI	Plant Related	DEPREXP	62,706,788	45,809,404	7,972,544	8,579,779	8,999	336,062
193	TI	Previously Deducted Amort - Reacquired Bonds	not_used	0	0	0	0	0	0
194	TI	R & D Credits CF	TOTPLT	-67,859	-49,396	-8,688	-9,415	-10	-350
195	TI	RE - Lease Liability	TOTPLT	519,350	378,047	66,491	72,057	74	2,680
196	TI	RE - ROU Lease Asset	TOTPLT	-594,984	-433,103	-76,175	-82,551	-85	-3,070
197	TI	Real Estate Taxes (nc)	TOTPLT	1,021,308	743,435	130,756	141,701	146	5,269
198	TI	Reversal of Book Income from Partnerships	TOTPLT	0	0	0	0	0	0
199	TI	Severance Pay (nc)	LABOR	-121,791	-104,062	-8,711	-8,141	-60	-817
200	TI	State NOL CF (c)	DEPREXP	-7,732,062	-5,648,530	-983,055	-1,057,930	-1,110	-41,438
201	TI	Unrealized G/L on Equity Securities	TOTPLT	-142,148	-103,473	-18,199	-19,722	-20	-733
202	TI	Previously Ded Amort-Reacq Bonds	not_used	0	0	0	0	0	0
203	TI	Clause - Deferred Fuel	not_used	0	0	0	0	0	0
204	TI	Gain on Sale of Services Corp Asset	not_used	0	0	0	0	0	0
205	TI	AFUDC / IDC	TOTPLT	345,079	251,191	44,180	47,878	49	1,780
206	TI	Capitalized interest-Section 263A	TOTPLT	-416,892	-303,465	-53,374	-57,842	-60	-2,151
207	TI	Cost of removal	TOTPLT	0	0	0	0	0	0
208	TI	Deferred Comp - officers	LABOR	15,155	12,949	1,084	1,013	7	102
209	TI	Deduction of Securitizartion	not_used	0	0	0	0	0	0
210	TI	Accrued vacation pay adjustment	LABOR	257,985	220,431	18,452	17,246	128	1,730
211	TI	Gain/loss bond reacq	not_used	0	0	0	0	0	0
212	TI	Amortization of Call Option Sale	LABOR	0	0	0	0	0	0
213	TI	Defer Dividend Equivalents/Restricted Stock-Temp.	LABOR	0	0	0	0	0	0
214	TI	Contribution in Aid of Construct	TOTPLTNET	0	0	0	0	0	0
215	TI	Pension Accrual Adjustment	LABOR	7,780,352	6,647,768	556,464	520,094	3,847	52,179
216	TI	Unallowable OPEB Amortization	LABOR	-47,224,310	-40,349,877	-3,377,564	-3,156,808	-23,347	-316,713
217	TI	Fin Def-Energy Competition Act Ct	TOTPLT	0	0	0	0	0	0
218	TI	Rabbi Trust Unrealized Losses		0	0	0	0	0	0
219	TI	Additional Real Estate Taxes	TOTPLT	0	0	0	0	0	0
220	TI	PIP Adjustment	LABOR	455,695	389,360	32,592	30,462	225	3,056

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
221	TI	Deferred NJ Corp Bus Tax(Net of FIT)	TOTPLTNET	0	0	0	0	0	0
222	TI	Misc	TOTPLT	0	0	0	0	0	0
223	TI	Construction Period Interest	TOTPLTNET	0	0	0	0	0	0
224	TI	Deferred Return on CIP ll	TOTPLT	-18,055	-13,143	-2,312	-2,505	-3	-93
225	TI	Deferred Depreciation on CIP ll	TOTPLT	-8,262	-6,014	-1,058	-1,146	-1	-43
226	TI	Investment Tax Credit	TOTPLT	-493,265	-359,060	-63,152	-68,438	-71	-2,545
227	TI	Assessment by Board of Public Utilities of the State of NJ	TOTPLTNET	-56,782	-41,276	-7,409	-7,811	-11	-276
228	TI	3rd Party Claims	TOTPLT	975	709	125	135	0	5
229	TI	Customer Connections Fees		0	0	0	0	0	0
230	TI	Legal Reserves (nc)	TOTPLTNET	418,012	303,860	54,544	57,500	79	2,029
231	TI	Material Supplies & Reserves	TOTPLTNET	-78,535	-57,089	-10,248	-10,803	-15	-381
232	TI	Stock Based Compensation	TOTPLTNET	325,229	236,415	42,437	44,737	61	1,578
233	TI	**TOTAL DEFERRED INCOME TAX**		28,705,516	16,872,797	5,491,510	6,239,968	-7,409	108,650
234	TI								
235	TI	**This Section is not used at this time**							
236	TI	**PROFORMA OPERATING INCOME ADJUSTMENTS**							
237	TI	Not Used	not_used	0	0	0	0	0	0
238	TI	Not Used	not_used	0	0	0	0	0	0
239	TI	Not Used	not_used	0	0	0	0	0	0
240	TI	**OPERATING INCOME ADJUSTED**		655,462,203	476,978,579	85,504,384	89,670,601	128,791	3,179,847

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
1	LR	**DEVELOPMENT OF LABOR ALLOCATION FACTOR**							
2	LR	Labor portion included in O&M Expense							
3	LR								
4	LR	**G700-G742 MANUFACTURED GAS LABOR EXP**	MFGO_M	778,312	583,871	60,147	134,294	0	0
5	LR	**G813 GAS SUPPLY LABOR EXPENSE**	EXP_813	0	0	0	0	0	0
6	LR	**G840-G843 STORAGE PLANT LABOR EXP**	STOREXP	407,976	306,054	31,528	70,395	0	0
7	LR	**G850-G867 TRANSMISSION LABOR EXP**	TRANEXP	483,267	301,701	59,922	116,208	0	5,435
8	LR								
9	LR	**DISTRIBUTION LABOR EXPENSE**							
10	LR	Operation							
11	LR	G870 Operation Supervision & Engineering	TLABDO	0	0	0	0	0	0
12	LR	G871 Load Dispatching	EXP_871	4,522,112	2,641,804	501,613	1,337,131	1,209	40,355
13	LR	G872 Compressor Station Labor & Expenses	EXP_872	0	0	0	0	0	0
14	LR	G874 Mains & Services	EXP_874	14,351,672	10,651,043	1,725,942	1,901,997	797	71,894
15	LR	G875-877 Meas & Reg Station	EXP_8757	1,368,583	854,400	169,696	329,095	0	15,392
16	LR	G878 Meter & House Reg	EXP_878	8,562,092	6,306,606	1,592,087	663,330	0	69
17	LR	G879 Customer Installations - Total	EXP_879	63,057,319	63,057,319	0	0	0	0
18	LR	G880.1 Miscellaneous Dist Exp	EXP_8801	5,219,383	4,174,315	503,427	525,010	220	16,409
19	LR	G880.3 Operation of Street Lighting	EXP_8803	0	0	0	0	0	0
20	LR	G881 Rents	EXP_881	-60	-35	-7	-18	0	-1
21	LR	Total Operation		97,081,101	87,685,453	4,492,758	4,756,545	2,226	144,119
22	LR								
23	LR	Maintenance							
24	LR	G885 Maint. Supervision & Engineering	TLABDM	0	0	0	0	0	0
25	LR	G886 Structures & Improvements	EXP_886	1,015,469	738,781	130,993	140,437	149	5,109
26	LR	G887 Mains	EXP_887	4,445,965	2,775,463	551,229	1,069,277	1	49,995
27	LR	G888 Compressor Station Equip	EXP_888	0	0	0	0	0	0
28	LR	G889-891 Meas & Reg Station	EXP_8891	2,185,363	1,364,311	270,971	525,502	0	24,578
29	LR	G892 Services	EXP_892	2,126,460	1,751,856	250,243	122,699	200	1,464
30	LR	G893 Meters & House Reg	EXP_893	5,044,535	3,362,194	1,166,064	516,261	0	16
31	LR	G894 Maint of Other Equipment - Total	EXP_894	71,094	2,208	478	528	67,862	19
32	LR	Not Used	not_used	0	0	0	0	0	0
33	LR	Total Maintenance		14,888,885	9,994,812	2,369,978	2,374,703	68,211	81,181
34	LR	TOTAL DISTRIBUTION LABOR EXPENSE		111,969,986	97,680,265	6,862,735	7,131,248	70,437	225,300
35	LR								
36	LR	**G901-G903,G905 CUST ACCOUNTS EXPENSE**	CUSTACCTS	45,109,566	38,650,888	3,663,362	1,987,637	1,472	806,207
37	LR	**G907-G910, xDSM CUST SERV & INFO EXP**	CUSTS_I	3,007,750	2,503,466	365,769	134,875	59	3,582
38	LR	**G911-G916 SALES EXPENSE**	SALESEXP	3,526	2,797	516	213	0	1
39	LR	**ADMIN & GENERAL EXP ACCOUNTS xG926**	AGEXP	6,954,680	4,126,207	1,022,812	1,703,243	11,444	90,974
40	LR	**Employee Pension/Benefits Acct G926**	LABOR	0	0	0	0	0	0
41	LR								
42	LR	**TOTAL OPERATION & MAINT LABOR EXPENSE**		168,715,063	144,155,248	12,066,791	11,278,114	83,412	1,131,499

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
1	CA	**DEVELOPMENT OF CAPITAL ADDITIONS ALLOCATION F.**							
2	CA								
3	CA	**INTANGIBLE PLANT - G301-G303**	INTANGPLT	0	0	0	0	0	0
4	CA	**PRODUCTION PLANT - G304-G347**	PRODPLT	-2,267,387	-1,700,938	-175,221	-391,228	0	0
5	CA	**STORAGE PLANT - G360-G363**	STORPLT	8,371,561	6,280,141	646,943	1,444,478	0	0
6	CA	TRANSMISSION PLANT - G365-G371	TRANPLT	11	7	1	3	0	0
7	CA								
8	CA	**DISTRIBUTION PLANT**							
9	CA	G374 Land and Land Rights & G375 Structure & Improveme	PLT_3745	2,620,552	1,906,523	338,045	362,416	384	13,184
10	CA	G376 Mains	PLT_376	226,633,216	141,479,307	28,098,909	54,506,455	45	2,548,501
11	CA	G377 Compressor Station Equipment	PLT_377	0	0	0	0	0	0
12	CA	G378-G379 Meas & Regul Eqmt	PLT_3789	57,069,064	35,627,943	7,076,207	13,723,072	0	641,842
13	CA	G380 Services	SERVICES	505,466,924	416,422,163	59,483,542	29,165,898	47,429	347,892
14	CA	G381 Meters	PLT_381	58,899,779	39,256,803	13,614,871	6,027,912	0	193
15	CA	G382 Meter Installations	PLT_382	-1,810,761	-1,650,843	-144,810	-15,106	0	-1
16	CA	G383-384 House Regulators & Install	PLT_3834	2,268,333	2,034,053	181,898	52,323	0	59
17	CA	G385 Ind Reg & Meas Eqmt	PLT_385	12,739,212	169,884	5,465,993	6,913,035	42	190,259
18	CA	TOTAL DISTRIBUTION PLANT		863,886,319	635,245,832	114,114,655	110,736,003	47,900	3,741,928
19	CA								
20	CA	**COMMON PLANT**	COMPLT	0	0	0	0	0	0
21	CA	**GENERAL PLANT EXCL INTANGIBLE PLT**	GENPLT	26,119,255	19,192,160	3,111,904	3,676,658	4,060	134,474
22									
23	CA	**TOTAL CAPITAL ADDITIONS**		896,109,759	659,017,202	117,698,282	115,465,913	51,960	3,876,402

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
1	AF	**ALLOCATION FACTOR TABLE**							
2	AF	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**							
3	AF								
4	AF	**CAPACITY RELATED**							
5	AF	Peak-Hour Sendout - delivery	PEAKHOUR_04	124,747	77,879	15,468	29,997	0	1,403
6	AF	**COMMODITY RELATED**							
7	AF	Annual transported gas @mtr - delivery	TRANSPORT_04	2,598,285,838	1,517,910,828	288,213,545	768,279,951	694,743	23,186,772
8	AF	Balancing therms - delivery	BALANCE_04	1,793,060	1,345,110	138,565	309,385	0	0
9	AF	Annual transported gas @mtr - access	TRANSPORT_03	2,598,285,838	1,517,910,828	288,213,545	768,279,951	694,743	23,186,772
10	AF	Annual transported gas @mtr - meters	TRANSPORT_07	2,598,285,838	1,517,910,828	288,213,545	768,279,951	694,743	23,186,772
11	AF	TEFA $ responsibility W/N - delivery	TEFA_04						
12	AF								
13	AF	**BILLING DETERMINANTS**							
14	AF	Number of Customers		1,894,095	1,728,739	145,499	19,809	16	32
15	AF	Transported Gas at Meter (calendar)		2,598,285,838	1,517,910,828	288,213,545	768,279,951	694,743	23,186,772
16	AF								
17	AF								
18	AF	**CUSTOMER RELATED**							
19	AF	G380 services - access	SERVICES_03	1,215,746,207	1,001,946,668	143,090,682	69,881,536	0	827,321
20	AF	Cust Installns LDC G879 - delivery	CINST_04	100	100	0	0	0	0
21	AF	Avg Customer Bills - delivery	CUSTAVG_04	661,048	598,870	50,415	11,719	9	34
22	AF	Avg Customer Bills - cust svs	CUSTAVG_06	661,048	598,870	50,415	11,719	9	34
23	AF	G381 meters - measurement	SMMETERS_07	95,373,410	63,566,590	22,045,940	9,760,574	0	306
24	AF								
25	AF	Billing Function costs - cust svs	BILLING_06	20,835,825	16,641,744	1,688,285	1,648,379	1,464	855,952
26	AF	Competitive Service work - delivery	COMPSVSWK_04	100	100	0	0	0	0
27	AF								
28	AF	Account Maint - cust svs	ACCTMAINT_06	67,192,728	60,880,342	5,167,551	1,014,774	411	129,650
29	AF	G382 meter install - measurement	MTRINSTAL_07	149,490,256	136,288,569	11,955,000	1,246,610	0	78
30	AF	G383 house regulators - access	HOUSEREG_03	27,726,351	23,488,422	2,877,517	1,358,260	0	2,151
31	AF	G384 house reg install - access	HSEREGINST_03	49,550,462	45,273,401	3,573,995	702,709	0	356
32	AF	G385 lrg regulators - access	LRGREG_03	42,370,365	527,983	950,933	40,715,751	0	175,698
33	AF	G385 lrg mtrs - measurement	LRGMTR_07	6,790,868	0	5,728,862	886,308	0	175,698
34	AF	G380 services - reserve - access	SERVICESR_03	302,262,539	252,625,678	34,242,308	15,042,822	0	351,731
35	AF	G381 meters - reserve - measurement	SMMETERSR_07	39,637,552	26,782,366	8,862,287	3,992,767	0	131
36	AF	G382 meter install - reserve -measurement	MTRINSTALR_07	70,947,597	65,486,599	4,964,044	496,929	0	24
37	AF	G383 house regulators - reserve - access	HOUSEREGR_03	4,745,170	3,992,277	503,093	248,837	0	963
38	AF	G384 house reg install - reserve - access	HSEREGINSTR_03	9,880,504	9,043,509	697,932	138,864	0	198
39	AF	G385 lrg regulators - reserve - access	LRGREGR_03	6,940,251	13,538	164,305	6,702,764	0	59,644
40	AF	G385 lrg mtrs - reserve - measurement	LRGMTRR_07	1,112,795	0	940,755	112,396	0	59,644
41	AF	Direct LVG - delivery	DIRLVG_04	0	0	0	0	0	0
42	AF	Direct LVG - cust svs	DIRLVG_06	0	0	0	0	0	0
43	**AF**	**ALLOCATION FACTOR TABLE**							
44	**AF**	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**							

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				(1)	(2)	(3)	(4)	(5)	(6)
45	AF								
46	AF	Direct SLG - streetlights	DIRSLG_05	1	0	0	0	1	0
47	AF	Meter Reading Costs - measurement	MRCOST_07	16,284,753	14,755,434	1,241,888	287,431	0	0
48	AF	Other Utility work by Cust Ops - delivery	UTILWORK_04	6,776,917	5,374,648	991,409	409,204	176	1,480
49	AF	Direct SLG - access	DIRSLG_03	1	0	0	0	1	0
50	AF	Direct Competitive Services - delivery	DIRCOMPSVS_04	0	0	0	0	0	0
51	AF	Direct TSG-F - access	DIRTSGF_03	0	0	0	0	0	0
52	AF	Direct TSG-F - delivery	DIRTSGF_04	0	0	0	0	0	0
53	AF	Direct TSG-F - measurement	DIRTSGF_07	0	0	0	0	0	0
54	AF	Direct - RSG - delivery	DIRRSG_04	0	0	0	0	0	0
55	AF	Choice - delivery	CHOICE_04	1,894,095	1,728,739	145,499	19,809	16	32
56	AF								
57	AF								
58	AF	Dummy allocator for unused lines	not_used	0	0	0	0	0	0
59	AF								
60	AF								
61	AF	**Plant Related**							
62	AF	Acct G301-G303 Intangible Plt	INTANGPLT	0	0	0	0	0	0
63	AF	Acct G399.10-23 Oth Tangible Plt	TANGPLT	16,791,854	14,306,794	1,416,896	787,996	597	279,572
64	AF	Production Plant Total	PRODPLT	52,043,670	39,041,892	4,021,862	8,979,916	0	0
65	AF	Storage Plant Total	STORPLT	19,575,233	14,684,863	1,512,747	3,377,624	0	0
66	AF	Transmission Plant Total	TRANPLT	103,544,395	64,642,269	12,838,857	24,898,729	0	1,164,539
67	AF	Distribution Plant Total	DISTPLT	10,498,076,770	7,637,637,323	1,354,227,179	1,451,856,664	1,538,485	52,817,119
68	AF	G391-G398 General Plant	GENPLT	200,812,197	147,554,738	23,925,192	28,267,180	31,216	1,033,872
69	AF	Common Plant	COMPLT	102,234,955	84,260,302	9,479,747	7,064,405	6,518	1,423,983
70	AF	Accts C389-C399, G391-E398 Com & Gen Plt	COMGENPLT	303,047,153	231,815,040	33,404,939	35,331,585	37,734	2,457,855
71	AF	Total Prod, Storage, Transmission, & Dist Plant	PSTDPLT	10,673,240,067	7,756,006,347	1,372,600,645	1,489,112,933	1,538,485	53,981,658
72	AF	Total Plant	TOTPLT	10,993,079,074	8,002,128,180	1,407,422,480	1,525,232,514	1,576,816	56,719,085
73	AF								
74	AF	Distribution Plant x Meters & Installs	DISTPLTXMTR	9,895,589,959	7,271,177,742	1,178,981,626	1,392,945,368	1,538,245	50,946,978
75	AF	Acct G374-375 - Land & Structures	PLT_3745	96,512,525	70,215,496	12,449,888	13,347,431	14,144	485,566
76	AF	Acct G376 - Mains	PLT_376	3,775,184,891	2,356,717,833	468,062,797	907,951,391	747	42,452,124
77	AF	Acct G377 - Compressor Station Equip	PLT_377	0	0	0	0	0	0
78	AF	Acct G378-379 - Meas & Regul Station Equip	PLT_3789	285,986,290	178,539,869	35,460,510	68,769,490	0	3,216,420
79	AF	Acct G380 & 387.2 - Services	SERVICES	5,447,689,486	4,488,006,097	641,086,199	314,336,599	511,168	3,749,423
80	AF	Acct G376, G380 & 387.2 - Mains & Services	MAIN_SERV	9,222,874,377	6,844,723,929	1,109,148,995	1,222,287,991	511,915	46,201,547
81	AF	Acct G381 - House Meters	PLT_381	477,048,047	317,953,337	110,271,175	48,821,975	1	1,559
82	AF	Acct G382 - Meter Installations	PLT_382	52,631,537	47,983,374	4,209,056	439,073	0	33
83	AF	Acct G381,382, & 385 - Meters	METERPLT	602,486,811	366,459,581	175,245,553	58,911,296	240	1,870,140
84	AF	Acct G381-384 - Meters & House Regulators	PLT_3814	680,862,120	501,504,659	126,603,602	52,748,351	4	5,504
85	AF	Acct G382-384 - House Reg & Install & Meter Install	PLT_3824	203,814,074	183,551,322	16,332,427	3,926,376	4	3,945
86	AF	Acct G383-384 - House Reg & Installation	PLT_3834	151,182,537	135,567,948	12,123,371	3,487,303	3	3,912
87	**AF**	**ALLOCATION FACTOR TABLE CONTINUED**							
88	**AF**	**INTERNALLY DEVELOPED ALLOCATION FACTORS**							

PUBLIC SERVICE ELECTRIC & GAS COMPANY
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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
89	AF								
90	AF	Acct G385 - Ind & Com Meas & Regul Station Equip	PLT_385	145,614,455	1,941,847	62,478,553	79,018,841	479	2,174,735
91	AF	Acct G386 - Other Property on Cust Premises	PLT_386	0	0	0	0	0	0
92	AF	Acct G387.1 - Other Equipment (St Ltg Posts)	PLT_387_1	1,011,930	0	0	0	1,011,930	0
93	AF								
94	AF	Total Distribution Plant Reserve	TOTDRESERVE	2,718,471,978	1,987,170,038	327,714,788	387,006,388	19,576	16,561,188
95	AF	Total Net Plant	TOTPLTNET	8,274,607,096	6,014,958,143	1,079,707,691	1,138,226,125	1,557,240	40,157,897
96	AF								
97	AF								
98	AF	**Revenue Related**							
99	AF	Total Operating Revenue	TOTREV	1,469,037,356	1,075,112,184	185,345,543	199,798,009	476,671	8,304,949
100	AF	Intra Dept Rev Req - 5.62% GS / 94.38% LV	INTRAREV	194,617,062	0	10,213,580	184,403,482	0	0
101	AF								
102	AF								
103	AF	**Expense Related**							
104	AF	Manufactured Gas O&M Excl Fuel Expense	MFGO_M	2,114,238	1,586,050	163,385	364,803	0	0
105	AF	Other Storage Plant O&M Expense	STOREXP	2,714,605	2,036,430	209,781	468,394	0	0
106	AF	Transmission Plant O&M Expense	TRANEXP	2,593,507	1,619,114	321,579	623,646	0	29,169
107	AF	Acct 813-Other Gas Supply Expense	EXP_813	72	42	8	21	0	1
108	AF	Acct 871 - Distribution Load Dispatching	EXP_871	5,839,316	3,411,311	647,723	1,726,611	1,561	52,109
109	AF	Acct 872 - Compressor Station Labor & Expenses	EXP_872	0	0	0	0	0	0
110	AF	Acct 874-Mains & Services Expenses	EXP_874	20,733,577	15,387,352	2,493,434	2,747,777	1,151	103,864
111	AF	Acct 875-877 - Meas & Regulating Station Exp	EXP_8757	3,019,152	1,884,842	374,356	725,998	0	33,956
112	AF	Acct 878 - Meter & House Regulator Expenses	EXP_878	11,492,061	8,464,742	2,136,903	890,323	0	93
113	AF	Acct 879 - Customer Installation Expenses	EXP_879	17,355,157	17,355,157	0	0	0	0
114	AF	Acct 880.0,.1,.2 - Other Expenses	EXP_8801	14,050,188	11,236,945	1,355,188	1,413,289	593	44,173
115	AF	Acct 880.3 - Operation of Street Lighting Exp	EXP_8803	0	0	0	0	0	0
116	AF	Acct 881 - Rents	EXP_881	-1,088,602	-635,958	-120,753	-321,886	-291	-9,715
117	AF	Acct 886-Maint of Structures & Improvements Exp	EXP_886	8,016,449	5,832,185	1,034,103	1,108,654	1,175	40,332
118	AF	Acct 887-Maint of Mains Exp	EXP_887	8,706,285	5,435,034	1,079,441	2,093,906	2	97,903
119	AF	Acct 888-Maint of Compressor Station Equip Exp	EXP_888	0	0	0	0	0	0
120	AF	Acct 889-891 - Main of Meas & Reg Station Equip	EXP_8891	4,163,462	2,599,229	516,243	1,001,164	0	46,825
121	AF	Acct 892-Main of Services Exp	EXP_892	3,610,466	2,974,434	424,881	208,327	339	2,485
122	AF	Acct 893-Maint of Meters & House Regulators Exp	EXP_893	6,767,990	4,510,880	1,564,448	692,640	0	22
123	AF	Acct 894-Maint of Other Equipment	EXP_894	207,897	6,456	1,397	1,543	198,445	57
124	AF								
125	AF	Distr Oper Exp	DISTEXPO	71,400,849	57,104,391	6,886,851	7,182,113	3,014	224,480
126	AF	Distr Maint Exp	DISTEXPM	31,472,549	21,358,219	4,620,512	5,106,235	199,960	187,623
127	AF	Cust Serv & Info Expense	CUSTS_I	4,034,218	3,357,834	490,597	180,904	79	4,804
128	AF	Acct 901-903,905 Cust Acct Exp Excl 904	CACCTEXP	72,712,827	62,301,980	5,905,031	3,203,904	2,373	1,299,538
129	AF	Accts 901-910 Excl 904 - Cust Accts,Serv & Info	CUSTSVSX	76,747,044	65,659,814	6,395,628	3,384,808	2,452	1,304,342
130	AF	Sales Expense	SALESEXP	88,423	70,127	12,936	5,339	2	19
131	**AF**	**ALLOCATION FACTOR TABLE CONTINUED**							
132	**AF**	**INTERNALLY DEVELOPED ALLOCATION FACTORS**							

PUBLIC SERVICE ELECTRIC & GAS COMPANY
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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
133	AF								
134	AF	Total O&M Expense Excl A&G Expense	TOTOMXAG	242,970,637	190,666,402	24,292,056	25,908,750	205,429	1,898,001
135	AF	Total O&M Expense Excl 904 Expense	TOTOMX904	255,675,994	194,775,471	26,612,211	31,766,568	269,194	2,252,549
136	AF	Total O&M Expense Excl Fuel & 904 Expense	TOMXFUEL904	223,769,120	170,839,713	24,146,493	26,261,172	269,194	2,252,549
137	AF	Tot Admin & Genl Exp xPension/Ben	AGEXP	38,752,071	22,991,576	5,699,198	9,490,616	63,765	506,916
138	AF	Accts 901-905 Cust Accts Exp Excl 904-Uncol	CUSTACCTS	72,712,827	62,301,980	5,905,031	3,203,904	2,373	1,299,538
139	AF	O&M + Capital Additions	EXPENDITURES	1,177,832,467	872,675,179	147,689,537	150,865,279	321,154	6,281,319
140	AF								
141	AF	Depreciation Expense (total)	DEPREXP	203,691,216	148,803,241	25,897,310	27,869,800	29,232	1,091,633
142	AF								
143	AF	NJ State Income Tax (CBT)	STATEINCTAX	77,634,124	56,530,606	10,095,876	10,612,856	14,966	379,821
144	AF	NJ State Deferred Income Tax	DFSTATEINCTAX	-39,443,958	-33,702,109	-2,821,100	-2,636,714	-19,501	-264,534
145	AF								
146	AF	**Labor Expense Related**							
147	AF	Total Distribution Exp (Oper) Labor	TLABDO	97,081,101	87,685,453	4,492,758	4,756,545	2,226	144,119
148	AF	Total Distribution Exp (Maint) Labor	TLABDM	14,888,885	9,994,812	2,369,978	2,374,703	68,211	81,181
149	AF	Total Labor	LABOR	168,715,063	144,155,248	12,066,791	11,278,114	83,412	1,131,499
150	AF								
151	AF	**REVENUES AND BILLING DETERMINANTS**							
152	AF								
153	AF	Base Rate Sales Revenue	SALESREV	1,401,350,320	1,015,564,742	181,736,301	195,384,067	470,352	8,194,858
154	AF								
155	AF	Residential Service Gas	REVRSG	1,015,564,742	1,015,564,742	0	0	0	0
156	AF	General Service Gas	REVGSG	181,736,301	0	181,736,301	0	0	0
157	AF	Large Volume Service Gas	REVLVG	195,384,067	0	0	195,384,067	0	0
158	AF	Street Light Gas	REVSLG	470,352	0	0	0	470,352	0
159	AF	Firm Transportation Gas Service	REVTSGF	8,194,858	0	0	0	0	8,194,858
160	AF								
161	AF								
162	AF	Total Rev Req @ desired ROR	REVREQ	1,401,350,320	1,015,564,742	181,736,301	195,384,067	470,352	8,194,858
163	AF								
164	AF								
165	AF	**PRESENT REVENUES FROM SALES INPUT**							
166	AF								
167	AF	Total Sales of Gas Revenue Requirement		0	0	0	0	0	0
168	AF	Sales of Gas Revenues - Rates		1,101,761	808,939	129,770	150,330	438	12,284
169	AF	Sales of Gas Revenues - Other		0	0	0	0	0	0
170	AF								
171	AF	**RATE OF RETURN**							
172	AF	Rate of Return (Equalized)	CALCULATED	7.55%	7.55%	7.55%	7.55%	7.55%	7.55%

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
1	AP	**ALLOCATION PROPORTIONS TABLE**							
2	AP	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**							
3	AP								
4	AP	**CAPACITY RELATED**							
5	AP	Peak-Hour Sendout - delivery	PEAKHOUR_04	1.000000	0.624295	0.123994	0.240464	0.000000	0.011247
6	AP								
7	AP	**COMMODITY RELATED**							
8	AP	Annual transported gas @mtr - delivery	TRANSPORT_04	1.000000	0.584197	0.110924	0.295687	0.000267	0.008924
9	AP	Balancing therms - delivery	BALANCE_04	1.000000	0.750176	0.077279	0.172546	0.000000	0.000000
10	AP	Annual transported gas @mtr - access	TRANSPORT_03	1.000000	0.584197	0.110924	0.295687	0.000267	0.008924
11	AP	Annual transported gas @mtr - meters	TRANSPORT_07	1.000000	0.584197	0.110924	0.295687	0.000267	0.008924
12	AP	TEFA $ responsibility W/N - delivery	TEFA_04	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
13	AF								
14	AP	**BILLING DETERMINANTS**							
15	AP	Number of Customers		1.000000	0.912699	0.076817	0.010458	0.000008	0.000017
16	AP	Transported Gas at Meter (calendar)		1.000000	0.584197	0.110924	0.295687	0.000267	0.008924
17	AP								
18	AP								
19	AP	**CUSTOMER RELATED**							
20	AP	G380 services - access	SERVICES_03	1.000000	0.824141	0.117698	0.057480	0.000000	0.000681
21	AP	Cust Installns LDC G879 - delivery	CINST_04	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000
22	AP	Avg Customer Bills - delivery	CUSTAVG_04	1.000000	0.905940	0.076266	0.017728	0.000014	0.000052
23	AP	Avg Customer Bills - cust svs	CUSTAVG_06	1.000000	0.905940	0.076266	0.017728	0.000014	0.000052
24	AP	G381 meters - measurement	SMMETERS_07	1.000000	0.666502	0.231154	0.102341	0.000000	0.000003
25	AP								
26	AP	Billing Function costs - cust svs	BILLING_06	1.000000	0.798708	0.081028	0.079113	0.000070	0.041081
27	AP	Competitive Service work - delivery	COMPSVSWK_04	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000
28	AF								
29	AP	Account Maint - cust svs	ACCTMAINT_06	1.000000	0.906056	0.076906	0.015102	0.000006	0.001930
30	AP	G382 meter install - measurement	MTRINSTAL_07	1.000000	0.911689	0.079972	0.008339	0.000000	0.000001
31	AP	G383 house regulators - access	HOUSEREG_03	1.000000	0.847152	0.103783	0.048988	0.000000	0.000078
32	AP	G384 house reg install - access	HSEREGINST_03	1.000000	0.913683	0.072128	0.014182	0.000000	0.000007
33	AP	G385 lrg regulators - access	LRGREG_03	1.000000	0.012461	0.022443	0.960949	0.000000	0.004147
34	AP	G385 lrg mtrs - measurement	LRGMTR_07	1.000000	0.000000	0.843613	0.130515	0.000000	0.025873
35	AP	G380 services - reserve - access	SERVICESR_03	1.000000	0.835782	0.113287	0.049767	0.000000	0.001164
36	AP	G381 meters - reserve - measurement	SMMETERSR_07	1.000000	0.675682	0.223583	0.100732	0.000000	0.000003
37	AP	G382 meter install - reserve -measurement	MTRINSTALR_07	1.000000	0.923028	0.069968	0.007004	0.000000	0.000000
38	AP	G383 house regulators - reserve - access	HOUSEREGR_03	1.000000	0.841335	0.106022	0.052440	0.000000	0.000203
39	AP	G384 house reg install - reserve - access	HSEREGINSTR_03	1.000000	0.915288	0.070637	0.014054	0.000000	0.000020
40	AP	G385 lrg regulators - reserve - access	LRGREGR_03	1.000000	0.001951	0.023674	0.965781	0.000000	0.008594
41	AP	G385 lrg mtrs - reserve - measurement	LRGMTRR_07	1.000000	0.000000	0.845398	0.101003	0.000000	0.053598
42	AP	Direct LVG - delivery	DIRLVG_04	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
43	AP	Direct LVG - cust svs	DIRLVG_06	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
44	**AP**	**ALLOCATION PROPORTIONS TABLE CONTINUED**							

PUBLIC SERVICE ELECTRIC & GAS COMPANY
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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
45	AP	EXTERNALLY DEVELOPED ALLOCATION FACTORS							
46	AP								
47	AP	Direct SLG - streetlights	DIRSLG_05	1.000000	0.000000	0.000000	0.000000	1.000000	0.000000
48	AP	Meter Reading Costs - measurement	MRCOST_07	1.000000	0.906089	0.076261	0.017650	0.000000	0.000000
49	AP	Other Utility work by Cust Ops - delivery	UTILWORK_04	1.000000	0.793082	0.146292	0.060382	0.000026	0.000218
50	AP	Direct SLG - access	DIRSLG_03	1.000000	0.000000	0.000000	0.000000	1.000000	0.000000
51	AP	Direct Competitive Services - delivery	DIRCOMPSVS_04	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
52	AP	Direct TSG-F - access	DIRTSGF_03	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
53	AP	Direct TSG-F - delivery	DIRTSGF_04	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
54	AP	Direct TSG-F - measurement	DIRTSGF_07	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
55	AP	Direct - RSG - delivery	DIRRSG_04	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
56	AP	Choice - delivery	CHOICE_04	1.000000	0.912699	0.076817	0.010458	0.000008	0.000017
57	AP								
58	AP								
59	AP	Dummy allocator for unused lines	not_used	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
60	AP								
61	AP								
62	AP	Plant Related							
63	AP	Acct G301-G303 Intangible Plt	INTANGPLT	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
64	AP	Acct G399.10-23 Oth Tangible Plt	TANGPLT	1.000000	0.852008	0.084380	0.046927	0.000036	0.016649
65	AP	Production Plant Total	PRODPLT	1.000000	0.750176	0.077279	0.172546	0.000000	0.000000
66	AP	Storage Plant Total	STORPLT	1.000000	0.750176	0.077279	0.172546	0.000000	0.000000
67	AP	Transmission Plant Total	TRANPLT	1.000000	0.624295	0.123994	0.240464	0.000000	0.011247
68	AP	Distribution Plant Total	DISTPLT	1.000000	0.727527	0.128998	0.138297	0.000147	0.005031
69	AP	G391-G398 General Plant	GENPLT	1.000000	0.734790	0.119142	0.140764	0.000155	0.005148
70	AP	Common Plant	COMPLT	1.000000	0.824183	0.092725	0.069100	0.000064	0.013929
71	AP	Accts C389-C399, G391-E398 Com & Gen Plt	COMGENPLT	1.000000	0.764947	0.110230	0.116588	0.000125	0.008110
72	AP	Total Prod, Storage, Transmission, & Dist Plant	PSTDPLT	1.000000	0.726678	0.128602	0.139518	0.000144	0.005058
73	AP	Total Plant	TOTPLT	1.000000	0.727924	0.128028	0.138745	0.000143	0.005160
74	AP								
75	AP	Distribution Plant x Meters & Installs	DISTPLTXMTR	1.000000	0.734790	0.119142	0.140764	0.000155	0.005148
76	AP	Acct G374-375 - Land & Structures	PLT_3745	1.000000	0.727527	0.128998	0.138297	0.000147	0.005031
77	AP	Acct G376 - Mains	PLT_376	1.000000	0.624266	0.123984	0.240505	0.000000	0.011245
78	AP	Acct G377 - Compressor Station Equip	PLT_377	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
79	AP	Acct G378-379 - Meas & Regul Station Equip	PLT_3789	1.000000	0.624295	0.123994	0.240464	0.000000	0.011247
80	AP	Acct G380 & 387.2 - Services	SERVICES	1.000000	0.823837	0.117680	0.057701	0.000094	0.000688
81	AP	Acct G376, G380 & 387.2 - Mains & Services	MAIN_SERV	1.000000	0.742146	0.120261	0.132528	0.000056	0.005009
82	AP	Acct G381 - House Meters	PLT_381	1.000000	0.666502	0.231153	0.102342	0.000000	0.000003
83	AP	Acct G382 - Meter Installations	PLT_382	1.000000	0.911685	0.079972	0.008342	0.000000	0.000001
84	AP	Acct G381,382, & 385 - Meters	METERPLT	1.000000	0.608245	0.290870	0.097780	0.000000	0.003104
85	AP	Acct G381-384 - Meters & House Regulators	PLT_3814	1.000000	0.736573	0.185946	0.077473	0.000000	0.000008
86	AP	Acct G382-384 - House Reg & Install & Meter Install	PLT_3824	1.000000	0.900582	0.080134	0.019264	0.000000	0.000019
87	AP	Acct G383-384 - House Reg & Installation	PLT_3834	1.000000	0.896717	0.080190	0.023067	0.000000	0.000026
88	AP	ALLOCATION PROPORTIONS TABLE CONTINUED							

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
89	**AP**	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**							
90	AP								
91	AP	Acct G385 - Ind & Com Meas & Regul Station Equip	PLT_385	1.000000	0.013336	0.429068	0.542658	0.000003	0.014935
92	AP	Acct G386 - Other Property on Cust Premises	PLT_386	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
93	AP	Acct G387.1 - Other Equipment (St Ltg Posts)	PLT_387_1	1.000000	0.000000	0.000000	0.000000	1.000000	0.000000
94	AP								
95	AP	Total Distribution Plant Reserve	TOTDRESERVE	1.000000	0.730988	0.120551	0.142362	0.000007	0.006092
96	AP	Total Net Plant	TOTPLTNET	1.000000	0.726918	0.130484	0.137557	0.000188	0.004853
97	AP								
98	AP								
99	AP	**Revenue Related**							
100	AP	Total Operating Revenue	TOTREV	1.000000	0.731848	0.126168	0.136006	0.000324	0.005653
101	AP	Intra Dept Rev Req - 5.62% GS / 94.38% LV	INTRAREV	1.000000	0.000000	0.052480	0.947520	0.000000	0.000000
102	AP								
103	AP								
104	AP	**Expense Related**							
105	AP	Manufactured Gas O&M Excl Fuel Expense	MFGO_M	1.000000	0.750176	0.077279	0.172546	0.000000	0.000000
106	AP	Other Storage Plant O&M Expense	STOREXP	1.000000	0.750176	0.077279	0.172546	0.000000	0.000000
107	AP	Transmission Plant O&M Expense	TRANEXP	1.000000	0.624295	0.123994	0.240464	0.000000	0.011247
108	AP	Acct 813-Other Gas Supply Expense	EXP_813	1.000000	0.584197	0.110924	0.295687	0.000267	0.008924
109	AP	Acct 871 - Distribution Load Dispatching	EXP_871	1.000000	0.584197	0.110924	0.295687	0.000267	0.008924
110	AP	Acct 872 - Compressor Station Labor & Expenses	EXP_872	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
111	AP	Acct 874-Mains & Services Expenses	EXP_874	1.000000	0.742146	0.120261	0.132528	0.000056	0.005009
112	AP	Acct 875-877 - Meas & Regulating Station Exp	EXP_8757	1.000000	0.624295	0.123994	0.240464	0.000000	0.011247
113	AP	Acct 878 - Meter & House Regulator Expenses	EXP_878	1.000000	0.736573	0.185946	0.077473	0.000000	0.000008
114	AP	Acct 879 - Customer Installation Expenses	EXP_879	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000
115	AP	Acct 880.0,.1,.2 - Other Expenses	EXP_8801	1.000000	0.799772	0.096453	0.100589	0.000042	0.003144
116	AP	Acct 880.3 - Operation of Street Lighting Exp	EXP_8803	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
117	AP	Acct 881 - Rents	EXP_881	1.000000	0.584197	0.110924	0.295687	0.000267	0.008924
118	AP	Acct 886-Maint of Structures & Improvements Exp	EXP_886	1.000000	0.727527	0.128998	0.138297	0.000147	0.005031
119	AP	Acct 887-Maint of Mains Exp	EXP_887	1.000000	0.624266	0.123984	0.240505	0.000000	0.011245
120	AP	Acct 888-Maint of Compressor Station Equip Exp	EXP_888	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
121	AP	Acct 889-891 - Main of Meas & Reg Station Equip	EXP_8891	1.000000	0.624295	0.123994	0.240464	0.000000	0.011247
122	AP	Acct 892-Main of Services Exp	EXP_892	1.000000	0.823837	0.117680	0.057701	0.000094	0.000688
123	AP	Acct 893-Maint of Meters & House Regulators Exp	EXP_893	1.000000	0.666502	0.231154	0.102341	0.000000	0.000003
124	AP	Acct 894-Maint of Other Equipment	EXP_894	1.000000	0.031052	0.006718	0.007424	0.954533	0.000273
125	AP								
126	AP	Distr Oper Exp	DISTEXPO	1.000000	0.799772	0.096453	0.100589	0.000042	0.003144
127	AP	Distr Maint Exp	DISTEXPM	1.000000	0.678630	0.146811	0.162244	0.006353	0.005961
128	AP	Cust Serv & Info Expense	CUSTS_I	1.000000	0.832338	0.121609	0.044842	0.000019	0.001191
129	AP	Acct 901-903,905 Cust Acct Exp Excl 904	CACCTEXP	1.000000	0.856822	0.081210	0.044062	0.000033	0.017872
130	AP	Accts 901-910 Excl 904 - Cust Accts,Serv & Info	CUSTSVSX	1.000000	0.855535	0.083334	0.044103	0.000032	0.016995
131	AP	Sales Expense	SALESEXP	1.000000	0.793082	0.146292	0.060382	0.000026	0.000218
132	AP	Total O&M Expense Excl A&G Expense	TOTOMXAG	1.000000	0.784730	0.099979	0.106633	0.000845	0.007812

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
133	AP	Total O&M Expense Excl 904 Expense	TOTOMX904	1.000000	0.761806	0.104086	0.124245	0.001053	0.008810
134	AP	Total O&M Expense Excl Fuel & 904 Expense	TOMXFUEL904	1.000000	0.763464	0.107908	0.117358	0.001203	0.010066
135	AP	Tot Admin & Genl Exp xPension/Ben	AGEXP	1.000000	0.593299	0.147068	0.244906	0.001645	0.013081
136	AP	Accts 901-905 Cust Accts Exp Excl 904-Uncol	CUSTACCTS	1.000000	0.856822	0.081210	0.044062	0.000033	0.017872
137	AP	O&M + Capital Additions	EXPENDITURES	1.000000	0.740916	0.125391	0.128087	0.000273	0.005333
138	AP								
139	AP	Depreciation Expense (total)	DEPREXP	1.000000	0.730533	0.127140	0.136824	0.000144	0.005359
140	AP								
141	AP	NJ State Income Tax (CBT)	STATEINCTAX	1.000000	0.728167	0.130044	0.136703	0.000193	0.004892
142	AP	NJ State Deferred Income Tax	DFSTATEINCTAX	1.000000	0.854430	0.071522	0.066847	0.000494	0.006707
143	AP								
144	AP	**Labor Expense Related**							
145	AP	Total Distribution Exp (Oper) Labor	TLABDO	1.000000	0.903219	0.046278	0.048996	0.000023	0.001485
146	AP	Total Distribution Exp (Maint) Labor	TLABDM	1.000000	0.671294	0.159178	0.159495	0.004581	0.005452
147	AP	Total Labor	LABOR	1.000000	0.854430	0.071522	0.066847	0.000494	0.006707
148	AP								
149	AP	**REVENUES AND BILLING DETERMINANTS**							
150	AP								
151	AP	Base Rate Sales Revenue	SALESREV	1.000000	0.724704	0.129687	0.139426	0.000336	0.005848
152	AP								
153	AP	Residential Service Gas	REVRSG	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000
154	AP	General Service Gas	REVGSG	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
155	AP	Large Volume Service Gas	REVLVG	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000
156	AP	Street Light Gas	REVSLG	1.000000	0.000000	0.000000	0.000000	1.000000	0.000000
157	AP	Firm Transportation Gas Service	REVTSGF	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000
158	AP								
159	AP	Total Rev Req @ desired ROR	REVREQ	1.000000	0.724704	0.129687	0.139426	0.000336	0.005848
160	AP								
161	AP	**PRESENT REVENUES FROM SALES INPUT**							
162	AP	Total Sales of Gas Revenue Requirement		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
163	AP	Sales of Gas Revenues - Rates		1.000000	0.734224	0.117784	0.136445	0.000397	0.011149
164	AP	Sales of Gas Revenues - Other		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
1	ADA	**ALLOCATED DIRECT ASSIGNMENTS**							
2	ADA	**DIRECT ASSIGN TO CLASSES W/SALES REV FUNCTIONS**							
3	ADA								
4	ADA	**Account 904 - Uncollectible Accounts**							
5	ADA	Residential Service Gas	REVRSG	1,015,564,742	1,015,564,742	0	0	0	0
6	ADA	General Service Gas	REVGSG	181,736,301	0	181,736,301	0	0	0
7	ADA	Large Volume Service Gas	REVLVG	195,384,067	0	0	195,384,067	0	0
8	ADA	Street Light Gas	REVSLG	0	0	0	0	0	0
9	ADA	Firm Transportation Gas Service	REVTSGF	8,194,858	0	0	0	0	8,194,858
10	ADA								
11	ADA	Total 904-Uncollectible	EXP_904	1,400,879,968	1,015,564,742	181,736,301	195,384,067	0	8,194,858
12	ADA								
13	ADA	Total 904-Uncollectible	EXP_904	1.000000	0.724948	0.129730	0.139472	0.0	0.005850
14	ADA								
15	ADA	Additional Net Write-Offs at Claimed Rate	EXP_904	0	0	0	0	0	0
16	ADA								
17	ADA	**Rev Req (cal) to Customers Late Payment fees**							
18	ADA	Residential Service Gas	REVRSG	0	0	0	0	0	0
19	ADA	General Service Gas	REVGSG	181,736,301	0	181,736,301	0	0	0
20	ADA	Large Volume Service Gas	REVLVG	195,384,067	0	0	195,384,067	0	0
21	ADA	Street Light Gas	REVSLG	0	0	0	0	0	0
22	ADA	Firm Transportation Gas Service	REVTSGF	0	0	0	0	0	0
23	ADA								
24	ADA	Total Late Payment Fees	REVLATEP	377,120,368	0	181,736,301	195,384,067	0	0
25	ADA								
26	ADA	Total Late Payment Fees	REVLATEP	1.000000	0.0	0.481905	0.518095	0.0	0.0
27	ADA								
28	ADA	**ALLOCATED DIRECT ASSIGNMENTS**							
29	ADA	**DIRECT ASSIGN TO CLASSES W/SALES REV FUNCTIONS**							
30	ADA								
31	ADA	**AVAILABLE**							
32	ADA	Residential Service Gas	REVRSG	0	0	0	0	0	0
33	ADA	General Service Gas	REVGSG	0	0	0	0	0	0
34	ADA	Large Volume Service Gas	REVLVG	0	0	0	0	0	0
35	ADA	Street Light Gas	REVSLG	0	0	0	0	0	0
36	ADA	Firm Transportation Gas Service	REVTSGF	0	0	0	0	0	0
37	ADA								
38	ADA	Total Available	REVAVAIL	0	0	0	0	0	0
39	ADA								
40	ADA	Total Available	REVAVAIL	0.0	0.0	0.0	0.0	0.0	0.0

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				(1)	(2)	(3)	(4)	(5)	(6)
1	RRW	**REVENUE REQUIREMENTS**							
2	RRW								
3	RRW	PRESENT RATES							
4	RRW	--							
5	RRW	RATE BASE		8,681,618,581	6,317,597,079	1,132,508,397	1,187,690,081	1,705,842	42,117,183
6	RRW	NET OPER INC (PRESENT RATES)		655,462,203	476,978,579	85,504,384	89,670,601	128,791	3,179,847
7	RRW	RATE OF RETURN (PRES RATES)		7.55%	7.55%	7.55%	7.55%	7.55%	7.55%
8	RRW	RELATIVE RATE OF RETURN		1.00	1.00	1.00	1.00	1.00	1.00
9	RRW	SALES REVENUE (PRE RATES)		1,401,350,320	1,015,564,742	181,736,301	195,384,067	470,352	8,194,858
10	RRW	REVENUE PRES RATES $/THERM		$0.5393	$0.6691	$0.6306	$0.2543	$0.6770	$0.3534
11	RRW	REVENUE REQUIRED - $/MO/CUST		$61.65	$48.95	$104.09	$821.95	$2,449.75	$21,340.78
12	RRW								
13	RRW								
14	RRW	CLAIMED RATE OF RETURN							
15	RRW	--							
16	RRW	CLAIMED RATE OF RETURN		7.55%	7.55%	7.55%	7.55%	7.55%	7.55%
17	RRW	RETURN REQ FOR CLAIMED ROR		655,462,203	476,978,579	85,504,384	89,670,601	128,791	3,179,847
18	RRW	SALES REVENUE REQ CLAIMED ROR		1,401,350,320	1,015,564,742	181,736,301	195,384,067	470,352	8,194,858
19	RRW	REVENUE DEFICIENCY SALES REV		0	0	0	0	0	0
20	RRW	PERCENT INCREASE REQUIRED		0.0	0.0	0.0	0.0	0.0	0.0
21	RRW	ANNUAL BOOKED THERM SALES		2,598,285,838	1,517,910,828	288,213,545	768,279,951	694,743	23,186,772
22	RRW	SALES REV REQUIRED $/THERM		$0.5393	$0.6691	$0.6306	$0.2543	$0.6770	$0.3534
23	RRW	REVENUE DEFICIENCY $/THERM		0.0	0.0	0.0	0.0	0.0	0.0

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
1	S	**SUMMARY OF RESULTS**							
2	S	**DEVELOPMENT OF RETURN**							
3	S								
4	S	**RATE BASE**							
5	S	Plant in Service							
6	S	Production Plant 304-320	CALCULATED	52,043,670	0	52,043,670	0	0	0
7	S	Storage Plant 360-363	CALCULATED	19,575,233	0	19,575,233	0	0	0
8	S	Transmission Plant 365-371	CALCULATED	103,544,395	0	103,544,395	0	0	0
9	S	Distribution Plant							
10	S	Land & Structures 374-375	CALCULATED	96,512,525	52,625,554	38,287,314	9,389	0	5,590,267
11	S	Mains 376	CALCULATED	3,775,184,891	0	3,775,184,891	0	0	0
12	S	Compressor Station Equipment 377	CALCULATED	0	0	0	0	0	0
13	S	Meas & Regulating Station Equip 378-379	CALCULATED	285,986,290	0	285,986,290	0	0	0
14	S	Services 380	CALCULATED	5,447,179,699	5,447,179,699	0	0	0	0
15	S	Meters 381	CALCULATED	477,048,047	0	0	0	0	477,048,047
16	S	Meter Installations 382	CALCULATED	52,631,537	0	0	0	0	52,631,537
17	S	House Regulators & Install 383-384	CALCULATED	151,182,537	151,182,537	0	0	0	0
18	S	Industrial Meas & Reg Station Equip 385	CALCULATED	145,614,455	72,807,227	0	0	0	72,807,227
19	S	Other Property on Cust Premises 386	CALCULATED	0	0	0	0	0	0
20	S	Other Equipment (Street Lighting) 387	CALCULATED	1,521,717	509,787	0	1,011,930	0	0
21	S	Asset Retirement Obligation 388	CALCULATED	65,215,073	0	65,215,073	0	0	0
22	S	Total Distribution Plant	CALCULATED	10,498,076,770	5,724,304,805	4,164,673,568	1,021,319	0	608,077,078
23	S	General Plant E389-E399	CALCULATED	200,812,197	116,163,890	84,514,137	20,726	0	113,444
24	S	Common Plant C389-C399	CALCULATED	102,234,955	15,246,506	16,357,253	2,720	57,691,885	12,936,591
25	S	Intangible Plant E301-E303, E399, C303-C390	CALCULATED	16,791,854	283,770	1,334,206	51	12,410,339	2,763,489
26	S	Total Plant in Service	CALCULATED	10,993,079,074	5,855,998,970	4,442,042,462	1,044,816	70,102,224	623,890,602
27	S								
28	S	Less: Reserve for Depreciation and Amorization	CALCULATED	2,718,471,978	1,288,707,941	1,277,621,837	11,318	36,625,623	115,505,260
29	S								
30	S	Plus: Rate Base Additions							
31	S	Working Capital	CALCULATED	645,513,843	318,693,200	236,499,683	135,294	35,561,075	54,624,592
32	S	Capital Stimulas Adjust (Pro Forma #13)	CALCULATED	0	0	0	0	0	0
33	S	Capital Lease Plt & Reserve Deduct	CALCULATED	96,280	51,288	38,905	9	614	5,464
34	S	Other Rate Base Additions		1,727,003,584	942,713,147	682,925,226	172,250	620,711	100,572,249
35	S	Plus: Rate Base Deductions							
36	S	Customer Advances	CALCULATED	-24,909,672	-14,713,434	-10,196,237	0	0	0
37	S	Unbilled Revenue	CALCULATED	-256,132,009	-136,441,189	-103,496,869	-24,344	-1,633,339	-14,536,269
38	S	Deferred Income Taxes and Credits	CALCULATED	-1,684,560,542	-896,261,680	-681,949,929	-159,773	-10,723,857	-95,465,303
39	S								
40	S	Other Rate Base Deductions							
41	S	TOTAL RATE BASE		8,681,618,581	4,781,332,362	3,288,241,403	1,156,935	57,301,806	553,586,075
42	S								
43	S								
44	S	**SUMMARY OF RESULTS**							

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
45	S	**DEVELOPMENT OF RETURN**							
46	S								
47	S	**RATE BASE**	CALCULATED	8,681,618,581	4,781,332,362	3,288,241,403	1,156,935	57,301,806	553,586,075
48	S								
49	S	**OPERATING REVENUES**							
50	S	Rate Revenues from Customers	CALCULATED	1,401,350,320	694,814,985	519,849,840	388,577	77,033,143	109,263,775
51	S	Other Operating Revenues	CALCULATED	67,687,036	9,836,184	55,161,661	5,220	1,073,038	1,610,932
52	S	Revenues from Other Sources	CALCULATED	0	0	0	0	0	0
53	S	Less: Provisions for Rate Refunds	CALCULATED	0	0	0	0	0	0
54	S	TOTAL OPERATING REVENUES		1,469,037,356	704,651,169	575,011,501	393,797	78,106,181	110,874,707
55	S								
56	S	**OPERATING EXPENSES**							
57	S	Operation and Maintenance Expense							
58	S	Gas Production and Supply Expense	CALCULATED	31,906,945	0	31,906,945	0	0	0
59	S	Storage Expense	CALCULATED	2,714,605	0	2,714,605	0	0	0
60	S	Transmission Expense	CALCULATED	2,593,507	0	2,593,507	0	0	0
61	S	Distribution Expense	CALCULATED	102,873,398	26,407,965	57,901,140	199,225	0	18,365,069
62	S	Customer Accounts Expense	CALCULATED	98,759,541	12,917,426	12,378,126	0	58,423,147	15,040,841
63	S	Customer Service & Information Expense	CALCULATED	4,034,218	0	2,596,868	0	1,437,350	0
64	S	Sales Expense	CALCULATED	88,423	0	88,423	0	0	0
65	S	Administrative and General Expense	CALCULATED	38,752,071	6,447,431	14,708,128	58,280	11,599,521	5,938,711
66	S	Total Operation and Maintenance Expense	CALCULATED	281,722,708	45,772,822	124,887,742	257,504	71,460,018	39,344,621
67	S	Depreciation Expense	CALCULATED	203,691,216	108,184,098	80,336,675	19,302	3,717,640	11,433,501
68	S	Amortization Expense	CALCULATED	2,351,634	614,823	529,938	110	909,279	297,484
69	S	Taxes Other Than Income Taxes	CALCULATED	-24,480,722	-8,227,412	-11,490,393	-6,368	-2,580,832	-2,175,717
70	S	Proforma Expense Adjustments	CALCULATED	100,619,236	46,198,643	42,567,781	15,589	5,064,367	6,772,855
71	S	State Income Taxes	CALCULATED	77,634,124	42,515,895	29,577,648	10,186	599,441	4,930,955
72	S	Federal Income Taxes	CALCULATED	143,331,440	78,828,704	54,187,539	19,587	1,041,476	9,254,135
73	S	Provision for Deferred Income Taxes	CALCULATED	28,705,516	29,773,002	6,152,346	-9,462	-6,431,494	-778,876
74	S	Income Taxes Deferred in Prior Years	CALCULATED	0	0	0	0	0	0
75	S	Investment Tax Credit Adjustement (Net)	CALCULATED	0	0	0	0	0	0
76	S	TOTAL OPERATING EXPENSES		813,575,153	343,660,576	326,749,276	306,449	73,779,895	69,078,958
77	S								
78	S	**OPERATING INCOME (RETURN)**		655,462,203	360,990,593	248,262,226	87,349	4,326,286	41,795,749
79	S	Plus Operating Income Adjustment	CALCULATED						
80	S	TOTAL NET OPERATING INCOME		655,462,203	360,990,593	248,262,226	87,349	4,326,286	41,795,749
81	S								
82	S	**RATE OF RETURN ON RATE BASE (PRESENT)**		7.55%	7.55%	7.55%	7.55%	7.55%	7.55%
83	S	**INDEX RATE OF RETURN (PRESENT)**		1.00	1.00	1.00	1.00	1.00	1.00
84	S								
85	S								
86	S	**EQUALIZED RETURN AT PROPOSED ROR**							
87	S	**DEVELOPMENT OF RETURN (EQUALIZED RATE LEVELS)**							
88	S								

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
89	S	**RATE BASE**	CALCULATED	8,681,618,581	4,781,332,362	3,288,241,403	1,156,935	57,301,806	553,586,075
90	S								
91	S	**RATE OF RETURN**		7.55%	7.55%	7.55%	7.55%	7.55%	7.55%
92	S								
93	S	**RETURN (RATE BASE * 7.40% ROR)**		655,462,203	360,990,593	248,262,226	87,349	4,326,286	41,795,749
94	S								
95	S	**PLUS:**							
96	S	**OPERATING EXPENSES**							
97	S	Total Operation and Maintenance Expense	CALCULATED	281,722,708	45,772,822	124,887,742	257,504	71,460,018	39,344,621
98	S	Depreciation Expense	CALCULATED	203,691,216	108,184,098	80,336,675	19,302	3,717,640	11,433,501
99	S	Amortization Expense	CALCULATED	2,351,634	614,823	529,938	110	909,279	297,484
100	S	Taxes Other Than Income Taxes	CALCULATED	-24,480,722	-8,227,412	-11,490,393	-6,368	-2,580,832	-2,175,717
101	S	Proforma Expense Adjustments	CALCULATED	100,619,236	46,198,643	42,567,781	15,589	5,064,367	6,772,855
102	S	Income Taxes	CALCULATED	220,965,564	121,344,599	83,765,187	29,773	1,640,917	14,185,089
103	S	Provision for Deferred Income Taxes	CALCULATED	28,705,516	29,773,002	6,152,346	-9,462	-6,431,494	-778,876
104	S	Income Taxes Deferred in Prior Years	CALCULATED	0	0	0	0	0	0
105	S	Investment Tax Credit Adjustement (Net)	CALCULATED						
106	S	**TOTAL OPERATING EXPENSES**		813,575,153	343,660,576	326,749,276	306,449	73,779,895	69,078,958
107	S								
108	S	**EQUALS TOTAL COST OF SERVICE**		1,469,037,356	704,651,169	575,011,501	393,797	78,106,181	110,874,707
109	S								
110	S	**LESS:**							
111	S	Other Operating Revenues	CALCULATED	67,687,036	9,836,184	55,161,661	5,220	1,073,038	1,610,932
112	S	Revenues from Other Sources	CALCULATED	0	0	0	0	0	0
113	S	Plus: Provisions for Rate Refunds	CALCULATED	0	0	0	0	0	0
114	S	**EQUALS:**							
115	S	**BASE RATE SALES @ EQUALIZED ROR 7.40%**		1,401,350,320	694,814,985	519,849,840	388,577	77,033,143	109,263,775
116	S								
117	S	**TOTAL COST OF SERVICE INCREASE/DECREASE**		0	0	0	0	0	0
118	S	**REVENUE INCREASE TO RETAIL REVENUES (%)**		0.00	0.00	0.00	0.00	0.00	0.00

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12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
1	RBP	**DEVELOPMENT OF RATE BASE**							
2	RBP								
3	RBP	**GAS PLANT IN SERVICE**							
4	RBP								
5	RBP	INTANGIBLE PLANT - G301-G303							
6	RBP	General - AWMS & Misc.	TOTPLT	0	0	0	0	0	0
7	RBP	Choice Progect	not_used	0	0	0	0	0	0
8	RBP	GSMIS - meter related	not_used	0	0	0	0	0	0
9	RBP	- regulator related	not_used	0	0	0	0	0	0
10	RBP	- appliance safety related	not_used	0	0	0	0	0	0
11	RBP	- Comp Svs related	not_used	0	0	0	0	0	0
12	RBP	- Cust Svs related	not_used	0	0	0	0	0	0
13	RBP	TOTAL INTANGIBLE PLANT		0	0	0	0	0	0
14	RBP								
15	RBP	C303 - INTANGIBLE PLANT - CUST SERVICE							
16	RBP	Customer Service	CUSTSVSX	16,301,302	0	1,127,751	0	12,410,339	2,763,212
17	RBP	Measurement	MRCOST_07	0	0	0	0	0	0
18	RBP	Not Used	not_used	0	0	0	0	0	0
19	RBP	G399.1 Asset Retirement Costs of General Plt	GENPLT	490,552	283,770	206,454	51	0	277
20	RBP	Not Used	not_used	0	0	0	0	0	0
21	RBP	TOTAL ACCOUNTS C303-C390.4,G399		16,791,854	283,770	1,334,206	51	12,410,339	2,763,489
22	RBP								
23	RBP	TOTAL INTANGIBLE PLANT		16,791,854	283,770	1,334,206	51	12,410,339	2,763,489
24	RBP								
25	RBP	PRODUCTION PLANT							
26	RBP	G304-G320 - All Land & Equipment	BALANCE_04	52,043,670	0	52,043,670	0	0	0
27	RBP	Not Used	not_used	0	0	0	0	0	0
28	RBP	TOTAL PRODUCTION PLANT		52,043,670	0	52,043,670	0	0	0
29	RBP								
30	RBP	STORAGE PLANT							
31	RBP	G360-G363 - All Land & Equipment	BALANCE_04	19,575,233	0	19,575,233	0	0	0
32	RBP	Not Used	not_used	0	0	0	0	0	0
33	RBP	TOTAL STORAGE PLANT		19,575,233	0	19,575,233	0	0	0
34	RBP								
35	RBP	TRANSMISSION PLANT							
36	RBP	G365 Land & Land Rights	PEAKHOUR_04	5,421,128	0	5,421,128	0	0	0
37	RBP	G366 Structures & Improvements	PEAKHOUR_04	0	0	0	0	0	0
38	RBP	G367 Mains	PEAKHOUR_04	93,786,847	0	93,786,847	0	0	0
39	RBP	G369 Meas. & Reg. Station Equipment	PEAKHOUR_04	4,336,420		4,336,420			
40	RBP	TOTAL TRANSMISSION PLANT		103,544,395	0	103,544,395	0	0	0
41	RBP								
42	RBP								
43	RBP								
44	RBP	**GAS PLANT IN SERVICE CONTINUED**							

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
45	RBP								
46	RBP	DISTRIBUTION PLANT							
47	RBP	G374-G375 Land & Structures							
48	RBP	General	DISTPLT	96,512,525	52,625,554	38,287,314	9,389	0	5,590,267
49	RBP	Not Used	not_used	0	0	0	0	0	0
50	RBP	Total Accounts G374-G375		96,512,525	52,625,554	38,287,314	9,389	0	5,590,267
51	RBP								
52	RBP	G376 Mains							
53	RBP	Firm Allocation	PEAKHOUR_04	3,772,391,917	0	3,772,391,917	0	0	0
54	RBP	CIG, TSG-NF & CSG Redistribution	TRANSPORT_04	2,792,974	0	2,792,974	0	0	0
55	RBP	Not Used	not_used	0	0	0	0	0	0
56	RBP	Total Account G376		3,775,184,891	0	3,775,184,891	0	0	0
57	RBP								
58	RBP	G377 Compressor Station Equip	DISTPLTXMTR	0	0	0	0	0	0
59	RBP								
60	RBP	G378-G379 Meas & Regulatory Equipment							
61	RBP	Firm Investment	PEAKHOUR_04	285,986,290	0	285,986,290	0	0	0
62	RBP	Not Used	not_used	0	0	0	0	0	0
63	RBP	Total Account G378-G379		285,986,290	0	285,986,290	0	0	0
64	RBP								
65	RBP	G380 Services							
66	RBP	Firm Allocation	SERVICES_03	5,442,013,091	5,442,013,091	0	0	0	0
67	RBP	CIG, TSG-NF & CSG Redistribution	TRANSPORT_03	5,166,608	5,166,608	0	0	0	0
68	RBP	Not Used	not_used	0	0	0	0	0	0
69	RBP	Total Account G380		5,447,179,699	5,447,179,699	0	0	0	0
70	RBP								
71	RBP	G381 Meters							
72	RBP	Firm Allocation	SMMETERS_07	477,045,042	0	0	0	0	477,045,042
73	RBP	CIG, TSG-NF & CSG Redistribution	TRANSPORT_07	3,005	0	0	0	0	3,005
74	RBP	Not Used	not_used	0	0	0	0	0	0
75	RBP	Total Account G381		477,048,047	0	0	0	0	477,048,047
76	RBP								
77	RBP	G382 Meter Installations							
78	RBP	Firm Allocation	MTRINSTAL_07	52,630,927	0	0	0	0	52,630,927
79	RBP	CIG, TSG-NF & CSG Redistribution	TRANSPORT_07	609	0	0	0	0	609
80	RBP	Not Used	not_used	0	0	0	0	0	0
81	RBP	Total Account G382		52,631,537	0	0	0	0	52,631,537
82	RBP								
83	RBP								
84	RBP								
85	RBP								
86	RBP								
87	RBP								
88	RBP	**GAS PLANT IN SERVICE CONTINUED**							

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12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
89	RBP								
90	RBP	DISTRIBUTION PLANT CONTINUED							
91	RBP								
92	RBP	G383 House Regulators & Installation							
93	RBP	Firm Allocation - Regulators - G383	HOUSEREG_03	38,488,025	38,488,025	0	0	0	0
94	RBP	CIG, TSG-NF & CSG Redistribution	TRANSPORT_03	11,098	11,098	0	0	0	0
95	RBP	Not Used	not_used	0	0	0	0	0	0
96	RBP	Total Account G383		38,499,123	38,499,123	0	0	0	0
97	RBP								
98	RBP	G384 House Regulators & Installation		0	0	0	0	0	0
99	RBP	Firm Allocation - Installation - G384	HSEREGINST_03	112,681,544	112,681,544	0	0	0	0
100	RBP	G384 CIG. TSG-NF & CSG Redistribution	TRANSPORT_03	1,870	1,870	0	0	0	0
101	RBP	Total Account G384		112,683,414	112,683,414	0	0	0	0
102	RBP	G385 Industrial Meas and Regul Station Equip							
103	RBP	Firm Allocation - Regulators	LRGREG_03	71,912,204	71,912,204	0	0	0	0
104	RBP	Firm Allocation - Meters	LRGMTR_07	71,912,204	0	0	0	0	71,912,204
105	RBP	CIG, TSG-NF & CSG Redistribution - Regulators	TRANSPORT_03	895,023	895,023	0	0	0	0
106	RBP	CIG, TSG-NF & CSG Redistribution - Meters	TRANSPORT_07	895,023	0	0	0	0	895,023
107	RBP	Not Used	not_used	0	0	0	0	0	0
108	RBP	Total Account G385		145,614,455	72,807,227	0	0	0	72,807,227
109	RBP								
110	RBP	G386 Other Prop on Cust Prem	TRANSPORT_04	0	0	0	0	0	0
111	RBP								
112	RBP	G387-Other Equipment							
113	RBP	G387.1 Other Eqmt - Street Ltg Posts	DIRSLG_05	1,011,930	0	0	1,011,930	0	0
114	RBP	G387.2 Other Eqmt - Street Ltg Services	DIRSLG_03	509,787	509,787	0	0	0	0
115	RBP	Total Accounts G387		1,521,717	509,787	0	1,011,930	0	0
116	RBP								
117	RBP	G388 - Asset Retirement Obligations	PLT_376	65,215,073	0	65,215,073	0	0	0
118	RBP								
119	RBP	TOTAL DISTRIBUTION PLANT		10,498,076,770	5,724,304,805	4,164,673,568	1,021,319	0	608,077,078
120	RBP								
121	RBP								
122	RBP								
123	RBP								
124	RBP								
125	RBP								
126	RBP								
127	RBP								
128	RBP								
129	RBP								
130	RBP								
131	RBP								
132	RBP								

PUBLIC SERVICE ELECTRIC & GAS COMPANY
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12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
133	RBP								
134	RBP								
135	RBP	**GAS PLANT IN SERVICE CONTINUED**							
136	RBP								
137	RBP	GENERAL AND COMMON PLANT							
138	RBP	E390-E398 GENERAL PLANT							
139	RBP	Meter Related	METERPLT	0	0	0	0	0	0
140	RBP	Regulator Plant Related	PLT_3834	0	0	0	0	0	0
141	RBP	Appliance Safety Related	CINST_04	0	0	0	0	0	0
142	RBP	Distribution Delivery	DISTPLTXMTR	200,812,197	116,163,890	84,514,137	20,726	0	113,444
143	RBP	Competitive Service	COMPSVSWK_04	0	0	0	0	0	0
144	RBP	SONP/RNP Related	CUSTAVG_04	0	0	0	0	0	0
145	RBP	Gas Peaking Plant Related	BALANCE_04	0	0	0	0	0	0
146	RBP	Total Accounts E390-E398		200,812,197	116,163,890	84,514,137	20,726	0	113,444
147	RBP								
148	RBP	C389-C399 COMMON PLANT							
149	RBP	ASB Work Related	CINST_04	0	0	0	0	0	0
150	RBP	Meter Plant Related	METERPLT	0	0	0	0	0	0
151	RBP	Meter Reading Related	MRCOST_07	0	0	0	0	0	0
152	RBP	Not Used	not_used	0	0	0	0	0	0
153	RBP	Customer Service Related	CUSTSVSX	75,768,117	0	5,241,765	0	57,683,000	12,843,352
154	RBP	Distribution Delivery Related	DISTPLTXMTR	25,073,523	14,504,288	10,552,482	2,588	0	14,165
155	RBP	Service & Support Related	UTILWORK_04	0	0	0	0	0	0
156	RBP	Unassigned	TOTPLT	1,393,316	742,218	563,006	132	8,885	79,075
157	RBP	Total Accounts C389-C399		102,234,955	15,246,506	16,357,253	2,720	57,691,885	12,936,591
158	RBP								
159	RBP	TOTAL GENERAL AND COMMON PLANT		303,047,153	131,410,396	100,871,390	23,446	57,691,885	13,050,035
160	RBP								
161	RBP								
162	RBP	**TOTAL GAS PLANT IN SERVICE (101)**		10,993,079,074	5,855,998,970	4,442,042,462	1,044,816	70,102,224	623,890,602

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
1	RBD	**LESS: DEPRECIATION RESERVE & AMORT**							
2	RBD								
3	RBD	G301-G303 - INTANGILE PLANT - RESERVE							
4	RBD	General - AWMS & Misc.	TOTPLT	0	0	0	0	0	0
5	RBD	Choice Progect	not_used	0	0	0	0	0	0
6	RBD	GSMIS - meter related	not_used	0	0	0	0	0	0
7	RBD	- regulator related	not_used	0	0	0	0	0	0
8	RBD	- appliance safety related	not_used	0	0	0	0	0	0
9	RBD	- Comp Svs related	not_used	0	0	0	0	0	0
10	RBD	- Cust Svs related	not_used	0	0	0	0	0	0
11	RBD	Total Accounts E301-E303 Reserve		0	0	0	0	0	0
12	RBD								
13	RBD	C303 - INTANGIBLE PLANT - CUST SERVICE							
14	RBD	Customer Service	CUSTSVSX	9,821,603	0	679,475	0	7,477,281	1,664,847
15	RBD	Measurement	MRCOST_07	0	0	0	0	0	0
16	RBD	Not Used	not_used	0	0	0	0	0	0
17	RBD	G399.1 Asset Retirement Costs of General Plt	GENPLT	0	0	0	0	0	0
18	RBD	Not Used	not_used	0	0	0	0	0	0
19	RBD	TOTAL ACCOUNTS C303-C390.4,G399		9,821,603	0	679,475	0	7,477,281	1,664,847
20	RBD								
21	RBD	TOTAL INTANGIBLE PLANT		9,821,603	0	679,475	0	7,477,281	1,664,847
22	RBD								
23	RBD	PRODUCTION PLANT G304-G320 RESERVE	BALANCE_04	56,077,402	0	56,077,402	0	0	0
24	RBD								
25	RBD	STORAGE PLANT G360-G363 RESERVE	BALANCE_04	9,476,790	0	9,476,790	0	0	0
26	RBD								
27	RBD	TRANSMISSION PLANT G365-G369 RESERVE	TRANPLT	50,246,121	0	50,246,121	0	0	0
28	RBD								
29	RBD	DISTRIBUTION PLANT RESERVE							
30	RBD	G374-G375 Land & Structures Reserve	PLT_3745	432,406	235,779	171,539	42	0	25,046
31	RBD								
32	RBD	G376 Mains Reserve							
33	RBD	Firm Allocation	PEAKHOUR_04	1,017,890,245	0	1,017,890,245	0	0	0
34	RBD	CIG, TSG-NF & CSG Redistribution	TRANSPORT_04	759,994	0	759,994	0	0	0
35	RBD	Not Used	not_used	0	0	0	0	0	0
36	RBD	Total Account G376		1,018,650,239	0	1,018,650,239	0	0	0
37	RBD								
38	RBD	G377 Compressor Station Equip Reserve	DISTPLTXMTR						
39	RBD								
40	RBD	G378-G379 Meas & Regulatory Equip Reserve							
41	RBD	Firm Investment	PEAKHOUR_04	93,669,010	0	93,669,010	0	0	0
42	RBD	Not Used	not_used	0	0	0	0	0	0
43	RBD	Total Account G378-G379		93,669,010	0	93,669,010	0	0	0
44	RBD	**DEPRECIATION RESERVE & AMORT CONTINUED**							

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12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
45	RBD								
46	RBD	**DISTRIBUTION PLANT CONTINUED**							
47	RBD								
48	RBD	G380 Services Reserve							
49	RBD	Firm Allocation	SERVICESR_03	1,126,944,013	1,126,944,013	0	0	0	0
50	RBD	CIG, TSG-NF & CSG Redistribution	TRANSPORT_03	2,349,910	2,349,910	0	0	0	0
51	RBD	Not Used	not_used	0	0	0	0	0	0
52	RBD	Total Account G380		1,129,293,923	1,129,293,923	0	0	0	0
53	RBD								
54	RBD	G381 Meters Reserve							
55	RBD	Firm Allocation	SMMETERSR_07	61,006,069	0	0	0	0	61,006,069
56	RBD	CIG, TSG-NF & CSG Redistribution	TRANSPORT_07	1,948	0	0	0	0	1,948
57	RBD	Not Used	not_used	0	0	0	0	0	0
58	RBD	Total Account G381		61,008,018	0	0	0	0	61,008,018
59	RBD								
60	RBD	G382 Meter Installations Reserve							
61	RBD	Firm Allocation	MTRINSTALR_07	33,652,945	0	0	0	0	33,652,945
62	RBD	CIG, TSG-NF & CSG Redistribution	TRANSPORT_07	279	0	0	0	0	279
63	RBD	Not Used	not_used	0	0	0	0	0	0
64	RBD	Total Account G382		33,653,224	0	0	0	0	33,653,224
65	RBD								
66	RBD	G383 House Regulators & Installation Reserve							
67	RBD	Firm Allocation - Regulators - G383	HOUSEREGR_03	25,030,964	25,030,964	0	0	0	0
68	RBD	CIG, TSG-NF & CSG Redistribution	TRANSPORT_03	4,827	4,827	0	0	0	0
69	RBD	Not Used	not_used	0	0	0	0	0	0
70	RBD	Total Account G383		25,035,791	25,035,791	0	0	0	0
71	RBD								
72	RBD	G384 House Regulators & Installation Reserve		0	0	0	0	0	0
73	RBD	Firm Allocation - Installation - G384	HSEREGINSTR_03	58,406,745	58,406,745	0	0	0	0
74	RBD	G384 CIG. TSG-NF & CSG Redistribution	TRANSPORT_03	1,006	1,006	0	0	0	0
75	RBD	Total Account G384		58,407,752	58,407,752	0	0	0	0
76	RBD	G385 Industrial Meas and Regul Sta Equip Reserve							
77	RBD	Firm Allocation - Regulators	LRGREGR_03	12,236,618	12,236,618	0	0	0	0
78	RBD	Firm Allocation - Meters	LRGMTRR_07	12,236,618	0	0	0	0	12,236,618
79	RBD	CIG, TSG-NF & CSG Redistribution - Regulators	TRANSPORT_03	295,977	295,977	0	0	0	0
80	RBD	CIG, TSG-NF & CSG Redistribution - Meters	TRANSPORT_07	295,977	0	0	0	0	295,977
81	RBD	Not Used	not_used	0	0	0	0	0	0
82	RBD	Total Account G385		25,065,190	12,532,595	0	0	0	12,532,595
83	RBD								
84	RBD	G386 Other Prop on Cust Prem	TRANSPORT_04	0	0	0	0	0	0
85	RBD	G387.1 Other Eqmt - Street Ltg Posts	DIRSLG_05	0	0	0	0	0	0
86	RBD	G387.2 Other Eqmt - Street Ltg Services	DIRSLG_03	0	0	0	0	0	0
87	RBD								
88	RBD	TOTAL DISTRIBUTION PLANT RESERVE		2,445,215,554	1,225,505,840	1,112,490,788	42	0	107,218,883

PUBLIC SERVICE ELECTRIC & GAS COMPANY
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12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
89	RBD								
90	RBD	**DEPRECIATION RESERVE & AMORT CONTINUED**							
91	RBD								
92	RBD	GENERAL AND COMMON PLANT RESERVE							
93	RBD								
94	RBD	E390-E398 GENERAL PLANT - RESERVE							
95	RBD	Meter Related	METERPLT	0	0	0	0	0	0
96	RBD	Regulator Plant Related	PLT_3834	0	0	0	0	0	0
97	RBD	Appliance Safety Related	CINST_04	0	0	0	0	0	0
98	RBD	Distribution Delivery	DISTPLTXMTR	94,949,830	54,925,656	39,960,735	9,800	0	53,640
99	RBD	Competitive Service	COMPSVSWK_04	0	0	0	0	0	0
100	RBD	SONP/RNP Related	CUSTAVG_04	0	0	0	0	0	0
101	RBD	Gas Peaking Plant Related	BALANCE_04	0	0	0	0	0	0
102	RBD	Total Accounts E390-E398		94,949,830	54,925,656	39,960,735	9,800	0	53,640
103	RBD								
104	RBD	C389-C399 COMMON PLANT							
105	RBD	ASB Work Related	CINST_04	0	0	0	0	0	0
106	RBD	Meter Reading Related	MRCOST_07	0	0	0	0	0	0
107	RBD	Not Used	not_used	0	0	0	0	0	0
108	RBD	Customer Service Related	CUSTSVSX	38,276,434	0	2,648,028	0	29,140,219	6,488,187
109	RBD	Distribution Delivery Related	DISTPLTXMTR	13,134,595	7,597,973	5,527,846	1,356	0	7,420
110	RBD	Service & Support Related	UTILWORK_04	0	0	0	0	0	0
111	RBD	Unassigned	TOTPLT	1,273,650	678,472	514,652	121	8,122	72,284
112	RBD	Total Accounts C389-C399 Reserve		52,684,679	8,276,445	8,690,526	1,477	29,148,341	6,567,890
113	RBD								
114	RBD	**TOTAL DEPRECIATION RESERVE & AMORT.**		2,718,471,978	1,288,707,941	1,277,621,837	11,318	36,625,623	115,505,260
115	RBD								
116	RBD								
117	RBD	**NET GAS PLANT IN SERVICE**		8,274,607,096	4,567,291,030	3,164,420,625	1,033,497	33,476,602	508,385,342
118	RBD	Meter Plant Related	METERPLT	0	0	0	0	0	0

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
1	RBO	**ADDITIONS AND DEDUCTIONS TO RATE BASE**							
2	RBO								
3	RBO	**PLUS: ADDITIONS TO RATE BASE**							
4	RBO								
5	RBO	Working Capital							
6	RBO	Materials and Supplies Excl Fuel Stock	PSTDPLT	59,382,049	31,847,963	24,145,283	5,682	0	3,383,121
7	RBO	Fuel Stock & Fuel Stock Expense	not_used	0	0	0	0	0	0
8	RBO	Gas Stored Underground	not_used	0	0	0	0	0	0
9	RBO	Cash (lead/lag)	EXPENDITURES	586,016,094	286,788,615	212,312,481	129,586	35,554,055	51,231,356
10	RBO	Prepayments/Working Funds	EXPENDITURES	115,700	56,622	41,918	26	7,020	10,115
11	RBO	Total Working Capital		645,513,843	318,693,200	236,499,683	135,294	35,561,075	54,624,592
12	RBO	CEF-EC Adjustment	not_used	0	0	0	0	0	0
13	RBO	CEF-EV Adjustment	not_used	0	0	0	0	0	0
14	RBO	Net Plant Adds - Distribution	DISTPLT	1,573,578,886	858,028,130	624,251,712	153,088	0	91,145,957
15	RBO	Capital Stimulas Adjust	DISTPLT	0	0	0	0	0	0
16	RBO	Plant Held for Future Use	TOTPLT	96,280	51,288	38,905	9	614	5,464
17	RBO	Net Plant Adds - General & Other	TOTPLTNET	153,424,698	84,685,018	58,673,514	19,163	620,711	9,426,293
18	RBO	TOTAL ADDITIONS TO RATE BASE		2,372,613,708	1,261,457,636	919,463,813	307,554	36,182,400	155,202,305
19	RBO								
20	RBO	**PLUS: DEDUCTIONS TO RATE BASE**							
21	RBO								
22	RBO	Customer Advances for Construction	MAIN_SERV	-24,909,672	-14,713,434	-10,196,237	0	0	0
23	RBO	IAP Adjustment	not_used	0	0	0	0	0	0
24	RBO	GSMP II EXT Adjustment	TOTPLT	-256,132,009	-136,441,189	-103,496,869	-24,344	-1,633,339	-14,536,269
25	RBO	Deferred Income Taxes and Credits							
26	RBO	ADIT Test/Post year	TOTPLT	0	0	0	0	0	0
27	RBO	Liberalized Depreciation	TOTPLT	35,377,684	18,845,647	14,295,283	3,362	225,601	2,007,791
28	RBO	Liberalized Depreciation - Production	BALANCE_04	-1,955,963	0	-1,955,963	0	0	0
29	RBO	Cost of Removal	TOTPLT	9,569,770	5,097,804	3,866,917	910	61,026	543,114
30	RBO	3% Investment Tax Credit	DISTPLT	0	0	0	0	0	0
31	RBO	Computer Software	TOTPLT	0	0	0	0	0	0
32	RBO	Capitalized Interest	TOTPLTNET	-160,793	-88,752	-61,491	-20	-651	-9,879
33	RBO	NJ Corporate Business Tax	STATEINCTAX	4,194,912	2,297,320	1,598,210	550	32,390	266,441
34	RBO	Defrd Tax & Consolidated Tax Adjustment	TOTPLT	-1,731,586,152	-922,413,698	-699,692,885	-164,575	-11,042,224	-98,272,770
35	RBO	Total Deferred Income Taxes and Credits		-1,684,560,542	-896,261,680	-681,949,929	-159,773	-10,723,857	-95,465,303
36	RBO								
37	RBO	TOTAL DEDUCTIONS TO RATE BASE		-1,965,602,222	-1,047,416,303	-795,643,035	-184,117	-12,357,196	-110,001,572
38	RBO								
39	RBO								
40	RBO	**TOTAL RATE BASE**		8,681,618,581	4,781,332,362	3,288,241,403	1,156,935	57,301,806	553,586,075

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
1	REV	**OPERATING REVENUES**							
2	REV								
3	REV	**SALES REVENUES**							
4	REV	BASE RATE SALES @ EQUALIZED ROR 7.40%		1,401,350,320	694,814,985	519,849,840	388,577	77,033,143	109,263,775
5	REV	Revenue Requirement - Other #1	not_used	0	0	0	0	0	0
6	REV	Revenue Requirement - Other #2	not_used	0	0	0	0	0	0
7	REV	TOTAL SALES OF GAS		1,401,350,320	694,814,985	519,849,840	388,577	77,033,143	109,263,775
8	REV								
9	REV	**OTHER OPERATING REVENUES**							
10	REV	G487-Forfeited Discounts	REVLATEP	1,447,215	495,259	773,135	0	37,655	141,166
11	REV	G488-Miscellaneous Service Revenues	COMPSVSWK_04	40,880,111	0	40,880,111	0	0	0
12	REV	G489-Revenues from Transmission from Others	not_used	0	0	0	0	0	0
13	REV	G493-Rent from Gas Property	TOTPLT	0	0	0	0	0	0
14	REV	G495-Other Gas Revenues							
15	REV	Miscellaneous Gas Revenues	TOTREV	19,473,704	9,340,925	7,622,409	5,220	1,035,383	1,469,766
16	REV	Peak Shaving Revenues	BALANCE_04	5,886,006	0	5,886,006	0	0	0
17	REV	Not Used	not_used	0	0	0	0	0	0
18	REV	Not Used	not_used	0	0	0	0	0	0
19	REV	TOTAL OTHER OPERATING REV		67,687,036	9,836,184	55,161,661	5,220	1,073,038	1,610,932
20	REV								
21	REV	**OTHER REVENUE SOURCES**							
22	REV	Not Used	not_used	0	0	0	0	0	0
23	REV	Not Used	not_used	0	0	0	0	0	0
24	REV	TOTAL OTHER REVENUE SOURCES		0	0	0	0	0	0
25	REV								
26	REV	LESS: E496 Provision for Rate Refunds	TOTREV	0	0	0	0	0	0
27	REV								
28	REV	**TOTAL OPERATING REVENUES**		1,469,037,356	704,651,169	575,011,501	393,797	78,106,181	110,874,707

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
1	E	**OPERATION & MAINTENANCE EXPENSE**							
2	E								
3	E	MANUFACTURED GAS PRODUCTION EXPENSE							
4	E	G710-G718 Production Expenses Incl Labor	BALANCE_04	281,982	0	281,982	0	0	0
5	E	G722-G736 Gas Raw Materials	BALANCE_04	29,792,635	0	29,792,635	0	0	0
6	E	G739-G745 Operation & Maintenance Exp	BALANCE_04	1,832,256	0	1,832,256	0	0	0
7	E	Not Used	not_used	0	0	0	0	0	0
8	E	TOTAL MANUFACTURED GAS PRODUCTION EXP		31,906,873	0	31,906,873	0	0	0
9	E								
10	E	OTHER GAS SUPPLY EXPENSE							
11	E	G801 Natural Gas Field Line Purchases	not_used	0	0	0	0	0	0
12	E	G804 Natural Gas City Gate Purchases	not_used	0	0	0	0	0	0
13	E	G805 Other Gas Purchases	not_used	0	0	0	0	0	0
14	E	G808.1,.2 GasInject & W/D from Storage	not_used	0	0	0	0	0	0
15	E	G812 Gas Used for Other Util Oper	not_used	0	0	0	0	0	0
16	E	G813 Other Gas Supply Expenses							
17	E	Supply Related	not_used	0	0	0	0	0	0
18	E	Distribution Related	TRANSPORT_04	72		72			
19	E	TOTAL OTHER GAS SUPPLY EXPENSE		72		72			
20	E	TOTAL GAS PRODUCTION AND SUPPLY		31,906,945	0	31,906,945	0	0	0
21	E								
22	E	OTHER STORAGE EXPENSE							
23	E	G840-G842 Operation	BALANCE_04	8,906	0	8,906	0	0	0
24	E	G843 Maintenance	BALANCE_04	2,705,699		2,705,699			
25	E	TOTAL OTHER STORAGE EXPENSE		2,714,605	0	2,714,605	0	0	0
26	E								
27	E	TRANSMISSION EXPENSES							
28	E	G850-G867 Transmission Exp	TRANPLT	2,593,507		2,593,507			
29	E	TOTAL TRANSMISSION EXPENSE		2,593,507	0	2,593,507	0	0	0
30	E								
31	E	DISTRIBUTION EXPENSES							
32	E	Operation							
33	E	G870 Operation Supervision & Engineering	TLABDO	0	0	0	0	0	0
34	E	G871 Load Dispatching	TRANSPORT_04	5,839,316	0	5,839,316	0	0	0
35	E	G872 Compressor Station Labor & Expenses	TRANSPORT_04	0	0	0	0	0	0
36	E	G874 Mains & Services	MAIN_SERV	20,733,577	12,246,734	8,486,843	0	0	0
37	E	G875 Meas & Reg Station - General	PLT_3789	2,497,019	0	2,497,019	0	0	0
38	E	G876 Meas & Reg Station - Industrial	PLT_3789	7,594	0	7,594	0	0	0
39	E	G877 Meas & Reg Station - City Gate	PLT_3789	514,539	0	514,539	0	0	0
40	E	G878 Meter & House Reg	PLT_3814	11,492,061	2,551,763	0	0	0	8,940,298
41	E	G879 Customer Installations							
42	E	- Customer Installations	CINST_04	17,355,157	0	17,355,157	0	0	0
43	E	- Competitive Services by ASB	COMPSVSWK_04	0	0	0	0	0	0
44	**E**	**OPERATION & MAINTENANCE EXPENSE CONTINUED**							

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
45	E								
46	E	G880.0,.1,.2 Other Expenses	DISTEXPO	14,050,188	3,625,445	8,234,483	0	0	2,190,260
47	E	G880.3 Operation of Street Lighting	DIRSLG_05	0	0	0	0	0	0
48	E	G881 Rents	TRANSPORT_04	-1,088,602	0	-1,088,602	0	0	0
49	E	Total Distribution Operation		71,400,849	18,423,942	41,846,349	0	0	11,130,558
50	E								
51	E	DISTRIBUTION EXPENSES CONTINUED							
52	E	Maintenance							
53	E	G885 Maint. Supervision & Engineering	TLABDM	0	0	0	0	0	0
54	E	G886 Structures & Improvements	PLT_3745	8,016,449	4,371,143	3,180,191	780	0	464,334
55	E	G887 Mains	PLT_376	8,706,285	0	8,706,285	0	0	0
56	E	G888 Compressor Station Equip	PLT_377	0	0	0	0	0	0
57	E	G889 Meas & Reg Station - General	PLT_3789	1,007,898	0	1,007,898	0	0	0
58	E	G891 Meas & Reg Station - City Gate	PLT_3789	3,155,564	0	3,155,564	0	0	0
59	E	G892 Services	SERVICES	3,610,466	3,610,466	0	0	0	0
60	E	G893 Meters & House Reg							
61	E	G893.1 - Meters	SMMETERS_07	6,767,990	0	0	0	0	6,767,990
62	E	G893.4 - House Regulators	PLT_3834	0	0	0	0	0	0
63	E	Not Used	not_used	0	0	0	0	0	0
64	E	G894 Maint of Other Equipment							
65	E	G894.0 - Maint of Other Equip	DISTEXPM	9,513	2,413	4,853	60	0	2,187
66	E	G894.1 - Maint of Gas Streetlights	DIRSLG_05	198,384	0	0	198,384	0	0
67	E	Total Distribution Maintenance		31,472,549	7,984,022	16,054,791	199,225		7,234,511
68	E	TOTAL DISTRIBUTION PLANT O&M EXPENSES		102,873,398	26,407,965	57,901,140	199,225	0	18,365,069
69	E								
70	E	TOTAL OPER & MAINT EXP (PROD,STOR, TRAN,& DIST)		140,088,455	26,407,965	95,116,197	199,225	0	18,365,069
71	E								
72	E	CUSTOMER ACCOUNTS EXPENSES							
73	E	G901 Supervision	CUSTACCTS	0	0	0	0	0	0
74	E	G902 Meter Reading							
75	E	- Meter Reading Related	MRCOST_07	12,907,838	0	0	0	0	12,907,838
76	E	- Meter O&M Related	METERPLT	38,249	0	0	0	0	38,249
77	E	- Remaining	MRCOST_07	0	0	0	0	0	0
78	E	G903 Customer Records and Collection							
79	E	- SONP/RNP	CUSTAVG_06	526,534	0	0	0	526,534	0
80	E	- Meter O&M Related	METERPLT	0	0	0	0	0	0
81	E	- Meter Reading Related	MRCOST_07	63,202	0	0	0	0	63,202
82	E	- Billing Related	BILLING_06	16,558,655	0	0	0	16,558,655	0
83	E	- Acct Maint Related	ACCTMAINT_06	26,073,286	0	0	0	26,073,286	0
84	E	- Utility Work Related	UTILWORK_04	2,712,621	0	2,712,621	0	0	0
85	E	- Remaining	BILLING_06	13,832,442	0	0	0	13,832,442	0
86	E	Not used	not_used	0	0	0	0	0	0
87	**E**	**OPERATION & MAINTENANCE EXPENSE CONTINUED**							
88	E								

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				(1)	(2)	(3)	(4)	(5)	(6)
89	E	G904 Uncollectible Accounts	EXP_904	26,046,715	12,917,426	9,665,506	0	1,432,230	2,031,553
90	E	G905 Misc Customer Accounts	CUSTACCTS	0	0	0	0	0	0
91	E	TOTAL CUSTOMER ACCTS EXPENSE		98,759,541	12,917,426	12,378,126	0	58,423,147	15,040,841
92	E								
93	E	CUSTOMER SERVICE & INFO EXPENSES							
94	E	G907 & 908 - Customer Service & Information							
95	E	- Billing	BILLING_06	37,379	0	0	0	37,379	0
96	E	- Acct Maint related	ACCTMAINT_06	746,413	0	0	0	746,413	0
97	E	- Utility work related	UTILWORK_04	1,684,915	0	1,684,915	0	0	0
98	E	- Remaining	ACCTMAINT_06	0	0	0	0	0	0
99	E	G909 Info & Instr Advertising	TRANSPORT_04	0	0	0	0	0	0
100	E	G910 - Misc Cust Service & Info							
101	E	- Utility work related	UTILWORK_04	911,953	0	911,953	0	0	0
102	E	- Remaining	ACCTMAINT_06	653,558				653,558	
103	E	TOTAL CUSTOMER SERVICE & INFO EXPENSES		4,034,218	0	2,596,868	0	1,437,350	0
104	E								
105	E	SALES EXPENSES							
106	E	G912 - Demonstrating and Selling	UTILWORK_04	88,423	0	88,423	0	0	0
107	E	G913 - Advertising	UTILWORK_04	0	0	0	0	0	0
108	E	G916 - Miscellaneous	UTILWORK_04	0	0	0	0	0	0
109	E								
110	E	SALES EXPENSES TOTAL (ACCT 916)		88,423	0	88,423	0	0	0
111	E								
112	E	TOTAL OPER & MAINT EXCL A&G		242,970,637	39,325,391	110,179,614	199,225	59,860,497	33,405,910
113	E								
114	E	ADMINISTRATIVE & GENERAL EXPENSE							
115	E	G920 A&G Salaries	LABOR	6,954,680	641,537	3,827,369	3,233	1,587,412	895,130
116	E	G921 Office Supplies & Exp	LABOR	652,569	60,196	359,128	303	148,949	83,992
117	E	G923 Outside Services Employed							
118	E	- Gas Peaking Plant Related	BALANCE_04	0	0	0	0	0	0
119	E	- Remaining	TOMXFUEL904	61,043,177	8,962,800	22,728,044	70,246	19,103,255	10,178,832
120	E	G924 Property Insurance	TOTPLT	296,480	157,935	119,801	28	1,891	16,826
121	E	G925 Injuries & Damages	LABOR	15,351,785	1,416,130	8,448,547	7,136	3,504,058	1,975,914
122	E	G926 Employee Pension & Benefits							
123	E	- Gas Peaking Plant Related	BALANCE_04	0	0	0	0	0	0
124	E	- Remaining	LABOR	-60,778,346	-5,606,517	-33,448,145	-28,250	-13,872,711	-7,822,723
125	E	G928 Regulatory Comm Exp	TRANSPORT_04	5,147,284	0	5,147,284	0	0	0
126	E	G929 Duplicate Charges - credit	INTRAREV	764,611	197,570	510,117	0	15,221	41,704
127	E	G930.1 General Advertising Expenses	TRANSPORT_04	1,968,152	0	1,968,152	0	0	0
128	E	G930.2 Misc General Expenses	TRANSPORT_04	3,638,524	0	3,638,524	0	0	0
129	E	G931 Rents	AGEXP	3,713,155	617,781	1,409,307	5,584	1,111,446	569,037
130	E	G932 Maint of General Plant	COMGENPLT	0	0	0	0	0	0
131	E	G935 Other A&G Maint	COMGENPLT	0	0	0	0	0	0
132	E	Not Used	not_used	0	0	0	0	0	0

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				(1)	(2)	(3)	(4)	(5)	(6)
133	E	TOTAL A&G EXPENSE		38,752,071	6,447,431	14,708,128	58,280	11,599,521	5,938,711
134	E								
135	E	**TOTAL OPERATION & MAINTENANCE EXPENSES**		281,722,708	45,772,822	124,887,742	257,504	71,460,018	39,344,621
136	E	G890 Meas & Reg Station - Industrial	PLT_3789	0	0	0	0	0	0

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
1	DE	**DEPRECIATION AND AMORTIZATION EXPENSES**							
2	DE								
3	DE	G403 DEPRECIATION EXPENSE							
4	DE	Production Plant	BALANCE_04	1,670	0	1,670	0	0	0
5	DE	Storage Plant	BALANCE_04	114,612	0	114,612	0	0	0
6	DE	Transmission Plant	TRANPLT	1,172,631	0	1,172,631	0	0	0
7	DE	Distribution Plant	DISTPLT	182,874,076	99,716,069	72,547,653	17,791	0	10,592,562
8	DE	General and Common Plant	COMGENPLT	19,528,227	8,468,029	6,500,109	1,511	3,717,640	840,939
9	DE	Not Used	not_used	0	0	0	0	0	0
10	DE	TOTAL DEPRECIATION EXPENSE		203,691,216	108,184,098	80,336,675	19,302	3,717,640	11,433,501
11	DE								
12	DE	G404.3 AMORT OF OTHER LIMITED TERM PLANT							
13	DE	Customer Service related	CUSTSVSX	1,194,362	0	82,628	0	909,279	202,455
14	DE	AWMS	DISTPLT	0	0	0	0	0	0
15	DE	Distribution	DISTPLT	1,127,553	614,823	447,310	110	0	65,311
16	DE	Metering	METERPLT	29,719	0	0	0	0	29,719
17	DE	All Other	PSTDPLT	0	0	0	0	0	0
18	DE	TOTAL AMORT OF OTHER LIMITED TERM PLT		2,351,634	614,823	529,938	110	909,279	297,484
19	DE								
20	DE	G407 AMORT OF PROPERTY LOSSES							
21	DE	Remediation Adjustment Clause	not_used	0	0	0	0	0	0
22	DE	Excess Cost of Removal	TOTPLT						
23	DE	TOTAL AMORT OF PROPERTY LOSSES		0	0	0	0	0	0
24	DE								
25	DE	TOTAL AMORTIZATION EXPENSE		2,351,634	614,823	529,938	110	909,279	297,484
26	DE								
27	DE	**TOTAL DEPRECIATION AND AMORTIZATION EXPENSES**		206,042,850	108,798,921	80,866,612	19,412	4,626,919	11,730,985

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
1	EO	**OTHER OPERATING EXPENSES**							
2	EO								
3	EO	**G408 TAXES OTHER THAN INCOME TAXES**							
4	EO	Payroll	LABOR	-2,034	-188	-1,119	-1	-464	-262
5	EO	TEFA	TEFA_04	0	0	0	0	0	0
6	EO	Real Estate Taxes	TOTPLT	-13,552,354	-7,219,321	-5,476,185	-1,288	-86,423	-769,137
7	EO	State Unemploy Insur (SUI) Tax	LABOR	0	0	0	0	0	0
8	EO	Fed Insur Contr & UnempTax	LABOR	-60,481	-5,579	-33,285	-28	-13,805	-7,784
9	EO	Fed Insur Contr & UnempTax - Gas Peaking Plts	BALANCE_04	0	0	0	0	0	0
10	EO	FICA	LABOR	-10,865,853	-1,002,324	-5,979,805	-5,051	-2,480,141	-1,398,534
11	EO	Miscellaneous State and Municipal Tax	TOTPLT	0	0	0	0	0	0
12	EO	Federal Environmental Tax	PSTDPLT	0.0	0.0	0.0	0.0	0.0	0.0
13	EO	**TOTAL TAXES OTHER THAN INCOME**		-24,480,722	-8,227,412	-11,490,393	-6,368	-2,580,832	-2,175,717
14	EO								
15	EO	**PROFORMA EXPENSE ADJUSTMENTS**							
16	EO	Amortization of CEF-EC Program Regulatory Assets		0	0	0	0	0	0
17	EO	Amortization of CEF-EV Program Regulatory Assets		0	0	0	0	0	0
18	EO	BGS Administrative Expense Adjustment		0	0	0	0	0	0
19	EO	CIP Revenue Accrual Adjustment	not_used	0	0	0	0	0	0
20	EO	Deferred Compensation & Severance Expense	LABOR	-361,345	-33,332	-198,859	-168	-82,477	-46,508
21	EO	Gas Bad Debt Adjustment	not_used	0	0	0	0	0	0
22	EO	TAC Revenue Accrual Adjustment	not_used	0	0	0	0	0	0
23	EO	Tax Bad Debt Adjustment	SALESREV	2,990,017	1,482,505	1,109,187	829	164,363	233,133
24	EO	TSG-NF Gas Margin Reset	not_used	0	0	0	0	0	0
25	EO	Wage Increases (Rate Year)	LABOR	7,223,753	666,357	3,975,448	3,358	1,648,828	929,762
26	EO	Payroll Taxes (Rate Year)	LABOR	508,958	46,949	280,095	237	116,170	65,508
27	EO	Interest Syncronization	TOTPLTNET	-1,864,683	-1,029,239	-713,102	-233	-7,544	-114,565
28	EO	- add'l tax effects on rev req	TOTPLTNET	-729,117	-402,447	-278,833	-91	-2,950	-44,796
29	EO	Pension & Fringe Benefit (Rate Year)	LABOR	7,091,402	654,149	3,902,611	3,296	1,618,619	912,728
30	EO	Adj #5 - Gas COLI Interest Expense	LABOR	0	0	0	0	0	0
31	EO	- add'l tax effects on rev req	LABOR	0	0	0	0	0	0
32	EO	Postage	CUSTACCTS	0	0	0	0	0	0
33	EO	BPU / Rate Counsel Assessment	TRANSPORT_04	738,301	0	738,301	0	0	0
34	EO	Adj #6 - Weather Normalization	not_used	0	0	0	0	0	0
35	EO	Gains / Losses Normalization	TOTPLT	-207,450	-110,508	-83,826	-20	-1,323	-11,773
36	EO	- add'l tax effects on rev req	TOTPLT	-81,116	-43,210	-32,777	-8	-517	-4,604
37	EO	Test Year Corrections	TOTPLT	0	0	0	0	0	0
38	EO	Customer Information System Amort	CUSTSVSX	0	0	0	0	0	0
39	EO	Real Estate Tax Increases (Rate Year)	TOTPLT	158,827	84,607	64,178	15	1,013	9,014
40	EO	Capital Stimulus (Depreciation)	DISTPLT	0	0	0	0	0	0
41	EO	Insurance Premium Increases (Rate Year)	TOTPLT	237,517	126,525	95,975	23	1,515	13,480
42	EO	Adj #15 - Excess COR Refund Recovery	TOTPLT	0	0	0	0	0	0
43	EO	Test Year Amortization Adjustments	TOTPLT	-5,932,749	-3,160,368	-2,397,283	-564	-37,833	-336,702
44	EO	Adj #11 - TSGNF Margin Sharing	not_used	0	0	0	0	0	0

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
45	EO	Adj #12 - Depreciation Rate Change/Annualization	DEPREXP	0	0	0	0	0	0
46	EO	Capital Stimulus Revenue	DISTPLT	0	0	0	0	0	0
47	EO	ASB Margin	TOTPLT	15,265,290	8,131,800	6,168,342	1,451	97,346	866,352
48	EO	Adj #13 - Storm Cost Amortization	TOTPLTNET	0	0	0	0	0	0
49	EO	Other Regulatory Asset / Liability Amortizations	TOTPLT	0	0	0	0	0	0
50	EO	Rate Case Expenses	TOTPLT	141,376	75,311	57,127	13	902	8,024
51	EO	Tax - Repair Allowance	DISTPLT	0	0	0	0	0	0
52	EO	Tax - Flow Through Items	DISTPLT	0	0	0	0	0	0
53	EO	Adj #14 Post Rate Case Storm Cost Normalization	TOTPLT	0	0	0	0	0	0
54	EO	Recovery of Credit Card Fees	CUSTSVSX	0	0	0	0	0	0
55	EO	Adj #20 - Vacation Accrual	LABOR	0	0	0	0	0	0
56	EO	Energy Strong II / IAP Revenue Adjustment	TOTPLT						
57	EO	Depreciation Rate Change	DEPREXP	74,624,206	39,634,269	29,432,102	7,071	1,361,993	4,188,771
58	EO	TOTAL PROFORMA EXPENSE ADJUSTMENTS		100,619,236	46,198,643	42,567,781	15,589	5,064,367	6,772,855
59	EO								
60	EO	**TOTAL OTHER OPERATING EXPENSES**		76,138,514	37,971,231	31,077,388	9,221	2,483,535	4,597,138
61	EO	COLI Interest Expense Recovery	LABOR	816,048	75,277	449,096	379	186,264	105,033

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
1	TI	**DEVELOPMENT OF INCOME TAXES**							
2	TI								
3	TI	TOTAL OPERATING REVENUES	CALCULATED	1,469,037,356	704,651,169	575,011,501	393,797	78,106,181	110,874,707
4	TI	LESS:							
5	TI	OPERATION & MAINTAINENCE EXPENSE	CALCULATED	281,722,708	45,772,822	124,887,742	257,504	71,460,018	39,344,621
6	TI	DEPRECIATION & AMORTIZATION EXPENSE	CALCULATED	206,042,850	108,798,921	80,866,612	19,412	4,626,919	11,730,985
7	TI	OTHER OPERATING EXPENSES	CALCULATED	76,138,514	37,971,231	31,077,388	9,221	2,483,535	4,597,138
8	TI	NET OPERATING INCOME BEFORE TAXES		905,133,284	512,108,194	338,179,759	107,660	-464,291	55,201,962
9	TI	LESS:							
10	TI	G427 - G431 INTEREST CHARGES	TOTPLTNET	100,820,068	55,649,119	38,556,163	12,592	407,888	6,194,306
11	TI	**TOTAL OPERATING INCOME BEFORE TAXES**		804,313,216	456,459,075	299,623,596	95,067	-872,180	49,007,657
12	TI								
13	TI	**TAX ADJUSTMENTS - FEDERAL**							
14	TI								
15	TI	Assessment by Board of Public Utilities of the State of NJ	TOTPLTNET	56,782	31,342	21,715	7	230	3,489
16	TI	Injuries and Damages ;		0	0	0	0	0	0
17	TI	Bankrupticies & Acc. Prov. For Rents Receivable	TOTPLTNET	52,256	28,843	19,984	7	211	3,211
18	TI	Capitalized interest-Section 263A	TOTPLT	416,892	222,078	168,456	40	2,658	23,660
19	TI	Casualty Loss Deferred O&M & Ins Proceeds	TOTPLTNET	-1,095,802	-604,844	-419,062	-137	-4,433	-67,325
20	TI	Deduction for New Network Meter Equipment		0	0	0	0	0	0
21	TI	Defer Dividend Equivalents/Restricted Stock-Temp.		0	0	0	0	0	0
22	TI	Deferred Depreciation on CIP ll	TOTPLT	8,262	4,401	3,338	1	53	469
23	TI	Deferred Return on CIP ll	TOTPLT	18,055	9,618	7,296	2	115	1,025
24	TI	Diesel Fuel Credit		0	0	0	0	0	0
25	TI	Environmental Accrual		0	0	0	0	0	0
26	TI	FIN48 Reg Asset Reversal		0	0	0	0	0	0
27	TI	FIN48 Services Allocation		0	0	0	0	0	0
28	TI	GainState LILOAudit Refunds not yet received		0	0	0	0	0	0
29	TI	LCAPP		0	0	0	0	0	0
30	TI	Legal Reserves (c & nc)	TOTPLTNET	-418,012	-230,728	-159,858	-52	-1,691	-25,682
31	TI	Material Supplies & Reserves	TOTPLT	78,535	41,836	31,734	7	501	4,457
32	TI	Misc Adj - Permanent		0	0	0	0	0	0
33	TI	Miscellaneous		0	0	0	0	0	0
34	TI	Partnership income/loss per K-1		0	0	0	0	0	0
35	TI	Performance Incentive Plan Adjustment	TOTPLTNET	-455,695	-251,528	-174,269	-57	-1,844	-27,998
36	TI	RAC-Environmental Cleanup Costs		0	0	0	0	0	0
37	TI	Repair Allow Deferral Carrying Charges		0	0	0	0	0	0
38	TI	SBC-Societal Benefits Clause		0	0	0	0	0	0
39	TI	Stock Based Compensation	TOTPLTNET	-325,229	-179,515	-124,376	-41	-1,316	-19,982
40	TI	TAX ADJUSTMENTS - FEDERAL CONTINUED		0	0	0	0	0	0
41	TI	Uncollectible Accounts		0	0	0	0	0	0
42	TI	Utility Commodity Costs		0	0	0	0	0	0
43	TI	Additional Expenses on Rental Property	TOTPLT	0	0	0	0	0	0
44	TI	Additional Rental Income - NJ Properties	TOTPLT	0	0	0	0	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
45	TI	Amort of Def Gain on Sale of Services Assets	not_used	0	0	0	0	0	0
46	TI	Amort of Deferred Gain on Sale of Generation Assets	not_used	0	0	0	0	0	0
47	TI	Amortization of Limited-Term Utility Plant	TOTPLT	-14	-7	-6	0	0	-1
48	TI	Amortization of Reacquisition of Pref Stock	TOTPLT	7,787	4,148	3,146	1	50	442
49	TI	CECL Reserve	not_used	0	0	0	0	0	0
50	TI	CEF- EC AMI	TOTPLT	0	0	0	0	0	0
51	TI	CEF- EV Deferral	TOTPLT	0	0	0	0	0	0
52	TI	Clause - Demographic Studies	not_used	0	0	0	0	0	0
53	TI	Clause - Navigant Studies	not_used	0	0	0	0	0	0
54	TI	Clause - RAC (Environmental Clean Up)	not_used	0	0	0	0	0	0
55	TI	Clause - Societal Benefits Clause (AAP)	not_used	0	0	0	0	0	0
56	TI	Company Owned Life Insurance - Book	LABOR	-352,245	-32,493	-193,851	-164	-80,400	-45,337
57	TI	Company Owned Life Insurance - Tax	LABOR	-14,570	-1,344	-8,018	-7	-3,326	-1,875
58	TI	COVID Deferrals	not_used	0	0	0	0	0	0
59	TI	Current SHARE -- FT	DEPREXP	-21,771,486	-11,563,231	-8,586,766	-2,063	-397,359	-1,222,067
60	TI	Customer Advances	TOTPLTNET	294,687	162,657	112,696	37	1,192	18,105
61	TI	Customer Connection Fees (Contributions in Aid of Constructi	TOTPLTNET	0	0	0	0	0	0
62	TI	Deduction for Retention Payments (c)	LABOR	-4,379	-404	-2,410	-2	-999	-564
63	TI	Deferred Employer ER FICA	LABOR	-5,798,258	-534,862	-3,190,955	-2,695	-1,323,457	-746,288
64	TI	Diesel Fuel Tax Credit	TOTPLT	928	494	375	0	6	53
65	TI	Entertainment (100%)	LABOR	36,298	3,348	19,976	17	8,285	4,672
66	TI	FAS 5 (ASC40) Reserve - Sales Tax	not_used	0	0	0	0	0	0
67	TI	Fed Amort of Deferred Gain on Sale of Generation Assets	not_used	0	0	0	0	0	0
68	TI	Injuries & Damages - FT	TOTPLT	1,044,758	556,541	422,162	99	6,662	59,293
69	TI	Line Pack Adjustment	not_used	0	0	0	0	0	0
70	TI	Plant Related	DEPREXP	-61,904,159	-32,878,422	-24,415,262	-5,866	-1,129,835	-3,474,776
71	TI	Previously Deducted Amort - Reacquired Bonds	not_used	0	0	0	0	0	0
72	TI	Qualified Transportation Fringe	LABOR	139,386	12,858	76,708	65	31,815	17,940
73	TI	R & D Credits CF	not_used	0	0	0	0	0	0
74	TI	R&D Credit - Fed	TOTPLT	-75,718	-40,335	-30,596	-7	-483	-4,297
75	TI	R&D Expenditure	TOTPLT	-16,866	-8,984	-6,815	-2	-108	-957
76	TI	Rabbi Trust	not_used	0	0	0	0	0	0
77	TI	RE - Lease Liability	TOTPLT	-519,350	-276,657	-209,857	-49	-3,312	-29,475
78	TI	RE - ROU Lease Asset	TOTPLT	594,984	316,947	240,419	57	3,794	33,767
79	TI	Reversal of Book Income from Partnerships	TOTPLT	0	0	0	0	0	0
80	TI	Severance Pay (nc)	LABOR	121,791	11,235	67,025	57	27,799	15,676
81	TI	State NOL CF (c)	DEPREXP	7,732,062	4,106,638	3,049,558	733	141,121	434,013
82	TI	Tax Net Bad Debt Writeoffs - FT	TOTPLT	-81,087	-43,195	-32,765	-8	-517	-4,602
83	TI	Unicap book/tax inventory FS	not_used	0	0	0	0	0	0
84	TI	Unrealized G/L on Equity Securities	TOTPLT	142,148	75,722	57,439	14	906	8,067
85	TI	Credits & Adjustments	TOTPLT	0	0	0	0	0	0
86	TI	Repair Allowance	TOTPLT	0	0	0	0	0	0
87	TI	Uncollectible Accounts - Writeoff	EXP_904	0	0	0	0	0	0
88	TI	Injuries and Damages	TOTPLT	0	0	0	0	0	0

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				(1)	(2)	(3)	(4)	(5)	(6)
89	TI	Meals & entertainment	LABOR	-459,207	-42,360	-252,715	-213	-104,814	-59,104
90	TI	Company owned life insurance	LABOR	0	0	0	0	0	0
91	TI	ESOP/401(k) Cash Dividends	TOTPLTNET	-844,650	-466,217	-323,016	-105	-3,417	-51,895
92	TI	Medicare Subsidy		0	0	0	0	0	0
93	TI	Allowable Depreciation	DEPREXP	0	0	0	0	0	0
94	TI	Book Depreciation	DEPREXP	0	0	0	0	0	0
95	TI	Previously Ded Amort-Reacq Bonds	not_used	0	0	0	0	0	0
96	TI	Amortization of Computer Software	INTANGPLT	0	0	0	0	0	0
97	TI	Amort Def Gain - Sale of Gen Asset	not_used	0	0	0	0	0	0
98	TI	Gain on Sale of Services Corp Asset	not_used	0	0	0	0	0	0
99	TI	AFUDC / IDC	TOTPLT	-345,079	-183,823	-139,438	-33	-2,201	-19,584
100	TI	Cost of removal	TOTPLT	0	0	0	0	0	0
101	TI	*Utility Commodity Costs-Non-Taxable Income	not_used	0	0	0	0	0	0
102	TI	*RAC-Environmental Cleanup Costs - Debit	not_used	0	0	0	0	0	0
103	TI	*SBC-Societal Benefits Clause - Unallow Deductions	not_used	0	0	0	0	0	0
104	TI	Deferred Comp - officers	LABOR	-15,155	-1,398	-8,340	-7	-3,459	-1,951
105	TI	Deduction of Securitizartion	not_used	0	0	0	0	0	0
106	TI	Accrued vacation pay adjustment	LABOR	-257,985	-23,798	-141,977	-120	-58,885	-33,205
107	TI	3rd Party Claims	TOTPLT	-975	-519	-394	0	-6	-55
108	TI	Gain/loss bond reacq	not_used	0	0	0	0	0	0
109	TI	Amortization of Call Option Sale	LABOR	0	0	0	0	0	0
110	TI	Contribution in Aid of Construct	TOTPLTNET	0	0	0	0	0	0
111	TI	Pension Accrual Adjustment	LABOR	-7,780,352	-717,701	-4,281,761	-3,616	-1,775,872	-1,001,402
112	TI	Unallowable OPEB Amortization	LABOR	47,224,310	4,356,221	25,988,953	21,950	10,778,990	6,078,196
113	TI	NJ BPU assessment	TOTPLTNET	0	0	0	0	0	0
114	TI	Unicap book/tax inventory	TOTPLTNET	0	0	0	0	0	0
115	TI	W-2 Earnings Exceeding $1,000,000	LABOR	1,506,831	138,998	829,254	700	343,936	193,943
116	TI	Diesel Fuel Tax Credit	not_used	0	0	0	0	0	0
117	TI	Deferred Depreciation & Return on CIP II	TOTPLTNET	0	0	0	0	0	0
118	TI	Capitalized Interest - Section 263A	TOTPLT	0	0	0	0	0	0
119	TI	Clause - Deferred Fuel	not_used	0	0	0	0	0	0
120	TI	Restricted Stock - Permanent	LABOR	-67,594	-6,235	-37,199	-31	-15,429	-8,700
121	TI	Materials & Supplies Reserve	TOTPLT	0	0	0	0	0	0
122	TI	Amortization of Reacquisition of Pref Stock	TOTPLTNET	0	0	0	0	0	0
123	TI	Lobbying Expenses	LABOR	0	0	0	0	0	0
124	TI	Penalties	not_used	0	0	0	0	0	0
125	TI	Dividends Received Deduction	TOTPLTNET	0	0	0	0	0	0
126	TI	Real Estate Taxes	TOTPLTNET	-1,021,308	-563,726	-390,574	-128	-4,132	-62,748
127	TI	Line Pack Adjustment	TOTPLTNET	0	0	0	0	0	0
128	TI	Legal Reserves	TOTPLTNET	0	0	0	0	0	0
129	TI	Casualty Insurance Proceeds	TOTPLT	0	0	0	0	0	0
130	TI	Miscellaneous (R&D Exp., Limit Term Util Plant, ARO Fin 47, F	TOTPLT	0	0	0	0	0	0
131	TI	**TOTAL TAX ADJUSTMENTS - FEDERAL**		-44,148,425	-38,568,401	-12,010,047	8,388	6,431,029	-9,393
132	TI								

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				(1)	(2)	(3)	(4)	(5)	(6)
133	TI								
134	TI	**DEVELOPMENT OF INCOME TAXES CONTINUED**							
135	TI								
136	TI	**TAX ADJUSTMENTS - STATE**							
137	TI	Reverse TEFA	TEFA_04	0	0	0	0	0	0
138	TI	Federal Depreciation Reversal	TOTPLT	64,677,176	34,453,448	26,134,512	6,147	412,443	3,670,626
139	TI	State Tax Depreciation	DEPREXP	37,759,415	20,054,710	14,892,472	3,578	689,160	2,119,494
140	TI	Amortization of Service's Asset Sale	TOTPLTNET	0	0	0	0	0	0
141	TI	NOL Utilization	TOTPLTNET	0	0	0	0	0	0
142	TI	**TOTAL TAX ADJUSTMENTS - STATE**		102,436,591	54,508,158	41,026,985	9,725	1,101,603	5,790,120
143	TI								
144	TI	**TAXABLE NET INCOME - STATE**		862,601,382	472,398,832	328,640,533	113,181	6,660,453	54,788,383
145	TI	State Tax Liability		77,634,124	42,515,895	29,577,648	10,186	599,441	4,930,955
146	TI	Prior Year Adjustment & State Credit	TOTPLTNET	0	0	0	0	0	0
147	TI	**TOTAL STATE INCOME TAX LIABILITY**		77,634,124	42,515,895	29,577,648	10,186	599,441	4,930,955
148	TI								
149	TI	**TAXABLE NET INCOME - FEDERAL**		682,530,667	375,374,779	258,035,900	93,269	4,959,409	44,067,309
150	TI	Federal Tax Liability		143,331,440	78,828,704	54,187,539	19,587	1,041,476	9,254,135
151	TI	Prior Yr & Oth Adjustments	TOTPLTNET	0	0	0	0	0	0
152	TI	Not Used	not_used	0	0	0	0	0	0
153	TI	**TOTAL FEDERAL INCOME TAX LIABILITY**		143,331,440	78,828,704	54,187,539	19,587	1,041,476	9,254,135
154	TI								
155	TI	**TOTAL INCOME TAX EXPENSE**		220,965,564	121,344,599	83,765,187	29,773	1,640,917	14,185,089
156	TI								
157	TI	**TAX RATES**							
158	TI	FEDERAL TAX RATE - CURRENT		21.000%					
159	TI	NEW JERSEY CORP BUSINESS TAX RATE		9.000%					
160	TI	CUSTOMER ACCT UNCOLLECTIBLE RATE		0.000					
161	TI	EFFECTIVE TAX RATE		28.110%					
162	TI	COMPOSITE RATE		28.110%					
163	TI	1 - EFFECTIVE TAX RATE		71.89000%					
164	TI								
165	TI	**DEVELOPMENT OF OPERATING INCOME ADJUSTED**							
166	TI								
167	TI	**G410 + G411- PROVISION FOR DEFERRED INCOME TAX**							
168	TI	Additional Rental Income - NJ Properties	TOTPLT	0	0	0	0	0	0
169	TI	Amort of Def Gain on Sale of Services Assets	not_used	0	0	0	0	0	0
170	TI	Amort of Deferred Gain on Sale of Generation Assets	not_used	0	0	0	0	0	0
171	TI	Amortization of Limited-Term Utility Plant	TOTPLT	14	7	6	0	0	1
172	TI	Bankruptcies and Accum Provision for Rent Receivable	TOTPLT	-31,746	-16,911	-12,828	-3	-202	-1,802
173	TI	Casualty Loss Deferred O&M	TOTPLTNET	1,095,802	604,844	419,062	137	4,433	67,325
174	TI	CECL Reserve	not_used	0	0	0	0	0	0
175	TI	CEF- EC AMI	TOTPLT	0	0	0	0	0	0
176	TI	CEF- EV Deferral	TOTPLT	0	0	0	0	0	0

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
177	TI	Clause - Demographic Studies	not_used	0	0	0	0	0	0
178	TI	Clause - Navigant Studies	not_used	0	0	0	0	0	0
179	TI	Clause - RAC (Environmental Clean Up)	not_used	0	0	0	0	0	0
180	TI	Clause - Societal Benefits Clause (AAP)	not_used	0	0	0	0	0	0
181	TI	COVID Deferrals	not_used	0	0	0	0	0	0
182	TI	Current SHARE -- FT	DEPREXP	5,506,769	2,924,745	2,171,893	522	100,506	309,103
183	TI	Customer Advances	TOTPLTNET	-294,687	-162,657	-112,696	-37	-1,192	-18,105
184	TI	Deduction for Retention Payments (c)	LABOR	4,379	404	2,410	2	999	564
185	TI	Deferred Employer ER FICA	LABOR	5,798,258	534,862	3,190,955	2,695	1,323,457	746,288
186	TI	FAS 5 (ASC40) Reserve - Sales Tax	not_used	0	0	0	0	0	0
187	TI	Fed Amort of Deferred Gain on Sale of Generation Assets	not_used	0	0	0	0	0	0
188	TI	Injuries & Damages - FT	TOTPLT	-264,256	-140,769	-106,780	-25	-1,685	-14,997
189	TI	Line Pack Adjustment	not_used	0	0	0	0	0	0
190	TI	Medicare Subsidy	not_used	0	0	0	0	0	0
191	TI	Partnership Income/Loss (nc)	TOTPLT	0	0	0	0	0	0
192	TI	Plant Related	DEPREXP	62,706,788	33,304,712	24,731,822	5,942	1,144,484	3,519,828
193	TI	Previously Deducted Amort - Reacquired Bonds	not_used	0	0	0	0	0	0
194	TI	R & D Credits CF	TOTPLT	-67,859	-36,148	-27,420	-6	-433	-3,851
195	TI	RE - Lease Liability	TOTPLT	519,350	276,657	209,857	49	3,312	29,475
196	TI	RE - ROU Lease Asset	TOTPLT	-594,984	-316,947	-240,419	-57	-3,794	-33,767
197	TI	Real Estate Taxes (nc)	TOTPLT	1,021,308	544,049	412,686	97	6,513	57,962
198	TI	Reversal of Book Income from Partnerships	TOTPLT	0	0	0	0	0	0
199	TI	Severance Pay (nc)	LABOR	-121,791	-11,235	-67,025	-57	-27,799	-15,676
200	TI	State NOL CF (c)	DEPREXP	-7,732,062	-4,106,638	-3,049,558	-733	-141,121	-434,013
201	TI	Unrealized G/L on Equity Securities	TOTPLT	-142,148	-75,722	-57,439	-14	-906	-8,067
202	TI	Previously Ded Amort-Reacq Bonds	not_used	0	0	0	0	0	0
203	TI	Clause - Deferred Fuel	not_used	0	0	0	0	0	0
204	TI	Gain on Sale of Services Corp Asset	not_used	0	0	0	0	0	0
205	TI	AFUDC / IDC	TOTPLT	345,079	183,823	139,438	33	2,201	19,584
206	TI	Capitalized interest-Section 263A	TOTPLT	-416,892	-222,078	-168,456	-40	-2,658	-23,660
207	TI	Cost of removal	TOTPLT	0	0	0	0	0	0
208	TI	Deferred Comp - officers	LABOR	15,155	1,398	8,340	7	3,459	1,951
209	TI	Deduction of Securitizartion	not_used	0	0	0	0	0	0
210	TI	Accrued vacation pay adjustment	LABOR	257,985	23,798	141,977	120	58,885	33,205
211	TI	Gain/loss bond reacq	not_used	0	0	0	0	0	0
212	TI	Amortization of Call Option Sale	LABOR	0	0	0	0	0	0
213	TI	Defer Dividend Equivalents/Restricted Stock-Temp.	LABOR	0	0	0	0	0	0
214	TI	Contribution in Aid of Construct	TOTPLTNET	0	0	0	0	0	0
215	TI	Pension Accrual Adjustment	LABOR	7,780,352	717,701	4,281,761	3,616	1,775,872	1,001,402
216	TI	Unallowable OPEB Amortization	LABOR	-47,224,310	-4,356,221	-25,988,953	-21,950	-10,778,990	-6,078,196
217	TI	Fin Def-Energy Competition Act Ct	TOTPLT	0	0	0	0	0	0
218	TI	Rabbi Trust Unrealized Losses		0	0	0	0	0	0
219	TI	Additional Real Estate Taxes	TOTPLT	0	0	0	0	0	0
220	TI	PIP Adjustment	LABOR	455,695	42,036	250,783	212	104,013	58,652

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				(1)	(2)	(3)	(4)	(5)	(6)
221	TI	Deferred NJ Corp Bus Tax(Net of FIT)	TOTPLTNET	0	0	0	0	0	0
222	TI	Misc	TOTPLT	0	0	0	0	0	0
223	TI	Construction Period Interest	TOTPLTNET	0	0	0	0	0	0
224	TI	Deferred Return on CIP ll	TOTPLT	-18,055	-9,618	-7,296	-2	-115	-1,025
225	TI	Deferred Depreciation on CIP ll	TOTPLT	-8,262	-4,401	-3,338	-1	-53	-469
226	TI	Investment Tax Credit	TOTPLT	-493,265	-262,762	-199,317	-47	-3,146	-27,994
227	TI	Assessment by Board of Public Utilities of the State of NJ	TOTPLTNET	-56,782	-31,342	-21,715	-7	-230	-3,489
228	TI	3rd Party Claims	TOTPLT	975	519	394	0	6	55
229	TI	Customer Connections Fees		0	0	0	0	0	0
230	TI	Legal Reserves (nc)	TOTPLTNET	418,012	230,728	159,858	52	1,691	25,682
231	TI	Material Supplies & Reserves	TOTPLTNET	-78,535	-43,349	-30,034	-10	-318	-4,825
232	TI	Stock Based Compensation	TOTPLTNET	325,229	179,515	124,376	41	1,316	19,982
233	TI	**TOTAL DEFERRED INCOME TAX**		28,705,516	29,773,002	6,152,346	-9,462	-6,431,494	-778,876
234	TI								
235	TI	**This Section is not used at this time**							
236	TI	**PROFORMA OPERATING INCOME ADJUSTMENTS**							
237	TI	Not Used	not_used	0	0	0	0	0	0
238	TI	Not Used	not_used	0	0	0	0	0	0
239	TI	Not Used	not_used	0	0	0	0	0	0
240	TI	**OPERATING INCOME ADJUSTED**		655,462,203	360,990,593	248,262,226	87,349	4,326,286	41,795,749

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
1	LR	**DEVELOPMENT OF LABOR ALLOCATION FACTOR**							
2	LR	Labor portion included in O&M Expense							
3	LR								
4	LR	**G700-G742 MANUFACTURED GAS LABOR EXP**	MFGO_M	778,312	0	778,312	0	0	0
5	LR	**G813 GAS SUPPLY LABOR EXPENSE**	EXP_813	0	0	0	0	0	0
6	LR	**G840-G843 STORAGE PLANT LABOR EXP**	STOREXP	407,976	0	407,976	0	0	0
7	LR	**G850-G867 TRANSMISSION LABOR EXP**	TRANEXP	483,267	0	483,267	0	0	0
8	LR								
9	LR	**DISTRIBUTION LABOR EXPENSE**							
10	LR	Operation							
11	LR	G870 Operation Supervision & Engineering	TLABDO	0	0	0	0	0	0
12	LR	G871 Load Dispatching	EXP_871	4,522,112	0	4,522,112	0	0	0
13	LR	G872 Compressor Station Labor & Expenses	EXP_872	0	0	0	0	0	0
14	LR	G874 Mains & Services	EXP_874	14,351,672	8,477,124	5,874,548	0	0	0
15	LR	G875-877 Meas & Reg Station	EXP_8757	1,368,583	0	1,368,583	0	0	0
16	LR	G878 Meter & House Reg	EXP_878	8,562,092	1,901,176	0	0	0	6,660,916
17	LR	G879 Customer Installations - Total	EXP_879	63,057,319	0	63,057,319	0	0	0
18	LR	G880.1 Miscellaneous Dist Exp	EXP_8801	5,219,383	1,346,785	3,058,957	0	0	813,641
19	LR	G880.3 Operation of Street Lighting	EXP_8803	0	0	0	0	0	0
20	LR	G881 Rents	EXP_881	-60	0	-60	0	0	0
21	LR	Total Operation		97,081,101	11,725,086	77,881,458	0	0	7,474,557
22	LR								
23	LR	Maintenance							
24	LR	G885 Maint. Supervision & Engineering	TLABDM	0	0	0	0	0	0
25	LR	G886 Structures & Improvements	EXP_886	1,015,469	553,706	402,845	99	0	58,819
26	LR	G887 Mains	EXP_887	4,445,965	0	4,445,965	0	0	0
27	LR	G888 Compressor Station Equip	EXP_888	0	0	0	0	0	0
28	LR	G889-891 Meas & Reg Station	EXP_8891	2,185,363	0	2,185,363	0	0	0
29	LR	G892 Services	EXP_892	2,126,460	2,126,460	0	0	0	0
30	LR	G893 Meters & House Reg	EXP_893	5,044,535	0	0	0	0	5,044,535
31	LR	G894 Maint of Other Equipment - Total	EXP_894	71,094	825	1,659	67,862	0	748
32	LR	Not Used	not_used	0	0	0	0	0	0
33	LR	Total Maintenance		14,888,885	2,680,991	7,035,832	67,960		5,104,101
34	LR	TOTAL DISTRIBUTION LABOR EXPENSE		111,969,986	14,406,077	84,917,290	67,960	0	12,578,658
35	LR								
36	LR	**G901-G903,G905 CUST ACCOUNTS EXPENSE**	CUSTACCTS	45,109,566	0	1,682,855	0	35,356,012	8,070,699
37	LR	**G907-G910, xDSM CUST SERV & INFO EXP**	CUSTS_I	3,007,750	0	1,936,120	0	1,071,630	0
38	LR	**G911-G916 SALES EXPENSE**	SALESEXP	3,526	0	3,526	0	0	0
39	LR	**ADMIN & GENERAL EXP ACCOUNTS xG926**	AGEXP	6,954,680	1,157,095	2,639,609	10,459	2,081,720	1,065,797
40	LR	**Employee Pension/Benefits Acct G926**	LABOR	0	0	0	0	0	0
41	LR								
42	LR	**TOTAL OPERATION & MAINT LABOR EXPENSE**		168,715,063	15,563,172	92,848,956	78,420	38,509,362	21,715,154

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
1	CA	**DEVELOPMENT OF CAPITAL ADDITIONS ALLOCATION F/**							
2	CA								
3	CA	**INTANGIBLE PLANT - G301-G303**	INTANGPLT	0	0	0	0	0	0
4	CA	**PRODUCTION PLANT - G304-G347**	PRODPLT	-2,267,387	0	-2,267,387	0	0	0
5	CA	**STORAGE PLANT - G360-G363**	STORPLT	8,371,561	0	8,371,561	0	0	0
6	CA	TRANSMISSION PLANT - G365-G371	TRANPLT	11	0	11	0	0	0
7	CA								
8	CA	**DISTRIBUTION PLANT**							
9	CA	G374 Land and Land Rights & G375 Structure & Improvemei	PLT_3745	2,620,552	1,428,913	1,039,595	255	0	151,789
10	CA	G376 Mains	PLT_376	226,633,216	0	226,633,216	0	0	0
11	CA	G377 Compressor Station Equipment	PLT_377	0	0	0	0	0	0
12	CA	G378-G379 Meas & Regul Eqmt	PLT_3789	57,069,064	0	57,069,064	0	0	0
13	CA	G380 Services	SERVICES	505,466,924	505,466,924	0	0	0	0
14	CA	G381 Meters	PLT_381	58,899,779	0	0	0	0	58,899,779
15	CA	G382 Meter Installations	PLT_382	-1,810,761	0	0	0	0	-1,810,761
16	CA	G383-384 House Regulators & Install	PLT_3834	2,268,333	2,268,333	0	0	0	0
17	CA	G385 Ind Reg & Meas Eqmt	PLT_385	12,739,212	6,369,606				6,369,606
18	CA	TOTAL DISTRIBUTION PLANT		863,886,319	515,533,776	284,741,875	255	0	63,610,413
19	CA								
20	CA	**COMMON PLANT**	COMPLT	0	0	0	0	0	0
21	CA	**GENERAL PLANT EXCL INTANGIBLE PLT**	GENPLT	26,119,255	15,109,213	10,992,591	2,696	0	14,755
22									
23	CA	**TOTAL CAPITAL ADDITIONS**		896,109,759	530,642,989	301,838,650	2,951	0	63,625,169

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				(1)	(2)	(3)	(4)	(5)	(6)
1	AF	**ALLOCATION FACTOR TABLE**							
2	AF	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**							
3	AF								
4	AF	**CAPACITY RELATED**							
5	AF	Peak-Hour Sendout - delivery	PEAKHOUR_04	124,747	0	124,747	0	0	0
6	AF								
7	AF	**COMMODITY RELATED**							
8	AF	Annual transported gas @mtr - delivery	TRANSPORT_04	2,598,285,838	0	2,598,285,838	0	0	0
9	AF	Balancing therms - delivery	BALANCE_04	1,793,060	0	1,793,060	0	0	0
10	AF	Annual transported gas @mtr - access	TRANSPORT_03	2,598,285,838	2,598,285,838	0	0	0	0
11	AF	Annual transported gas @mtr - meters	TRANSPORT_07	2,598,285,838	0	0	0	0	2,598,285,838
12	AF	TEFA $ responsibility W/N - delivery	TEFA_04						
13	AF								
14	AF	**BILLING DETERMINANTS**							
15	AF	Number of Customers		1,894,095	1,894,095	1,894,095	1,894,095	1,894,095	1,894,095
16	AF	Transported Gas at Meter (calendar)		2,598,285,838	2,598,285,838	2,598,285,838	2,598,285,838	2,598,285,838	2,598,285,838
17	AF								
18	AF								
19	AF	**CUSTOMER RELATED**							
20	AF	G380 services - access	SERVICES_03	1,215,746,207	1,215,746,207	0	0	0	0
21	AF	Cust Installns LDC G879 - delivery	CINST_04	100	0	100	0	0	0
22	AF	Avg Customer Bills - delivery	CUSTAVG_04	661,048	0	661,048	0	0	0
23	AF	Avg Customer Bills - cust svs	CUSTAVG_06	661,048	0	0	0	661,048	0
24	AF	G381 meters - measurement	SMMETERS_07	95,373,410	0	0	0	0	95,373,410
25	AF								
26	AF	Billing Function costs - cust svs	BILLING_06	20,835,825	0	0	0	20,835,825	0
27	AF	Competitive Service work - delivery	COMPSVSWK_04	100	0	100	0	0	0
28	AF								
29	AF	Account Maint - cust svs	ACCTMAINT_06	67,192,728	0	0	0	67,192,728	0
30	AF	G382 meter install - measurement	MTRINSTAL_07	149,490,256	0	0	0	0	149,490,256
31	AF	G383 house regulators - access	HOUSEREG_03	27,726,351	27,726,351	0	0	0	0
32	AF	G384 house reg install - access	HSEREGINST_03	49,550,462	49,550,462	0	0	0	0
33	AF	G385 lrg regulators - access	LRGREG_03	42,370,365	42,370,365	0	0	0	0
34	AF	G385 lrg mtrs - measurement	LRGMTR_07	6,790,868	0	0	0	0	6,790,868
35	AF	G380 services - reserve - access	SERVICESR_03	302,262,539	302,262,539	0	0	0	0
36	AF	G381 meters - reserve - measurement	SMMETERSR_07	39,637,552	0	0	0	0	39,637,552
37	AF	G382 meter install - reserve -measurement	MTRINSTALR_07	70,947,597	0	0	0	0	70,947,597
38	AF	G383 house regulators - reserve - access	HOUSEREGR_03	4,745,170	4,745,170	0	0	0	0
39	AF	G384 house reg install - reserve - access	HSEREGINSTR_03	9,880,504	9,880,504	0	0	0	0
40	AF	G385 lrg regulators - reserve - access	LRGREGR_03	6,940,251	6,940,251	0	0	0	0
41	AF	G385 lrg mtrs - reserve - measurement	LRGMTRR_07	1,112,795	0	0	0	0	1,112,795
42	AF	Direct LVG - delivery	DIRLVG_04	0	0	0	0	0	0
43	AF	Direct LVG - cust svs	DIRLVG_06	0	0	0	0	0	0
44	AF	ALLOCATION FACTOR TABLE							

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				(1)	(2)	(3)	(4)	(5)	(6)
45	AF	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**							
46	AF								
47	AF	Direct SLG - streetlights	DIRSLG_05	1	0	0	1	0	0
48	AF	Meter Reading Costs - measurement	MRCOST_07	16,284,753	0	0	0	0	16,284,753
49	AF	Other Utility work by Cust Ops - delivery	UTILWORK_04	6,776,917	0	6,776,917	0	0	0
50	AF	Direct SLG - access	DIRSLG_03	1	1	0	0	0	0
51	AF	Direct Competitive Services - delivery	DIRCOMPSVS_04	0	0	0	0	0	0
52	AF	Direct TSG-F - access	DIRTSGF_03	0	0	0	0	0	0
53	AF	Direct TSG-F - delivery	DIRTSGF_04	0	0	0	0	0	0
54	AF	Direct TSG-F - measurement	DIRTSGF_07	0	0	0	0	0	0
55	AF	Direct - RSG - delivery	DIRRSG_04	0	0	0	0	0	0
56	AF	Choice - delivery	CHOICE_04	1,894,095	0	1,894,095	0	0	0
57	AF								
58	AF								
59	AF	Dummy allocator for unused lines	not_used	0	0	0	0	0	0
60	AF								
61	AF								
62	AF	**Plant Related**							
63	AF	Acct G301-G303 Intangible Plt	INTANGPLT	0	0	0	0	0	0
64	AF	Acct G399.10-23 Oth Tangible Plt	TANGPLT	16,791,854	283,770	1,334,206	51	12,410,339	2,763,489
65	AF	Production Plant Total	PRODPLT	52,043,670	0	52,043,670	0	0	0
66	AF	Storage Plant Total	STORPLT	19,575,233	0	19,575,233	0	0	0
67	AF	Transmission Plant Total	TRANPLT	103,544,395	0	103,544,395	0	0	0
68	AF	Distribution Plant Total	DISTPLT	10,498,076,770	5,724,304,805	4,164,673,568	1,021,319	0	608,077,078
69	AF	G391-G398 General Plant	GENPLT	200,812,197	116,163,890	84,514,137	20,726	0	113,444
70	AF	Common Plant	COMPLT	102,234,955	15,246,506	16,357,253	2,720	57,691,885	12,936,591
71	AF	Accts C389-C399, G391-E398 Com & Gen Plt	COMGENPLT	303,047,153	131,410,396	100,871,390	23,446	57,691,885	13,050,035
72	AF	Total Prod, Storage, Transmission, & Dist Plant	PSTDPLT	10,673,240,067	5,724,304,805	4,339,836,866	1,021,319	0	608,077,078
73	AF	Total Plant	TOTPLT	10,993,079,074	5,855,998,970	4,442,042,462	1,044,816	70,102,224	623,890,602
74	AF								
75	AF	Distribution Plant x Meters & Installs	DISTPLTXMTR	9,895,589,959	5,724,304,805	4,164,673,568	1,021,319	0	5,590,267
76	AF	Acct G374-375 - Land & Structures	PLT_3745	96,512,525	52,625,554	38,287,314	9,389	0	5,590,267
77	AF	Acct G376 - Mains	PLT_376	3,775,184,891	0	3,775,184,891	0	0	0
78	AF	Acct G377 - Compressor Station Equip	PLT_377	0	0	0	0	0	0
79	AF	Acct G378-379 - Meas & Regul Station Equip	PLT_3789	285,986,290	0	285,986,290	0	0	0
80	AF	Acct G380 & 387.2 - Services	SERVICES	5,447,689,486	5,447,689,486	0	0	0	0
81	AF	Acct G376, G380 & 387.2 - Mains & Services	MAIN_SERV	9,222,874,377	5,447,689,486	3,775,184,891	0	0	0
82	AF	Acct G381 - House Meters	PLT_381	477,048,047	0	0	0	0	477,048,047
83	AF	Acct G382 - Meter Installations	PLT_382	52,631,537	0	0	0	0	52,631,537
84	AF	Acct G381,382, & 385 - Meters	METERPLT	602,486,811	0	0	0	0	602,486,811
85	AF	Acct G381-384 - Meters & House Regulators	PLT_3814	680,862,120	151,182,537	0	0	0	529,679,583
86	AF	Acct G382-384 - House Reg & Install & Meter Install	PLT_3824	203,814,074	151,182,537	0	0	0	52,631,537
87	AF	Acct G383-384 - House Reg & Installation	PLT_3834	151,182,537	151,182,537	0	0	0	0
88	**AF**	**ALLOCATION FACTOR TABLE CONTINUED**							

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
89	AF	**INTERNALLY DEVELOPED ALLOCATION FACTORS**							
90	AF								
91	AF	Acct G385 - Ind & Com Meas & Regul Station Equip	PLT_385	145,614,455	72,807,227	0	0	0	72,807,227
92	AF	Acct G386 - Other Property on Cust Premises	PLT_386	0	0	0	0	0	0
93	AF	Acct G387.1 - Other Equipment (St Ltg Posts)	PLT_387_1	1,011,930	0	0	1,011,930	0	0
94	AF								
95	AF	Total Distribution Plant Reserve	TOTDRESERVE	2,718,471,978	1,288,707,941	1,277,621,837	11,318	36,625,623	115,505,260
96	AF	Total Net Plant	TOTPLTNET	8,274,607,096	4,567,291,030	3,164,420,625	1,033,497	33,476,602	508,385,342
97	AF								
98	AF								
99	AF	**Revenue Related**							
100	AF	Total Operating Revenue	TOTREV	1,469,037,356	704,651,169	575,011,501	393,797	78,106,181	110,874,707
101	AF	Intra Dept Rev Req - 5.62% GS / 94.38% LV	INTRAREV	194,617,062	50,287,593	129,840,506	0	3,874,123	10,614,841
102	AF								
103	AF								
104	AF	**Expense Related**							
105	AF	Manufactured Gas O&M Excl Fuel Expense	MFGO_M	2,114,238	0	2,114,238	0	0	0
106	AF	Other Storage Plant O&M Expense	STOREXP	2,714,605	0	2,714,605	0	0	0
107	AF	Transmission Plant O&M Expense	TRANEXP	2,593,507	0	2,593,507	0	0	0
108	AF	Acct 813-Other Gas Supply Expense	EXP_813	72	0	72	0	0	0
109	AF	Acct 871 - Distribution Load Dispatching	EXP_871	5,839,316	0	5,839,316	0	0	0
110	AF	Acct 872 - Compressor Station Labor & Expenses	EXP_872	0	0	0	0	0	0
111	AF	Acct 874-Mains & Services Expenses	EXP_874	20,733,577	12,246,734	8,486,843	0	0	0
112	AF	Acct 875-877 - Meas & Regulating Station Exp	EXP_8757	3,019,152	0	3,019,152	0	0	0
113	AF	Acct 878 - Meter & House Regulator Expenses	EXP_878	11,492,061	2,551,763	0	0	0	8,940,298
114	AF	Acct 879 - Customer Installation Expenses	EXP_879	17,355,157	0	17,355,157	0	0	0
115	AF	Acct 880.0,.1,.2 - Other Expenses	EXP_8801	14,050,188	3,625,445	8,234,483	0	0	2,190,260
116	AF	Acct 880.3 - Operation of Street Lighting Exp	EXP_8803	0	0	0	0	0	0
117	AF	Acct 881 - Rents	EXP_881	-1,088,602	0	-1,088,602	0	0	0
118	AF	Acct 886-Maint of Structures & Improvements Exp	EXP_886	8,016,449	4,371,143	3,180,191	780	0	464,334
119	AF	Acct 887-Maint of Mains Exp	EXP_887	8,706,285	0	8,706,285	0	0	0
120	AF	Acct 888-Maint of Compressor Station Equip Exp	EXP_888	0	0	0	0	0	0
121	AF	Acct 889-891 - Main of Meas & Reg Station Equip	EXP_8891	4,163,462	0	4,163,462	0	0	0
122	AF	Acct 892-Main of Services Exp	EXP_892	3,610,466	3,610,466	0	0	0	0
123	AF	Acct 893-Maint of Meters & House Regulators Exp	EXP_893	6,767,990	0	0	0	0	6,767,990
124	AF	Acct 894-Maint of Other Equipment	EXP_894	207,897	2,413	4,853	198,445	0	2,187
125	AF								
126	AF	Distr Oper Exp	DISTEXPO	71,400,849	18,423,942	41,846,349	0	0	11,130,558
127	AF	Distr Maint Exp	DISTEXPM	31,472,549	7,984,022	16,054,791	199,225	0	7,234,511
128	AF	Cust Serv & Info Expense	CUSTS_I	4,034,218	0	2,596,868	0	1,437,350	0
129	AF	Acct 901-903,905 Cust Acct Exp Excl 904	CACCTEXP	72,712,827	0	2,712,621	0	56,990,917	13,009,288
130	AF	Accts 901-910 Excl 904 - Cust Accts,Serv & Info	CUSTSVSX	76,747,044	0	5,309,489	0	58,428,267	13,009,288
131	AF	Sales Expense	SALESEXP	88,423	0	88,423	0	0	0
132	**AF**	**ALLOCATION FACTOR TABLE CONTINUED**							

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
133	AF	**INTERNALLY DEVELOPED ALLOCATION FACTORS**							
134	AF								
135	AF	Total O&M Expense Excl A&G Expense	TOTOMXAG	242,970,637	39,325,391	110,179,614	199,225	59,860,497	33,405,910
136	AF	Total O&M Expense Excl 904 Expense	TOTOMX904	255,675,994	32,855,396	115,222,236	257,504	70,027,788	37,313,068
137	AF	Total O&M Expense Excl Fuel & 904 Expense	TOMXFUEL904	223,769,120	32,855,396	83,315,363	257,504	70,027,788	37,313,068
138	AF	Tot Admin & Genl Exp xPension/Ben	AGEXP	38,752,071	6,447,431	14,708,128	58,280	11,599,521	5,938,711
139	AF	Accts 901-905 Cust Accts Exp Excl 904-Uncol	CUSTACCTS	72,712,827	0	2,712,621	0	56,990,917	13,009,288
140	AF	O&M + Capital Additions	EXPENDITURES	1,177,832,467	576,415,811	426,726,393	260,455	71,460,018	102,969,790
141	AF								
142	AF	Depreciation Expense (total)	DEPREXP	203,691,216	108,184,098	80,336,675	19,302	3,717,640	11,433,501
143	AF								
144	AF	NJ State Income Tax (CBT)	STATEINCTAX	77,634,124	42,515,895	29,577,648	10,186	599,441	4,930,955
145	AF	NJ State Deferred Income Tax	DFSTATEINCTAX	-39,443,958	-3,638,520	-21,707,192	-18,334	-9,003,118	-5,076,794
146	AF								
147	AF	**Labor Expense Related**							
148	AF	Total Distribution Exp (Oper) Labor	TLABDO	97,081,101	11,725,086	77,881,458	0	0	7,474,557
149	AF	Total Distribution Exp (Maint) Labor	TLABDM	14,888,885	2,680,991	7,035,832	67,960	0	5,104,101
150	AF	Total Labor	LABOR	168,715,063	15,563,172	92,848,956	78,420	38,509,362	21,715,154
151	AF								
152	AF	**REVENUES AND BILLING DETERMINANTS**							
153	AF								
154	AF	Base Rate Sales Revenue	SALESREV	1,401,350,320	694,814,985	519,849,840	388,577	77,033,143	109,263,775
155	AF								
156	AF	Residential Service Gas	REVRSG	1,015,564,742	565,250,132	312,527,400	0	65,497,713	72,289,497
157	AF	General Service Gas	REVGSG	181,736,301	80,572,051	67,939,726	0	6,068,891	27,155,634
158	AF	Large Volume Service Gas	REVLVG	195,384,067	48,484,259	133,526,481	0	3,743,433	9,629,894
159	AF	Street Light Gas	REVSLG	470,352	72,339	6,417	388,577	2,995	24
160	AF	Firm Transportation Gas Service	REVTSGF	8,194,858	436,204	5,849,816	0	1,720,111	188,726
161	AF								
162	AF								
163	AF	Total Rev Req @ desired ROR	REVREQ	1,401,350,320	694,814,985	519,849,840	388,577	77,033,143	109,263,775
164	AF								
165	AF								
166	AF	**PRESENT REVENUES FROM SALES INPUT**							
167	AF								
168	AF	Total Sales of Gas Revenue Requirement		0	0	0	0	0	0
169	AF	Sales of Gas Revenues - Rates		1,101,761	1,101,761	1,101,761	1,101,761	1,101,761	1,101,761
170	AF	Sales of Gas Revenues - Other		0	0	0	0	0	0
171	AF								
172	AF	**RATE OF RETURN**							
173	AF	Rate of Return (Equalized)	CALCULATED	7.55%	7.55%	7.55%	7.55%	7.55%	7.55%

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
1	AP	**ALLOCATION PROPORTIONS TABLE**							
2	AP	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**							
3	AP								
4	AP	**CAPACITY RELATED**							
5	AP	Peak-Hour Sendout - delivery	PEAKHOUR_04	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
6	AP								
7	AP	**COMMODITY RELATED**							
8	AP	Annual transported gas @mtr - delivery	TRANSPORT_04	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
9	AP	Balancing therms - delivery	BALANCE_04	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
10	AP	Annual transported gas @mtr - access	TRANSPORT_03	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000
11	AP	Annual transported gas @mtr - meters	TRANSPORT_07	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000
12	AP	TEFA $ responsibility W/N - delivery	TEFA_04	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
13	AF								
14	AP	**BILLING DETERMINANTS**							
15	AP	Number of Customers		1.000000	1.000000	1.000000	1.000000	1.000000	1.000000
16	AP	Transported Gas at Meter (calendar)		1.000000	1.000000	1.000000	1.000000	1.000000	1.000000
17	AP								
18	AP								
19	AP	**CUSTOMER RELATED**							
20	AP	G380 services - access	SERVICES_03	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000
21	AP	Cust Installns LDC G879 - delivery	CINST_04	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
22	AP	Avg Customer Bills - delivery	CUSTAVG_04	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
23	AP	Avg Customer Bills - cust svs	CUSTAVG_06	1.000000	0.000000	0.000000	0.000000	1.000000	0.000000
24	AP	G381 meters - measurement	SMMETERS_07	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000
25	AP								
26	AP	Billing Function costs - cust svs	BILLING_06	1.000000	0.000000	0.000000	0.000000	1.000000	0.000000
27	AP	Competitive Service work - delivery	COMPSVSWK_04	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
28	AF								
29	AP	Account Maint - cust svs	ACCTMAINT_06	1.000000	0.000000	0.000000	0.000000	1.000000	0.000000
30	AP	G382 meter install - measurement	MTRINSTAL_07	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000
31	AP	G383 house regulators - access	HOUSEREG_03	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000
32	AP	G384 house reg install - access	HSEREGINST_03	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000
33	AP	G385 lrg regulators - access	LRGREG_03	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000
34	AP	G385 lrg mtrs - measurement	LRGMTR_07	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000
35	AP	G380 services - reserve - access	SERVICESR_03	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000
36	AP	G381 meters - reserve - measurement	SMMETERSR_07	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000
37	AP	G382 meter install - reserve -measurement	MTRINSTALR_07	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000
38	AP	G383 house regulators - reserve - access	HOUSEREGR_03	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000
39	AP	G384 house reg install - reserve - access	HSEREGINSTR_03	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000
40	AP	G385 lrg regulators - reserve - access	LRGREGR_03	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000
41	AP	G385 lrg mtrs - reserve - measurement	LRGMTRR_07	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000
42	AP	Direct LVG - delivery	DIRLVG_04	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
43	AP	Direct LVG - cust svs	DIRLVG_06	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
44	**AP**	**ALLOCATION PROPORTIONS TABLE CONTINUED**							

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
45	AP	EXTERNALLY DEVELOPED ALLOCATION FACTORS							
46	AP								
47	AP	Direct SLG - streetlights	DIRSLG_05	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000
48	AP	Meter Reading Costs - measurement	MRCOST_07	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000
49	AP	Other Utility work by Cust Ops - delivery	UTILWORK_04	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
50	AP	Direct SLG - access	DIRSLG_03	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000
51	AP	Direct Competitive Services - delivery	DIRCOMPSVS_04	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
52	AP	Direct TSG-F - access	DIRTSGF_03	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
53	AP	Direct TSG-F - delivery	DIRTSGF_04	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
54	AP	Direct TSG-F - measurement	DIRTSGF_07	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
55	AP	Direct - RSG - delivery	DIRRSG_04	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
56	AP	Choice - delivery	CHOICE_04	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
57	AP								
58	AP								
59	AP	Dummy allocator for unused lines	not_used	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
60	AP								
61	AP								
62	AP	Plant Related							
63	AP	Acct G301-G303 Intangible Plt	INTANGPLT	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
64	AP	Acct G399.10-23 Oth Tangible Plt	TANGPLT	1.000000	0.016899	0.079456	0.000003	0.739069	0.164573
65	AP	Production Plant Total	PRODPLT	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
66	AP	Storage Plant Total	STORPLT	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
67	AP	Transmission Plant Total	TRANPLT	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
68	AP	Distribution Plant Total	DISTPLT	1.000000	0.545272	0.396708	0.000097	0.000000	0.057923
69	AP	G391-G398 General Plant	GENPLT	1.000000	0.578470	0.420862	0.000103	0.000000	0.000565
70	AP	Common Plant	COMPLT	1.000000	0.149132	0.159997	0.000027	0.564307	0.126538
71	AP	Accts C389-C399, G391-E398 Com & Gen Plt	COMGENPLT	1.000000	0.433630	0.332857	0.000077	0.190373	0.043063
72	AP	Total Prod, Storage, Transmission, & Dist Plant	PSTDPLT	1.000000	0.536323	0.406609	0.000096	0.000000	0.056972
73	AP	Total Plant	TOTPLT	1.000000	0.532699	0.404076	0.000095	0.006377	0.056753
74	AP								
75	AP	Distribution Plant x Meters & Installs	DISTPLTXMTR	1.000000	0.578470	0.420862	0.000103	0.000000	0.000565
76	AP	Acct G374-375 - Land & Structures	PLT_3745	1.000000	0.545272	0.396708	0.000097	0.000000	0.057923
77	AP	Acct G376 - Mains	PLT_376	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
78	AP	Acct G377 - Compressor Station Equip	PLT_377	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
79	AP	Acct G378-379 - Meas & Regul Station Equip	PLT_3789	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
80	AP	Acct G380 & 387.2 - Services	SERVICES	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000
81	AP	Acct G376, G380 & 387.2 - Mains & Services	MAIN_SERV	1.000000	0.590672	0.409328	0.000000	0.000000	0.000000
82	AP	Acct G381 - House Meters	PLT_381	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000
83	AP	Acct G382 - Meter Installations	PLT_382	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000
84	AP	Acct G381,382, & 385 - Meters	METERPLT	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000
85	AP	Acct G381-384 - Meters & House Regulators	PLT_3814	1.000000	0.222046	0.000000	0.000000	0.000000	0.777954
86	AP	Acct G382-384 - House Reg & Install & Meter Install	PLT_3824	1.000000	0.741767	0.000000	0.000000	0.000000	0.258233
87	AP	Acct G383-384 - House Reg & Installation	PLT_3834	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000
88	AP	**ALLOCATION PROPORTIONS TABLE CONTINUED**							

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				(1)	(2)	(3)	(4)	(5)	(6)
89	AP	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**							
90	AP								
91	AP	Acct G385 - Ind & Com Meas & Regul Station Equip	PLT_385	1.000000	0.500000	0.000000	0.000000	0.000000	0.500000
92	AP	Acct G386 - Other Property on Cust Premises	PLT_386	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
93	AP	Acct G387.1 - Other Equipment (St Ltg Posts)	PLT_387_1	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000
94	AP								
95	AP	Total Distribution Plant Reserve	TOTDRESERVE	1.000000	0.474056	0.469978	0.000004	0.013473	0.042489
96	AP	Total Net Plant	TOTPLTNET	1.000000	0.551965	0.382425	0.000125	0.004046	0.061439
97	AP								
98	AP								
99	AP	**Revenue Related**							
100	AP	Total Operating Revenue	TOTREV	1.000000	0.479669	0.391421	0.000268	0.053168	0.075474
101	AP	Intra Dept Rev Req - 5.62% GS / 94.38% LV	INTRAREV	1.000000	0.258393	0.667159	0.000000	0.019906	0.054542
102	AP								
103	AP								
104	AP	**Expense Related**							
105	AP	Manufactured Gas O&M Excl Fuel Expense	MFGO_M	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
106	AP	Other Storage Plant O&M Expense	STOREXP	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
107	AP	Transmission Plant O&M Expense	TRANEXP	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
108	AP	Acct 813-Other Gas Supply Expense	EXP_813	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
109	AP	Acct 871 - Distribution Load Dispatching	EXP_871	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
110	AP	Acct 872 - Compressor Station Labor & Expenses	EXP_872	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
111	AP	Acct 874-Mains & Services Expenses	EXP_874	1.000000	0.590672	0.409328	0.000000	0.000000	0.000000
112	AP	Acct 875-877 - Meas & Regulating Station Exp	EXP_8757	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
113	AP	Acct 878 - Meter & House Regulator Expenses	EXP_878	1.000000	0.222046	0.000000	0.000000	0.000000	0.777954
114	AP	Acct 879 - Customer Installation Expenses	EXP_879	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
115	AP	Acct 880.0,.1,.2 - Other Expenses	EXP_8801	1.000000	0.258035	0.586076	0.000000	0.000000	0.155888
116	AP	Acct 880.3 - Operation of Street Lighting Exp	EXP_8803	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
117	AP	Acct 881 - Rents	EXP_881	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
118	AP	Acct 886-Maint of Structures & Improvements Exp	EXP_886	1.000000	0.545272	0.396708	0.000097	0.000000	0.057923
119	AP	Acct 887-Maint of Mains Exp	EXP_887	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
120	AP	Acct 888-Maint of Compressor Station Equip Exp	EXP_888	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
121	AP	Acct 889-891 - Main of Meas & Reg Station Equip	EXP_8891	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
122	AP	Acct 892-Main of Services Exp	EXP_892	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000
123	AP	Acct 893-Maint of Meters & House Regulators Exp	EXP_893	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000
124	AP	Acct 894-Maint of Other Equipment	EXP_894	1.000000	0.011608	0.023342	0.954532	0.000000	0.010518
125	AP								
126	AP	Distr Oper Exp	DISTEXPO	1.000000	0.258035	0.586076	0.000000	0.000000	0.155888
127	AP	Distr Maint Exp	DISTEXPM	1.000000	0.253682	0.510120	0.006330	0.000000	0.229867
128	AP	Cust Serv & Info Expense	CUSTS_I	1.000000	0.000000	0.643710	0.000000	0.356290	0.000000
129	AP	Acct 901-903,905 Cust Acct Exp Excl 904	CACCTEXP	1.000000	0.000000	0.037306	0.000000	0.783781	0.178913
130	AP	Accts 901-910 Excl 904 - Cust Accts,Serv & Info	CUSTSVSX	1.000000	0.000000	0.069182	0.000000	0.761310	0.169509
131	AP	Sales Expense	SALESEXP	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
132	AP	Total O&M Expense Excl A&G Expense	TOTOMXAG	1.000000	0.161852	0.453469	0.000820	0.246369	0.137489

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
133	AP	Total O&M Expense Excl 904 Expense	TOTOMX904	1.000000	0.128504	0.450657	0.001007	0.273893	0.145939
134	AP	Total O&M Expense Excl Fuel & 904 Expense	TOMXFUEL904	1.000000	0.146827	0.372327	0.001151	0.312947	0.166748
135	AP	Tot Admin & Genl Exp xPension/Ben	AGEXP	1.000000	0.166376	0.379544	0.001504	0.299326	0.153249
136	AP	Accts 901-905 Cust Accts Exp Excl 904-Uncol	CUSTACCTS	1.000000	0.000000	0.037306	0.000000	0.783781	0.178913
137	AP	O&M + Capital Additions	EXPENDITURES	1.000000	0.489387	0.362298	0.000221	0.060671	0.087423
138	AP								
139	AP	Depreciation Expense (total)	DEPREXP	1.000000	0.531118	0.394404	0.000095	0.018251	0.056132
140	AP								
141	AP	NJ State Income Tax (CBT)	STATEINCTAX	1.000000	0.547644	0.380988	0.000131	0.007721	0.063515
142	AP	NJ State Deferred Income Tax	DFSTATEINCTAX	1.000000	0.092245	0.550330	0.000465	0.228251	0.128709
143	AP								
144	AP	**Labor Expense Related**							
145	AP	Total Distribution Exp (Oper) Labor	TLABDO	1.000000	0.120776	0.802231	0.000000	0.000000	0.076993
146	AP	Total Distribution Exp (Maint) Labor	TLABDM	1.000000	0.180067	0.472556	0.004565	0.000000	0.342813
147	AP	Total Labor	LABOR	1.000000	0.092245	0.550330	0.000465	0.228251	0.128709
148	AP								
149	AP	**REVENUES AND BILLING DETERMINANTS**							
150	AP								
151	AP	Base Rate Sales Revenue	SALESREV	1.000000	0.495818	0.370964	0.000277	0.054971	0.077970
152	AP								
153	AP	Residential Service Gas	REVRSG	1.000000	0.556587	0.307738	0.000000	0.064494	0.071182
154	AP	General Service Gas	REVGSG	1.000000	0.443346	0.373837	0.000000	0.033394	0.149423
155	AP	Large Volume Service Gas	REVLVG	1.000000	0.248148	0.683405	0.000000	0.019159	0.049287
156	AP	Street Light Gas	REVSLG	1.000000	0.153797	0.013643	0.826140	0.006369	0.000052
157	AP	Firm Transportation Gas Service	REVTSGF	1.000000	0.053229	0.713840	0.000000	0.209901	0.023030
158	AP								
159	AP	Total Rev Req @ desired ROR	REVREQ	1.000000	0.495818	0.370964	0.000277	0.054971	0.077970
160	AP								
161	AP	**PRESENT REVENUES FROM SALES INPUT**							
162	AP	Total Sales of Gas Revenue Requirement		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
163	AP	Sales of Gas Revenues - Rates		1.000000	1.000000	1.000000	1.000000	1.000000	1.000000
164	AP	Sales of Gas Revenues - Other		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
1	ADA	**ALLOCATED DIRECT ASSIGNMENTS**							
2	ADA	**DIRECT ASSIGN TO CLASSES W/SALES REV FUNCTIONS**							
3	ADA								
4	ADA	**Account 904 - Uncollectible Accounts**							
5	ADA	Residential Service Gas	REVRSG	1,015,564,742	565,250,132	312,527,400	0	65,497,713	72,289,497
6	ADA	General Service Gas	REVGSG	181,736,301	80,572,051	67,939,726	0	6,068,891	27,155,634
7	ADA	Large Volume Service Gas	REVLVG	195,384,067	48,484,259	133,526,481	0	3,743,433	9,629,894
8	ADA	Street Light Gas	REVSLG	0	0	0	0	0	0
9	ADA	Firm Transportation Gas Service	REVTSGF	8,194,858	436,204	5,849,816	0	1,720,111	188,726
10	ADA								
11	ADA	Total 904-Uncollectible	EXP_904	1,400,879,968	694,742,646	519,843,424	0	77,030,147	109,263,751
12	ADA								
13	ADA	Total 904-Uncollectible	EXP_904	1.000000	0.495933	0.371083		0.054987	0.077997
14	ADA								
15	ADA	Additional Net Write-Offs at Claimed Rate	EXP_904	0	0	0	0	0	0
16	ADA								
17	ADA	**Rev Req (cal) to Customers Late Payment fees**							
18	ADA	Residential Service Gas	REVRSG	0	0	0	0	0	0
19	ADA	General Service Gas	REVGSG	181,736,301	80,572,051	67,939,726	0	6,068,891	27,155,634
20	ADA	Large Volume Service Gas	REVLVG	195,384,067	48,484,259	133,526,481	0	3,743,433	9,629,894
21	ADA	Street Light Gas	REVSLG	0	0	0	0	0	0
22	ADA	Firm Transportation Gas Service	REVTSGF	0	0	0	0	0	0
23	ADA								
24	ADA	Total Late Payment Fees	REVLATEP	377,120,368	129,056,310	201,466,207	0	9,812,323	36,785,528
25	ADA								
26	ADA	Total Late Payment Fees	REVLATEP	1.000000	0.342215	0.534223		0.026019	0.097543
27	ADA								
28	ADA	**ALLOCATED DIRECT ASSIGNMENTS**							
29	ADA	**DIRECT ASSIGN TO CLASSES W/SALES REV FUNCTIONS**							
30	ADA								
31	ADA	**AVAILABLE**							
32	ADA	Residential Service Gas	REVRSG	0	0	0	0	0	0
33	ADA	General Service Gas	REVGSG	0	0	0	0	0	0
34	ADA	Large Volume Service Gas	REVLVG	0	0	0	0	0	0
35	ADA	Street Light Gas	REVSLG	0	0	0	0	0	0
36	ADA	Firm Transportation Gas Service	REVTSGF	0	0	0	0	0	0
37	ADA								
38	ADA	Total Available	REVAVAIL	0	0	0	0	0	0
39	ADA								
40	ADA	Total Available	REVAVAIL	0.0	0.0	0.0	0.0	0.0	0.0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
1	RRW	**REVENUE REQUIREMENTS**							
2	RRW								
3	RRW	PRESENT RATES							
4	RRW	--							
5	RRW	RATE BASE		8,681,618,581	4,781,332,362	3,288,241,403	1,156,935	57,301,806	553,586,075
6	RRW	NET OPER INC (PRESENT RATES)		655,462,203	360,990,593	248,262,226	87,349	4,326,286	41,795,749
7	RRW	RATE OF RETURN (PRES RATES)		7.55%	7.55%	7.55%	7.55%	7.55%	7.55%
8	RRW	RELATIVE RATE OF RETURN		1.00	1.00	1.00	1.00	1.00	1.00
9	RRW	SALES REVENUE (PRE RATES)		1,401,350,320	694,814,985	519,849,840	388,577	77,033,143	109,263,775
10	RRW	REVENUE PRES RATES $/THERM		$0.5393	$0.2674	$0.2001	$0.0001	$0.0296	$0.0421
11	RRW	REVENUE REQUIRED - $/MO/CUST		$61.65	$30.57	$22.87	$0.02	$3.39	$4.81
12	RRW								
13	RRW								
14	RRW	CLAIMED RATE OF RETURN							
15	RRW	--							
16	RRW	CLAIMED RATE OF RETURN		7.55%	7.55%	7.55%	7.55%	7.55%	7.55%
17	RRW	RETURN REQ FOR CLAIMED ROR		655,462,203	360,990,593	248,262,226	87,349	4,326,286	41,795,749
18	RRW	SALES REVENUE REQ CLAIMED ROR		1,401,350,320	694,814,985	519,849,840	388,577	77,033,143	109,263,775
19	RRW	REVENUE DEFICIENCY SALES REV		0	0	0	0	0	0
20	RRW	PERCENT INCREASE REQUIRED		0.0	0.0	0.0	0.0	0.0	0.0
21	RRW	ANNUAL BOOKED THERM SALES		2,598,285,838	2,598,285,838	2,598,285,838	2,598,285,838	2,598,285,838	2,598,285,838
22	RRW	SALES REV REQUIRED $/THERM		$0.5393	$0.2674	$0.2001	$0.0001	$0.0296	$0.0421
23	RRW	REVENUE DEFICIENCY $/THERM		0.0	0.0	0.0	0.0	0.0	0.0

Based on 12 months actual

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

line #	FUNCTIONAL SEGMENTS REV REQ	Total Company	RSG	GSG	LVG	SLG	TSG-F
		(1)	(2)	(3)	(4)	(5)	(6)
1	Distribution Access	$694,814,985	$565,250,132	$80,572,051	$48,484,259	$72,339	$436,204
2	Distribution Delivery	$519,849,840	$312,527,400	$67,939,726	$133,526,481	$6,417	$5,849,816
3	Street Lighting	$388,577				$388,577	
4	Customer Service	$77,033,143	$65,497,713	$6,068,891	$3,743,433	$2,995	$1,720,111
5	Measurement	$109,263,775	$72,289,497	$27,155,634	$9,629,894	$24	$188,726
6	Total	$1,401,350,320	$1,015,564,742	$181,736,301	$195,384,067	$470,352	$8,194,858

Cost of Service and Rate Design Sync

Part 1: Cost of Service Study Results

		(1)	(2)	(3)	(4)	(5)	(6)	
line #		Total	RSG	GSG	LVG	SLG	TSG-F	Note:
	Functionalized Revenue Requirements							
1	Distribution Access	$ 694,814,985	565,250,132	80,572,051	48,484,259	72,339	436,204	SS-G6 R-1, line 1
2	Distribution Delivery	$ 519,849,840	312,527,400	67,939,726	133,526,481	6,417	5,849,816	SS-G6 R-1, line 2
3	Streetlighting Fixtures	$ 388,577	-	-	-	388,577	-	SS-G6 R-1, line 3
4	Customer Service	$ 77,033,143	65,497,713	6,068,891	3,743,433	2,995	1,720,111	SS-G6 R-1, line 4
5	Measurement	$ 109,263,775	72,289,497	27,155,634	9,629,894	24	188,726	SS-G6 R-1, line 5
6	Total	$ 1,401,350,320	$ 1,015,564,742	$ 181,736,301	$ 195,384,067	$ 470,352	$ 8,194,858	
	Part 2: Redistribution of TSG-F Revenue Requirements							
7	BGSS Therms Supplied - COS period	1,997,312,383	1,485,348,311	231,153,115	280,116,216	694,743		COS workpapers
8	% of Total BGSS Therms Supplied	100.0000%	74.3674%	11.5732%	14.0247%	0.0348%		= line 7 / line 7 Col 1 rounded to .0001%
	Redistribution of TSG-F Revenue Requirements							
9	Distribution Access	$ 436,204	$ 324,393	$ 50,483	$ 61,176	$ 152		= TSG-F line 1 * line 8
10	Distribution Delivery	$ 5,849,816	$ 4,350,352	$ 677,010	$ 820,418	$ 2,036		= TSG-F line 2 * line 8
11	Streetlighting Fixtures	$ -	$ -	$ -	$ -	$ -		= TSG-F line 3 * line 8
12	Customer Service	$ 1,720,111	$ 1,279,200	$ 199,072	$ 241,240	$ 599		= TSG-F line 4 * line 8
13	Measurement	$ 188,726	$ 140,350	$ 21,842	$ 26,468	$ 66		= TSG-F line 5 * line 8
14	Total	$ 8,194,857	$ 6,094,295	$ 948,407	$ 1,149,302	$ 2,853		
	Functionalized Revenue Requirements - Total							
15	Distribution Access	$ 694,814,985	$ 565,574,525	$ 80,622,534	$ 48,545,435	$ 72,491		= line 1 + line 9
16	Distribution Delivery	$ 519,849,840	$ 316,877,752	$ 68,616,736	$ 134,346,899	$ 8,453		= line 2 + line 10
17	Streetlighting Fixtures	$ 388,577	$ -	$ -	$ -	$ 388,577		= line 3 + line 11
18	Customer Service	$ 77,033,142	$ 66,776,913	$ 6,267,963	$ 3,984,673	$ 3,594		= line 4 + line 12
19	Measurement	$ 109,263,775	$ 72,429,847	$ 27,177,476	$ 9,656,362	$ 90		= line 5 + line 13
20	Total	$ 1,401,350,319	$ 1,021,659,037	$ 182,684,708	$ 196,533,369	$ 473,205		

Part 3: Calculation of Sync Factors

line #		(7)	(8) RSG	(9) GSG	(10) LVG	(11) SLG	Notes:
1	# of Customers - Rate Design period		1,714,741	140,142	19,609	16	SS-G11 R-1
2	# of Customers - Cost of Service period		1,728,739	145,499	19,809	16	COS workpapers
3	Customer Sync Adjustment Factor		0.99190	0.96318	0.98990	1.00000	= line 1 / line 2
4	Therms Delivered - Rate Design period		1,440,407,705	275,945,122	731,129,378	695,404	SS-G11 R-1
5	Therms Delivered - Cost of Service period		1,542,348,577	293,860,816	759,845,113	694,743	COS workpapers
6	Delivery Sync Adjustment Factor		0.93391	0.93903	0.96221	1.00095	= line 4 / line 5
7	# of Streetlights - Rate Design period					2,550	SS-G11 R-1
8	# of Streetlights - Cost of Service period					2,501	COS Workpapers - SLG Analysis
9	Streetlight Sync Adjustment Factor					1.01971	= line 7 / line 8

Part 4: Initial Snyc

line #		Total	RSG	GSG	LVG	SLG	Notes
10	Distribution Access	$ 686,776,891	560,994,937	77,654,164	48,055,300	72,491	= Page 1, line 15 * line 3
11	Distribution Delivery	$ 489,645,440	295,933,852	64,433,407	129,269,720	8,461	= Page 1, line 16 * line 6
12	Streetlighting Fixtures	$ 396,234	-	-	-	396,234	= Page 1, line 17 * line 9
13	Customer Service	$ 76,221,429	66,236,204	6,037,188	3,944,442	3,594	= Page 1, line 18 * line 3
14	Measurement	$ 107,579,175	71,843,365	26,176,852	9,558,867	90	= Page 1, line 19 * line 3
15	Total	$ 1,360,619,169	$ 995,008,359	$ 174,301,611	$ 190,828,329	$ 480,870	

Part 5: 2023 Base Rate Case Final Revenue Allocation

line #					Notes
16	Requested increase in Revenue Requirements	$	401,374,501		=SS-G8 R-1, pg 1, line 1 * 1000
17	Total Target Distribution Revenue Requirements	$	1,559,057,341		=SS-G8 R-1, pg 2, line 11 * 1000
18	Sum of Initial Sync Revenue Requirements	$	1,360,619,169		Total, col 7, line 15
19	Final Sync Adjustment Factor		1.14584		= line 17 / line 18

line #		Total	RSG	GSG	LVG	SLG	Notes
20	Distribution Access	$ 786,939,195	$ 642,812,695	$ 88,979,559	$ 55,063,878	$ 83,063	= line 10 * line 19
21	Distribution Delivery	$ 561,057,300	$ 339,094,036	$ 73,830,634	$ 148,122,936	$ 9,695	= line 11 * line 19
22	Streetlighting Fixtures	$ 454,022	$ -	$ -	$ -	$ 454,022	= line 12 * line 19
23	Customer Service	$ 87,337,868	$ 75,896,359	$ 6,917,676	$ 4,519,715	$ 4,119	= line 13 * line 19
24	Measurement	$ 123,268,955	$ 82,321,291	$ 29,994,590	$ 10,952,971	$ 103	= line 14 * line 19
25	Total	$ 1,559,057,341	$ 1,140,124,380	$ 199,722,459	$ 218,659,499	$ 551,003	

Inter Class Revenue Allocations

Calculation of Increase Limits

$ 1,559,057

line #		(in $1,000)		Notes:
1	Requested Revenue Increase to be recovered from rate schedule charges =	$ 401,375		SS-G10 R-1
2	Present Distribution Revenue =	$ 1,157,683	from RSG, GSG, LVG & SLG	SS-G8 R-1, pg 2, col 3, line 11
3	Present Total Customer Bills (all on BGSS) =	$ 2,628,737		SS-G8 R-1, pg 2, col 5, line 11
4	Average Distribution Increase =	34.671%		= Line 1 / Line 2
5	Average Total Bill Increase =	15.269%		= Line 1 / Line 3
6	Lower Distribution increase limit =	17.336%	in Distribution charges	= 0.5 * Line 4
7	Upper Distribution increase limit #1 =	52.007%	in Distribution charges	= 1.5 * Line 4
8	Upper Bill increase limit #2 =	30.538%	in Bill Increase	= 2.0 * Line 5

all rounded to 0.001%

Inter Class Revenue Allocations
Calculation of Increases

line #	(1) Rate Schedule	(2) Proposed Distribution Revenue Requirement (from COS) (in $1,000)	(3) Present Distribution Revenue (in $1,000)	(4) Unlimited COS Distribution Charge $ Increase (in $1,000)	(5) Present Total Bill Revenue (all on BGSS) (in $1,000)	(6) Unlimited Distribution Charge Increase (%)	(7) Change in MAC & BGSS credits (in $1,000)	(8) Limited Final Distribution Charge Increase (%)	(9) Proposed Total Bill Increase (%)	(10) Proposed Distribution Revenue Increase (in $1,000)
	Calculation of TSG-F Increase									
1	TSG-F	$ 8,194.858	$ 4,228	$ 3,967.153	$ 16,677	93.837%	$ (42.383)	52.007%	12.930%	$ 2,199
	Calculation of TSG-NF & CIG Increase									
2	TSG-NF	----	$ 13,765	----	$ 77,546	----		34.671%	6.155%	$ 4,773
3	CIG	----	$ 2,571	----	$ 11,930	----		34.671%	7.472%	$ 891
4	CSG[1]	----	$ 7,853	----	$ 8,604	----		----	1.081%	$ 93
	Calculation of Margin Rates (RSG, GSG, LVG & SLG) Increase									
5	RSG	$ 1,140,124	$ 864,539	$ 275,585	$ 1,689,567	31.877%	$ (5,185.00)	31.876%	16.004%	$ 275,579
6	GSG	$ 199,722	$ 131,832	$ 67,890	$ 319,548	51.497%	$ (772.00)	51.496%	21.004%	$ 67,889
7	LVG	$ 218,659	$ 160,846	$ 57,814	$ 618,429	35.944%	$ (1,946.0)	35.943%	9.034%	$ 57,813
8	SLG	$ 551.003	$ 465.867		$ 1,193.478					
9	Distribution Only*	$ 96.980	$ 37.376	$ 59.604		159.468%	$ (2.0340)	52.007%	1.458%	$ 19.438
10	Fixtures*	$ 454.022	$ 428.491	$ 25.531		5.958%		17.336%	6.224%	$ 74.280
11	Total for Margin Rates	$ 1,559,057	$ 1,157,683	$ 401,375	$ 2,628,737	34.671%	$ (7,905)	34.671%	14.968%	$ 401,375 $ 1,559,057 $ 0.0069

[1] CSG Credits all flow back through BGSS

** SLG rows shaded grey (including Distribution & Fixtures) are shown to 3 decimal points*

Notes:	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
	for TSG-F - from 2023 Rate Case Schedule SS-G7 R-1, pg 1, col 6, line 6 for RSG, GSG, LVG & SLG from page 1, line 21	SS-G12 R-1	= (2) - (3)	Page 6	= (4) / (3)	SS-G12 R-1	calculated on limits	= (Col 10 + Col 7) / Col 5	= (3) * (8)

Inter Class Revenue Allocations
Calculation of Increases

EXHIBIT P-9G R-1
Schedule SS-G8 R-1

line #	(1) Rate Schedule	(2) Proposed Distribution Revenue Increase (in $000s)	(3) Proposed Tax Adjustment Credit (in $000s)	(4) Proposed SBC Bad Debts (in $000s)	(5) Proposed SRC (DAC) (in $000s)	(6) Net Delivery Revenue Increase (in $000s)	(7) Net Total Bill Increase (in %)
	Calculation of TSG-F Increase						
1	TSG-F	$ 2,199	$ 359	$ 263	$ 10	$ 2,831	17.0%
	Calculation of TSG-NF & CIG Increase						
2	TSG-NF	$ 4,773	$ 1,032	$ 1,582	$ 62	$ 7,449	9.6%
3	CIG	$ 891	$ 306	$ 315	$ 12	$ 1,524	12.8%
4	CSG	$ 93	$ 599	$ -	$ -	$ 692	8.0%
	Calculation of Margin Rates (RSG, GSG, LVG & SLG) Increase						
					$ -		
5	RSG	$ 275,579	$ (77,037)	$ 19,169	$ 749	$ 218,461	12.9%
6	GSG	$ 67,889	$ (12,593)	$ 3,628	$ 142	$ 59,066	18.5%
7	LVG	$ 57,813	$ (15,330)	$ 9,494	$ 371	$ 52,348	8.5%
8	SLG					$ -	0.0%
9	*Distribution Only**	$ 19.438	$ (49.129)	$ 8.508	$ 0.333	$ (20.850)	-1.7%
10	*Fixtures**	$ 74.280				$ 74.280	6.2%
11	Total for Margin Rates	$ 401,375	$ (102,712)	$ 34,460	$ 1,347	$ 334,470	12.7%
	Distribution Only*						
	Fixtures*						
		Column 10 SS-G8 R-1 Page 2	SS-TAC-6G R-1	SS-SBC-3 R-1	SS-SRC-3G R-1	Col 6 = Col2+ Col3+ Col4+ Col5	Col7 = Col 6 / Page 2 Col 5

** SLG rows shaded grey (including Distribution & Fixtures) are shown to 3 decimal points*

Service Charge Calculations

line #	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	Notes:
1			Average Distribution Increase =		34.671%					SS-G8 R-1 Page 1, line 4
	Rate Schedule	Distribution Access Rev Req (in $1,000)	Customer Service Rev Req (in $1,000)	Measurement Rev Req (in $1,000)	COS Indicated Total Rev Req (in $1,000)	# of Customers	Cost Based Monthly Service Charge ($/month)	Current Monthly Service Charge ($/month)	Proposed Limited Monthly Service Charge ($/month)	
2	RSG	642,813	75,896	82,321	801,030	1,714,741	$ 38.93	$ 8.08	$ 12.28	move to costs, limited @ 1.5 times overall avg Distribution % increase
3	GSG	88,980	6,918	29,995	125,892	140,142	$ 74.86	$ 18.97	$ 28.84	move to costs, limited @ 1.5 times overall avg Distribution % increase
4	LVG	55,064	4,520	10,953	70,537	19,609	$ 299.76	$ 168.50	$ 256.13	move to costs, limited @ 1.5 times overall avg Distribution % increase
5	TSG-F	436	148	189	772	64	$ 1,005.79	$ 902.42	$ 1,005.79	move to costs, limited @ 1.5 times overall avg Distribution % increase
6	TSG-NF					0.230 2.305 148		$ 902.42	$ 1,005.79	set equal to new TSG-F Service Charge
7	CIG					**10**		$ 199.11	$ 268.14	increase current @ average Distribution % increase
8	CSG							$ 902.42	$ 1,005.79	set equal to new TSG-F Service Charge
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	
Notes:	values for RSG, GSG & LVG for Cols 2, 3, & 4 from page 2, lines 16, 19 & 20 values for TSG-F for Cols 2, 3 & 4 from 2023 Rate Case Schedule SS-G7 R-1, page 1, lines 1, 4 & 5				= (2) + (3) + (4)	RSG, GSG & LVG from 2023 Rate Case Schedule SS-G7 R-1, page 2, line 1 TSG-F from COS workpapers	= Col 5 * 1000 / Col 6 / 12 rounded to $0.01	From Tariff	based on methodology described	

COMMODITY BGSS
ACTUAL
"9 and 3" Months Ended May 31, 2024
(Units, $, 000)

	REVENUES	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Total
1	BGSS-RSG	18,127	13,877	12,299	13,731	18,234	41,837	73,841	90,777	87,422	83,489	53,071	29,063	535,768
2	BGSSF-GSG	3,120	2,666	2,729	2,736	3,853	8,952	16,781	20,006	19,075	19,165	11,177	6,078	116,337
3	BGSSF-LVG	3,470	3,124	2,987	2,966	4,570	10,666	21,272	23,787	23,482	24,383	14,617	7,422	142,746
4	BGSSF-SLG	17	11	11	12	12	13	12	12	12	11	11	11	146
5	TSGF	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.000
6	Emergency Sales - TSGF	0.0	0.0	0.0	0.1	0.0	18.8	16.6	0.0	305.9	0.0	0.0	0.0	341.463
7	BGSSI-TSGNF	42	88	12	99	143	491	371	634	834	266	260	261	3,501
8	BGSSI-TSGNF - Pilot Use	0	0	0	2	(4)	0	0	0	0	0	0	0	(2.806)
9	BGSSI-TSGNF - Penalty Use	0	0	0	0	0	0	0	0	0	0	0	0	0.0000
10	Emergency Sales - TSGNF	0	0	0	0	0	0	0	0	0	0	0	0	0.0000
11	CIG - Supply Component	992	376	181	979	444	934	839	730	732	626	560	557	7,950
12	CSG - BGSS-F	0	0	0	0	0	0	0	0	0	0	0	0	0.000
13	CSG - BGSS-I	0	0	0	0	0	0	0	0	0	0	0	0	0.000
14	CSG - Emergency Sales	0	0	0	0	0	0	0	0	0	0	0	0	0.000
15														
16														
17	**THERMS**	**Jun-23**	**Jul-23**	**Aug-23**	**Sep-23**	**Oct-23**	**Nov-23**	**Dec-23**	**Jan-24**	**Feb-24**	**Mar-24**	**Apr-24**	**May-24**	**Total**
18	BGSS-RSG	41,058	31,489	27,923	31,172	46,401	112,489	198,384	243,792	234,597	223,952	142,357	77,960	1,411,573
19	BGSSF-GSG	6,787	5,608	5,501	5,511	7,371	16,142	30,661	38,319	37,404	37,236	22,201	12,018	224,759
20	BGSSF-LVG	7,375	6,335	5,888	6,010	8,690	19,112	38,491	45,338	45,605	47,374	29,033	14,677	273,926
21	BGSSF-SLG	37	22	22	24	22	24	23	23	23	22	22	22	286
22	TSGF	0	0	0	0	0	0	0	0	0	0	0	0	0
23	Emergency Sales - TSGF	0	0	0	0	0	33	31	0	517	0	0	0	580.933
24	BGSSI-TSGNF	97	186	26	212	289	888	708	1,303	930	616	616	616	6,488
25	BGSSI-TSGNF - Pilot Use	0	0	0	0	0	0	0	0	0	0	0	0	0
26	BGSSI-TSGNF - Penalty Use	0	0	0	0	0	0	0	0	0	0	0	0	0
27	Emergency Sales - TSGNF	0	0	0	0	0	0	0	0	0	0	0	0	0
28	CIG - Supply Component	3,797	1,493	651	3,475	1,458	2,863	2,718	2,509	2,638	2,091	2,091	2,091	27,874
29	CSG - BGSS-F	0	0	0	0	0	0	0	0	0	0	0	0	0
30	CSG - BGSS-I	0	0	0	0	0	0	0	0	0	0	0	0	0
31	CSG - Emergency Sales	0	0	0	0	0	0	0	0	0	0	0	0	0
32														
33														
34	**AVG $/THERM**	**Jun-23**	**Jul-23**	**Aug-23**	**Sep-23**	**Oct-23**	**Nov-23**	**Dec-23**	**Jan-24**	**Feb-24**	**Mar-24**	**Apr-24**	**May-24**	**Total**
35	BGSS-RSG	0.441494	0.440687	0.440465	0.440480	0.392964	0.371924	0.210892	0.372356	0.372648	0.372799	0.372799	0.372799	0.379554
36	BGSSF-GSG	0.459648	0.475397	0.495998	0.496471	0.522756	0.554560	0.547311	0.522093	0.509963	0.514690	0.503473	0.505696	0.517608
37	BGSSF-LVG	0.470539	0.493123	0.507319	0.493556	0.525821	0.558050	0.552646	0.524667	0.514908	0.514690	0.503473	0.505696	0.521109
38	BGSSF-SLG	0.467343	0.499357	0.503216	0.504393	0.523142	0.557499	0.541373	0.521833	0.507696	0.514690	0.503473	0.505696	0.510493
39	TSGF	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
40	Emergency Sales - TSGF	0.473821	0.000000	0.000000	0.511911	0.000000	0.571444	0.531448	0.000000	0.592267	0.000000	0.000000	0.000000	0.587783
41	BGSSI-TSGNF	0.431487	0.474112	0.462786	0.466892	0.495541	0.553052	0.523544	0.486531	0.896739	0.432091	0.421095	0.423274	0.539559
42	BGSSI-TSGNF - Pilot Use	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
43	BGSSI-TSGNF - Penalty Use	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
44	Emergency Sales - TSGNF	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
45	CIG - Supply Component	0.261212	0.251871	0.277094	0.281846	0.304848	0.326348	0.308574	0.290868	0.277570	0.299419	0.267786	0.266243	0.285199
46	CSG - BGSS-F	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
47	CSG - BGSS-I	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
48	CSG - Emergency Sales	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000

	REVENUES	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Total
1	BGSS-RSG	21,171	13,880	12,302	13,734	19,733	44,531	83,421	108,013	106,528	83,489	53,071	29,063	588,937
2	BGSSF-GSG	3,161	2,666	2,729	2,736	3,859	9,417	19,204	23,881	23,510	19,165	11,177	6,078	127,582
3	BGSSF-LVG	3,791	3,124	2,987	2,966	4,917	11,146	23,336	27,004	27,078	24,383	14,617	7,422	152,771
4	BGSSF-SLG	17	11	11	12	12	13	12	12	12	11	11	11	146
5	TSGF	0.0000	0.0000	0.0000	0.0000	0.0000	0	0	0	0	0	0	0	0
6	Emergency Sales - TSGF	0.0294	0.0000	0.0000	0.0731	0.0000	19	17	0	323	0	0	0	358.073
7	BGSSI-TSGNF	42	88	12	99	143	491	371	634	834	266	260	261	3,501
8	BGSSI-TSGNF - Pilot Use	0	0	0	2	(4)	0	0	0	0	0	0	0	(2.806)
9	BGSSI-TSGNF - Penalty Use	0	0	0	0	0	0	0	0	0	0	0	0	0.00
10	Emergency Sales - TSGNF	0	0	0	0	0	0	0	0	0	0	0	0	0.00
11	CIG - Supply Component	992	376	181	979	444	934	839	730	732	626	560	557	7,950
12	CSG - BGSS-F	0	0	0	0	0	0	0	0	0	0	0	0	0
13	CSG - BGSS-I	0	0	0	0	0	0	0	0	0	0	0	0	0
14	CSG - Emergency Sales	0	0	0	0	0	0	0	0	0	0	0	0	0
15														
16														
17	**THERMS**	**Jun-23**	**Jul-23**	**Aug-23**	**Sep-23**	**Oct-23**	**Nov-23**	**Dec-23**	**Jan-24**	**Feb-24**	**Mar-24**	**Apr-24**	**May-24**	**Total**
18	BGSS-RSG	47,953	31,496	27,930	31,180	50,216	119,730	224,123	290,081	285,868	223,952	142,357	77,960	1,552,846
19	BGSSF-GSG	6,876	5,608	5,501	5,511	7,382	16,980	35,089	45,741	46,101	37,236	22,201	12,018	246,245
20	BGSSF-LVG	8,056	6,335	5,888	6,010	9,351	19,973	42,226	51,469	52,589	47,374	29,033	14,677	292,980
21	BGSSF-SLG	37	22	22	24	22	24	23	23	23	22	22	22	286
22	TSGF	0.000	0.000	0.000	0.000	0.000	0	0	0	0	0	0	0	0.000
23	Emergency Sales - TSGF	0.062	0.000	0.000	0.143	0.000	33	31	0	517	0	0	0	580.933
24	BGSSI-TSGNF	97	186	26	212	289	888	708	1,303	930	616	616	616	6,488
25	BGSSI-TSGNF - Pilot Use	0	0	0	0	0	0	0	0	0	0	0	0	0
26	BGSSI-TSGNF - Penalty Use	0	0	0	0	0	0	0	0	0	0	0	0	0
27	Emergency Sales - TSGNF	0	0	0	0	0	0	0	0	0	0	0	0	0
28	CIG - Supply Component	3,797	1,493	651	3,475	1,458	2,863	2,718	2,509	2,638	2,091	2,091	2,091	27,874
29	CSG - BGSS-F	0	0	0	0	0	0	0	0	0	0	0	0	0
30	CSG - BGSS-I	0	0	0	0	0	0	0	0	0	0	0	0	0
31	CSG - Emergency Sales	0	0	0	0	0	0	0	0	0	0	0	0	0
32														
33														
34	**AVG $/THERM**	**Jun-23**	**Jul-23**	**Aug-23**	**Sep-23**	**Oct-23**	**Nov-23**	**Dec-23**	**Jan-24**	**Feb-24**	**Mar-24**	**Apr-24**	**May-24**	**Total**
35	BGSS-RSG	0.441496	0.440687	0.440465	0.440480	0.392965	0.371924	0.372212	0.372356	0.372648	0.372799	0.372799	0.372799	0.379263
36	BGSSF-GSG	0.459648	0.475397	0.495998	0.496471	0.522756	0.554560	0.547311	0.522093	0.509963	0.514690	0.503473	0.505696	0.518112
37	BGSSF-LVG	0.470539	0.493123	0.507319	0.493556	0.525821	0.558050	0.552646	0.524667	0.514908	0.514690	0.503473	0.505696	0.521439
38	BGSSF-SLG	0.467343	0.499357	0.503216	0.504393	0.523142	0.557499	0.541373	0.521833	0.507696	0.514690	0.503473	0.505696	0.510493
39	TSGF	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
40	Emergency Sales - TSGF	0.473821	0.000000	0.000000	0.511911	0.000000	0.571444	0.531448	0.000000	0.624424	0.000000	0.000000	0.000000	0.616376
41	BGSSI-TSGNF	0.431487	0.474112	0.462786	0.466892	0.495541	0.553052	0.523544	0.486531	0.896739	0.432091	0.421095	0.423274	0.539559
42	BGSSI-TSGNF - Pilot Use	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
43	BGSSI-TSGNF - Penalty Use	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
44	Emergency Sales - TSGNF	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
45	CIG - Supply Component	0.261212	0.251871	0.277094	0.281846	0.304848	0.326348	0.308574	0.290868	0.277570	0.299419	0.267786	0.266243	0.285199
46	CSG - BGSS-F	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
47	CSG - BGSS-I	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
48	CSG - Emergency Sales	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000

Filing "9 and 3"

COMMODITY BGSS
WEATHER NORMALIZED ALL @ BGSS
"9 and 3" Months Ended May 31, 2024

REVENUES	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Total
BGSS-RSG	21,624	14,226	12,612	14,071	19,084	45,475	85,267	110,306	108,790	85,227	54,197	29,660	600,539
BGSSF-GSG	4,012	3,609	3,431	3,536	4,850	11,979	22,799	28,764	28,456	18,630	11,237	6,980	148,283
BGSSF-LVG	13,375	12,606	12,521	13,470	14,980	34,352	54,404	64,391	65,361	45,169	30,989	20,432	382,050
BGSSF-SLG	34	29	27	29	30	32	30	31	29	23	23	26	343
TSGF @ BGSSF (LVG)	679	737	719	778	688	1,143	1,465	1,093	1,340	930	834	739	11,145
Emergency Sales - TSGF	0	0	0	0	0	19	17	0	262	0	0	0	298
TSGNF @ BGSSI	3,607	3,976	3,451	4,646	4,213	5,924	7,602	4,599	5,908	4,294	4,558	4,176	56,954
BGSSI-TSGNF - Pilot Use	0	0	0	0	0	0	0	0	0	0	0	0	0
BGSSI-TSGNF - Penalty Use	0	0	0	0	0	0	0	0	0	0	0	0	0
Emergency Sales - TSGNF	0	0	0	0	0	0	0	0	0	0	0	0	0
CIG - Supply Component	932	431	181	986	444	991	815	730	732	393	384	499	7,518
CSG - BGSS-F	19,279	25,384	35,786	59,724	31,142	47,305	37,967	18,654	27,666	6,816	19,869	24,382	353,974
CSG - BGSS-I	17,757	23,549	33,139	55,365	29,081	44,399	35,451	17,252	25,532	6,175	17,966	22,430	328,096
CSG - Emergency Sales	19,521	25,690	36,204	60,391	31,314	47,687	38,090	18,788	27,770	6,844	19,996	24,681	356,976

THERMS	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Total
BGSS-RSG	48,877	32,156	28,507	31,806	51,190	121,982	228,721	295,885	291,820	228,614	145,379	79,560	1,584,498
BGSSF-GSG	8,573	7,062	6,866	6,985	9,139	20,962	43,039	55,468	56,302	44,986	27,607	15,125	302,113
BGSSF-LVG	28,578	24,666	25,055	26,607	28,230	60,111	102,700	124,169	129,321	109,071	76,131	44,274	778,914
BGSSF-SLG	71.681	56.796	54.164	56.744	56.558	56.339	57.329	59.418	56.659	56.572	56.572	56.572	695
TSGF @ BGSSF (LVG)	1,452	1,441	1,439	1,537	1,296	2,001	2,765	2,109	2,651	2,245	2,049	1,601	22,584
Emergency Sales - TSGF	0	0	0	0	0	33	31	0	517	0	0	0	**581**
TSGNF @ BGSSI	8,369	8,387	7,458	9,900	8,502	11,045	15,369	9,590	12,666	11,445	12,382	9,836	124,946
BGSSI-TSGNF - Pilot Use	0	0	0	0	0	0	0	0	0	0	0	0	0
BGSSI-TSGNF - Penalty Use	0	0	0	0	0	0	0	0	0	0	0	0	0
BGSSI-TSGNF - Less Pilot & P	8,369	8,387	7,458	9,900	8,502	11,045	15,369	9,590	12,666	11,445	12,382	9,836	124,946
Emergency Sales - TSGNF	0	0	0	0	0	0	0	0	0				0
CIG - Supply Component	3,797	1,493	651	3,475	1,458	2,863	2,718	2,509	2,638	2,091	2,091	2,091	27,874
CSG - BGSS-F	41,194	49,669	71,609	117,969	58,686	82,778	71,672	35,971	54,739	16,459	48,812	52,834	702,392
CSG - BGSS-I	41,194	49,669	71,609	117,969	58,686	82,778	71,672	35,971	54,739	16,459	48,812	52,834	702,392
CSG - Emergency Sales	41,194	49,669	71,609	117,969	58,686	82,778	71,672	35,971	54,739	16,459	48,812	52,834	702,392

AVG $/THERM w/o SUT	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Total
BGSS-RSG	0.442408	0.442408	0.442408	0.442408	0.372799	0.372799	0.372799	0.372799	0.372799	0.372799	0.372799	0.372799	0.379009
BGSS RSG OFF Peak	0.279082	0.279082	0.279082	0.279082	0.279082	-	-	-	-	-	-	0.279082	0.279082
BGSSF-GSG (BGSS-F)	0.468006	0.511067	0.499741	0.506271	0.530652	0.571468	0.529734	0.518577	0.505414	0.414128	0.407046	0.461490	0.490820
BGSSF-LVG (BGSS-F)	0.468006	0.511067	0.499741	0.506271	0.530652	0.571468	0.529734	0.518577	0.505414	0.414128	0.407046	0.461490	0.490491
BGSSF-SLG (BGSS-F)	0.468006	0.511067	0.499741	0.506271	0.530652	0.571468	0.529734	0.518577	0.505414	0.414128	0.407046	0.461490	0.493178
TSGF @ BGSSF	0.468006	0.511067	0.499741	0.506271	0.530652	0.571468	0.529734	0.518577	0.505414	0.414128	0.407046	0.461490	0.493484
Emergency Sales - TSGF	0.473888	0.517224	0.505582	0.511918	0.533592	0.576082	0.531449	0.522306	0.507327	0.415786	0.409663	0.467143	0.512968
TSGNF @ BGSSI	0.431051	0.474112	0.462786	0.469316	0.495541	0.536357	0.494622	0.479606	0.466443	0.375157	0.368076	0.424528	0.455827
BGSSI-TSGNF - Pilot Use	0.431051	0.474112	0.462786	0.469316	0.495541	0.536357	0.494622	0.479606	0.466443	0.375157	0.368076	0.424528	0.000000
BGSSI-TSGNF - Penalty Use	0.431051	0.474112	0.462786	0.469316	0.495541	0.536357	0.494622	0.479606	0.466443	0.375157	0.368076	0.424528	0.000000
Emergency Sales - TSGNF	0.473888	0.517224	0.505582	0.511918	0.533592	0.576082	0.531449	0.522306	0.507327	0.415786	0.409663	0.467143	0.000000
CIG - Supply Component	0.245365	0.288423	0.277094	0.283624	0.304848	0.346269	0.299746	0.290868	0.277570	0.188040	0.183414	0.238835	0.269709
CSG - BGSS-F	0.468006	0.511067	0.499741	0.506271	0.530652	0.571468	0.529734	0.518577	0.505414	0.414128	0.407046	0.461490	0.503955
CSG - BGSS-I	0.431051	0.474112	0.462786	0.469316	0.495541	0.536357	0.494622	0.479606	0.466443	0.375157	0.368076	0.424528	0.467112
CSG - Emergency Sales	0.473888	0.517224	0.505582	0.511918	0.533592	0.576082	0.531449	0.522306	0.507327	0.415786	0.409663	0.467143	0.508229

BGSS-RSG "Weather Normalized All" - used tariff rates with out SUT (effective 6/1/2023 the rate was $0.442408; and effective as of 10/1/2023 the rate is $0.372799).
BGSS-RSG excludes Off-Peak volume because it has its own specific BGSS-RSGOP rate (effective as of 5/1/2023 the rate is $0.279082). Applicable May - October only.
BGSS-RSG does not include any BGSS-RSG Bill Credits.
GSG includes Off-Peak usage.
All BGSS rates (BGSS-Firm, BGSS-Interruptible, BGSS-CIG) are monthly changing rates and are based on the most current Tariff rates applicable for that month.
All BGSS rates exclude SUT.

Gas Proof of Revenue by Rate Schedule

Narrative for Rate Schedule Design

The summary and each rate schedule provide the details of 1) a) Actual and b) Weather Normalized and also 2) a) Annualized Weather Normalized (all customers assumed to be on BGSS and revenue based on current tariff rates), b) the Proposed rate design.

1) Actual and Weather Normalized

All the components are separated into Delivery and Supply. In addition to the Distribution components of Delivery, also included in the schedule are lines for Balancing Charge, Societal Benefits Charge, Margin Adjustment Charge, Gas Conservation Incentive Program, Green Programs Recovery Charge, Tax Adjustment Credit, Facilities Charge, Minimum Charge, Miscellaneous items, and Unbilled Revenue. The first column shows the actual billing units for the test year from Schedule SS-G2. The second column shows annual average rates (without Sales and Use Tax, SUT) occurring during the test period. The commodity rates in the second column reflect class-weighted averages for the test year from SS-G11. The third column presents annualized revenue for the test period. The fourth column shows the weather normalized billing units for the test year from SS-G2. The fifth column shows the applicable rates. Column six (6) presents weather normalized revenue. Columns seven (7) and eight (8) show the differential revenue, in thousands of dollars and percent increase, respectively, for each of the billing unit blocks.

2) Annualized Weather Normalized (all customers assumed to be on BGSS) and the Proposed rate design.

All the components are separated into Delivery and Supply. In addition to the Distribution components of Delivery, also included in the Schedule are lines for Balancing Charge, Societal Benefits Charge, Margin Adjustment Charge, Gas Conservation Incentive Program, Green Programs Recovery Charge, Tax Adjustment Credit, Facilities Charge, Minimum Charge, Miscellaneous items, and Unbilled Revenue. The first column shows the annualized weather normalized billing units for the test year from Schedule SS-G2. The second column shows present Delivery rates (without Sales and Use Tax, SUT) effective April 1, 2024. The commodity rates in the second column reflect class-weighted averages for the test year from SS-G11. The third column presents annualized revenue for the test period assuming all customers are provided service under their applicable BGSS provision. The fourth column repeats the billing units of the first column. The fifth column shows the proposed rates that result in the proposed revenues shown in column six (6). Columns seven (7) and eight (8) show the proposed revenue increase, in thousands of dollars and percent increase, respectively, for each of the billing unit blocks.

GAS PROOF OF REVENUE
SUMMARY
GAS RATE INCREASE
"9 and 3" Months Ended May 31, 2024
(Therms & Revenue - Thousands, Rate - $/Therm)

	Rate Schedule		Actual		Weather Normalized		Difference	
			Therms	Revenue	Therms	Revenue	Revenue	Percent
			(1)	(2)	(3)	(4)	(5)	(6)
1	RSG		1,440,408	$1,433,661	1,584,498	$1,563,307	$129,646	9.04
2	GSG		275,945	268,875	302,113	292,786	23,910	8.89
3	LVG		731,129	359,239	778,914	377,698	18,458	5.14
6	SLG		695	881	695	881	0	0.00
7		Subtotal	2,448,178	2,062,657	2,666,220	2,234,671	172,015	8.34
8								
9	TSG-F		22,584	4,428	22,584	4,444	17	0.38
10	TSG-NF		124,946	22,711	124,946	22,711	0	0.00
11	CIG		27,874	12,004	27,874	12,004	0	0.00
12	CSG		702,392	8,469	0	8,454	(15)	(0.17)
15		Subtotal	877,797	47,612	175,405	47,614	2	0.21
16								
17		Totals	3,325,975	$2,110,268	2,841,625	$2,282,285	$172,017	8.15

Notes: SLG units and revenues shown to 3 decimals.
TSG-F revenues shown to 3 decimals.

GAS PROOF OF REVENUE
SUMMARY
GAS RATE INCREASE
"9 and 3" Months Ended May 31, 2024
(Therms & Revenue - Thousands, Rate - $/Therm)

	Rate Schedule		**Annualized Weather Normalized**		**Proposed**		**Difference**	
			Therms	**Revenue**	**Therms**	**Revenue**	**Revenue**	**Percent**
			(1)	(2)	(3)	(4)	(5)	(6)
1	RSG		1,584,498	$1,689,567	1,584,498	$1,962,789	$273,222	16.17
2	GSG		302,113	319,548	302,113	387,206	67,658	21.17
3	LVG		778,914	618,429	778,914	675,645	57,217	9.25
6	SLG		695	1,193.478	695	1,286.117	92.639	7.76
7		Subtotal	2,666,220	2,628,737	2,666,220	3,026,927	398,189	15.15
8								
9	TSG-F		22,584	16,676.820	22,584	18,875.523	2,198.703	13.18
10	TSG-NF		124,946	77,546	124,946	82,319	4,773	6.16
11	CIG		27,874	11,930	27,874	12,821	891	7.47
12	CSG		702,392	8,604	702,392	8,703	99	1.15
13		Subtotal	877,797	114,757	877,797	122,718	7,962	6.94
14								
15		Totals	3,544,017	2,743,494	3,544,017	3,149,645	$406,151	14.80
16								
17								
18					Less change in MAC included above		$4,777	$401,374
19								
20					Gas Revenue Requirement		$401,374	
21								
22								

			Increase Before Mac Adjustment	**Increase Above**	**MAC Adjustment**
23					
24	RSG		$270,394	$273,222	2,828
25	GSG		67,118	67,658	540
26	LVG		55,866	57,217	1,351
27	SLG		91.405	92.639	1.234
28		Subtotal	393,469	398,189	4,720
29					
30	TSG-F		2,156.321	2,198.703	42.382
31	TSG-NF		4,773	4,773	0
32	CIG		891	891	0
33	CSG		99	99	0
34		Subtotal	7,919	7,962	42
35					
36		Totals	$401,389	$406,151	4,763

37
38
39 Notes:
40 All customers assumed to be on BGSS.
41 SLG units and revenues shown to 3 decimals.
42 TSG-F revenues shown to 3 decimals.
43 Annualized Weather Normalized Revenue reflects Delivery rates as of 4/1/2024
44 plus applicable BGSS charges.

RATE SCHEDULE RSG
RESIDENTIAL SERVICE
"9 and 3" Months Ended May 31, 2024
(Therms & Revenue - Thousands, Rate - $/Therm)

		Actual			Weather Normalized			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Service Charge	20,576.897	8.08	$166,262	20,576.897	8.08	$166,262	0	0.00
2	Distribution Charge	1,440,366	0.437475	630,124	1,584,457	0.437467	693,148	63,025	10.00
3	Off-Peak Dist Non Exempt	41	0.369107	15	41	0.369107	15	0	0.00
4	Balancing Charge	1,041,528	0.091825	95,638	1,185,618	0.091841	108,888	13,250	13.85
5	SBC	1,440,408	0.048379	69,685	1,584,498	0.048055	76,143	6,458	9.27
6	Margin Adjustment	1,440,408	(0.005858)	(8,437)	1,584,498	(0.005855)	(9,277)	(840)	9.95
7	Weather Normalization	1,041,528	0.000000	0	1,185,618	0.000000	0	0	0.00
8	Green Programs Recovery Charge	1,440,408	0.009014	12,984	1,584,498	0.009012	14,280	1,296	9.98
9	Tax Adjustment Credit	1,440,408	(0.057837)	(83,309)	1,584,498	(0.058379)	(92,501)	(9,192)	11.03
10	Gas Conservation Incentive Program	1,440,408	0.009014	12,984	1,584,498	0.009012	14,280	1,296	9.98
11	Facilities Charges			0			0	0	0.00
12	Minimum			0			0	0	0.00
13	Miscellaneous			0			0	0	0.00
14	Delivery Subtotal	1,440,408		$895,945	1,584,498		$971,239	75,294	8.40
15	Unbilled Delivery			4,826			5,744	918	19.02
16	Delivery Subtotal w unbilled			$900,771			$976,983	76,212	8.46
17									
18	**Supply**								
19	BGSS-RSG	1,411,573	0.379554	$535,768	1,552,846	0.379263	$588,937	53,169	9.92
20	Emergency Sales Service	0	0.000000	0	0	0.000000	0	0	0.00
21	Off-Peak Comm. Charge	41	0.383134	16	41	0.383134	16	0	0.00
22									
23	Miscellaneous			0			0	0	0.00
24	Supply subtotal	1,411,573		$535,783	1,552,846		$588,953	53,169	9.92
25	Unbilled Supply			(2,893)			(2,628)	266	(9.18)
26	Supply Subtotal w unbilled			$532,890			$586,325	53,435	10.03
27									
28	Total Delivery + Supply	1,440,408		$1,433,661	1,584,498		$1,563,307	129,646	9.04
29									
30									
31									
32									

33 Notes:
34 Rates are annual averages derived from actual, excluding SUT.
35

RATE SCHEDULE RSG
RESIDENTIAL SERVICE
"9 and 3" Months Ended May 31, 2024
(Therms & Revenue - Thousands, Rate - $/Therm)

		Annualized Weather Normalized			Proposed			Difference	
		Units	**Rate**	**Revenue**	**Units**	**Rate**	**Revenue**	**Revenue**	**Percent**
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Service Charge	20,576.897	8.08	$166,261	20,576.897	12.28	$252,729	86,468	52.01
2	Distribution Charge	1,584,457	0.437491	693,186	1,584,457	0.555821	880,675	187,489	27.05
3	Off-Peak Dist	41	0.218746	9	41	0.277911	11	2	22.22
4	Balancing Charge	1,185,618	0.091830	108,875	1,185,618	0.091830	108,875	0	0.00
5	SBC	1,584,498	0.056327	89,250	1,584,498	0.056327	89,250	0	0.00
6	Margin Adjustment	1,584,498	(0.005916)	(9,374)	1,584,498	(0.005916)	(9,374)	0	0.00
7	Weather Normalization	1,185,618	0.000000	0	1,185,618	0.000000	0	0	0.00
8	Green Programs Recovery Charge	1,584,498	0.009026	14,302	1,584,498	0.009026	14,302	0	0.00
9	Tax Adjustment Credit	1,584,498	(0.046366)	(73,467)	1,584,498	(0.046366)	(73,467)	0	0.00
10	Gas Conservation Incentive Program	1,584,498	0.060736	96,236	1,584,498	0.060736	96,236	0	0.00
11	Facilities Charges			0			0	0	0.00
12	Minimum			0			0	0	0.00
13	Miscellaneous			0			0	0	0.00
14	Delivery Subtotal	1,584,498		$1,085,278	1,584,498		$1,359,237	$273,959	25.24
15	Unbilled Delivery			6,419			8,038	1,619	25.22
16	Delivery Subtotal w unbilled			$1,091,697			$1,367,275	$275,578	25.24
17									
18	**Supply**								
19	BGSS-RSG	1,584,498	0.379009	$600,539	1,584,498	0.379009	$600,539	$0	0.00
20	Emergency Sales Service	0	0.000000	0	0	0.000000	0	0	0.00
21	BGSS Contrib. from TSG-F, TSG-NF & CIG	0	0.000000	0	1,584,498	(0.001494)	(2,367)	(2,367)	0.00
22	Off-Peak Comm. Charge	41	0.279082	11	41	0.279082	11	0	0.00
23									
24	Miscellaneous			0			0	0.00	0.00
25	Supply subtotal	1,584,540		$600,550	1,584,540		$598,183	(2,367.00)	(0.39)
26	Unbilled Supply			(2,680)			(2,669)	11.00	(0.41)
27	Supply Subtotal w unbilled			$597,870			$595,514	(2,356.00)	(0.39)
28									
29	Total Delivery + Supply	1,584,498		$1,689,567	1,584,498		$1,962,789	273,222.00	16.17
30									
31									
32									

33 Notes:
34 All customers assumed to be on BGSS.
35 Annualized Weather Normalized Revenue reflects Delivery rates as of 4/1/2024
36 plus applicable BGSS charges.
37

RATE SCHEDULE GSG
GENERAL SERVICE
"9 and 3" Months Ended May 31, 2024
(Therms & Revenue - Thousands, Rate - $/Therm)

		Actual			Weather Normalized			Difference	
		Units	**Rate**	**Revenue**	**Units**	**Rate**	**Revenue**	**Revenue**	**Percent**
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Service Charge	1,681.703	18.97	$31,896	1,681.703	18.97	$31,896	$0	0.00
2	Distribution Charge Pre 7/14/97	1,704	0.328455	560	1,862	0.328471	612	52	9.29
3	Distribution Charge All others	274,230	0.328482	90,079	300,239	0.328491	98,626	8,546	9.49
4	Off-Peak Dist Charge - Pre 7/14/97	0	0.000000	0	0	0.000000	0	0	0.00
5	Off-Peak Dist Charge - All Others	12	0.164055	2	12	0.164055	2	0	0.00
6	Balancing Charge	187,599	0.091815	17,224	213,767	0.091818	19,628	2,403	13.95
7	SBC	275,945	0.048395	13,354	302,113	0.048090	14,529	1,174	8.79
8	Margin Adjustment	275,945	(0.005858)	(1,616)	302,113	(0.005855)	(1,769)	(153)	9.44
9	Weather Normalization	187,599	0.000000	0	213,767	0.000000	0	0	0.00
10	Green Programs Recovery Charge	275,945	0.009005	2,485	302,113	0.009006	2,721	236	9.49
11	Tax Adjustment Credit	275,945	(0.048986)	(13,517)	302,113	(0.049497)	(14,954)	(1,436)	10.63
12	Gas Conservation Incentive Program	275,945	0.042515	11,732	302,113	0.042675	12,893	1,161	9.89
13	Facilities Charges			0			0	0	0.00
14	Minimum			2			2	0	0.00
15	Miscellaneous			(63)			(63)	0	0.00
16	Delivery Subtotal	275,945		$152,137	302,113		$164,121	$11,984	7.88
17	Unbilled Delivery			726			1,030	303	41.79
18	Delivery Subtotal w unbilled			$152,863			$165,151	$12,287	8.04
19									
20	**Supply**								
21	BGSS	224,759	0.517608	$116,337	246,245	0.518112	$127,582	11,246	9.67
22	Emergency Sales Service	0	0.000000	0	0	0.000000	0	0	0.00
23									
24	Miscellaneous			0			0	0	0.00
25	Supply subtotal	224,759		$116,337	246,245		$127,582	$11,246	9.67
26	Unbilled Supply			(325)			53	378	(116.25)
27	Supply Subtotal w unbilled			$116,012			$127,635	$11,623	10.02
28									
29	Total Delivery + Supply	275,945		$268,875	302,113		$292,786	$23,910	8.89
30									
31									
32									
33	Notes:								
34	Rates are annual averages derived from actual, excluding SUT.								
35									

RATE SCHEDULE GSG
GENERAL SERVICE
"9 and 3" Months Ended May 31, 2024
(Therms & Revenue - Thousands, Rate - $/Therm)

		Annualized Weather Normalized			Proposed			Difference	
		Units	**Rate**	**Revenue**	**Units**	**Rate**	**Revenue**	**Revenue**	**Percent**
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Service Charge	1,681.703	18.97	$31,902	1,681.703	28.84	$48,493	$16,591	52.01
2	Distribution Charge - Pre 7/14/97	1,862	0.328263	611	1,862	0.496662	925	314	51.39
3	Distribution Charge - All Others	300,239	0.328263	98,557	300,239	0.496662	149,117	50,560	51.30
4	Off-Peak Dist Charge - Pre 7/14/97	0	0.164132	0	0	0.248331	0	0	0.00
5	Off-Peak Dist Charge - All Others	12	0.164132	2	12	0.248331	3	1	50.00
6	Balancing Charge	213,767	0.091830	19,630	213,767	0.091830	19,630	0	0.00
7	SBC	302,113	0.056327	17,017	302,113	0.056327	17,017	0	0.00
8	Margin Adjustment	302,113	(0.005916)	(1,787)	302,113	(0.005916)	(1,787)	0	0.00
9	Weather Normalization	213,767	0.000000	0	213,767	0.000000	0	0	0.00
10	Green Programs Recovery Charge	302,113	0.009026	2,727	302,113	0.009026	2,727	0	0.00
11	Tax Adjustment Credit	302,113	(0.039352)	(11,889)	302,113	(0.039352)	(11,889)	0	0.00
12	Gas Conservation Incentive Program	302,113	0.044451	13,429	302,113	0.044451	13,429	0	0.00
13	Facilities Charges			0			0	0	0.00
14	Minimum			2			2	0	0.00
15	Miscellaneous			(63)			(63)	0	0.00
16	Delivery Subtotal	302,113		$170,137	302,113		$237,603	$67,466	39.65
17	Unbilled Delivery			1,067			1,490	423	39.64
18	Delivery Subtotal w unbilled			$171,204			$239,093	$67,889	39.65
19									
20	**Supply**								
21	BGSS	302,113	0.490820	$148,283	302,113	0.490820	$148,283	$0	0.00
22	Emergency Sales Service	0	0.000000	0	0	0.000000	0	0	0.00
23	BGSS Contrib. from TSG-F, TSG-NF & CIG	0	0.000000	0	302,113	(0.000766)	(231)	(231)	0.00
24									
25	Miscellaneous			0			0	0	0.00
26	Supply subtotal	302,113		$148,283	302,113		$148,052	(231)	(0.16)
27	Unbilled Supply			61			61	0	0.00
28	Supply Subtotal w unbilled			$148,344			$148,113	(231)	(0.16)
29									
30	Total Delivery + Supply	302,113		$319,548	302,113		$387,206	$67,658	21.17
31									
32									
33									
34	Notes:								
35	All customers assumed to be on BGSS.								
36	Annualized Weather Normalized Revenue reflects Delivery rates as of 4/1/2024								
37	plus applicable BGSS charges.								
38									

RATE SCHEDULE LVG
LARGE VOLUME SERVICE
"9 and 3" Months Ended May 31, 2024
(Therms & Revenue - Thousands, Rate - $/Therm)

		Actual			Weather Normalized			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Service Charge	235.304	168.43	$39,631	235.304	168.43	$39,631	$0	0.00
2	Demand Charge	18,912	4.2799	80,942	20,258	4.2980	87,070	6,129	7.57
3	Distribution Charge 0-1,000 pre 7/14/97	6,821	0.033160	226	7,221	0.033123	239	13	5.74
4	Distribution Charge over 1,000 pre 7/14/97	33,268	0.049572	1,649	35,658	0.049526	1,766	117	7.09
5	Distribution Charge 0-1,000 post 7/14/97	132,159	0.033026	4,365	140,501	0.032991	4,635	271	6.20
6	Distribution Charge over 1,000 post 7/14/97	558,881	0.048732	27,235	595,534	0.048733	29,022	1,787	6.56
7	Balancing Charge	422,124	0.091824	38,761	469,908	0.091837	43,155	4,394	11.34
8	SBC	731,129	0.048315	35,325	778,914	0.048101	37,466	2,141	6.06
9	Margin Adjustment	731,129	(0.005855)	(4,281)	778,914	(0.005854)	(4,560)	(279)	6.51
10	Weather Normalization	422,124	0.000000	0	469,908	0.000000	0	0	0.00
11	Green Programs Recovery Charge	731,129	0.008948	6,542	778,914	0.008944	6,966	424	6.48
12	Tax Adjustment Credit	731,129	(0.022913)	(16,753)	778,914	(0.023073)	(17,972)	(1,219)	7.28
13	Gas Conservation Incentive Program	731,129	0.004589	3,355	778,914	0.004594	3,578	223	6.65
14	Facilities Charges			0			0	0	0.00
15	Minimum			216			216	0	0.00
16	Miscellaneous			(310)			(310)	0	0.00
17	Delivery Subtotal	731,129		$216,903	778,914		$230,904	$14,001	6.45
18	Unbilled Delivery			1,006			(5,404)	(6,410)	(637.11)
19	Delivery Subtotal w unbilled			$217,909			$225,500	$7,591	3.48
20									
21									
22	**Supply**								
23	BGSS	273,926	0.521109	$142,746	292,980	0.521439	$152,771	$10,026	7.02
24	Emergency Sales Service	0	0.000000	0	0	0.000000	0	0	0.00
25									
26	Miscellaneous			0			0	0	0.00
27	Supply Subtotal	273,926		$142,746	292,980		$152,771	$10,026	7.02
28	Unbilled Supply			(1,416)			(574)	842	(59.46)
29	Supply Subtotal w unbilled			$141,330			$152,197	$10,868	7.69
30									
31	Total Delivery + Supply	731,129		$359,239	778,914		$377,698	$18,458	5.14
32									
33									
34									
35	Notes:								
36	Rates are annual averages derived from actual, excluding SUT.								
37									

RATE SCHEDULE LVG
LARGE VOLUME SERVICE
"9 and 3" Months Ended May 31, 2024
(Therms & Revenue - Thousands, Rate - $/Therm)

		Annualized Weather Normalized			Proposed			Difference	
		Units	**Rate**	**Revenue**	**Units**	**Rate**	**Revenue**	**Revenue**	**Percent**
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Service Charge	235.304	168.50	$39,649	235.304	256.13	$60,269	$20,620	52.01
2	Demand Charge	20,258	4.3754	88,639	20,258	5.7242	115,963	27,324	30.83
3	Distribution Charge 0-1,000 pre 7/14/97	7,221	0.033054	239	7,221	0.102208	738	499	208.79
4	Distribution Charge over 1,000 pre 7/14/97	35,658	0.050101	1,787	35,658	0.051748	1,845	58	3.25
5	Distribution Charge 0-1,000 post 7/14/97	140,501	0.033054	4,644	140,501	0.102208	14,360	9,716	209.22
6	Distribution Charge over 1,000 post 7/14/97	595,534	0.050101	29,837	595,534	0.051748	30,818	981	3.29
7	Balancing Charge	469,908	0.091830	43,152	469,908	0.091830	43,152	0	0.00
8	SBC	778,914	0.056327	43,874	778,914	0.056327	43,874	0	0.00
9	Margin Adjustment	778,914	(0.005916)	(4,608)	778,914	(0.005916)	(4,608)	0	0.00
10	Weather Normalization	469,908	0.000000	0	469,908	0.000000	0	0	0.00
11	Green Programs Recovery Charge	778,914	0.009026	7,030	778,914	0.009026	7,030	0	0.00
12	Tax Adjustment Credit	778,914	(0.018403)	(14,334)	778,914	(0.018403)	(14,334)	0	0.00
13	Gas Conservation Incentive Program	778,914	0.004748	$3,698	778,914	0.004748	$3,698	0	0.00
14	Facilities Charges			0			0	0	0.00
15	Minimum			216			216	0	0.00
16	Miscellaneous			(310)			(311)	(0)	0.07
17	Delivery Subtotal	778,914		$243,513	778,914		$302,710	$59,198	24.31
18	Unbilled Delivery			(5,699)			(7,085)	(1,386)	24.32
19	Delivery Subtotal w unbilled			$237,814			$295,625	$57,812	24.31
20									
21									
22	**Supply**								
23	BGSS	778,914	0.490491	$382,050	778,914	0.490491	$382,050	$0	0.00
24	Emergency Sales Service	0	0.000000	0	0	0.000000	0	0	0.00
25	BGSS Contrib. from TSG-F, TSG-NF & CIG	0	0.000000	0	778,914	(0.000766)	(597)	(597)	0.00
26									
27	Miscellaneous			0			0	0	0.00
28	Supply Subtotal	778,914		$382,050	778,914		$381,453	($597)	(0.16)
29	Unbilled Supply			(1,435)			(1,433)	2	(0.14)
30	Supply Subtotal w unbilled			$380,615			$380,020	($595)	(0.16)
31									
32	Total Delivery + Supply	778,914		$618,429	778,914		$675,645	$57,217	9.25
33									
34									
35									

36 Notes:
37 All customers assumed to be on BGSS.
38 Annualized Weather Normalized Revenue reflects Delivery rates as of 4/1/2024
39 plus applicable BGSS charges.
40

RATE SCHEDULE SLG
STREET LIGHTING SERVICE
"9 and 3" Months Ended May 31, 2024
(Therms & Revenue - Thousands, Rate - $/Therm)

		Actual			Weather Normalized			Difference	
		Units	**Rate**	**Revenue**	**Units**	**Rate**	**Revenue**	**Revenue**	**Percent**
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Single	11.276	13.2351	$149.236	11.276	13.2351	$149.236	$0.000	0.00
2	Double Inverted	0.108	13.2351	1.430	0.108	13.2351	1.430	0.000	0.00
3	Double Upright	0.619	13.2351	8.194	0.619	13.2351	8.194	0.000	0.00
4	Triple prior to 1/1/93	18.168	13.2351	240.457	18.168	13.2351	240.457	0.000	0.00
5	Triple on and after 1/1/93	0.432	67.4762	29.174	0.432	67.4762	29.174	0.000	0.00
6	Distribution Therm Charge	695.404	0.053493	37.199	695.404	0.053500	37.199	0.000	0.00
7	SBC	695.404	0.047302	32.894	695.404	0.047302	32.894	0.000	0.00
8	Margin Adjustment	695.404	(0.005847)	(4.066)	695.404	(0.005847)	(4.066)	0.000	0.00
9	Green Programs Recovery Charge	695.404	0.008949	6.223	695.404	0.008949	6.223	0.000	0.00
10	Tax Adjustment Credit	695.404	(0.084412)	(58.700)	695.404	(0.084412)	(58.700)	0.000	0.00
11	Gas Conservation Incentive Program	695.404	0.000000	0.000	695.404	0.000000	0.000	0.000	0.00
12	Facilities Charges			0.000			0.000	0.000	0.00
13	Minimum			0.000			0.000	0.000	0.00
14	Miscellaneous			0.150			0.150	0.000	0.00
15	Delivery Subtotal	695.404		$442.191	695.404		$442.191	$0.000	0.00
16	Unbilled Delivery			0.000			0.000	0.000	0.00
17	Delivery Subtotal w unbilled			$442.191			$442.191	$0.000	0.00
18									
19	**Supply**								
20	BGSS	286.411	0.510493	$146.211	286.411	0.510493	$146.211	$0.000	0.00
21	Emergency Sales Service	0.000	0.000000	0.000	0.000	0.000000	0.000	0.000	0.00
22	Miscellaneous			146.211			146.211	0.000	0.00
23	Supply Subtotal	286.411		$292.421	286.411		$292.421	$0.000	0.00
24	Unbilled Supply			146.211			146.211	0.000	0.00
25	Supply Subtotal w unbilled			$438.632			$438.632	$0.000	0.00
26									
27	Total Delivery + Supply	695.404		$880.823	695.404		$880.823	$0.000	0.00
28									
29									
30									

31 Notes:
32 SLG units and revenues shown to 3 decimals.
33 Rates are annual averages derived from actual, excluding SUT.

RATE SCHEDULE SLG
STREET LIGHTING SERVICE
"9 and 3" Months Ended May 31, 2024
(Therms & Revenue - Thousands, Rate - $/Therm)

		Annualized Weather Normalized			Proposed			Difference	
		Units	**Rate**	**Revenue**	**Units**	**Rate**	**Revenue**	**Revenue**	**Percent**
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Single	11.276	13.2351	$149.236	11.276	15.5295	$175.107	$25.871	17.34
2	Double Inverted	0.108	13.2351	1.430	0.108	15.5295	1.678	0.248	17.34
3	Double Upright	0.619	13.2351	8.194	0.619	15.5295	9.614	1.420	17.33
4	Triple prior to 1/1/93	18.168	13.2351	240.457	18.168	15.5295	282.141	41.684	17.34
5	Triple on and after 1/1/93	0.432	67.4762	29.174	0.432	79.1739	34.232	5.058	17.34
6	Distribution Therm Charge	695.404	0.053531	37.226	695.404	0.081371	56.586	19.360	52.01
7	SBC	695.404	0.056327	39.170	695.404	0.056327	39.170	0.000	0.00
8	Margin Adjustment	695.404	(0.005916)	(4.114)	695.404	(0.005916)	(4.114)	0.000	0.00
9	Green Programs Recovery Charge	695.404	0.009026	6.277	695.404	0.009026	6.277	0.000	0.00
10	Tax Adjustment Credit	695.404	(0.068269)	(47.475)	695.404	(0.068269)	(47.475)	0.000	0.00
11	Gas Conservation Incentive Program	695.404	0.000000	0.000	695.404	0.000000	0.000	0.000	0.00
12	Facilities Charges			0.000			0.000	0.000	0.00
13	Minimum			0.000			0.000	0.000	0.00
14	Miscellaneous			0.150			(0.053)	(0.203)	(134.90)
15	Delivery Subtotal	695.404		$459.725	695.404		$553.163	$93.438	20.32
16	Unbilled Delivery			0.000			0.000	0.000	0.00
17	Delivery Subtotal w unbilled			$459.725			$553.163	$93.438	20.32
18									
19	**Supply**								
20	BGSS	695.404	0.493178	$342.958	695.404	0.493178	$342.958	$0.000	0.00
21	Emergency Sales Service	0.000	0.000000	0.000	0.000	0.000000	0.000	0.000	0.00
22	BGSS Contrib. from TSG-F, TSG-NF & CIG	0.000	0.000000	0.000	695.404	(0.000766)	(0.533)	(0.533)	0.00
23	Miscellaneous			146.211			146.211	0.000	0.00
24	Supply Subtotal	695.404		$489.169	695.404		$488.636	($0.533)	(0.11)
25	Unbilled Supply			244.584			244.318	(0.266)	(0.11)
26	Supply Subtotal w unbilled			$733.753			$732.954	($0.799)	(0.11)
27									
28	Total Delivery + Supply	695.404		$1,193.478	695.404		$1,286.117	$92.639	7.76
29									
30									
31									

32 Notes:
33 All customers assumed to be on BGSS.
34 SLG units and revenues shown to 3 decimals.
35 Annualized Weather Normalized Revenue reflects Delivery rates as of 4/1/2024
36 plus applicable BGSS charges.

RATE SCHEDULE CIG
COGENERATION INTERRUPTIBLE SERVICE
"9 and 3" Months Ended May 31, 2024
(Therms & Revenue - Thousands, Rate - $/Therm)

		Actual			Weather Normalized			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Service Charge	0.110	200.92	$22	0.110	200.92	$22	$0	0.00
2	Margin 0-600,000	26,259	0.087879	2,308	26,259	0.087879	2,308	0	0.00
3	Margin over 600,000	1,615	0.083336	135	1,615	0.083336	135	0	0.00
4	Extended Gas Service	0	0.000000	0	0	0.000000	0	0	0.00
5	SBC	27,874	0.046961	1,309	27,874	0.046961	1,309	0	0.00
6	Green Programs Recovery Charge	27,874	0.008911	248	27,874	0.008911	248	0	0.00
7	Tax Adjustment Credit	27,874	(0.015025)	(419)	27,874	(0.015025)	(419)	0	0.00
8	Gas Conservation Incentive Program	27,874	0.000000	0	27,874	0.000000	0	0	0.00
9	Facilities Charges			0			0	0	0.00
10	Minimum			0			0	0	0.00
11	Miscellaneous			0			0	0	0.00
12	Delivery Subtotal	27,874		$3,603	27,874		$3,603	$0	0.00
13	Unbilled Delivery			123			123	0	0.00
14	Delivery Subtotal w unbilled			$3,726			$3,726	$0	0.00
15									
16	**Supply**								
17	Commodity Component	27,874	0.285199	$7,950	27,874	0.285199	$7,950	$0	0.00
18	Pilot Use	0	0.000000	0	0	0.000000	0	0	0.00
19	Penalty Use	0		0	0		0	0	0.00
20	Extended Gas Service	1,278	0.000000	0	0	0.000000	0	0	0.00
21	Miscellaneous			0			0	0	0.00
22	Supply Subtotal	29,153		$7,950	27,874		$7,950	$0	0.00
23	Unbilled Supply			328			328	0	0.00
24	Supply Subtotal w unbilled			$8,278			$8,278	$0	0.00
25									
26	Total Delivery + Supply	27,874		$12,004	27,874		$12,004	$0	0.00
27									
28									
29									
30	Notes:								
31	Rates are annual averages derived from actual, excluding SUT.								
32									

RATE SCHEDULE CIG
COGENERATION INTERRUPTIBLE SERVICE
"9 and 3" Months Ended May 31, 2024
(Therms & Revenue - Thousands, Rate - $/Therm)

		Annualized Weather Normalized			Proposed			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Service Charge	0.110	199.11	$22	0.110	268.14	$30	$8	36.36
2	Margin 0-600,000	26,259	0.088960	2,336	26,259	0.119577	3,140	804	34.42
3	Margin over 600,000	1,615	0.078960	128	1,615	0.109577	177	49	38.28
4	Extended Gas Service	0	0.150000	0	0	0.150000	0	0	0.00
5	SBC	27,874	0.056327	1,570	27,874	0.056327	1,570	0	0.00
6	Green Programs Recovery Charge	27,874	0.009026	252	27,874	0.009026	252	0	0.00
7	Tax Adjustment Credit	27,874	(0.012281)	(342)	27,874	(0.012281)	(342)	0	0.00
8	Gas Conservation Incentive Program	27,874	0.000000	0	27,874	0.000000	0	0	0.00
9	Facilities Charges			0			0	0	0.00
10	Minimum			0			0	0	0.00
11	Miscellaneous			0			0	0	0.00
12	Delivery Subtotal	27,874		$3,966	27,874		$4,827	$861	21.71
13	Unbilled Delivery			136			166	30	22.06
14	Delivery Subtotal w unbilled			$4,102			$4,993	$891	21.72
15									
16	**Supply**								
17	Commodity Component	27,874	0.269709	$7,518	27,874	0.269709	$7,518	$0	0.00
18	Pilot Use	0	1.89	0	0	1.89	0	0	0.00
19	Penalty Use	0		0	0		0	0	0.00
20	Extended Gas Service	0		0	0		0	0	0.00
21	Miscellaneous			0			0	0	0.00
22	Supply Subtotal	27,874		$7,518	27,874		$7,518	$0	0.00
23	Unbilled Supply			310			310	0	0.00
24	Supply Subtotal w unbilled			$7,828			$7,828	$0	0.00
25									
26	Total Delivery + Supply	27,874		$11,930	27,874		$12,821	$891	7.47
27									
28									
29									

30 Notes:
31 All customers assumed to be on BGSS.
32 Annualized Weather Normalized Revenue reflects Delivery rates as of 4/1/2024
33 plus applicable BGSS charges.
34

RATE SCHEDULE TSG-F
FIRM TRANSPORTATION GAS SERVICE
"9 and 3" Months Ended May 31, 2024
(Therms & Revenue - Thousands, Rate - $/Therm)

		Actual			Weather Normalized			Difference	
		Units	**Rate**	**Revenue**	**Units**	**Rate**	**Revenue**	**Revenue**	**Percent**
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Service Charge	0.371	903.23	$334.748	0.371	903.23	$334.748	$0.000	0.00
2	Demand Charge	812	1.2117	984.047	812	1.2117	984.047	0.000	0.00
3	Demand Charge, Agreements	0	0.0000	0.000	0	0.0000	0.000	0.000	0.00
4	Distribution Charge	22,584	0.082662	1,866.872	22,584	0.082662	1,866.872	0.000	0.00
5	Distribution Charge, Agreements	0	0.000000	0.000	0	0.000000	0.000	0.000	0.00
6	SBC	22,584	0.047595	1,074.908	22,584	0.047595	1,074.908	0.000	0.00
7	SBC, Agreements	0	0.000000	0.000	0	0.000000	0.000	0.000	0.00
8	Margin Adjustment	22,584	(0.005850)	(132.126)	22,584	(0.005850)	(132.126)	0.000	0.00
9	Margin Adjustment, Agreements	0	0.000000	0.000	0	0.000000	0.000	0.000	0.00
10	Green Programs Recovery Charge	22,584	0.009001	203.279	22,584	0.009001	203.279	0.000	0.00
11	Green Programs Recovery Charge, Agreements	0	0.000000	0.000	0	0.000000	0.000	0.000	0.00
12	Tax Adjustment Credit	22,584	(0.019798)	(447.131)	22,584	(0.019798)	(447.131)	0.000	0.00
13	Gas Conservation Incentive Program	22,584	0.000000	0.000	22,584	0.000000	0.000	0.000	0.00
14	Facilities Charges			0.000			0.000	0.000	0.00
15	Minimum			0.000			0.000	0.000	0.00
16	Miscellaneous			(4.098)			(4.098)	0.000	0.00
17	Delivery Subtotal	22,584		3,880.499	22,584		3,880.499	0.000	0.00
18	Unbilled Delivery			222.220			222.220	0.000	0.00
19	Delivery Subtotal w unbilled			4,102.72			4,102.72	0.000	0.00
20									
21	**Supply**								
22	Commodity Charge, BGSS	0	0.000000	$0.000	0	0.000000	$0.000	$0.000	0.00
23	Emergency Sales Service	581	0.587783	341.463	581	0.616376	358.073	16.611	4.86
24	Miscellaneous			(16.611)			(16.611)	0.000	0.00
25	Supply Subtotal	581		$324.852	581		$341.463	$16.611	5.11
26	Unbilled Supply			0.000			0.000	0.000	0.00
27	Supply Subtotal w unbilled			$324.852			$341.463	$16.611	5.11
28									
29	Total Delivery + Supply	22,584		$4,427.571	22,584		$4,444.181	$16.611	0.38

30

31 Notes:

32 TSG-F revenues shown to 3 decimals.

33 Rates are annual averages derived from actual, excluding SUT.

RATE SCHEDULE TSG-F
FIRM TRANSPORTATION GAS SERVICE
"9 and 3" Months Ended May 31, 2024
(Therms & Revenue - Thousands, Rate - $/Therm)

		Annualized Weather Normalized			Proposed			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Service Charge	0.371	902.42	$334.449	0.371	1,005.79	$372.760	$38.311	11.45
2	Demand Charge	812	2.1896	1,778.148	812	3.4080	2,767.596	989.448	55.64
3	Demand Charge, Agreements	0	0.0000	0.000	0	0.0000	0.000	0.000	0.00
4	Distribution Charge	22,584	0.083696	1,890.216	22,584	0.130270	2,942.057	1,051.841	55.65
5	Distribution Charge, Agreements	0	0.000000	0.000	0	0.000000	0.000	0.000	0.00
6	SBC	22,584	0.056327	1,272.106	22,584	0.056327	1,272.106	0.000	0.00
7	SBC, Agreements	0	0.000000	0.000	0	0.000000	0.000	0.000	0.00
8	Margin Adjustment	22,584	(0.005916)	(133.609)	22,584	(0.005916)	(133.609)	0.000	0.00
9	Margin Adjustment, Agreements	0	(0.005916)	0.000	0	(0.005916)	0.000	0.000	0.00
10	Green Programs Recovery Charge	22,584	0.009026	203.846	22,584	0.009026	203.846	0.000	0.00
11	Green Programs Recovery Charge, Agreements	0	0.000000	0.000	0	0.000000	0.000	0.000	0.00
12	Tax Adjustment Credit	22,584	(0.016605)	(375.012)	22,584	(0.016605)	(375.012)	0.000	0.00
13	Gas Conservation Incentive Program	22,584	0.000000	0.000	22,584	0.000000	0.000	0.000	0.00
14	Facilities Charges			0.000			0.000	0.000	0.00
15	Minimum			0.000			0.000	0.000	0.00
16	Miscellaneous			(4.098)			(4.085)	0.013	(0.32)
17	Delivery Subtotal	22,584		4,966.046	22,584		7,045.659	2,079.613	41.88
18	Unbilled Delivery			284.384			403.474	119.090	41.88
19	Delivery Subtotal w unbilled			5,250.430			7,449.133	2,198.703	41.88
20									
21	**Supply**								
22	Commodity Charge, BGSS-F	22,584	0.493484	$11,145.000	22,584	0.493484	$11,145.000	$0.000	0.00
23	Emergency Sales Service	581	0.512968	298.000	581	0.512968	298.000	0.000	0.00
24	Miscellaneous			(16.611)			(16.611)	0.000	0.00
25	Supply Subtotal	23,165		$11,426.389	23,165		$11,426.389	$0.000	0.00
26	Unbilled Supply			0.000			0.000	0.000	0.00
27	Supply Subtotal w unbilled			$11,426.389			$11,426.389	$0.000	0.00
28									
29	Total Delivery + Supply	22,584		$16,676.820	22,584		$18,875.523	$2,198.703	13.18
30									
31									
32									

33 Notes:
34 All customers assumed to be on BGSS.
35 TSG-F revenues shown to 3 decimals.
36 Annualized Weather Normalized Revenue reflects Delivery rates as of 4/1/2024
37 plus applicable BGSS charges.

Filing "9 and 3"

RATE SCHEDULE TSG-NF
NON-FIRM TRANSPORTATION GAS SERVICE
"9 and 3" Months Ended May 31, 2024
(Therms & Revenue - Thousands, Rate - $/Therm)

EXHIBIT P-9G R-1
Schedule SS-G11 R-1

		Actual			Weather Normalized			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Service Charge	1.677	900.89	$1,511	1.677	900.89	$1,511	$0	0.00
2	Dist Charge 0-50,000	49,749	0.099633	4,957	49,749	0.099633	4,957	0	0.00
3	Dist Charge 0-50,000, Agreements	0	0.000000	0	0	0.000000	0	0	0.00
4	Dist Charge over 50,000	75,197	0.099732	7,500	75,197	0.099732	7,500	0	0.00
5	Dist Charge over 50,000, Agreements	0	0.000000	0	0	0.000000	0	0	0.00
6	SBC	124,946	0.046236	5,777	124,946	0.046236	5,777	0	0.00
7	SBC, Agreements	0	0.000000	0	0	0.000000	0	0	0.00
8	Green Programs Recovery Charge	124,946	0.008720	1,090	124,946	0.008720	1,090	0	0.00
9	Green Programs Recovery Charge, Agreements	0	0.000000	0	0	0.000000	0	0	0.00
10	Tax Adjustment Credit	124,946	(0.010024)	(1,252)	124,946	(0.010024)	(1,252)	0	0.00
11	Gas Conservation Incentive Program	124,946	0.000000	0	124,946	0.000000	0	0	0.00
12	Facilities Charges			3			3	0	0.00
13	Minimum			0			0	0	0.00
14	Miscellaneous			(80)			(80)	0	0.00
15	Delivery Subtotal	124,946		$19,505	124,946		$19,505	$0	0.00
16	Unbilled Delivery			0			0	0	0.00
17	Delivery Subtotal w unbilled			$19,505			$19,505	$0	0.00
18									
19	**Supply**								
20	Commodity Charge, BGSS-I	6,488	0.539559	$3,501	6,488	0.539559	$3,501	$0	0.00
21	Emergency Sales Service	0	0.000000	0	0	0.000000	0	0	0.00
22	Pilot Use	0	0.000000	(3)	0	0.000000	(3)	0	0.00
23	Penalty Use	0	0.000000	0	0	0.000000	0	0	0.00
24	Miscellaneous			(291)			(291)	0	0.00
25	Supply Subtotal	6,488		$3,207	6,488		$3,207	$0	0.00
26	Unbilled Supply			0			0	0	0.00
27	Supply Subtotal w unbilled			$3,207			$3,207	$0	0.00
28									
29	Total Delivery + Supply	124,946		$22,711	124,946		$22,711	$0	0.00
30									
31									
32									
33	Notes:								
34	Rates are annual averages derived from actual, excluding SUT.								

RATE SCHEDULE TSG-NF
NON-FIRM TRANSPORTATION GAS SERVICE
"9 and 3" Months Ended May 31, 2024
(Therms & Revenue - Thousands, Rate - $/Therm)

		Annualized Weather Normalized			Proposed			Difference	
		Units	**Rate**	**Revenue**	**Units**	**Rate**	**Revenue**	**Revenue**	**Percent**
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Service Charge	1.677	902.42	$1,513	1.677	1,005.79	$1,687	$174	11.50
2	Dist Charge 0-50,000	49,749	0.098680	4,909	49,749	0.135482	6,740	1,831	37.30
3	Dist Charge 0-50,000, Agreements	0	0.000000	0	0	0.000000	0	0	0.00
4	Dist Charge over 50,000	75,197	0.098680	7,420	75,197	0.135482	10,188	2,768	37.30
5	Dist Charge over 50,000, Agreements	0	0.000000	0	0	0.000000	0	0	0.00
6	SBC	124,946	0.056327	7,038	124,946	0.056327	7,038	0	0.00
7	SBC, Agreements	0	0.000000	0	0	0.000000	0	0	0.00
8	Green Programs Recovery Charge	124,946	0.009026	1,128	124,946	0.009026	1,128	0	0.00
9	Green Programs Recovery Charge, Agreements	0	0.000000	0	0	0.000000	0	0	0.00
10	Tax Adjustment Credit	124,946	(0.008389)	(1,048)	124,946	(0.008389)	(1,048)	0	0.00
11	Gas Conservation Incentive Program	124,946	0.000000	0	124,946	0.000000	0	0	0.00
12	Facilities Charges			3			3	0	0.00
13	Minimum			0			0	0	0.00
14	Miscellaneous			(80)			(80)	0	0.00
15	Delivery Subtotal	124,946		$20,883	124,946		$25,656	$4,773	22.86
16	Unbilled Delivery			0			0	0	0.00
17	Delivery Subtotal w unbilled			$20,883			$25,656	$4,773	22.86
18									
19	**Supply**								
20	Commodity Charge, BGSS-I	124,946	0.455827	$56,954	124,946	0.455827	$56,954	$0	0.00
21	Emergency Sales Service	0	0.000000	0	0	0.000000	0	0	0.00
22	Pilot Use	0	1.890000	0	0	1.890000	0	0	0.00
23	Penalty Use	0	0.000000	0	0	0.000000	0	0	0.00
24	Miscellaneous			(291)			(291)	0	0.00
25	Supply Subtotal	124,946		$56,663	124,946		$56,663	$0	0.00
26	Unbilled Supply			0			0	0	0.00
27	Supply Subtotal w unbilled			$56,663			$56,663	$0	0.00
28									
29	Total Delivery + Supply	124,946		$77,546	124,946		$82,319	$4,773	6.16
30									
31									
32									

33 Notes:
34 All customers assumed to be on BGSS.
35 Annualized Weather Normalized Revenue reflects Delivery rates as of 4/1/2024
36 plus applicable BGSS charges.

RATE SCHEDULE CSG
CONTRACT SERVICES
"9 and 3" Months Ended May 31, 2024
(Therms & Revenue - Thousands, Rate - $/Therm)

		Actual			Weather Normalized			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Service Charge - Power	0.0000	0.00	$0	0.0000	0.00	$0	$0	0.00
2	Service Charge - Power- Non Firm	0.0000	0.00	0	0.0000	0.00	0	0	0.00
3	Service Charge - Other	0.2319	902.42	209	0.2319	902.42	209	0	0.00
4	Distribution Charge - Power	0	0.000000	0	0	0.000000	0	0	0.00
5	Distribution Charge - Power- Non Firm	0	0.000000	0	0	0.000000	0	0	0.00
6	Distribution Charge - Other	702,392	0.008292	5,824	702,392	0.008292	5,824	0	0.00
7	Maintenance - Power	0	0.000000	0	0	0.000000	0	0	0.00
8	Maintenance - Power- Non Firm	0	0.000000	0	0	0.000000	0	0	0.00
9	Maintenance - Other	702,392	0.000153	107	702,392	0.000153	107	0	0.00
10	Pilot Use	0	0.000000	0	0	0.000000	0	0	0.00
11	Penalty Use	0	0.000000	0	0	0.000000	0	0	0.00
12	Balancing Charge (applicable only if customer uses BGSS-F)	0	0.000000	0	0	0.000000	0	0	0.00
13	SBC	702,392	0.001555	1,092	702,392	0.001555	1,092	0	0.00
14	Green Programs Recovery Charge	702,392	0.000372	261	702,392	0.000372	261	0	0.00
15	Tax Adjustment Credit	702,392	(0.001124)	(790)	702,392	(0.001124)	(790)	0	0.00
16	Gas Conservation Incentive Program	702,392	0.000000	0	702,392	0.000000	0	0	0.00
17	Facilities Chg.			762			762	0	0.00
18	Minimum			629			629	0	0.00
19	Sales Tax Discount - Delivery			(141)			(141)	0	0.00
20	Misc.			(0)			(0)	0	0.00
21	Delivery Subtotal	702,392		7,955	702,392		7,955	0	0.00
22	Unbilled Delivery			499			499	0	0.00
23	Delivery Subtotal w/ Unbilled	702,392		8,454	702,392		8,454	0	0.00
24									
25	**Supply:**								
26	BGSS-Firm - Power	0	0.000000	0	0	0.000000	0	0	0.00
27	BGSS-Firm - Power- Non Firm	0	0.000000	0	0	0.000000	0	0	0.00
28	BGSS-Firm - Other	0	0.000000	0	0	0.000000	0	0	0.00
29									
30	BGSS-Interruptible - Power	0	0.000000	0	0	0.000000	0	0	0.00
31	BGSS-Interruptible - Power- Non Firm	0	0.000000	0	0	0.000000	0	0	0.00
32	BGSS-Interruptible - Other	0	0.000000	0	0	0.000000	0	0	0.00
33									
34	Emergency Sales Svc. - Power	0	0.000000	0	0	0.000000	0	0	0.00
35	Emergency Sales Svc. - Power- Non Firm	0	0.000000	0	0	0.000000	0	0	0.00
36	Emergency Sales Svc - Other	0	0.000000	0	0	0.000000	0	0	0.00
37									
38	Pilot Use	0	0.00	0	0	0.000000	0	0	0.00
39	Penalty Use	0	0.000000	(0)	0	0.000000	0	0	(100.00)
40	Misc.			7			0	(7)	(100.00)
41	Supply Subtotal	0		7	0		0	(7)	(100.00)
42	Unbilled Supply			7			0	(7)	(100.00)
43	Supply Subtotal w/ Unbilled	0		15	0		0	(15)	(100.00)
44									
45	**Total Delivery & Supply**			8,469			8,454	-15	(0.17)
46									
47	Notes:								
48	Rates are annual averages derived from actual, excluding SUT.								

Filing "9 and 3"

RATE SCHEDULE CSG
CONTRACT SERVICES
"9 and 3" Months Ended May 31, 2024
(Therms & Revenue - Thousands, Rate - $/Therm)

		Annualized Weather Normalized			Proposed			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Service Charge - Power	0.0000	902.42	$0	0.0000	1,005.79	$0	$0	0.00
2	Service Charge - Power- Non Firm	0.0000	902.42	0	0.0000	1,005.79	0	0	0.00
3	Service Charge - Other	0.2319	902.42	209	0.2319	1,005.79	233	24	11.48
4	Distribution Charge Change (previously Power)	0	0.000000	0	69	1.000000	69	69	0.00
5	Distribution Charge - Power- Non Firm	0	0.098680	0	0	0.135482	0	0	0.00
6	Distribution Charge - Other	702,392	0.008292	5,824	702,392	0.008292	5,824	0	0.00
7	Maintenance - Power	0	0.000000	0	0	0.000000	0	0	0.00
8	Maintenance - Power- Non Firm	0	0.000000	0	0	0.000000	0	0	0.00
9	Maintenance - Other	702,392	0.000153	107	702,392	0.000153	107	0	0.00
10	Pilot Use	0	0.000000	0	0	0.000000	0	0	0.00
11	Penalty Use	0	0.000000	0	0	0.000000	0	0	0.00
12	Balancing Charge (applicable only if customer uses BGSS-F)	0	0.000000	0	0	0.000000	0	0	0.00
13	SBC	702,392	0.056327	1,092	702,392	0.056327	1,092	0	0.00
14	Green Programs Recovery Charge	702,392	0.009026	261	702,392	0.009026	261	0	0.00
15	Tax Adjustment Credit	702,392	(0.000923)	(648)	702,392	(0.000923)	(648)	0	0.00
16	Gas Conservation Incentive Program	702,392	0.000000	0	702,392	0.000000	0	0	0.00
17	Facilities Chg.			762			762	0	0.00
18	Minimum			629			629	0	0.00
19	Sales Tax Discount - Delivery			(141)			(141)	0	0.00
20	Misc.			(0)			(0)	0	0.00
21	Delivery Subtotal	702,392		8,096	702,392		8,189	93	1.15
22	Unbilled Delivery			508			514	6	1.18
23	Delivery Subtotal w/ Unbilled	702,392		8,604	702,392		8,703	99	1.15
24									
25	**Supply**								
26	BGSS-Firm - Power	0	0.000000	0	0	0.000000	0	0	0.00
27	BGSS-Firm - Power- Non Firm	0	0.000000	0	0	0.000000	0	0	0.00
28	BGSS-Firm - Other	0	0.000000	0	0	0.000000	0	0	0.00
29									
30	BGSS-Interruptible - Power	0	0.000000	0	0	0.000000	0	0	0.00
31	BGSS-Interruptible - Power- Non Firm	0	0.000000	0	0	0.000000	0	0	0.00
32	BGSS-Interruptible - Other	0	0.000000	0	0	0.000000	0	0	0.00
33									
34	Emergency Sales Svc. - Power	0	0.000000	0	0	0.000000	0	0	0.00
35	Emergency Sales Svc. - Power- Non Firm	0	0.000000	0	0	0.000000	0	0	0.00
36	Emergency Sales Svc - Other	0	0.000000	0	0	0.000000	0	0	0.00
37									
38	Pilot Use	0	1.89	0	0	1.89	0	0	0.00
39	Penalty Use	0	0.000000	0	0	0.000000	0	0	0.00
40	Misc.	0		0	0		0	0	0.00
41	Supply Subtotal	0		0	0		0.000	0	0.00
42	Unbilled Supply	0		0	0		0	0	0.00
43	Supply Subtotal w/ Unbilled	0		0	0		0.000	0	0.00
44									
45	**Total Delivery & Supply**	702,392		8,604	702,392		8,703	99.00	1.15
46									
47	Notes:								
48	All customers assumed to be on BGSS.								
49	Annualized Weather Normalized Revenue reflects Delivery rates as of 4/1/2024								
50	plus applicable BGSS charges.								
51									

		Current Total Distribution Charges		Proposed Total Distribution Charges		Difference	
Rate Schedule	Description	Charge without SUT	Charge Including SUT	Charge without SUT	Charge Including SUT	w/out SUT	% w/out SUT
RSG	Service Charge	$8.08	$8.62	$12.28	$13.10	$4.20	51.98%
	Distribution Charges	$0.437491	$0.466475	$0.555821	$0.592644	$0.12	27.43%
	Balancing Charge	$0.091830	$0.097914	$0.091830	$0.097914	$0.00	0.00%
	Off-Peak Use	$0.218746	$0.233238	$0.277911	$0.296323	$0.06	27.43%
GSG	Service Charge	$18.97	$20.23	$28.84	$30.75	$9.87	52.03%
	Distribution Charge - Pre July 14, 1997	$0.328263	$0.350010	$0.496662	$0.529566	$0.17	51.79%
	Distribution Charge - All Others	$0.328263	$0.350010	$0.496662	$0.529566	$0.17	51.79%
	Balancing Charge	$0.091830	$0.097914	$0.091830	$0.097914	$0.00	0.00%
	Off-Peak Use Dist Charge - Pre July 14, 1997	$0.164132	$0.175006	$0.248331	$0.264783	$0.08	48.74%
	Off-Peak Use Dist Charge - All Others	$0.164132	$0.175006	$0.248331	$0.264783	$0.08	48.74%
LVG	Service Charge	$168.50	$179.66	$256.13	$273.10	$87.63	52.01%
	Demand Charge	$4.3754	$4.6653	$5.7242	$6.1034	$1.35	30.85%
	Distribution Charge 0-1,000 pre July 14, 1997	$0.033054	$0.035244	$0.102208	$0.108979	$0.07	211.77%
	Distribution Charge over 1,000 pre July 14, 1997	$0.050101	$0.053420	$0.051748	$0.055176	$0.00	0.00%
	Distribution Charge 0-1,000 post July 14, 1997	$0.033054	$0.035244	$0.102208	$0.108979	$0.07	211.77%
	Distribution Charge over 1,000 post July 14, 1997	$0.050101	$0.053420	$0.051748	$0.055176	$0.00	0.00%
	Balancing Charge	$0.091830	0.097914	$0.091830	$0.097914	$0.00	0.00%
SLG	Single-Mantle Lamp	$13.2351	$14.1119	$15.5295	$16.5583	$2.29	17.30%
	Double-Mantle Lamp, inverted	$13.2351	$14.1119	$15.5295	$16.5583	$2.29	17.30%
	Double Mantle Lamp, upright	$13.2351	$14.1119	$15.5295	$16.5583	$2.29	17.30%
	Triple-Mantle Lamp, prior to January 1, 19933	$13.2351	$14.1119	$15.5295	$16.5583	$2.29	17.30%
	Triple-Mantle Lamp, on and after January 1, 1993	$67.4762	$71.9465	$79.1739	$84.4192	$11.70	17.34%
	Distribution Therm Charge	$0.053531	$0.057077	$0.081371	$0.086762	$0.03	56.04%

Gas Tariff Rates
For Petition Schedules 1 & 2

Filing "9 and 3"

		Current Total Distribution Charges		Proposed Total Distribution Charges		Difference	
Rate Schedule	Description	Charge without SUT	Charge Including SUT	Charge without SUT	Charge Including SUT	w/out SUT	% w/out SUT
TSG-F	Service Charge	$902.42	$962.21	$1,005.79	$1,072.42	$103.37	11.45%
	Demand Charge	$2.1896	$2.3347	$3.4080	$3.6338	$1.22	55.72%
	Distribution Charges	$0.083696	$0.089241	$0.130270	$0.138900	$0.05	59.74%
TSG-NF	Service Charge	$902.42	$962.21	$1,005.79	$1,072.42	$103.37	11.45%
	Distribution Charge 0-50,000	$0.098680	$0.105218	$0.135482	$0.144458	$0.04	40.54%
	Distribution Charge over 50,000	$0.098680	$0.105218	$0.135482	$0.144458	$0.04	40.54%
	Special Provision (d)	$1.89	$2.02	$1.89	$2.02	$0.00	$0.00
CIG	Service Charge	$199.11	$212.30	$268.14	$285.91	$69.03	34.67%
	Distribution Charge 0-600,000	$0.088960	$0.094854	$0.119577	$0.127499	$0.03	33.72%
	Distribution Charge over 600,000	$0.078960	$0.084191	$0.109577	$0.116836	$0.03	37.99%
	Special Provision (c) 1st para	$1.89	$2.02	$1.89	$2.02	$0.00	0.00%
BGSS RSG	Commodity Charge including Losses	$0.372799	$0.397497	$0.371274	$0.395871	$0.00	0.00%
CSG	Service Charge	$902.42	$962.21	$1,005.79	$1,072.42	$103.37	11.45%
	Distribution Charge - Non-Firm	$0.098680	$0.105218	$0.135482	$0.144458	$0.04	40.54%

COMPARISON OF TYPICAL BILLS
Rate Schedule RSG
Distribution Only

	Annual Usages										
Units	**Class Avg**	**Band 1**	**Band 2**	**Band 3**	**Band 4**	**Band 5**	**Band 6**	**Band 7**	**Band 8**	**Band 9**	**Band 10**
Service Charge	12	12	12	12	12	12	12	12	12	12	12
Therm Usage	922	109	347	518	646	760	875	1,004	1,159	1,386	2,151
Balancing Therms	690	34	176	303	401	483	568	659	770	930	1,289
Total	**922**	**109**	**347**	**518**	**646**	**760**	**875**	**1,004**	**1,159**	**1,386**	**2,151**
Average Therm Use	77	9	29	43	54	63	73	84	97	115	179
Present Bill											
Total Delivery	$673.84	$166.32	$309.92	$415.21	$494.97	$564.84	$635.80	$715.02	$810.64	$949.75	$1,402.31
Total Supply	366.69	43.50	138.04	205.73	256.88	301.97	347.67	398.90	460.69	550.74	855.06
	$1,040.53	$209.82	$447.96	$620.94	$751.85	$866.81	$983.47	$1,113.92	$1,271.33	$1,500.49	$2,257.37
Proposed Bill											
Total Delivery	$844.05	$233.94	$407.56	$534.34	$630.33	$714.50	$799.98	$895.45	$1,010.68	$1,178.38	$1,727.54
Total Supply	365.19	43.32	137.48	204.89	255.83	300.74	346.25	397.27	458.81	548.49	851.57
Totals	$1,209.24	$277.26	$545.04	$739.23	$886.16	$1,015.24	$1,146.23	$1,292.72	$1,469.49	$1,726.87	$2,579.11
Increase Amount											
Delivery	$170.21	$67.62	$97.64	$119.13	$135.36	$149.66	$164.18	$180.43	$200.04	$228.63	$325.23
Supply	(1.50)	(0.18)	(0.56)	(0.84)	(1.05)	(1.23)	(1.42)	(1.63)	(1.88)	(2.25)	(3.49)
Totals	$168.71	$67.44	$97.08	$118.29	$134.31	$148.43	$162.76	$178.80	$198.16	$226.38	$321.74
Increase Percent											
Delivery	25.3	40.7	31.5	28.7	27.3	26.5	25.8	25.2	24.7	24.1	23.2
Supply	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)
Totals	16.2	32.1	21.7	19.1	17.9	17.1	16.5	16.1	15.6	15.1	14.3

Notes: Bills include SUT
Each band represents a decile of customers segmented by annual therm usage.
Assumes approval of 2023 TAC filing in current rates

Filing "9 and 3"

Schedule SS-G12 R-1

COMPARISON OF TYPICAL BILLS

Rate Schedule RSG

Including Tax Adjustment Credit, Gas Bad Debts (incl in SBC Charge) and Distribution Adjustment Charge

	Annual Usages										
Units	**Class Avg**	**Band 1**	**Band 2**	**Band 3**	**Band 4**	**Band 5**	**Band 6**	**Band 7**	**Band 8**	**Band 9**	**Band 10**
Service Charge	12	12	12	12	12	12	12	12	12	12	12
Therm Usage	922	109	347	518	646	760	875	1,004	1,159	1,386	2,151
Balancing Therms	690	34	176	303	401	483	568	659	770	930	1,289
Total	**922**	**109**	**347**	**518**	**646**	**760**	**875**	**1,004**	**1,159**	**1,386**	**2,151**
Average Therm Use	77	9	29	43	54	63	73	84	97	115	179
Present Bill											
Total Delivery	$673.84	$166.32	$309.92	$415.21	$494.97	$564.84	$635.80	$715.02	$810.64	$949.75	$1,402.30
Total Supply	366.69	43.50	138.04	205.73	256.88	301.97	347.67	398.90	460.69	550.74	855.06
	$1,040.53	$209.82	$447.96	$620.94	$751.85	$866.81	$983.47	$1,113.92	$1,271.33	$1,500.49	$2,257.36
Proposed Bill											
Total Delivery	$812.43	$230.19	$395.65	$516.59	$608.19	$688.46	$770.00	$861.04	$970.94	$1,130.89	$1,653.80
Total Supply	365.19	43.32	137.48	204.89	255.83	300.74	346.25	397.27	458.81	548.49	851.57
Totals	$1,177.62	$273.51	$533.13	$721.48	$864.02	$989.20	$1,116.25	$1,258.31	$1,429.75	$1,679.38	$2,505.37
Increase Amount											
Delivery	$138.59	$63.87	$85.73	$101.38	$113.22	$123.62	$134.20	$146.02	$160.30	$181.14	$251.50
Supply	(1.50)	(0.18)	(0.56)	(0.84)	(1.05)	(1.23)	(1.42)	(1.63)	(1.88)	(2.25)	(3.49)
Totals	$137.09	$63.69	$85.17	$100.54	$112.17	$122.39	$132.78	$144.39	$158.42	$178.89	$248.01
Increase Percent											
Delivery	20.6	38.4	27.7	24.4	22.9	21.9	21.1	20.4	19.8	19.1	17.9
Supply	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)
Totals	13.2	30.4	19.0	16.2	14.9	14.1	13.5	13.0	12.5	11.9	11.0

Notes: Bills include SUT
Each band represents a decile of customers segmented by annual therm usage.
Assumes approval of proposed TAC filing, Gas Bad Debts (as part of SBC) and DAC

COMPARISON OF TYPICAL BILLS
Rate Schedule GSG
Distribution Only

	Annual Usages										
Units	**Class Avg**	**Band 1**	**Band 2**	**Band 3**	**Band 4**	**Band 5**	**Band 6**	**Band 7**	**Band 8**	**Band 9**	**Band 10**
Service Charge	12	12	12	12	12	12	12	12	12	12	12
Therm Usage	2,150	116	339	602	904	1,298	1,822	2,611	3,904	6,082	11,764
Balancing Therms	1,520	28	158	346	569	832	1,174	1,585	2,154	2,924	4,930
Total	**2,150**	**116**	**339**	**602**	**904**	**1,298**	**1,822**	**2,611**	**3,904**	**6,082**	**11,764**
Average Therm Use	179	10	28	50	75	108	152	218	325	507	980
Present Bill											
Total Delivery	$1,291.92	$294.00	$400.31	$528.70	$676.94	$867.70	$1,120.86	$1,491.30	$2,088.90	$3,076.09	$5,652.26
Total Supply	1,125.12	60.60	177.63	315.02	473.02	679.12	953.66	1,366.19	2,043.30	3,182.74	6,156.30
	$2,417.04	$354.60	$577.94	$843.72	$1,149.96	$1,546.82	$2,074.52	$2,857.49	$4,132.20	$6,258.83	$11,808.56
Proposed Bill											
Total Delivery	$1,804.24	$441.07	$587.53	$763.06	$965.51	$1,226.99	$1,574.34	$2,086.32	$2,916.23	$4,294.37	$7,890.79
Total Supply	1,123.36	60.51	177.35	314.53	472.28	678.06	952.17	1,364.06	2,040.11	3,177.77	6,146.69
Totals	$2,927.60	$501.58	$764.88	$1,077.59	$1,437.79	$1,905.05	$2,526.51	$3,450.38	$4,956.34	$7,472.14	$14,037.48
Increase Amount											
Delivery	$512.32	$147.07	$187.22	$234.36	$288.57	$359.29	$453.48	$595.02	$827.33	$1,218.28	$2,238.53
Supply	(1.76)	(0.09)	(0.28)	(0.49)	(0.74)	(1.06)	(1.49)	(2.13)	(3.19)	(4.97)	(9.61)
Totals	$510.56	$146.98	$186.94	$233.87	$287.83	$358.23	$451.99	$592.89	$824.14	$1,213.31	$2,228.92
Increase Percent											
Delivery	39.7	50.0	46.8	44.3	42.6	41.4	40.5	39.9	39.6	39.6	39.6
Supply	(0.2)	(0.1)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)
Totals	21.1	41.4	32.3	27.7	25.0	23.2	21.8	20.7	19.9	19.4	18.9

Notes: Bills include SUT
Each band represents a decile of customers segmented by annual therm usage.
Assumes approval of 2023 TAC filing in current rates

COMPARISON OF TYPICAL BILLS
Rate Schedule GSG
Including Tax Adjustment Credit, Gas Bad Debts (incl in SBC Charge) and Distribution Adjustment Charge

	Annual Usages										
Units	**Class Avg**	**Band 1**	**Band 2**	**Band 3**	**Band 4**	**Band 5**	**Band 6**	**Band 7**	**Band 8**	**Band 9**	**Band 10**
Service Charge	12	12	12	12	12	12	12	12	12	12	12
Therm Usage	2,150	116	339	602	904	1,298	1,822	2,611	3,904	6,082	11,764
Balancing Therms	1,520	28	158	346	569	832	1,174	1,585	2,154	2,924	4,930
Total	**2,150**	**116**	**339**	**602**	**904**	**1,298**	**1,822**	**2,611**	**3,904**	**6,082**	**11,764**
Average Therm Use	179	10	28	50	75	108	152	218	325	507	980
Present Bill											
Total Delivery	$1,291.92	$294.00	$400.31	$528.70	$676.94	$867.70	$1,120.86	$1,491.30	$2,088.90	$3,076.09	$5,652.26
Total Supply	1,125.12	60.60	177.63	315.02	473.02	679.12	953.66	1,366.19	2,043.30	3,182.74	6,156.30
	$2,417.04	$354.60	$577.94	$843.72	$1,149.96	$1,546.82	$2,074.52	$2,857.49	$4,132.20	$6,258.83	$11,808.56
Proposed Bill											
Total Delivery	$1,745.75	$437.92	$578.30	$746.69	$940.92	$1,191.69	$1,524.76	$2,015.29	$2,810.00	$4,128.90	$7,570.72
Total Supply	1,123.36	60.51	177.35	314.53	472.28	678.06	952.17	1,364.06	2,040.11	3,177.77	6,146.69
Totals	$2,869.11	$498.43	$755.65	$1,061.22	$1,413.20	$1,869.75	$2,476.93	$3,379.35	$4,850.11	$7,306.67	$13,717.41
Increase Amount											
Delivery	$453.83	$143.92	$177.99	$217.99	$263.98	$323.99	$403.90	$523.99	$721.10	$1,052.81	$1,918.46
Supply	(1.76)	(0.09)	(0.28)	(0.49)	(0.74)	(1.06)	(1.49)	(2.13)	(3.19)	(4.97)	(9.61)
Totals	$452.07	$143.83	$177.71	$217.50	$263.24	$322.93	$402.41	$521.86	$717.91	$1,047.84	$1,908.85
Increase Percent											
Delivery	35.1	49.0	44.5	41.2	39.0	37.3	36.0	35.1	34.5	34.2	33.9
Supply	(0.2)	(0.1)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)
Totals	18.7	40.6	30.7	25.8	22.9	20.9	19.4	18.3	17.4	16.7	16.2

Notes: Bills include SUT
Each band represents a decile of customers segmented by annual therm usage.
Assumes approval of proposed TAC filing, Gas Bad Debts (as part of SBC) and DAC

COMPARISON OF TYPICAL BILLS
Rate Schedule LVG
Distribution Only

		Annual Usages										
	Units	**Class Avg**	**Band 1**	**Band 2**	**Band 3**	**Band 4**	**Band 5**	**Band 6**	**Band 7**	**Band 8**	**Band 9**	**Band 10**
1	Service Charge	12	12	12	12	12	12	12	12	12	12	12
2	Therm Usage (0-1,000)	7,507	5,652	7,907	8,286	8,938	9,554	10,058	10,362	10,843	11,170	11,578
3	Therm Usage (1,000+)	32,064	1,064	4,212	7,501	10,453	13,873	18,384	24,621	34,102	54,770	225,003
4	Demand Therms	1,027	198	361	496	592	701	822	978	1,264	1,788	5,019
5												
6	Balancing Therms	23,816	3,433	7,187	10,252	12,307	14,283	16,426	19,923	25,445	35,568	78,098
7												
8	**Total**	**39,570**	**6,716**	**12,119**	**15,787**	**19,391**	**23,427**	**28,442**	**34,984**	**44,945**	**65,941**	**236,580**
9												
10	Average Therm Use	3,298	560	1,010	1,316	1,616	1,952	2,370	2,915	3,745	5,495	19,715
11												
12												
13	**Present Bill**											
14	Total Delivery	$13,186.72	$3,999.00	$5,639.41	$6,938.54	$7,940.60	$9,046.98	$10,325.21	$12,059.01	$14,942.70	$20,517.73	$57,195.63
15	Total Supply	20,694.73	3,512.29	6,338.17	8,256.23	10,141.10	12,252.04	14,874.81	18,296.05	23,505.54	34,486.05	123,728.10
16		$33,881.45	$7,511.29	$11,977.58	$15,194.77	$18,081.70	$21,299.02	$25,200.02	$30,355.06	$38,448.24	$55,003.78	$180,923.73
17												
18												
19												
20	**Proposed Bill**											
21	Total Delivery	$16,394.30	$5,823.37	$7,870.35	$9,397.69	$10,589.94	$11,905.39	$13,402.85	$15,394.53	$18,741.30	$25,129.97	$66,784.14
22	Total Supply	20,662.40	3,506.80	6,328.27	8,243.33	10,125.26	12,232.90	14,851.57	18,267.47	23,468.81	34,432.18	123,534.80
23	Totals	$37,056.70	$9,330.17	$14,198.62	$17,641.02	$20,715.20	$24,138.29	$28,254.42	$33,662.00	$42,210.11	$59,562.15	$190,318.94
24												
25												
26												
27	**Increase Amount**											
28	Delivery	$3,207.58	$1,824.37	$2,230.94	$2,459.15	$2,649.34	$2,858.41	$3,077.64	$3,335.52	$3,798.60	$4,612.24	$9,588.51
29	Supply	(32.33)	(5.49)	(9.90)	(12.90)	(15.84)	(19.14)	(23.24)	(28.58)	(36.73)	(53.87)	(193.30)
30	Totals	$3,175.25	$1,818.88	$2,221.04	$2,446.25	$2,633.50	$2,839.27	$3,054.40	$3,306.94	$3,761.87	$4,558.37	$9,395.21
31												
32												
33												
34	**Increase Percent**											
35	Delivery	24.3	45.6	39.6	35.4	33.4	31.6	29.8	27.7	25.4	22.5	16.8
36	Supply	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)
37	Totals	9.4	24.2	18.5	16.1	14.6	13.3	12.1	10.9	9.8	8.3	5.2
38												
39												
40												

41 Notes: Bills include SUT
42 Each band represents a decile of customers segmented by annual therm usage.
Assumes approval of 2023 TAC filing in current rates

COMPARISON OF TYPICAL BILLS
Rate Schedule LVG
Including Tax Adjustment Credit, Gas Bad Debts (incl in SBC Charge) and Distribution Adjustment Charge

		Annual Usages										
Units		**Class Avg**	**Band 1**	**Band 2**	**Band 3**	**Band 4**	**Band 5**	**Band 6**	**Band 7**	**Band 8**	**Band 9**	**Band 10**
Service Charge		12	12	12	12	12	12	12	12	12	12	12
Therm Usage (0-1,000)		7,507	5,652	7,907	8,286	8,938	9,554	10,058	10,362	10,843	11,170	11,578
Therm Usage (1,000+)		32,064	1,064	4,212	7,501	10,453	13,873	18,384	24,621	34,102	54,770	225,003
Demand Therms		1,027	198	361	496	592	701	822	978	1,264	1,788	5,019
Balancing Therms		23,816	3,433	7,187	10,252	12,307	14,283	16,426	19,923	25,445	35,568	78,098
	Total	**39,570**	**6,716**	**12,119**	**15,787**	**19,391**	**23,427**	**28,442**	**34,984**	**44,945**	**65,941**	**236,580**
Average Therm Use		3,298	560	1,010	1,316	1,616	1,952	2,370	2,915	3,745	5,495	19,715
Present Bill												
Total Delivery		$13,186.72	$3,999.00	$5,639.41	$6,938.54	$7,940.60	$9,046.98	$10,325.21	$12,059.01	$14,942.70	$20,517.73	$57,195.63
Total Supply		20,694.73	3,512.29	6,338.17	8,256.23	10,141.10	12,252.04	14,874.81	18,296.05	23,505.54	34,486.05	123,728.10
		$33,881.45	$7,511.29	$11,977.58	$15,194.77	$18,081.70	$21,299.02	$25,200.02	$30,355.06	$38,448.24	$55,003.78	$180,923.73
Proposed Bill												
Total Delivery		$16,187.00	$5,788.19	$7,806.86	$9,314.99	$10,488.36	$11,782.65	$13,253.84	$15,211.25	$18,505.84	$24,784.51	$65,544.70
Total Supply		20,662.40	3,506.80	6,328.27	8,243.33	10,125.26	12,232.90	14,851.57	18,267.47	23,468.81	34,432.18	123,534.80
Totals		$36,849.40	$9,294.99	$14,135.13	$17,558.32	$20,613.62	$24,015.55	$28,105.41	$33,478.72	$41,974.65	$59,216.69	$189,079.50
Increase Amount												
Delivery		$3,000.28	$1,789.19	$2,167.45	$2,376.45	$2,547.76	$2,735.67	$2,928.63	$3,152.24	$3,563.14	$4,266.78	$8,349.07
Supply		(32.33)	(5.49)	(9.90)	(12.90)	(15.84)	(19.14)	(23.24)	(28.58)	(36.73)	(53.87)	(193.30)
Totals		$2,967.95	$1,783.70	$2,157.55	$2,363.55	$2,531.92	$2,716.53	$2,905.39	$3,123.66	$3,526.41	$4,212.91	$8,155.77
Increase Percent												
Delivery		22.8	44.7	38.4	34.3	32.1	30.2	28.4	26.1	23.8	20.8	14.6
Supply		(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)
Totals		8.8	23.7	18.0	15.6	14.0	12.8	11.5	10.3	9.2	7.7	4.5

Notes: Bills include SUT
Each band represents a decile of customers segmented by annual therm usage.
Assumes approval of proposed TAC filing, Gas Bad Debts (as part of SBC) and DAC

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
1	S	**SUMMARY OF RESULTS**							
2	S	**DEVELOPMENT OF RETURN**							
3	S								
4	S	**RATE BASE**							
5	S	Plant in Service							
6	S	Production Plant 304-320	CALCULATED	52,043,670	39,041,892	4,021,862	8,979,916	0	0
7	S	Storage Plant 360-363	CALCULATED	19,575,233	14,684,863	1,512,747	3,377,624	0	0
8	S	Transmission Plant 365-371	CALCULATED	103,544,395	62,040,662	11,990,912	28,481,645	17,348	1,013,828
9	S	Distribution Plant							
10	S	Land & Structures 374-375	CALCULATED	96,512,525	69,254,169	12,136,562	14,671,363	20,554	429,877
11	S	Mains 376	CALCULATED	3,775,184,891	2,261,934,505	437,169,958	1,038,486,336	632,773	36,961,319
12	S	Compressor Station Equipment 377	CALCULATED	0	0	0	0	0	0
13	S	Meas & Regulating Station Equip 378-379	CALCULATED	285,986,290	171,354,314	33,118,514	78,665,388	47,914	2,800,160
14	S	Services 380	CALCULATED	5,447,179,699	4,488,006,097	641,086,199	314,336,599	1,381	3,749,423
15	S	Meters 381	CALCULATED	477,048,047	317,953,337	110,271,175	48,821,975	1	1,559
16	S	Meter Installations 382	CALCULATED	52,631,537	47,983,374	4,209,056	439,073	0	33
17	S	House Regulators & Install 383-384	CALCULATED	151,182,537	135,567,948	12,123,371	3,487,303	3	3,912
18	S	Industrial Meas & Reg Station Equip 385	CALCULATED	145,614,455	1,941,847	62,478,553	79,018,841	479	2,174,735
19	S	Other Property on Cust Premises 386	CALCULATED	0	0	0	0	0	0
20	S	Other Equipment (Street Lighting) 387	CALCULATED	1,521,717	0	0	0	1,521,717	0
21	S	Asset Retirement Obligation 388	CALCULATED	65,215,073	39,074,172	7,551,967	17,939,509	10,931	638,495
22	S	Total Distribution Plant	CALCULATED	10,498,076,770	7,533,069,762	1,320,145,353	1,595,866,388	2,235,754	46,759,512
23	S	General Plant E389-E399	CALCULATED	200,812,197	145,432,738	23,233,566	31,189,583	45,366	910,945
24	S	Common Plant C389-C399	CALCULATED	102,234,955	83,912,187	9,391,523	7,489,732	8,419	1,433,095
25	S	Intangible Plant E301-E303, E399, C303-C390	CALCULATED	16,791,854	14,286,709	1,415,779	804,020	641	284,706
26	S	Total Plant in Service	CALCULATED	10,993,079,074	7,892,468,811	1,371,711,742	1,676,188,908	2,307,527	50,402,086
27	S								
28	S	Less: Reserve for Depreciation and Amorization	CALCULATED	2,718,471,978	1,956,775,950	317,824,430	428,830,574	221,981	14,819,043
29	S								
30	S	Plus: Rate Base Additions							
31	S	Working Capital	CALCULATED	645,513,843	471,907,638	79,739,307	90,486,856	204,693	3,175,348
32	S	Capital Stimulas Adjust (Pro Forma #13)	CALCULATED	0	0	0	0	0	0
33	S	Capital Lease Plt & Reserve Deduct	CALCULATED	96,280	79,025	8,845	7,054	8	1,350
34	S	Other Rate Base Additions		1,727,003,584	1,239,205,145	217,420,162	262,335,837	373,791	7,668,650
35	S	Plus: Rate Base Deductions							
36	S	Customer Advances	CALCULATED	-24,909,672	-18,230,629	-2,912,216	-3,653,782	-3,090	-109,954
37	S	Unbilled Revenue	CALCULATED	-256,132,009	-183,889,689	-31,960,043	-39,054,175	-53,764	-1,174,338
38	S	Deferred Income Taxes and Credits	CALCULATED	-1,684,560,542	-1,209,488,302	-210,096,949	-256,906,795	-353,004	-7,715,492
39	S								
40	S	Other Rate Base Deductions		0	0	0	0	0	0
41	S	TOTAL RATE BASE		8,681,618,581	6,235,276,049	1,106,086,416	1,300,573,328	2,254,181	37,428,607
42	S								
43	S								
44	S								

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
45	S								
46	S	**SUMMARY OF RESULTS**							
47	S	**DEVELOPMENT OF RETURN**							
48	S								
49	S	**RATE BASE**	CALCULATED	8,681,618,581	6,235,276,049	1,106,086,416	1,300,573,328	2,254,181	37,428,607
50	S								
51	S	**OPERATING REVENUES**							
52	S	Rate Revenues from Customers	CALCULATED	1,401,350,320	1,001,979,781	178,047,445	213,229,775	561,110	7,532,209
53	S	Other Operating Revenues	CALCULATED	67,687,036	59,364,939	3,520,285	4,693,084	7,538	101,189
54	S	Revenues from Other Sources	CALCULATED	0	0	0	0	0	0
55	S	Less: Provisions for Rate Refunds	CALCULATED	0	0	0	0	0	0
56	S	TOTAL OPERATING REVENUES		1,469,037,356	1,061,344,721	181,567,730	217,922,859	568,648	7,633,399
57	S								
58	S	**OPERATING EXPENSES**							
59	S	Operation and Maintenance Expense							
60	S	Gas Production and Supply Expense	CALCULATED	31,906,945	23,935,800	2,465,727	5,505,418	0	1
61	S	Storage Expense	CALCULATED	2,714,605	2,036,430	209,781	468,394	0	0
62	S	Transmission Expense	CALCULATED	2,593,507	1,553,951	300,340	713,388	435	25,394
63	S	Distribution Expense	CALCULATED	102,873,398	77,699,719	11,258,713	13,338,995	208,062	367,909
64	S	Customer Accounts Expense	CALCULATED	98,759,541	80,933,107	9,215,702	7,168,765	2,373	1,439,594
65	S	Customer Service & Information Expense	CALCULATED	4,034,218	3,287,677	493,290	222,739	121	30,392
66	S	Sales Expense	CALCULATED	88,423	70,127	12,936	5,339	2	19
67	S	Administrative and General Expense	CALCULATED	38,752,071	21,675,904	6,046,494	10,418,767	73,670	537,236
68	S	Total Operation and Maintenance Expense	CALCULATED	281,722,708	211,192,715	30,002,983	37,841,805	284,662	2,400,544
69	S	Depreciation Expense	CALCULATED	203,691,216	146,793,062	25,243,756	30,634,719	42,609	977,070
70	S	Amortization Expense	CALCULATED	2,351,634	2,067,920	194,832	68,025	48	20,808
71	S	Taxes Other Than Income Taxes	CALCULATED	-24,480,722	-19,023,027	-2,468,458	-2,845,174	-8,536	-135,526
72	S	Proforma Expense Adjustments	CALCULATED	100,619,236	74,359,380	11,662,197	14,055,338	26,320	516,002
73	S	State Income Taxes	CALCULATED	77,634,124	55,792,643	9,859,372	11,624,350	19,881	337,879
74	S	Federal Income Taxes	CALCULATED	143,331,440	103,000,554	18,257,239	21,418,824	37,704	617,120
75	S	Provision for Deferred Income Taxes	CALCULATED	28,705,516	16,398,132	5,306,284	6,931,686	-4,229	73,643
76	S	Income Taxes Deferred in Prior Years	CALCULATED	0	0	0	0	0	0
77	S	Investment Tax Credit Adjustement (Net)	CALCULATED	0	0	0	0	0	0
78	S	TOTAL OPERATING EXPENSES		813,575,153	590,581,379	98,058,206	119,729,572	398,458	4,807,539
79	S								
80	S	**OPERATING INCOME (RETURN)**		655,462,203	470,763,342	83,509,524	98,193,286	170,191	2,825,860
81	S	Plus Operating Income Adjustment	CALCULATED						
82	S	TOTAL NET OPERATING INCOME		655,462,203	470,763,342	83,509,524	98,193,286	170,191	2,825,860
83	S								
84	S	**RATE OF RETURN ON RATE BASE (PRESENT)**		7.55%	7.55%	7.55%	7.55%	7.55%	7.55%
85	S	**INDEX RATE OF RETURN (PRESENT)**		1	1	1	1	1	1
86	S								
87	S								
88	S	**EQUALIZED RETURN AT PROPOSED ROR**							

PUBLIC SERVICE ELECTRIC & GAS COMPANY
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12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
89	S	**DEVELOPMENT OF RETURN (EQUALIZED RATE LEVELS)**							
90	S								
91	S	**RATE BASE**	CALCULATED	8,681,618,581	6,235,276,049	1,106,086,416	1,300,573,328	2,254,181	37,428,607
92	S								
93	S	**RATE OF RETURN**		7.55%	7.55%	7.55%	7.55%	7.55%	7.55%
94	S								
95	S	**RETURN (RATE BASE * 7.40% ROR)**		655,462,203	470,763,342	83,509,524	98,193,286	170,191	2,825,860
96	S								
97	S	**PLUS:**							
98	S	**OPERATING EXPENSES**							
99	S	Total Operation and Maintenance Expense	CALCULATED	281,722,708	211,192,715	30,002,983	37,841,805	284,662	2,400,544
100	S	Depreciation Expense	CALCULATED	203,691,216	146,793,062	25,243,756	30,634,719	42,609	977,070
101	S	Amortization Expense	CALCULATED	2,351,634	2,067,920	194,832	68,025	48	20,808
102	S	Taxes Other Than Income Taxes	CALCULATED	-24,480,722	-19,023,027	-2,468,458	-2,845,174	-8,536	-135,526
103	S	Proforma Expense Adjustments	CALCULATED	100,619,236	74,359,380	11,662,197	14,055,338	26,320	516,002
104	S	Income Taxes	CALCULATED	220,965,564	158,793,196	28,116,611	33,043,174	57,584	954,998
105	S	Provision for Deferred Income Taxes	CALCULATED	28,705,516	16,398,132	5,306,284	6,931,686	-4,229	73,643
106	S	Income Taxes Deferred in Prior Years	CALCULATED	0	0	0	0	0	0
107	S	Investment Tax Credit Adjustement (Net)	CALCULATED	0	0	0	0	0	0
108	S	**TOTAL OPERATING EXPENSES**		813,575,153	590,581,379	98,058,206	119,729,572	398,458	4,807,539
109	S								
110	S	**EQUALS TOTAL COST OF SERVICE**		1,469,037,356	1,061,344,721	181,567,730	217,922,859	568,648	7,633,399
111	S								
112	S	**LESS:**							
113	S	Other Operating Revenues	CALCULATED	67,687,036	59,364,939	3,520,285	4,693,084	7,538	101,189
114	S	Revenues from Other Sources	CALCULATED	0	0	0	0	0	0
115	S	Plus: Provisions for Rate Refunds	CALCULATED	0	0	0	0	0	0
116	S	**EQUALS:**							
117	S	**BASE RATE SALES @ EQUALIZED ROR 7.40%**		1,401,350,320	1,001,979,781	178,047,445	213,229,775	561,110	7,532,209
118	S								
119	S	**TOTAL COST OF SERVICE INCREASE/DECREASE**		0	0	0	0	0	0
120	S	**REVENUE INCREASE TO RETAIL REVENUES (%)**		0.0	0.0	0.0	0.0	0.0	0.0

Updated for 9 and 3

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
1	RBP	**DEVELOPMENT OF RATE BASE**							
2	RBP								
3	RBP	**GAS PLANT IN SERVICE**							
4	RBP								
5	RBP	INTANGIBLE PLANT - G301-G303							
6	RBP	General - AWMS & Misc.	TOTPLT	0	0	0	0	0	0
7	RBP	Choice Progect	not_used	0	0	0	0	0	0
8	RBP	GSMIS - meter related	not_used	0	0	0	0	0	0
9	RBP	- regulator related	not_used	0	0	0	0	0	0
10	RBP	- appliance safety related	not_used	0	0	0	0	0	0
11	RBP	- Comp Svs related	not_used	0	0	0	0	0	0
12	RBP	- Cust Svs related	not_used	0	0	0	0	0	0
13	RBP	TOTAL INTANGIBLE PLANT		0	0	0	0	0	0
14	RBP								
15	RBP	C303 - INTANGIBLE PLANT - CUST SERVICE							
16	RBP	Customer Service	CUSTSVSX	16,301,302	13,931,440	1,359,023	727,829	530	282,481
17	RBP	Measurement	MRCOST_07	0	0	0	0	0	0
18	RBP	Not Used	not_used	0	0	0	0	0	0
19	RBP	G399.1 Asset Retirement Costs of General Plt	GENPLT	490,552	355,269	56,756	76,191	111	2,225
20	RBP	Not Used	not_used	0	0	0	0	0	0
21	RBP	TOTAL ACCOUNTS C303-C390.4,G399		16,791,854	14,286,709	1,415,779	804,020	641	284,706
22	RBP								
23	RBP	TOTAL INTANGIBLE PLANT		16,791,854	14,286,709	1,415,779	804,020	641	284,706
24	RBP								
25	RBP	PRODUCTION PLANT							
26	RBP	G304-G320 - All Land & Equipment	BALANCE_04	52,043,670	39,041,892	4,021,862	8,979,916	0	0
27	RBP	Not Used	not_used	0	0	0	0	0	0
28	RBP	TOTAL PRODUCTION PLANT		52,043,670	39,041,892	4,021,862	8,979,916	0	0
29	RBP								
30	RBP	STORAGE PLANT							
31	RBP	G360-G363 - All Land & Equipment	BALANCE_04	19,575,233	14,684,863	1,512,747	3,377,624	0	0
32	RBP	Not Used	not_used	0	0	0	0	0	0
33	RBP	TOTAL STORAGE PLANT		19,575,233	14,684,863	1,512,747	3,377,624	0	0
34	RBP								
35	RBP	TRANSMISSION PLANT							
36	RBP	G365 Land & Land Rights	AVGPEAK_04	5,421,128	3,248,175	627,791	1,491,173	908	53,080
37	RBP	G366 Structures & Improvements	AVGPEAK_04	0	0	0	0	0	0
38	RBP	G367 Mains	AVGPEAK_04	93,786,847	56,194,235	10,860,944	25,797,666	15,713	918,290
39	RBP	G369 Meas. & Reg. Station Equipment	AVGPEAK_04	4,336,420	2,598,252	502,177	1,192,806	727	42,459
40	RBP	TOTAL TRANSMISSION PLANT		103,544,395	62,040,662	11,990,912	28,481,645	17,348	1,013,828
41	RBP								
42	RBP								
43	RBP								
44	RBP	**GAS PLANT IN SERVICE CONTINUED**							

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
45	RBP								
46	RBP	DISTRIBUTION PLANT							
47	RBP	G374-G375 Land & Structures							
48	RBP	General	DISTPLT	96,512,525	69,254,169	12,136,562	14,671,363	20,554	429,877
49	RBP	Not Used	not_used	0	0	0	0	0	0
50	RBP	Total Accounts G374-G375		96,512,525	69,254,169	12,136,562	14,671,363	20,554	429,877
51	RBP								
52	RBP	G376 Mains							
53	RBP	Firm Allocation	AVGPEAK_04	3,772,391,917	2,260,302,858	436,860,148	1,037,660,490	632,027	36,936,395
54	RBP	CIG, TSG-NF & CSG Redistribution	TRANSPORT_04	2,792,974	1,631,647	309,809	825,847	747	24,924
55	RBP	Not Used	not_used	0	0	0	0	0	0
56	RBP	Total Account G376		3,775,184,891	2,261,934,505	437,169,958	1,038,486,336	632,773	36,961,319
57	RBP								
58	RBP	G377 Compressor Station Equip	DISTPLTXMTR	0	0	0	0	0	0
59	RBP								
60	RBP	G378-G379 Meas & Regulatory Equipment							
61	RBP	Firm Investment	AVGPEAK_04	285,986,290	171,354,314	33,118,514	78,665,388	47,914	2,800,160
62	RBP	Not Used	not_used	0	0	0	0	0	0
63	RBP	Total Account G378-G379		285,986,290	171,354,314	33,118,514	78,665,388	47,914	2,800,160
64	RBP								
65	RBP	G380 Services							
66	RBP	Firm Allocation	SERVICES_03	5,442,013,091	4,484,987,779	640,513,095	312,808,899	0	3,703,317
67	RBP	CIG, TSG-NF & CSG Redistribution	TRANSPORT_03	5,166,608	3,018,317	573,103	1,527,700	1,381	46,106
68	RBP	Not Used	not_used	0	0	0	0	0	0
69	RBP	Total Account G380		5,447,179,699	4,488,006,097	641,086,199	314,336,599	1,381	3,749,423
70	RBP								
71	RBP	G381 Meters							
72	RBP	Firm Allocation	SMMETERS_07	477,045,042	317,951,581	110,270,842	48,821,087	0	1,532
73	RBP	CIG, TSG-NF & CSG Redistribution	TRANSPORT_07	3,005	1,755	333	888	1	27
74	RBP	Not Used	not_used	0	0	0	0	0	0
75	RBP	Total Account G381		477,048,047	317,953,337	110,271,175	48,821,975	1	1,559
76	RBP								
77	RBP	G382 Meter Installations							
78	RBP	Firm Allocation	MTRINSTAL_07	52,630,927	47,983,018	4,208,988	438,893	0	27
79	RBP	CIG, TSG-NF & CSG Redistribution	TRANSPORT_07	609	356	68	180	0	5
80	RBP	Not Used	not_used	0	0	0	0	0	0
81	RBP	Total Account G382		52,631,537	47,983,374	4,209,056	439,073	0	33
82	RBP								
83	RBP								
84	RBP								
85	RBP								
86	RBP								
87	RBP								
88	RBP	**GAS PLANT IN SERVICE CONTINUED**							

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
89	RBP								
90	RBP	DISTRIBUTION PLANT CONTINUED							
91	RBP								
92	RBP	G383 House Regulators & Installation							
93	RBP	Firm Allocation - Regulators - G383	HOUSEREG_03	38,488,025	32,605,191	3,994,393	1,885,454	0	2,986
94	RBP	CIG, TSG-NF & CSG Redistribution	TRANSPORT_03	11,098	6,483	1,231	3,282	3	99
95	RBP	Not Used	not_used	0	0	0	0	0	0
96	RBP	Total Account G383		38,499,123	32,611,675	3,995,624	1,888,736	3	3,085
97	RBP								
98	RBP	G384 House Regulators & Installation		0	0	0	0	0	0
99	RBP	Firm Allocation - Installation - G384	HSEREGINST_03	112,681,544	102,955,181	8,127,539	1,598,014	0	810
100	RBP	G384 CIG. TSG-NF & CSG Redistribution	TRANSPORT_03	1,870	1,092	207	553	0	17
101	RBP	Total Account G384		112,683,414	102,956,273	8,127,747	1,598,567	0	827
102	RBP	G385 Industrial Meas and Regul Station Equip							
103	RBP	Firm Allocation - Regulators	LRGREG_03	71,912,204	896,108	1,613,951	69,103,946	0	298,200
104	RBP	Firm Allocation - Meters	LRGMTR_07	71,912,204	0	60,666,042	9,385,601	0	1,860,561
105	RBP	CIG, TSG-NF & CSG Redistribution - Regulators	TRANSPORT_03	895,023	522,870	99,280	264,647	239	7,987
106	RBP	CIG, TSG-NF & CSG Redistribution - Meters	TRANSPORT_07	895,023	522,870	99,280	264,647	239	7,987
107	RBP	Not Used	not_used	0	0	0	0	0	0
108	RBP	Total Account G385		145,614,455	1,941,847	62,478,553	79,018,841	479	2,174,735
109	RBP								
110	RBP	G386 Other Prop on Cust Prem	TRANSPORT_04	0	0	0	0	0	0
111	RBP								
112	RBP	G387-Other Equipment							
113	RBP	G387.1 Other Eqmt - Street Ltg Posts	DIRSLG_05	1,011,930	0	0	0	1,011,930	0
114	RBP	G387.2 Other Eqmt - Street Ltg Services	DIRSLG_03	509,787	0	0	0	509,787	0
115	RBP	Total Accounts G387		1,521,717	0	0	0	1,521,717	0
116	RBP								
117	RBP	G388 - Asset Retirement Obligations	PLT_376	65,215,073	39,074,172	7,551,967	17,939,509	10,931	638,495
118	RBP								
119	RBP	TOTAL DISTRIBUTION PLANT		10,498,076,770	7,533,069,762	1,320,145,353	1,595,866,388	2,235,754	46,759,512
120	RBP								
121	RBP								
122	RBP								
123	RBP								
124	RBP								
125	RBP								
126	RBP								
127	RBP								
128	RBP								
129	RBP								
130	RBP								
131	RBP								
132	RBP								

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
133	RBP								
134	RBP								
135	RBP	**GAS PLANT IN SERVICE CONTINUED**							
136	RBP								
137	RBP	GENERAL AND COMMON PLANT							
138	RBP	E390-E398 GENERAL PLANT							
139	RBP	Meter Related	METERPLT	0	0	0	0	0	0
140	RBP	Regulator Plant Related	PLT_3834	0	0	0	0	0	0
141	RBP	Appliance Safety Related	CINST_04	0	0	0	0	0	0
142	RBP	Distribution Delivery	DISTPLTXMTR	200,812,197	145,432,738	23,233,566	31,189,583	45,366	910,945
143	RBP	Competitive Service	COMPSVSWK_04	0	0	0	0	0	0
144	RBP	SONP/RNP Related	CUSTAVG_04	0	0	0	0	0	0
145	RBP	Gas Peaking Plant Related	BALANCE_04	0	0	0	0	0	0
146	RBP	Total Accounts E390-E398		200,812,197	145,432,738	23,233,566	31,189,583	45,366	910,945
147	RBP								
148	RBP	C389-C399 COMMON PLANT							
149	RBP	ASB Work Related	CINST_04	0	0	0	0	0	0
150	RBP	Meter Plant Related	METERPLT	0	0	0	0	0	0
151	RBP	Not Used	not_used	0	0	0	0	0	0
152	RBP	Customer Service Related	CUSTSVSX	75,768,116	64,753,044	6,316,710	3,382,935	2,462	1,312,966
153	RBP	Distribution Delivery Related	DISTPLTXMTR	25,073,523	18,158,813	2,900,956	3,894,349	5,664	113,741
154	RBP	Service & Support Related	UTILWORK_04	0	0	0	0	0	0
155	RBP	Unassigned	TOTPLT	1,393,316	1,000,330	173,857	212,448	292	6,388
156	RBP	Total Accounts C389-C399		102,234,955	83,912,187	9,391,523	7,489,732	8,419	1,433,095
157	RBP								
158	RBP	TOTAL GENERAL AND COMMON PLANT		303,047,153	229,344,924	32,625,089	38,679,316	53,784	2,344,039
159	RBP								
160	RBP								
161	RBP	**TOTAL GAS PLANT IN SERVICE (101)**		10,993,079,074	7,892,468,811	1,371,711,742	1,676,188,908	2,307,527	50,402,086

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
1	RBD	**LESS: DEPRECIATION RESERVE & AMORT**							
2	RBD								
3	RBD	G301-G303 - INTANGILE PLANT - RESERVE							
4	RBD	General - AWMS & Misc.	TOTPLT	0	0	0	0	0	0
5	RBD	Choice Progect	not_used	0	0	0	0	0	0
6	RBD	GSMIS - meter related	not_used	0	0	0	0	0	0
7	RBD	- regulator related	not_used	0	0	0	0	0	0
8	RBD	- appliance safety related	not_used	0	0	0	0	0	0
9	RBD	- Comp Svs related	not_used	0	0	0	0	0	0
10	RBD	- Cust Svs related	not_used	0	0	0	0	0	0
11	RBD	Total Accounts E301-E303 Reserve		0	0	0	0	0	0
12	RBD								
13	RBD	C303 - INTANGIBLE PLANT - CUST SERVICE							
14	RBD	Customer Service	CUSTSVSX	9,821,603	8,393,751	818,817	438,520	319	170,196
15	RBD	Measurement	MRCOST_07	0	0	0	0	0	0
16	RBD	Not Used	not_used	0	0	0	0	0	0
17	RBD	G399.1 Asset Retirement Costs of General Plt	GENPLT	0	0	0	0	0	0
18	RBD	Not Used	not_used	0	0	0	0	0	0
19	RBD	TOTAL ACCOUNTS C303-C390.4,G399		9,821,603	8,393,751	818,817	438,520	319	170,196
20	RBD								
21	RBD	TOTAL INTANGIBLE PLANT		9,821,603	8,393,751	818,817	438,520	319	170,196
22	RBD								
23	RBD	PRODUCTION PLANT G304-G320 RESERVE	BALANCE_04	56,077,402	42,067,900	4,333,584	9,675,919	0	0
24	RBD								
25	RBD	STORAGE PLANT G360-G363 RESERVE	BALANCE_04	9,476,790	7,109,257	732,353	1,635,180	0	0
26	RBD								
27	RBD	TRANSMISSION PLANT G365-G369 RESERVE	TRANPLT	50,246,121	30,105,952	5,818,729	13,821,049	8,418	491,972
28	RBD								
29	RBD	DISTRIBUTION PLANT RESERVE							
30	RBD	G374-G375 Land & Structures Reserve	PLT_3745	432,406	310,280	54,376	65,732	92	1,926
31	RBD								
32	RBD	G376 Mains Reserve							
33	RBD	Firm Allocation	AVGPEAK_04	1,017,890,245	609,888,973	117,876,322	279,988,006	170,537	9,966,408
34	RBD	CIG, TSG-NF & CSG Redistribution	TRANSPORT_04	759,994	443,986	84,302	224,720	203	6,782
35	RBD	Not Used	not_used	0	0	0	0	0	0
36	RBD	Total Account G376		1,018,650,239	610,332,959	117,960,624	280,212,726	170,741	9,973,190
37	RBD								
38	RBD	G377 Compressor Station Equip Reserve	DISTPLTXMTR						
39	RBD								
40	RBD	G378-G379 Meas & Regulatory Equip Reserve							
41	RBD	Firm Investment	AVGPEAK_04	93,669,010	56,123,631	10,847,298	25,765,253	15,693	917,136
42	RBD	Not Used	not_used	0	0	0	0	0	0
43	RBD	Total Account G378-G379		93,669,010	56,123,631	10,847,298	25,765,253	15,693	917,136
44	RBD	**DEPRECIATION RESERVE & AMORT CONTINUED**							

PUBLIC SERVICE ELECTRIC & GAS COMPANY
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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
45	RBD								
46	RBD	**DISTRIBUTION PLANT CONTINUED**							
47	RBD								
48	RBD	G380 Services Reserve							
49	RBD	Firm Allocation	SERVICESR_03	1,126,944,013	941,879,849	127,667,704	56,085,079	0	1,311,381
50	RBD	CIG, TSG-NF & CSG Redistribution	TRANSPORT_03	2,349,910	1,372,810	260,663	694,838	628	20,970
51	RBD	Not Used	not_used	0	0	0	0	0	0
52	RBD	Total Account G380		1,129,293,923	943,252,660	127,928,367	56,779,917	628	1,332,351
53	RBD								
54	RBD	G381 Meters Reserve							
55	RBD	Firm Allocation	SMMETERSR_07	61,006,069	41,220,681	13,639,927	6,145,259	0	202
56	RBD	CIG, TSG-NF & CSG Redistribution	TRANSPORT_07	1,948	1,138	216	576	1	17
57	RBD	Not Used	not_used	0	0	0	0	0	0
58	RBD	Total Account G381		61,008,018	41,221,819	13,640,143	6,145,836	1	219
59	RBD								
60	RBD	G382 Meter Installations Reserve							
61	RBD	Firm Allocation	MTRINSTALR_07	33,652,945	31,062,601	2,354,621	235,711	0	11
62	RBD	CIG, TSG-NF & CSG Redistribution	TRANSPORT_07	279	163	31	83	0	2
63	RBD	Not Used	not_used	0	0	0	0	0	0
64	RBD	Total Account G382		33,653,224	31,062,764	2,354,652	235,794	0	14
65	RBD								
66	RBD	G383 House Regulators & Installation Reserve							
67	RBD	Firm Allocation - Regulators - G383	HOUSEREGR_03	25,030,964	21,059,419	2,653,835	1,312,627	0	5,082
68	RBD	CIG, TSG-NF & CSG Redistribution	TRANSPORT_03	4,827	2,820	535	1,427	1	43
69	RBD	Not Used	not_used	0	0	0	0	0	0
70	RBD	Total Account G383		25,035,791	21,062,240	2,654,371	1,314,054	1	5,125
71	RBD								
72	RBD	G384 House Regulators & Installation Reserve		0	0	0	0	0	0
73	RBD	Firm Allocation - Installation - G384	HSEREGINSTR_03	58,406,745	53,459,006	4,125,696	820,870	0	1,173
74	RBD	G384 CIG. TSG-NF & CSG Redistribution	TRANSPORT_03	1,006	588	112	298	0	9
75	RBD	Total Account G384		58,407,752	53,459,594	4,125,808	821,168	0	1,182
76	RBD	G385 Industrial Meas and Regul Sta Equip Reserve							
77	RBD	Firm Allocation - Regulators	LRGREGR_03	12,236,618	23,869	289,692	11,817,896	0	105,161
78	RBD	Firm Allocation - Meters	LRGMTRR_07	12,236,618	0	10,344,813	1,235,941	0	655,864
79	RBD	CIG, TSG-NF & CSG Redistribution - Regulators	TRANSPORT_03	295,977	172,909	32,831	87,517	79	2,641
80	RBD	CIG, TSG-NF & CSG Redistribution - Meters	TRANSPORT_07	295,977	172,909	32,831	87,517	79	2,641
81	RBD	Not Used	not_used	0	0	0	0	0	0
82	RBD	Total Account G385		25,065,190	369,687	10,700,167	13,228,870	158	766,307
83	RBD								
84	RBD	G386 Other Prop on Cust Prem	TRANSPORT_04	0	0	0	0	0	0
85	RBD	G387.1 Other Eqmt - Street Ltg Posts	DIRSLG_05	0	0	0	0	0	0
86	RBD	G387.2 Other Eqmt - Street Ltg Services	DIRSLG_03	0	0	0	0	0	0
87	RBD								
88	RBD	TOTAL DISTRIBUTION PLANT RESERVE		2,445,215,554	1,757,195,634	290,265,805	384,569,350	187,315	12,997,450

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PUBLIC SERVICE ELECTRIC & GAS COMPANY
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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
89	RBD								
90	RBD	**DEPRECIATION RESERVE & AMORT CONTINUED**							
91	RBD								
92	RBD	GENERAL AND COMMON PLANT RESERVE							
93	RBD								
94	RBD	E390-E398 GENERAL PLANT - RESERVE							
95	RBD	Meter Related	METERPLT	0	0	0	0	0	0
96	RBD	Regulator Plant Related	PLT_3834	0	0	0	0	0	0
97	RBD	Appliance Safety Related	CINST_04	0	0	0	0	0	0
98	RBD	Distribution Delivery	DISTPLTXMTR	94,949,830	68,764,815	10,985,504	14,747,339	21,450	430,721
99	RBD	Competitive Service	COMPSVSWK_04	0	0	0	0	0	0
100	RBD	SONP/RNP Related	CUSTAVG_04	0	0	0	0	0	0
101	RBD	Gas Peaking Plant Related	BALANCE_04	0	0	0	0	0	0
102	RBD	Total Accounts E390-E398		94,949,830	68,764,815	10,985,504	14,747,339	21,450	430,721
103	RBD								
104	RBD	C389-C399 COMMON PLANT							
105	RBD	ASB Work Related	CINST_04	0	0	0	0	0	0
106	RBD	Not Used	not_used	0	0	0	0	0	0
107	RBD	Customer Service Related	CUSTSVSX	38,276,434	32,711,855	3,191,067	1,708,986	1,244	663,282
108	RBD	Distribution Delivery Related	DISTPLTXMTR	13,134,595	9,512,371	1,519,646	2,040,028	2,967	59,582
109	RBD	Service & Support Related	UTILWORK_04	0	0	0	0	0	0
110	RBD	Unassigned	TOTPLT	1,273,650	914,416	158,926	194,202	267	5,840
111	RBD	Total Accounts C389-C399 Reserve		52,684,679	43,138,641	4,869,638	3,943,217	4,478	728,704
112	RBD								
113	RBD	**TOTAL DEPRECIATION RESERVE & AMORT.**		2,718,471,978	1,956,775,950	317,824,430	428,830,574	221,981	14,819,043
114	RBD								
115	RBD								
116	RBD	**NET GAS PLANT IN SERVICE**		8,274,607,096	5,935,692,862	1,053,887,312	1,247,358,334	2,085,546	35,583,043
117	RBD	Meter Plant Related	METERPLT	0	0	0	0	0	0

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
1	RBO	**ADDITIONS AND DEDUCTIONS TO RATE BASE**							
2	RBO								
3	RBO	**PLUS: ADDITIONS TO RATE BASE**							
4	RBO								
5	RBO	Working Capital							
6	RBO	Materials and Supplies Excl Fuel Stock	PSTDPLT	59,382,049	42,555,365	7,442,317	9,106,038	12,535	265,794
7	RBO	Fuel Stock & Fuel Stock Expense	not_used	0	0	0	0	0	0
8	RBO	Gas Stored Underground	not_used	0	0	0	0	0	0
9	RBO	Cash (lead/lag)	EXPENDITURES	586,016,094	429,267,521	72,282,719	81,364,753	192,119	2,908,981
10	RBO	Prepayments/Working Funds	EXPENDITURES	115,700	84,752	14,271	16,064	38	574
11	RBO	Total Working Capital		645,513,843	471,907,638	79,739,307	90,486,856	204,693	3,175,348
12	RBO	CEF-EC Adjustment	not_used						
13	RBO	CEF-EV Adjustment	not_used						
14	RBO	Net Plant Adds - Distribution	DISTPLT	1,573,578,886	1,129,147,727	197,879,374	239,207,781	335,122	7,008,882
15	RBO	Capital Stimulas Adjust	DISTPLT	0	0	0	0	0	0
16	RBO	Capital Lease Plant & Reserve Deduction	COMPLT	96,280	79,025	8,845	7,054	8	1,350
17	RBO	Net Plant Adds - General & Other	TOTPLTNET	153,424,698	110,057,417	19,540,788	23,128,056	38,669	659,768
18	RBO	TOTAL ADDITIONS TO RATE BASE		2,372,613,708	1,711,191,808	297,168,314	352,829,747	578,492	10,845,348
19	RBO								
20	RBO	**PLUS: DEDUCTIONS TO RATE BASE**							
21	RBO								
22	RBO	Customer Advances for Construction	MAIN_SERV	(24,909,672)	(18,230,629)	(2,912,216)	(3,653,782)	(3,090)	(109,954)
23	RBO	IAP Adjustment	not_used						
24	RBO	GSMP II EXT Adjustment	TOTPLT	(256,132,009)	(183,889,689)	(31,960,043)	(39,054,175)	(53,764)	(1,174,338)
25	RBO	Deferred Income Taxes and Credits							
26	RBO	ADIT Test/Post year	TOTPLT						
27	RBO	Liberalized Depreciation	TOTPLT	35,377,684	25,399,369	4,414,412	5,394,274	7,426	162,203
28	RBO	Liberalized Depreciation - Production	BALANCE_04	(1,955,963)	(1,467,315)	(151,154)	(337,493)		
29	RBO	Cost of Removal	TOTPLT	9,569,770	6,870,606	1,194,112	1,459,167	2,009	43,876
30	RBO	3% Investment Tax Credit	DISTPLT	0	0	0	0	0	0
31	RBO	Computer Software	TOTPLT	0	0	0	0	0	0
32	RBO	Capitalized Interest	TOTPLTNET	(160,793)	(115,343)	(20,479)	(24,239)	(41)	(691)
33	RBO	NJ Corporate Business Tax	STATEINCTAX	4,194,912	3,014,721	532,745	628,115	1,074	18,257
34	RBO	Defrd Tax & Consolidated Tax Adjustment	TOTPLT	(1,731,586,152)	(1,243,190,339)	(216,066,585)	(264,026,619)	(363,472)	(7,939,136)
35	RBO	Total Deferred Income Taxes and Credits		(1,684,560,542)	(1,209,488,302)	(210,096,949)	(256,906,795)	(353,004)	(7,715,492)
36	RBO								
37	RBO	TOTAL DEDUCTIONS TO RATE BASE		(1,965,602,222)	(1,411,608,620)	(244,969,209)	(299,614,752)	(409,858)	(8,999,783)
38	RBO								
39	RBO								
40	RBO	**TOTAL RATE BASE**		8,681,618,581	6,235,276,049	1,106,086,416	1,300,573,328	2,254,181	37,428,607

PUBLIC SERVICE ELECTRIC & GAS COMPANY
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				(1)	(2)	(3)	(4)	(5)	(6)
1	REV	**OPERATING REVENUES**							
2	REV								
3	REV	**SALES REVENUES**							
4	REV	BASE RATE SALES @ EQUALIZED ROR 7.40%		1,401,350,320	1,001,979,781	178,047,445	213,229,775	561,110	7,532,209
5	REV	Revenue Requirement - Other #1	not_used	0	0	0	0	0	0
6	REV	Revenue Requirement - Other #2	not_used	0	0	0	0	0	0
7	REV	TOTAL SALES OF GAS		1,401,350,320	1,001,979,781	178,047,445	213,229,775	561,110	7,532,209
8	REV								
9	REV	**OTHER OPERATING REVENUES**							
10	REV	G487-Forfeited Discounts	REVLATEP	1,447,215	0	658,543	788,672	0	0
11	REV	G488-Miscellaneous Service Revenues	COMPSVSWK_04	40,880,111	40,880,111	0	0	0	0
12	REV	G489-Revenues from Transmission from Others	not_used	0	0	0	0	0	0
13	REV	G493-Rent from Gas Property	TOTPLT	0	0	0	0	0	0
14	REV	G495-Other Gas Revenues							
15	REV	Miscellaneous Gas Revenues	TOTREV	19,473,704	14,069,290	2,406,880	2,888,807	7,538	101,189
16	REV	Peak Shaving Revenues	BALANCE_04	5,886,006	4,415,538	454,862	1,015,606	0	0
17	REV	Not Used	not_used	0	0	0	0	0	0
18	REV	Not Used	not_used	0	0	0	0	0	0
19	REV	TOTAL OTHER OPERATING REV		67,687,036	59,364,939	3,520,285	4,693,084	7,538	101,189
20	REV								
21	REV	**OTHER REVENUE SOURCES**							
22	REV	Not Used	not_used	0	0	0	0	0	0
23	REV	Not Used	not_used	0	0	0	0	0	0
24	REV	TOTAL OTHER REVENUE SOURCES		0	0	0	0	0	0
25	REV								
26	REV	LESS: E496 Provision for Rate Refunds	TOTREV	0	0	0	0	0	0
27	REV								
28	REV	**TOTAL OPERATING REVENUES**		1,469,037,356	1,061,344,721	181,567,730	217,922,859	568,648	7,633,399

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				(1)	(2)	(3)	(4)	(5)	(6)
1	E	**OPERATION & MAINTENANCE EXPENSE**							
2	E								
3	E	MANUFACTURED GAS PRODUCTION EXPENSE							
4	E	G710-G718 Production Expenses Incl Labor	BALANCE_04	281,982	211,536	21,791	48,655	0	0
5	E	G722-G736 Gas Raw Materials	BALANCE_04	29,792,635	22,349,708	2,302,333	5,140,593	0	0
6	E	G739-G745 Operation & Maintenance Exp	BALANCE_04	1,832,256	1,374,514	141,594	316,148	0	0
7	E	Not Used	not_used	0	0	0	0	0	0
8	E	TOTAL MANUFACTURED GAS PRODUCTION EXP		31,906,873	23,935,758	2,465,719	5,505,396	0	0
9	E								
10	E	OTHER GAS SUPPLY EXPENSE							
11	E	G801 Natural Gas Field Line Purchases	not_used	0	0	0	0	0	0
12	E	G804 Natural Gas City Gate Purchases	not_used	0	0	0	0	0	0
13	E	G805 Other Gas Purchases	not_used	0	0	0	0	0	0
14	E	G808.1,.2 GasInject & W/D from Storage	not_used	0	0	0	0	0	0
15	E	G812 Gas Used for Other Util Oper	not_used	0	0	0	0	0	0
16	E	G813 Other Gas Supply Expenses							
17	E	Supply Related	not_used	0	0	0	0	0	0
18	E	Distribution Related	TRANSPORT_04	72	42	8	21	0	1
19	E	TOTAL OTHER GAS SUPPLY EXPENSE		72	42	8	21	0	1
20	E	TOTAL GAS PRODUCTION AND SUPPLY		31,906,945	23,935,800	2,465,727	5,505,418	0	1
21	E								
22	E	OTHER STORAGE EXPENSE							
23	E	G840-G842 Operation	BALANCE_04	8,906	6,681	688	1,537	0	0
24	E	G843 Maintenance	BALANCE_04	2,705,699	2,029,749	209,093	466,857		
25	E	TOTAL OTHER STORAGE EXPENSE		2,714,605	2,036,430	209,781	468,394	0	0
26	E								
27	E	TRANSMISSION EXPENSES							
28	E	G850-G867 Transmission Exp	TRANPLT	2,593,507	1,553,951	300,340	713,388	435	25,394
29	E	TOTAL TRANSMISSION EXPENSE		2,593,507	1,553,951	300,340	713,388	435	25,394
30	E								
31	E	DISTRIBUTION EXPENSES							
32	E	Operation							
33	E	G870 Operation Supervision & Engineering	TLABDO	0	0	0	0	0	0
34	E	G871 Load Dispatching	TRANSPORT_04	5,839,316	3,411,311	647,723	1,726,611	1,561	52,109
35	E	G872 Compressor Station Labor & Expenses	TRANSPORT_04	0	0	0	0	0	0
36	E	G874 Mains & Services	MAIN_SERV	20,733,577	15,174,273	2,423,985	3,041,227	2,572	91,520
37	E	G875 Meas & Reg Station - General	PLT_3789	2,497,019	1,496,138	289,166	686,848	418	24,449
38	E	G876 Meas & Reg Station - Industrial	PLT_3789	7,594	4,550	879	2,089	1	74
39	E	G877 Meas & Reg Station - City Gate	PLT_3789	514,539	308,296	59,586	141,533	86	5,038
40	E	G878 Meter & House Reg	PLT_3814	11,492,061	8,464,742	2,136,903	890,323	0	93
41	E	G879 Customer Installations							
42	E	- Customer Installations	CINST_04	17,355,157	17,355,157	0	0	0	0
43	E	- Competitive Services by ASB	COMPSVSWK_04	0	0	0	0	0	0
44	**E**	**OPERATION & MAINTENANCE EXPENSE CONTINUED**							

PUBLIC SERVICE ELECTRIC & GAS COMPANY
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12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
45	E								
46	E	G880.0,.1,.2 Other Expenses	DISTEXPO	14,050,188	11,166,159	1,332,116	1,510,775	1,065	40,072
47	E	G880.3 Operation of Street Lighting	DIRSLG_05	0	0	0	0	0	0
48	E	G881 Rents	TRANSPORT_04	-1,088,602	-635,958	-120,753	-321,886	-291	-9,715
49	E	Total Distribution Operation		71,400,849	56,744,669	6,769,606	7,677,520	5,413	203,641
50	E								
51	E	DISTRIBUTION EXPENSES CONTINUED							
52	E	Maintenance							
53	E	G885 Maint. Supervision & Engineering	TLABDM	0	0	0	0	0	0
54	E	G886 Structures & Improvements	PLT_3745	8,016,449	5,752,336	1,008,078	1,218,621	1,707	35,706
55	E	G887 Mains	PLT_376	8,706,285	5,216,446	1,008,196	2,394,944	1,459	85,240
56	E	G888 Compressor Station Equip	PLT_377	0	0	0	0	0	0
57	E	G889 Meas & Reg Station - General	PLT_3789	1,007,898	603,902	116,719	277,239	169	9,869
58	E	G891 Meas & Reg Station - City Gate	PLT_3789	3,155,564	1,890,718	365,429	867,991	529	30,897
59	E	G892 Services	SERVICES	3,610,466	2,974,434	424,881	208,327	339	2,485
60	E	G893 Meters & House Reg							
61	E	G893.1 - Meters	SMMETERS_07	6,767,990	4,510,880	1,564,448	692,640	0	22
62	E	G893.4 - House Regulators	PLT_3834	0	0	0	0	0	0
63	E	Not Used	not_used	0	0	0	0	0	0
64	E	G894 Maint of Other Equipment							
65	E	G894.0 - Maint of Other Equip	DISTEXPM	9,513	6,334	1,357	1,711	61	50
66	E	G894.1 - Maint of Gas Streetlights	DIRSLG_05	198,384	0	0	0	198,384	0
67	E	Total Distribution Maintenance		31,472,549	20,955,051	4,489,107	5,661,476	202,649	164,268
68	E	TOTAL DISTRIBUTION PLANT O&M EXPENSES		102,873,398	77,699,719	11,258,713	13,338,995	208,062	367,909
69	E								
70	E	TOTAL OPER & MAINT EXP (PROD,STOR, TRAN,& DIST)		140,088,455	105,225,900	14,234,561	20,026,195	208,496	393,303
71	E								
72	E	CUSTOMER ACCOUNTS EXPENSES							
73	E	G901 Supervision	CUSTACCTS	0	0	0	0	0	0
74	E	G902 Meter Reading							
75	E	- Meter Reading Related	MRCOST_07	12,907,838	11,695,648	984,362	227,828	0	0
76	E	- Meter O&M Related	METERPLT	38,249	23,265	11,125	3,740	0	119
77	E	G903 Customer Records and Collection							
78	E	- SONP/RNP	CUSTAVG_06	526,534	477,008	40,157	9,334	8	27
79	E	- Meter O&M Related	METERPLT	0	0	0	0	0	0
80	E	- Meter Reading Related	MRCOST_07	63,202	57,267	4,820	1,116	0	0
81	E	- Billing Related	BILLING_06	16,558,655	13,225,534	1,341,715	1,310,000	1,164	680,242
82	E	- Acct Maint Related	ACCTMAINT_06	26,073,286	23,623,844	2,005,203	393,770	159	50,309
83	E	- Utility Work Related	UTILWORK_04	2,712,621	2,151,329	396,835	163,794	70	592
84	E	- Remaining	BILLING_06	13,832,442	11,048,085	1,120,815	1,094,322	972	568,247
85	E	Not used	not_used	0	0	0	0	0	0
86	**E**	**OPERATION & MAINTENANCE EXPENSE CONTINUED**							
87	E								
88	E	G904 Uncollectible Accounts	EXP_904	26,046,715	18,631,127	3,310,670	3,964,861	0	140,056

PUBLIC SERVICE ELECTRIC & GAS COMPANY
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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
89	E	G905 Misc Customer Accounts	CUSTACCTS	0	0	0	0	0	0
90	E	TOTAL CUSTOMER ACCTS EXPENSE		98,759,541	80,933,107	9,215,702	7,168,765	2,373	1,439,594
91	E								
92	E	CUSTOMER SERVICE & INFO EXPENSES							
93	E	G907 & 908 - Customer Service & Information							
94	E	- Billing	BILLING_06	37,379	29,855	3,029	2,957	3	1,536
95	E	- Acct Maint related	ACCTMAINT_06	746,413	676,291	57,404	11,273	5	1,440
96	E	- Utility work related	UTILWORK_04	1,684,915	1,336,275	246,490	101,739	44	368
97	E	- Remaining	ACCTMAINT_06	0	0	0	0	0	0
98	E	G909 Info & Instr Advertising	TRANSPORT_04	0	0	0	0	0	0
99	E	G910 - Misc Cust Service & Info							
100	E	- Utility work related	UTILWORK_04	911,953	723,253	133,412	55,066	24	199
101	E	- Remaining	BILLING_06	653,558	522,002	52,957	51,705	46	26,849
102	E	TOTAL CUSTOMER SERVICE & INFO EXPENSES		4,034,218	3,287,677	493,290	222,739	121	30,392
103	E								
104	E	SALES EXPENSES							
105	E	G912 - Demonstrating and Selling	UTILWORK_04	88,423	70,127	12,936	5,339	2	19
106	E	G913 - Advertising	UTILWORK_04	0	0	0	0	0	0
107	E	G916 - Miscellaneous	UTILWORK_04	0	0	0	0	0	0
108	E								
109	E	SALES EXPENSES TOTAL (ACCT 916)		88,423	70,127	12,936	5,339	2	19
110	E								
111	E	TOTAL OPER & MAINT EXCL A&G		242,970,637	189,516,811	23,956,488	27,423,038	210,992	1,863,308
112	E								
113	E	ADMINISTRATIVE & GENERAL EXPENSE							
114	E	G920 A&G Salaries	TOMXFUEL904	6,954,680	5,240,842	752,956	881,780	8,847	70,255
115	E	G921 Office Supplies & Exp	TOMXFUEL904	652,569	491,757	70,651	82,739	830	6,592
116	E	G923 Outside Services Employed							
117	E	- Gas Peaking Plant Related	BALANCE_04	0	0	0	0	0	0
118	E	- Remaining	TOMXFUEL904	61,043,177	46,000,343	6,608,902	7,739,626	77,655	616,650
119	E	G924 Property Insurance	TOTPLT	296,480	212,857	36,995	45,206	62	1,359
120	E	G925 Injuries & Damages	LABOR	15,351,785	13,054,660	1,092,066	1,093,968	7,995	103,096
121	E	G926 Employee Pension & Benefits							
122	E	- Gas Peaking Plant Related	BALANCE_04	0	0	0	0	0	0
123	E	- Remaining	LABOR	-60,778,346	-51,683,934	-4,323,534	-4,331,063	-31,654	-408,162
124	E	G928 Regulatory Comm Exp	TRANSPORT_04	5,147,284	3,007,028	570,960	1,521,986	1,376	45,934
125	E	G929 Duplicate Charges - credit	INTRAREV	764,611	0	36,217	728,394	0	0
126	E	G930.1 General Advertising Expenses	TRANSPORT_04	1,968,152	1,149,789	218,316	581,957	526	17,564
127	E	G930.2 Misc General Expenses	TRANSPORT_04	3,638,524	2,125,615	403,601	1,075,865	973	32,470
128	E	G931 Rents	AGEXP	3,713,155	2,076,947	579,364	998,308	7,059	51,477
129	E	G932 Maint of General Plant	COMGENPLT	0	0	0	0	0	0
130	E	G935 Other A&G Maint	COMGENPLT	0	0	0	0	0	0
131	E	Not Used	not_used	0	0	0	0	0	0
132	E	TOTAL A&G EXPENSE		38,752,071	21,675,904	6,046,494	10,418,767	73,670	537,236

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
133	E								
134	E	**TOTAL OPERATION & MAINTENANCE EXPENSES**		281,722,708	211,192,715	30,002,983	37,841,805	284,662	2,400,544
135	E	G890 Meas & Reg Station - Industrial	PLT_3789	0	0	0	0	0	0

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PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
1	DE	**DEPRECIATION AND AMORTIZATION EXPENSES**							
2	DE								
3	DE	G403 DEPRECIATION EXPENSE							
4	DE	Production Plant	BALANCE_04	1,670	1,253	129	288	0	0
5	DE	Storage Plant	BALANCE_04	114,612	85,979	8,857	19,776	0	0
6	DE	Transmission Plant	TRANPLT	1,172,631	702,605	135,796	322,552	196	11,482
7	DE	Distribution Plant	DISTPLT	182,874,076	131,224,338	22,996,628	27,799,624	38,946	814,540
8	DE	General and Common Plant	COMGENPLT	19,528,227	14,778,887	2,102,347	2,492,478	3,466	151,049
9	DE	Not Used	not_used	0	0	0	0	0	0
10	DE	TOTAL DEPRECIATION EXPENSE		203,691,216	146,793,062	25,243,756	30,634,719	42,609	977,070
11	DE								
12	DE	G404.3 AMORT OF OTHER LIMITED TERM PLANT							
13	DE	Customer Service related	CUSTSVSX	1,194,362	1,020,727	99,573	53,326	39	20,697
14	DE	AWMS	DISTPLT	0	0	0	0	0	0
15	DE	Distribution	CHOICE_04	1,127,553	1,029,117	86,615	11,792	10	19
16	DE	Metering	METERPLT	29,719	18,076	8,644	2,906	0	92
17	DE	All Other	PSTDPLT	0	0	0	0	0	0
18	DE	TOTAL AMORT OF OTHER LIMITED TERM PLT		2,351,634	2,067,920	194,832	68,025	48	20,808
19	DE								
20	DE	G407 AMORT OF PROPERTY LOSSES							
21	DE	Remediation Adjustment Clause	not_used	0	0	0	0	0	0
22	DE	Excess Cost of Removal	TOTPLT						
23	DE	TOTAL AMORT OF PROPERTY LOSSES		0	0	0	0	0	0
24	DE								
25	DE	TOTAL AMORTIZATION EXPENSE		2,351,634	2,067,920	194,832	68,025	48	20,808
26	DE								
27	DE	**TOTAL DEPRECIATION AND AMORTIZATION EXPENSES**		206,042,850	148,860,982	25,438,589	30,702,743	42,657	997,878

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
1	EO	**OTHER OPERATING EXPENSES**							
2	EO								
3	EO	**G408 TAXES OTHER THAN INCOME TAXES**							
4	EO	Payroll	LABOR	-2,034	-1,730	-145	-145	-1	-14
5	EO	TEFA	TEFA_04	0	0	0	0	0	0
6	EO	Real Estate Taxes	TOTPLT	-13,552,354	-9,729,897	-1,691,057	-2,066,419	-2,845	-62,136
7	EO	State Unemploy Insur (SUI) Tax	LABOR	0	0	0	0	0	0
8	EO	Fed Insur Contr & UnempTax	LABOR	-60,481	-51,431	-4,302	-4,310	-31	-406
9	EO	Fed Insur Contr & UnempTax - Gas Peaking Plts	BALANCE_04	0	0	0	0	0	0
10	EO	FICA	LABOR	-10,865,853	-9,239,969	-772,954	-774,300	-5,659	-72,970
11	EO	Miscellaneous State and Municipal Tax	TOTPLT	0	0	0	0	0	0
12	EO	Federal Environmental Tax	PSTDPLT	0.0	0.0	0.0	0.0	0.0	0.0
13	EO	**TOTAL TAXES OTHER THAN INCOME**		-24,480,722	-19,023,027	-2,468,458	-2,845,174	-8,536	-135,526
14	EO								
15	EO	**PROFORMA EXPENSE ADJUSTMENTS**							
16	EO	Amortization of CEF-EC Program Regulatory Assets		0	0	0	0	0	0
17	EO	Amortization of CEF-EV Program Regulatory Assets		0	0	0	0	0	0
18	EO	BGS Administrative Expense Adjustment		0	0	0	0	0	0
19	EO	CIP Revenue Accrual Adjustment	not_used	0	0	0	0	0	0
20	EO	Deferred Compensation & Severance Expense	LABOR	-361,345	-307,276	-25,705	-25,749	-188	-2,427
21	EO	Gas Bad Debt Adjustment	not_used	0	0	0	0	0	0
22	EO	TAC Revenue Accrual Adjustment	not_used	0	0	0	0	0	0
23	EO	Tax Bad Debt Adjustment	SALESREV	2,990,017	2,137,893	379,894	454,962	1,197	16,071
24	EO	TSG-NF Gas Margin Reset	not_used	0	0	0	0	0	0
25	EO	Wage Increases (Rate Year)	LABOR	7,223,753	6,142,845	513,870	514,764	3,762	48,512
26	EO	Payroll Taxes (Rate Year)	LABOR	508,958	432,802	36,205	36,268	265	3,418
27	EO	Interest Syncronization	TOTPLTNET	-1,864,683	-1,337,609	-237,494	-281,092	-470	-8,019
28	EO	- add'l tax effects on rev req	TOTPLTNET	-729,117	-523,024	-92,863	-109,911	-184	-3,135
29	EO	Pension & Fringe Benefit (Rate Year)	LABOR	7,091,402	6,030,298	504,455	505,333	3,693	47,623
30	EO	Adj #5 - Gas COLI Interest Expense	LABOR	0	0	0	0	0	0
31	EO	- add'l tax effects on rev req	LABOR	0	0	0	0	0	0
32	EO	Postage	CUSTACCTS	0	0	0	0	0	0
33	EO	BPU / Rate Counsel Assessment	TRANSPORT_04	738,301	431,313	81,896	218,306	197	6,589
34	EO	Adj #6 - Weather Normalization	not_used	0	0	0	0	0	0
35	EO	Gains / Losses Normalization	TOTPLT	-207,450	-148,938	-25,886	-31,631	-44	-951
36	EO	- add'l tax effects on rev req	TOTPLT	-81,116	-58,237	-10,122	-12,368	-17	-372
37	EO	Test Year Corrections	TOTPLT	0	0	0	0	0	0
38	EO	Customer Information System Amort	CUSTSVSX	0	0	0	0	0	0
39	EO	Real Estate Tax Increases (Rate Year)	TOTPLT	158,827	114,029	19,818	24,217	33	728
40	EO	Capital Stimulus (Depreciation)	DISTPLT	0	0	0	0	0	0
41	EO	Insurance Premium Increases (Rate Year)	TOTPLT	237,517	170,525	29,637	36,216	50	1,089
42	EO	Adj #15 - Excess COR Refund Recovery	TOTPLT	0	0	0	0	0	0
43	EO	Test Year Amortization Adjustments	TOTPLT	-5,932,749	-4,259,410	-740,286	-904,606	-1,245	-27,201
44	EO	Adj #11 - TSGNF Margin Sharing	not_used	0	0	0	0	0	0

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
45	EO	Adj #12 - Depreciation Rate Change/Annualization	DEPREXP	0	0	0	0	0	0
46	EO	Capital Stimulus Revenue	DISTPLT	0	0	0	0	0	0
47	EO	ASB Margin	TOTPLT	15,265,290	10,959,698	1,904,796	2,327,602	3,204	69,990
48	EO	Adj #13 - Storm Cost Amortization	TOTPLTNET	0	0	0	0	0	0
49	EO	Other Regulatory Asset / Liability Amortizations	TOTPLT	0	0	0	0	0	0
50	EO	Rate Case Expenses	TOTPLT	141,376	101,501	17,641	21,557	30	648
51	EO	Tax - Repair Allowance	DISTPLT	0	0	0	0	0	0
52	EO	Tax - Flow Through Items	DISTPLT	0	0	0	0	0	0
53	EO	Adj #14 Post Rate Case Storm Cost Normalization	TOTPLT	0	0	0	0	0	0
54	EO	Recovery of Credit Card Fees	CUSTSVSX	0	0	0	0	0	0
55	EO	Adj #20 - Vacation Accrual	LABOR	0	0	0	0	0	0
56	EO	Energy Strong II / IAP Revenue Adjustment	TOTPLT						
57	EO	Depreciation Rate Change	DEPREXP	74,624,206	53,779,029	9,248,289	11,223,319	15,610	357,959
58	EO	TOTAL PROFORMA EXPENSE ADJUSTMENTS		100,619,236	74,359,380	11,662,197	14,055,338	26,320	516,002
59	EO								
60	EO	**TOTAL OTHER OPERATING EXPENSES**		76,138,514	55,336,353	9,193,739	11,210,164	17,783	380,475
61	EO	COLI Interest Expense Recovery	LABOR	816,048	693,941	58,050	58,152	425	5,480

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
1	TI	**DEVELOPMENT OF INCOME TAXES**							
2	TI								
3	TI	TOTAL OPERATING REVENUES	CALCULATED	1,469,037,356	1,061,344,721	181,567,730	217,922,859	568,648	7,633,399
4	TI	LESS:							
5	TI	OPERATION & MAINTAINENCE EXPENSE	CALCULATED	281,722,708	211,192,715	30,002,983	37,841,805	284,662	2,400,544
6	TI	DEPRECIATION & AMORTIZATION EXPENSE	CALCULATED	206,042,850	148,860,982	25,438,589	30,702,743	42,657	997,878
7	TI	OTHER OPERATING EXPENSES	CALCULATED	76,138,514	55,336,353	9,193,739	11,210,164	17,783	380,475
8	TI	NET OPERATING INCOME BEFORE TAXES		905,133,284	645,954,670	116,932,420	138,168,147	223,546	3,854,501
9	TI	LESS:							
10	TI	G427 - G431 INTEREST CHARGES	TOTPLTNET	100,820,068	72,322,099	12,840,850	15,198,154	25,411	433,553
11	TI	**TOTAL OPERATING INCOME BEFORE TAXES**		804,313,216	573,632,571	104,091,569	122,969,993	198,135	3,420,947
12	TI								
13	TI	**TAX ADJUSTMENTS - FEDERAL**							
14	TI								
15	TI	Assessment by Board of Public Utilities of the State of NJ	TOTPLTNET	56,782	40,732	7,232	8,560	14	244
16	TI	Injuries and Damages ;		0	0	0	0	0	0
17	TI	Bankrupticies & Acc. Prov. For Rents Receivable	TOTPLTNET	52,256	37,485	6,656	7,877	13	225
18	TI	Capitalized interest-Section 263A	TOTPLT	416,892	299,307	52,020	63,566	88	1,911
19	TI	Casualty Loss Deferred O&M & Ins Proceeds	TOTPLTNET	-1,095,802	-786,060	-139,566	-165,187	-276	-4,712
20	TI	Deduction for New Network Meter Equipment		0	0	0	0	0	0
21	TI	Defer Dividend Equivalents/Restricted Stock-Temp.		0	0	0	0	0	0
22	TI	Deferred Depreciation on CIP ll	TOTPLT	8,262	5,932	1,031	1,260	2	38
23	TI	Deferred Return on CIP ll	TOTPLT	18,055	12,963	2,253	2,753	4	83
24	TI	Diesel Fuel Credit		0	0	0	0	0	0
25	TI	Environmental Accrual		0	0	0	0	0	0
26	TI	FIN48 Reg Asset Reversal		0	0	0	0	0	0
27	TI	FIN48 Services Allocation		0	0	0	0	0	0
28	TI	GainState LILOAudit Refunds not yet received		0	0	0	0	0	0
29	TI	LCAPP		0	0	0	0	0	0
30	TI	Legal Reserves (c & nc)	TOTPLTNET	-418,012	-299,856	-53,240	-63,013	-105	-1,798
31	TI	Material Supplies & Reserves	TOTPLT	78,535	56,384	9,800	11,975	16	360
32	TI	Misc Adj - Permanent		0	0	0	0	0	0
33	TI	Miscellaneous		0	0	0	0	0	0
34	TI	Partnership income/loss per K-1		0	0	0	0	0	0
35	TI	Performance Incentive Plan Adjustment	TOTPLTNET	-455,695	-326,887	-58,039	-68,694	-115	-1,960
36	TI	RAC-Environmental Cleanup Costs		0	0	0	0	0	0
37	TI	Repair Allow Deferral Carrying Charges		0	0	0	0	0	0
38	TI	SBC-Societal Benefits Clause		0	0	0	0	0	0
39	TI	Stock Based Compensation	TOTPLTNET	-325,229	-233,300	-41,423	-49,027	-82	-1,399
40	TI	TAX ADJUSTMENTS - FEDERAL CONTINUED		0	0	0	0	0	0
41	TI	Uncollectible Accounts		0	0	0	0	0	0
42	TI	Utility Commodity Costs		0	0	0	0	0	0
43	TI	Additional Expenses on Rental Property	TOTPLT	0	0	0	0	0	0
44	TI	Additional Rental Income - NJ Properties	TOTPLT	0	0	0	0	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
45	TI	Amort of Def Gain on Sale of Services Assets	not_used	0	0	0	0	0	0
46	TI	Amort of Deferred Gain on Sale of Generation Assets	not_used	0	0	0	0	0	0
47	TI	Amortization of Limited-Term Utility Plant	TOTPLT	-14	-10	-2	-2	0	0
48	TI	Amortization of Reacquisition of Pref Stock	TOTPLT	7,787	5,590	972	1,187	2	36
49	TI	CECL Reserve	not_used	0	0	0	0	0	0
50	TI	CEF- EC AMI	TOTPLT	0	0	0	0	0	0
51	TI	CEF- EV Deferral	TOTPLT	0	0	0	0	0	0
52	TI	Clause - Demographic Studies	not_used	0	0	0	0	0	0
53	TI	Clause - Navigant Studies	not_used	0	0	0	0	0	0
54	TI	Clause - RAC (Environmental Clean Up)	not_used	0	0	0	0	0	0
55	TI	Clause - Societal Benefits Clause (AAP)	not_used	0	0	0	0	0	0
56	TI	Company Owned Life Insurance - Book	LABOR	-352,245	-299,538	-25,057	-25,101	-183	-2,366
57	TI	Company Owned Life Insurance - Tax	LABOR	-14,570	-12,390	-1,036	-1,038	-8	-98
58	TI	COVID Deferrals	not_used	0	0	0	0	0	0
59	TI	Current SHARE -- FT	DEPREXP	-21,771,486	-15,689,941	-2,698,173	-3,274,384	-4,554	-104,434
60	TI	Customer Advances	TOTPLTNET	294,687	211,390	37,532	44,423	74	1,267
61	TI	Customer Connection Fees (Contributions in Aid of Constructi	TOTPLTNET	0	0	0	0	0	0
62	TI	Deduction for Retention Payments (c)	LABOR	-4,379	-3,724	-311	-312	-2	-29
63	TI	Deferred Employer ER FICA	LABOR	-5,798,258	-4,930,650	-412,465	-413,184	-3,020	-38,939
64	TI	Diesel Fuel Tax Credit	TOTPLT	928	666	116	142	0	4
65	TI	Entertainment (100%)	LABOR	36,298	30,866	2,582	2,587	19	244
66	TI	FAS 5 (ASC40) Reserve - Sales Tax	not_used	0	0	0	0	0	0
67	TI	Fed Amort of Deferred Gain on Sale of Generation Assets	not_used	0	0	0	0	0	0
68	TI	Injuries & Damages - FT	TOTPLT	1,044,758	750,083	130,365	159,301	219	4,790
69	TI	Line Pack Adjustment	not_used	0	0	0	0	0	0
70	TI	Plant Related	DEPREXP	-61,904,159	-44,612,140	-7,671,875	-9,310,252	-12,949	-296,943
71	TI	Previously Deducted Amort - Reacquired Bonds	not_used	0	0	0	0	0	0
72	TI	Qualified Transportation Fringe	LABOR	139,386	118,530	9,915	9,933	73	936
73	TI	R & D Credits CF	not_used	0	0	0	0	0	0
74	TI	R&D Credit - Fed	TOTPLT	-75,718	-54,362	-9,448	-11,545	-16	-347
75	TI	R&D Expenditure	TOTPLT	-16,866	-12,109	-2,105	-2,572	-4	-77
76	TI	Rabbi Trust	not_used	0	0	0	0	0	0
77	TI	RE - Lease Liability	TOTPLT	-519,350	-372,866	-64,804	-79,189	-109	-2,381
78	TI	RE - ROU Lease Asset	TOTPLT	594,984	427,168	74,242	90,721	125	2,728
79	TI	Reversal of Book Income from Partnerships	TOTPLT	0	0	0	0	0	0
80	TI	Severance Pay (nc)	LABOR	121,791	103,567	8,664	8,679	63	818
81	TI	State NOL CF (c)	DEPREXP	7,732,062	5,572,224	958,246	1,162,885	1,617	37,089
82	TI	Tax Net Bad Debt Writeoffs - FT	TOTPLT	-81,087	-58,216	-10,118	-12,364	-17	-372
83	TI	Unicap book/tax inventory FS	not_used	0	0	0	0	0	0
84	TI	Unrealized G/L on Equity Securities	TOTPLT	142,148	102,055	17,737	21,674	30	652
85	TI	Credits & Adjustments	TOTPLT	0	0	0	0	0	0
86	TI	Repair Allowance	TOTPLT	0	0	0	0	0	0
87	TI	Uncollectible Accounts - Writeoff	REVREQ	0	0	0	0	0	0
88	TI	Injuries and Damages	TOTPLT	0	0	0	0	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
89	TI	Meals & entertainment	LABOR	-459,207	-390,495	-32,666	-32,723	-239	-3,084
90	TI	Company owned life insurance	LABOR	0	0	0	0	0	0
91	TI	ESOP/401(k) Cash Dividends	TOTPLTNET	-844,650	-605,900	-107,578	-127,327	-213	-3,632
92	TI	Medicare Subsidy		0	0	0	0	0	0
93	TI	Allowable Depreciation	DEPREXP	0	0	0	0	0	0
94	TI	Previously Ded Amort-Reacq Bonds	not_used	0	0	0	0	0	0
95	TI	Amortization of Computer Software	INTANGPLT	0	0	0	0	0	0
96	TI	Amort Def Gain - Sale of Gen Asset	not_used	0	0	0	0	0	0
97	TI	Gain on Sale of Services Corp Asset	not_used	0	0	0	0	0	0
98	TI	AFUDC / IDC	TOTPLT	-345,079	-247,749	-43,059	-52,616	-72	-1,582
99	TI	Cost of removal	TOTPLT	0	0	0	0	0	0
100	TI	*Utility Commodity Costs-Non-Taxable Income	not_used	0	0	0	0	0	0
101	TI	*RAC-Environmental Cleanup Costs - Debit	not_used	0	0	0	0	0	0
102	TI	*SBC-Societal Benefits Clause - Unallow Deductions	not_used	0	0	0	0	0	0
103	TI	Deferred Comp - officers	LABOR	-15,155	-12,887	-1,078	-1,080	-8	-102
104	TI	Deduction of Securitizartion	not_used	0	0	0	0	0	0
105	TI	Accrued vacation pay adjustment	LABOR	-257,985	-219,382	-18,352	-18,384	-134	-1,733
106	TI	3rd Party Claims	TOTPLT	-975	-700	-122	-149	0	-4
107	TI	Gain/loss bond reacq	not_used	0	0	0	0	0	0
108	TI	Amortization of Call Option Sale	LABOR	0	0	0	0	0	0
109	TI	Contribution in Aid of Construct	TOTPLTNET	0	0	0	0	0	0
110	TI	Pension Accrual Adjustment	LABOR	-7,780,352	-6,616,159	-553,464	-554,428	-4,052	-52,250
111	TI	Unallowable OPEB Amortization	LABOR	47,224,310	40,158,021	3,359,353	3,365,202	24,595	317,138
112	TI	NJ BPU assessment	TOTPLTNET	0	0	0	0	0	0
113	TI	Unicap book/tax inventory	TOTPLTNET	0	0	0	0	0	0
114	TI	W-2 Earnings Exceeding $1,000,000	LABOR	1,506,831	1,281,360	107,190	107,377	785	10,119
115	TI	Diesel Fuel Tax Credit	not_used	0	0	0	0	0	0
116	TI	Deferred Depreciation & Return on CIP II	TOTPLTNET	0	0	0	0	0	0
117	TI	Capitalized Interest - Section 263A	TOTPLT	0	0	0	0	0	0
118	TI	Clause - Deferred Fuel	not_used	0	0	0	0	0	0
119	TI	Restricted Stock - Permanent	LABOR	-67,594	-57,480	-4,808	-4,817	-35	-454
120	TI	Materials & Supplies Reserve	TOTPLT	0	0	0	0	0	0
121	TI	Amortization of Reacquisition of Pref Stock	TOTPLTNET	0	0	0	0	0	0
122	TI	Lobbying Expenses	LABOR	0	0	0	0	0	0
123	TI	Penalties	not_used	0	0	0	0	0	0
124	TI	Dividends Received Deduction	TOTPLTNET	0	0	0	0	0	0
125	TI	Real Estate Taxes	TOTPLTNET	-1,021,308	-732,623	-130,078	-153,957	-257	-4,392
126	TI	Line Pack Adjustment	TOTPLTNET	0	0	0	0	0	0
127	TI	Legal Reserves	TOTPLTNET	0	0	0	0	0	0
128	TI	Casualty Insurance Proceeds	TOTPLT	0	0	0	0	0	0
129	TI	Miscellaneous (R&D Exp., Limit Term Util Plant, ARO Fin 47, F	TOTPLT	0	0	0	0	0	0
130	TI	**TOTAL TAX ADJUSTMENTS - FEDERAL**		-44,148,425	-27,361,102	-7,292,963	-9,351,243	1,287	-144,404
131	TI								
132	TI								

PUBLIC SERVICE ELECTRIC & GAS COMPANY
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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
133	TI	**DEVELOPMENT OF INCOME TAXES CONTINUED**							
134	TI								
135	TI	**TAX ADJUSTMENTS - STATE**							
136	TI	Reverse TEFA	TEFA_04	0	0	0	0	0	0
137	TI	Federal Depreciation Reversal	TOTPLT	64,677,176	46,434,906	8,070,391	9,861,765	13,576	296,538
138	TI	State Tax Depreciation	DEPREXP	37,759,415	27,211,876	4,679,581	5,678,934	7,899	181,125
139	TI	Amortization of Service's Asset Sale	TOTPLTNET	0	0	0	0	0	0
140	TI	NOL Utilization	TOTPLTNET	0	0	0	0	0	0
141	TI	**TOTAL TAX ADJUSTMENTS - STATE**		102,436,591	73,646,782	12,749,971	15,540,700	21,475	477,663
142	TI								
143	TI	**TAXABLE NET INCOME - STATE**		862,601,382	619,918,251	109,548,578	129,159,450	220,897	3,754,207
144	TI	State Tax Liability		77,634,124	55,792,643	9,859,372	11,624,350	19,881	337,879
145	TI	Prior Year Adjustment & State Credit	TOTPLTNET	0	0	0	0	0	0
146	TI	**TOTAL STATE INCOME TAX LIABILITY**		77,634,124	55,792,643	9,859,372	11,624,350	19,881	337,879
147	TI								
148	TI	**TAXABLE NET INCOME - FEDERAL**		682,530,667	490,478,826	86,939,235	101,994,400	179,541	2,938,665
149	TI	Federal Tax Liability		143,331,440	103,000,554	18,257,239	21,418,824	37,704	617,120
150	TI	Prior Yr & Oth Adjustments	TOTPLTNET	0	0	0	0	0	0
151	TI	Not Used	not_used	0	0	0	0	0	0
152	TI	**TOTAL FEDERAL INCOME TAX LIABILITY**		143,331,440	103,000,554	18,257,239	21,418,824	37,704	617,120
153	TI								
154	TI	**TOTAL INCOME TAX EXPENSE**		220,965,564	158,793,196	28,116,611	33,043,174	57,584	954,998
155	TI								
156	TI	**TAX RATES**							
157	TI	FEDERAL TAX RATE - CURRENT		21.000%					
158	TI	NEW JERSEY CORP BUSINESS TAX RATE		9.000%					
159	TI	CUSTOMER ACCT UNCOLLECTIBLE RATE		0.0					
160	TI	EFFECTIVE TAX RATE		28.110%					
161	TI	COMPOSITE RATE		28.110%					
162	TI	1 - EFFECTIVE TAX RATE		71.89000%					
163	TI								
164	TI	**DEVELOPMENT OF OPERATING INCOME ADJUSTED**							
165	TI								
166	TI	**G410 + G411- PROVISION FOR DEFERRED INCOME TAX**							
167	TI	Additional Rental Income - NJ Properties	TOTPLT	0	0	0	0	0	0
168	TI	Amort of Def Gain on Sale of Services Assets	not_used	0	0	0	0	0	0
169	TI	Amort of Deferred Gain on Sale of Generation Assets	not_used	0	0	0	0	0	0
170	TI	Amortization of Limited-Term Utility Plant	TOTPLT	14	10	2	2	0	0
171	TI	Bankruptcies and Accum Provision for Rent Receivable	TOTPLT	-31,746	-22,792	-3,961	-4,841	-7	-146
172	TI	Casualty Loss Deferred O&M	TOTPLTNET	1,095,802	786,060	139,566	165,187	276	4,712
173	TI	CECL Reserve	not_used	0	0	0	0	0	0
174	TI	CEF- EC AMI	TOTPLT	0	0	0	0	0	0
175	TI	CEF- EV Deferral	TOTPLT	0	0	0	0	0	0
176	TI	Clause - Demographic Studies	not_used	0	0	0	0	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
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12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
177	TI	Clause - Navigant Studies	not_used	0	0	0	0	0	0
178	TI	Clause - RAC (Environmental Clean Up)	not_used	0	0	0	0	0	0
179	TI	Clause - Societal Benefits Clause (AAP)	not_used	0	0	0	0	0	0
180	TI	COVID Deferrals	not_used	0	0	0	0	0	0
181	TI	Current SHARE -- FT	DEPREXP	5,506,769	3,968,534	682,462	828,206	1,152	26,415
182	TI	Customer Advances	TOTPLTNET	-294,687	-211,390	-37,532	-44,423	-74	-1,267
183	TI	Deduction for Retention Payments (c)	LABOR	4,379	3,724	311	312	2	29
184	TI	Deferred Employer ER FICA	LABOR	5,798,258	4,930,650	412,465	413,184	3,020	38,939
185	TI	FAS 5 (ASC40) Reserve - Sales Tax	not_used	0	0	0	0	0	0
186	TI	Fed Amort of Deferred Gain on Sale of Generation Assets	not_used	0	0	0	0	0	0
187	TI	Injuries & Damages - FT	TOTPLT	-264,256	-189,722	-32,974	-40,293	-55	-1,212
188	TI	Line Pack Adjustment	not_used	0	0	0	0	0	0
189	TI	Medicare Subsidy	not_used	0	0	0	0	0	0
190	TI	Partnership Income/Loss (nc)	TOTPLT	0	0	0	0	0	0
191	TI	Plant Related	DEPREXP	62,706,788	45,190,566	7,771,346	9,430,965	13,117	300,793
192	TI	Previously Deducted Amort - Reacquired Bonds	not_used	0	0	0	0	0	0
193	TI	R & D Credits CF	TOTPLT	-67,859	-48,719	-8,467	-10,347	-14	-311
194	TI	RE - Lease Liability	TOTPLT	519,350	372,866	64,804	79,189	109	2,381
195	TI	RE - ROU Lease Asset	TOTPLT	-594,984	-427,168	-74,242	-90,721	-125	-2,728
196	TI	Real Estate Taxes (nc)	TOTPLT	1,021,308	733,247	127,438	155,726	214	4,683
197	TI	Reversal of Book Income from Partnerships	TOTPLT	0	0	0	0	0	0
198	TI	Severance Pay (nc)	LABOR	-121,791	-103,567	-8,664	-8,679	-63	-818
199	TI	State NOL CF (c)	DEPREXP	-7,732,062	-5,572,224	-958,246	-1,162,885	-1,617	-37,089
200	TI	Unrealized G/L on Equity Securities	TOTPLT	-142,148	-102,055	-17,737	-21,674	-30	-652
201	TI	Previously Ded Amort-Reacq Bonds	not_used	0	0	0	0	0	0
202	TI	Clause - Deferred Fuel	not_used	0	0	0	0	0	0
203	TI	Gain on Sale of Services Corp Asset	not_used	0	0	0	0	0	0
204	TI	AFUDC / IDC	TOTPLT	345,079	247,749	43,059	52,616	72	1,582
205	TI	Capitalized interest-Section 263A	TOTPLT	-416,892	-299,307	-52,020	-63,566	-88	-1,911
206	TI	Cost of removal	TOTPLT	0	0	0	0	0	0
207	TI	Deferred Comp - officers	LABOR	15,155	12,887	1,078	1,080	8	102
208	TI	Deduction of Securitizartion	not_used	0	0	0	0	0	0
209	TI	Accrued vacation pay adjustment	LABOR	257,985	219,382	18,352	18,384	134	1,733
210	TI	Gain/loss bond reacq	not_used	0	0	0	0	0	0
211	TI	Amortization of Call Option Sale	LABOR	0	0	0	0	0	0
212	TI	Defer Dividend Equivalents/Restricted Stock-Temp.	LABOR	0	0	0	0	0	0
213	TI	Contribution in Aid of Construct	TOTPLTNET	0	0	0	0	0	0
214	TI	Pension Accrual Adjustment	LABOR	7,780,352	6,616,159	553,464	554,428	4,052	52,250
215	TI	Unallowable OPEB Amortization	LABOR	-47,224,310	-40,158,021	-3,359,353	-3,365,202	-24,595	-317,138
216	TI	Fin Def-Energy Competition Act Ct	TOTPLT	0	0	0	0	0	0
217	TI	Rabbi Trust Unrealized Losses		0	0	0	0	0	0
218	TI	Additional Real Estate Taxes	TOTPLT	0	0	0	0	0	0
219	TI	PIP Adjustment	LABOR	455,695	387,508	32,416	32,473	237	3,060
220	TI	Deferred NJ Corp Bus Tax(Net of FIT)	TOTPLTNET	0	0	0	0	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
221	TI	Misc	TOTPLT	0	0	0	0	0	0
222	TI	Construction Period Interest	TOTPLTNET	0	0	0	0	0	0
223	TI	Deferred Return on CIP II	TOTPLT	-18,055	-12,963	-2,253	-2,753	-4	-83
224	TI	Deferred Depreciation on CIP II	TOTPLT	-8,262	-5,932	-1,031	-1,260	-2	-38
225	TI	Investment Tax Credit	TOTPLT	-493,265	-354,139	-61,549	-75,211	-104	-2,262
226	TI	Assessment by Board of Public Utilities of the State of NJ	TOTPLTNET	-56,782	-40,732	-7,232	-8,560	-14	-244
227	TI	3rd Party Claims	TOTPLT	975	700	122	149	0	4
228	TI	Customer Connections Fees		0	0	0	0	0	0
229	TI	Legal Reserves (nc)	TOTPLTNET	418,012	299,856	53,240	63,013	105	1,798
230	TI	Material Supplies & Reserves	TOTPLTNET	-78,535	-56,336	-10,003	-11,839	-20	-338
231	TI	Stock Based Compensation	TOTPLTNET	325,229	233,300	41,423	49,027	82	1,399
232	TI	**TOTAL DEFERRED INCOME TAX**		28,705,516	16,398,132	5,306,284	6,931,686	-4,229	73,643
233	TI								
234	TI	**This Section is not used at this time**							
235	TI	**PROFORMA OPERATING INCOME ADJUSTMENTS**							
236	TI	Not Used	not_used	0	0	0	0	0	0
237	TI	Not Used	not_used	0	0	0	0	0	0
238	TI	Not Used	not_used	0	0	0	0	0	0
239	TI	**OPERATING INCOME ADJUSTED**		655,462,203	470,763,342	83,509,524	98,193,286	170,191	2,825,860

PUBLIC SERVICE ELECTRIC & GAS COMPANY
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12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
1	LR	**DEVELOPMENT OF LABOR ALLOCATION FACTOR**							
2	LR	Labor portion included in O&M Expense							
3	LR								
4	LR	**G700-G742 MANUFACTURED GAS LABOR EXP**	MFGO_M	778,312	583,871	60,147	134,294	0	0
5	LR	**G813 GAS SUPPLY LABOR EXPENSE**	EXP_813	0	0	0	0	0	0
6	LR	**G840-G843 STORAGE PLANT LABOR EXP**	STOREXP	407,976	306,054	31,528	70,395	0	0
7	LR	**G850-G867 TRANSMISSION LABOR EXP**	TRANEXP	483,267	289,559	55,965	132,931	81	4,732
8	LR								
9	LR	**DISTRIBUTION LABOR EXPENSE**							
10	LR	Operation							
11	LR	G870 Operation Supervision & Engineering	TLABDO	0	0	0	0	0	0
12	LR	G871 Load Dispatching	EXP_871	4,522,112	2,641,804	501,613	1,337,131	1,209	40,355
13	LR	G872 Compressor Station Labor & Expenses	EXP_872	0	0	0	0	0	0
14	LR	G874 Mains & Services	EXP_874	14,351,672	10,503,551	1,677,869	2,105,122	1,780	63,350
15	LR	G875-877 Meas & Reg Station	EXP_8757	1,368,583	820,014	158,488	376,452	229	13,400
16	LR	G878 Meter & House Reg	EXP_878	8,562,092	6,306,606	1,592,087	663,330	0	69
17	LR	G879 Customer Installations - Total	EXP_879	63,057,319	63,057,319	0	0	0	0
18	LR	G880.1 Miscellaneous Dist Exp	EXP_8801	5,219,383	4,148,020	494,856	561,225	396	14,886
19	LR	G880.3 Operation of Street Lighting	EXP_8803	0	0	0	0	0	0
20	LR	G881 Rents	EXP_881	-60	-35	-7	-18	0	-1
21	LR	Total Operation		97,081,101	87,477,279	4,424,907	5,043,241	3,614	132,059
22	LR								
23	LR	Maintenance							
24	LR	G885 Maint. Supervision & Engineering	TLABDM	0	0	0	0	0	0
25	LR	G886 Structures & Improvements	EXP_886	1,015,469	728,666	127,696	154,367	216	4,523
26	LR	G887 Mains	EXP_887	4,445,965	2,663,838	514,847	1,223,006	745	43,529
27	LR	G888 Compressor Station Equip	EXP_888	0	0	0	0	0	0
28	LR	G889-891 Meas & Reg Station	EXP_8891	2,185,363	1,309,403	253,075	601,121	366	21,397
29	LR	G892 Services	EXP_892	2,126,460	1,751,856	250,243	122,699	200	1,464
30	LR	G893 Meters & House Reg	EXP_893	5,044,535	3,362,194	1,166,064	516,261	0	16
31	LR	G894 Maint of Other Equipment - Total	EXP_894	71,094	2,166	464	585	67,862	17
32	LR	Not Used	not_used	0	0	0	0	0	0
33	LR	Total Maintenance		14,888,885	9,818,123	2,312,389	2,618,038	69,389	70,946
34	LR	TOTAL DISTRIBUTION LABOR EXPENSE		111,969,986	97,295,402	6,737,296	7,661,279	73,003	203,005
35	LR								
36	LR	**G901-G903,G905 CUST ACCOUNTS EXPENSE**	CUSTACCTS	45,109,566	38,650,888	3,663,362	1,987,637	1,472	806,207
37	LR	**G907-G910, xDSM CUST SERV & INFO EXP**	CUSTS_I	3,007,750	2,451,159	367,777	166,065	90	22,659
38	LR	**G911-G916 SALES EXPENSE**	SALESEXP	3,526	2,797	516	213	0	1
39	LR	**ADMIN & GENERAL EXP ACCOUNTS xG926**	AGEXP	6,954,680	3,890,088	1,085,140	1,869,815	13,221	96,416
40	LR	**Employee Pension/Benefits Acct G926**	LABOR	0	0	0	0	0	0
41	LR								
42	LR	**TOTAL OPERATION & MAINT LABOR EXPENSE**		168,715,063	143,469,817	12,001,731	12,022,629	87,868	1,133,019

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
1	CA	**DEVELOPMENT OF CAPITAL ADDITIONS ALLOCATION F/**							
2	CA								
3	CA	**INTANGIBLE PLANT - G301-G303**	INTANGPLT	0	0	0	0	0	0
4	CA	**PRODUCTION PLANT - G304-G347**	PRODPLT	-2,267,387	-1,700,938	-175,221	-391,228	0	0
5	CA	**STORAGE PLANT - G360-G363**	STORPLT	8,371,561	6,280,141	646,943	1,444,478	0	0
6	CA	TRANSMISSION PLANT - G365-G371	TRANPLT	11	7	1	3	0	0
7	CA								
8	CA	**DISTRIBUTION PLANT**							
9	CA	G374 Land and Land Rights & G375 Structure & Improveme	PLT_3745	2,620,552	1,880,421	329,537	398,364	558	11,672
10	CA	G376 Mains	PLT_376	226,633,216	135,789,241	26,244,339	62,342,774	37,987	2,218,875
11	CA	G377 Compressor Station Equipment	PLT_377	0	0	0	0	0	0
12	CA	G378-G379 Meas & Regul Eqmt	PLT_3789	57,069,064	34,194,053	6,608,857	15,697,816	9,561	558,777
13	CA	G380 Services	SERVICES	505,466,924	416,422,163	59,483,542	29,165,898	47,429	347,892
14	CA	G381 Meters	PLT_381	58,899,779	39,256,803	13,614,871	6,027,912	0	193
15	CA	G382 Meter Installations	PLT_382	-1,810,761	-1,650,843	-144,810	-15,106	0	-1
16	CA	G383-384 House Regulators & Install	PLT_3834	2,268,333	2,034,053	181,898	52,323	0	59
17	CA	G385 Ind Reg & Meas Eqmt	PLT_385	12,739,212	169,884	5,465,993	6,913,035	42	190,259
18	CA	TOTAL DISTRIBUTION PLANT		863,886,319	628,095,774	111,784,228	120,583,014	95,577	3,327,725
19	CA								
20	CA	**COMMON PLANT**	COMPLT	0	0	0	0	0	0
21	CA	**GENERAL PLANT EXCL INTANGIBLE PLT**	GENPLT	26,119,255	18,916,156	3,021,945	4,056,769	5,901	118,485
22									
23	CA	**TOTAL CAPITAL ADDITIONS**		896,109,759	651,591,138	115,277,897	125,693,036	101,478	3,446,210

PUBLIC SERVICE ELECTRIC & GAS COMPANY
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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
1	AF	**ALLOCATION FACTOR TABLE**							
2	AF	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**							
3	AF								
4	AF	**CAPACITY RELATED**							
5	AF	Peak-Hour Sendout - delivery	PEAKHOUR_04	124,747	77,879	15,468	29,997	0	1,403
6	AF	Staff Average and Peak Allocator - delivery	AVGPEAK_04	1	1	0	0	0	0
7	AF								
8	AF	**COMMODITY RELATED**							
9	AF	Annual transported gas @mtr - delivery	TRANSPORT_04	2,598,285,838	1,517,910,828	288,213,545	768,279,951	694,743	23,186,772
10	AF	Balancing therms - delivery	BALANCE_04	1,793,060	1,345,110	138,565	309,385	0	0
11	AF	Annual transported gas @mtr - access	TRANSPORT_03	2,598,285,838	1,517,910,828	288,213,545	768,279,951	694,743	23,186,772
12	AF	Annual transported gas @mtr - meters	TRANSPORT_07	2,598,285,838	1,517,910,828	288,213,545	768,279,951	694,743	23,186,772
13	AF	TEFA $ responsibility W/N - delivery	TEFA_04						
14	AF								
15	AF	**BILLING DETERMINANTS**							
16	AF	Number of Customers		1,894,095	1,728,739	145,499	19,809	16	32
17	AF	Transported Gas at Meter (calendar)		2,598,285,838	1,517,910,828	288,213,545	768,279,951	694,743	23,186,772
18	AF								
19	AF								
20	AF	**CUSTOMER RELATED**							
21	AF	G380 services - access	SERVICES_03	1,215,746,207	1,001,946,668	143,090,682	69,881,536	0	827,321
22	AF	Cust Installns LDC G879 - delivery	CINST_04	100	100	0	0	0	0
23	AF	Avg Customer Bills - delivery	CUSTAVG_04	661,048	598,870	50,415	11,719	9	34
24	AF	Avg Customer Bills - cust svs	CUSTAVG_06	661,048	598,870	50,415	11,719	9	34
25	AF	G381 meters - measurement	SMMETERS_07	95,373,410	63,566,590	22,045,940	9,760,574	0	306
26	AF								
27	AF	Billing Function costs - cust svs	BILLING_06	20,835,825	16,641,744	1,688,285	1,648,379	1,464	855,952
28	AF	Competitive Service work - delivery	COMPSVSWK_04	100	100	0	0	0	0
29	AF								
30	AF	Account Maint - cust svs	ACCTMAINT_06	67,192,728	60,880,342	5,167,551	1,014,774	411	129,650
31	AF	G382 meter install - measurement	MTRINSTAL_07	149,490,256	136,288,569	11,955,000	1,246,610	0	78
32	AF	G383 house regulators - access	HOUSEREG_03	27,726,351	23,488,422	2,877,517	1,358,260	0	2,151
33	AF	G384 house reg install - access	HSEREGINST_03	49,550,462	45,273,401	3,573,995	702,709	0	356
34	AF	G385 lrg regulators - access	LRGREG_03	42,370,365	527,983	950,933	40,715,751	0	175,698
35	AF	G385 lrg mtrs - measurement	LRGMTR_07	6,790,868	0	5,728,862	886,308	0	175,698
36	AF	G380 services - reserve - access	SERVICESR_03	302,262,539	252,625,678	34,242,308	15,042,822	0	351,731
37	AF	G381 meters - reserve - measurement	SMMETERSR_07	39,637,552	26,782,366	8,862,287	3,992,767	0	131
38	AF	G382 meter install - reserve -measurement	MTRINSTALR_07	70,947,597	65,486,599	4,964,044	496,929	0	24
39	AF	G383 house regulators - reserve - access	HOUSEREGR_03	4,745,170	3,992,277	503,093	248,837	0	963
40	AF	G384 house reg install - reserve - access	HSEREGINSTR_03	9,880,504	9,043,509	697,932	138,864	0	198
41	AF	G385 lrg regulators - reserve - access	LRGREGR_03	6,940,251	13,538	164,305	6,702,764	0	59,644
42	AF	G385 lrg mtrs - reserve - measurement	LRGMTRR_07	1,112,795	0	940,755	112,396	0	59,644
43	AF	Direct LVG - delivery	DIRLVG_04	0	0	0	0	0	0
44	AF	Direct LVG - cust svs	DIRLVG_06	0	0	0	0	0	0

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
45	**AF**	**ALLOCATION FACTOR TABLE**							
46	**AF**	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**							
47	AF								
48	AF	Direct SLG - streetlights	DIRSLG_05	1	0	0	0	1	0
49	AF	Meter Reading Costs - measurement	MRCOST_07	16,284,753	14,755,434	1,241,888	287,431	0	0
50	AF	Other Utility work by Cust Ops - delivery	UTILWORK_04	6,776,917	5,374,648	991,409	409,204	176	1,480
51	AF	Direct SLG - access	DIRSLG_03	1	0	0	0	1	0
52	AF	Direct Competitive Services - delivery	DIRCOMPSVS_04	0	0	0	0	0	0
53	AF	Direct TSG-F - access	DIRTSGF_03	0	0	0	0	0	0
54	AF	Direct TSG-F - delivery	DIRTSGF_04	0	0	0	0	0	0
55	AF	Direct TSG-F - measurement	DIRTSGF_07	0	0	0	0	0	0
56	AF	Direct - RSG - delivery	DIRRSG_04	0	0	0	0	0	0
57	AF	Choice - delivery	CHOICE_04	1,894,095	1,728,739	145,499	19,809	16	32
58	AF								
59	AF								
60	AF	Dummy allocator for unused lines	not_used	0	0	0	0	0	0
61	AF								
62	AF								
63	AF	**Plant Related**							
64	AF	Acct G301-G303 Intangible Plt	INTANGPLT	0	0	0	0	0	0
65	AF	Acct G399.10-23 Oth Tangible Plt	TANGPLT	16,791,854	14,286,709	1,415,779	804,020	641	284,706
66	AF	Production Plant Total	PRODPLT	52,043,670	39,041,892	4,021,862	8,979,916	0	0
67	AF	Storage Plant Total	STORPLT	19,575,233	14,684,863	1,512,747	3,377,624	0	0
68	AF	Transmission Plant Total	TRANPLT	103,544,395	62,040,662	11,990,912	28,481,645	17,348	1,013,828
69	AF	Distribution Plant Total	DISTPLT	10,498,076,770	7,533,069,762	1,320,145,353	1,595,866,388	2,235,754	46,759,512
70	AF	G391-G398 General Plant	GENPLT	200,812,197	145,432,738	23,233,566	31,189,583	45,366	910,945
71	AF	Common Plant	COMPLT	102,234,955	83,912,187	9,391,523	7,489,732	8,419	1,433,095
72	AF	Accts C389-C399, G391-E398 Com & Gen Plt	COMGENPLT	303,047,153	229,344,924	32,625,089	38,679,316	53,784	2,344,039
73	AF	Total Prod, Storage, Transmission, & Dist Plant	PSTDPLT	10,673,240,067	7,648,837,179	1,337,670,874	1,636,705,572	2,253,102	47,773,340
74	AF	Total Plant	TOTPLT	10,993,079,074	7,892,468,811	1,371,711,742	1,676,188,908	2,307,527	50,402,086
75	AF								
76	AF	Distribution Plant x Meters & Installs	DISTPLTXMTR	9,895,589,959	7,166,610,181	1,144,899,800	1,536,955,091	2,235,514	44,889,372
77	AF	Acct G374-375 - Land & Structures	PLT_3745	96,512,525	69,254,169	12,136,562	14,671,363	20,554	429,877
78	AF	Acct G376 - Mains	PLT_376	3,775,184,891	2,261,934,505	437,169,958	1,038,486,336	632,773	36,961,319
79	AF	Acct G377 - Compressor Station Equip	PLT_377	0	0	0	0	0	0
80	AF	Acct G378-379 - Meas & Regul Station Equip	PLT_3789	285,986,290	171,354,314	33,118,514	78,665,388	47,914	2,800,160
81	AF	Acct G380 & 387.2 - Services	SERVICES	5,447,689,486	4,488,006,097	641,086,199	314,336,599	511,168	3,749,423
82	AF	Acct G376, G380 & 387.2 - Mains & Services	MAIN_SERV	9,222,874,377	6,749,940,601	1,078,256,156	1,352,822,936	1,143,942	40,710,742
83	AF	Acct G381 - House Meters	PLT_381	477,048,047	317,953,337	110,271,175	48,821,975	1	1,559
84	AF	Acct G382 - Meter Installations	PLT_382	52,631,537	47,983,374	4,209,056	439,073	0	33
85	AF	Acct G381,382, & 385 - Meters	METERPLT	602,486,811	366,459,581	175,245,553	58,911,296	240	1,870,140
86	AF	Acct G381-384 - Meters & House Regulators	PLT_3814	680,862,120	501,504,659	126,603,602	52,748,351	4	5,504
87	AF	Acct G382-384 - House Reg & Install & Meter Install	PLT_3824	203,814,074	183,551,322	16,332,427	3,926,376	4	3,945
88	AF	Acct G383-384 - House Reg & Installation	PLT_3834	151,182,537	135,567,948	12,123,371	3,487,303	3	3,912

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12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
89	**AF**	**ALLOCATION FACTOR TABLE CONTINUED**							
90	**AF**	**INTERNALLY DEVELOPED ALLOCATION FACTORS**							
91	AF								
92	AF	Acct G385 - Ind & Com Meas & Regul Station Equip	PLT_385	145,614,455	1,941,847	62,478,553	79,018,841	479	2,174,735
93	AF	Acct G386 - Other Property on Cust Premises	PLT_386	0	0	0	0	0	0
94	AF	Acct G387.1 - Other Equipment (St Ltg Posts)	PLT_387_1	1,011,930	0	0	0	1,011,930	0
95	AF								
96	AF	Total Distribution Plant Reserve	TOTDRESERVE	2,718,471,978	1,956,775,950	317,824,430	428,830,574	221,981	14,819,043
97	AF	Total Net Plant	TOTPLTNET	8,274,607,096	5,935,692,862	1,053,887,312	1,247,358,334	2,085,546	35,583,043
98	AF								
99	AF								
100	AF	**Revenue Related**							
101	AF	Total Operating Revenue	TOTREV	1,469,037,356	1,061,344,721	181,567,730	217,922,859	568,648	7,633,399
102	AF	Intra Dept Rev Req - 5.62% GS / 94.38% LV	INTRAREV	211,252,528	0	10,006,266	201,246,261	0	0
103	AF								
104	AF								
105	AF	**Expense Related**							
106	AF	Manufactured Gas O&M Excl Fuel Expense	MFGO_M	2,114,238	1,586,050	163,385	364,803	0	0
107	AF	Other Storage Plant O&M Expense	STOREXP	2,714,605	2,036,430	209,781	468,394	0	0
108	AF	Transmission Plant O&M Expense	TRANEXP	2,593,507	1,553,951	300,340	713,388	435	25,394
109	AF	Acct 813-Other Gas Supply Expense	EXP_813	72	42	8	21	0	1
110	AF	Acct 871 - Distribution Load Dispatching	EXP_871	5,839,316	3,411,311	647,723	1,726,611	1,561	52,109
111	AF	Acct 872 - Compressor Station Labor & Expenses	EXP_872	0	0	0	0	0	0
112	AF	Acct 874-Mains & Services Expenses	EXP_874	20,733,577	15,174,273	2,423,985	3,041,227	2,572	91,520
113	AF	Acct 875-877 - Meas & Regulating Station Exp	EXP_8757	3,019,152	1,808,984	349,632	830,469	506	29,561
114	AF	Acct 878 - Meter & House Regulator Expenses	EXP_878	11,492,061	8,464,742	2,136,903	890,323	0	93
115	AF	Acct 879 - Customer Installation Expenses	EXP_879	17,355,157	17,355,157	0	0	0	0
116	AF	Acct 880.0,.1,.2 - Other Expenses	EXP_8801	14,050,188	11,166,159	1,332,116	1,510,775	1,065	40,072
117	AF	Acct 880.3 - Operation of Street Lighting Exp	EXP_8803	0	0	0	0	0	0
118	AF	Acct 881 - Rents	EXP_881	-1,088,602	-635,958	-120,753	-321,886	-291	-9,715
119	AF	Acct 886-Maint of Structures & Improvements Exp	EXP_886	8,016,449	5,752,336	1,008,078	1,218,621	1,707	35,706
120	AF	Acct 887-Maint of Mains Exp	EXP_887	8,706,285	5,216,446	1,008,196	2,394,944	1,459	85,240
121	AF	Acct 888-Maint of Compressor Station Equip Exp	EXP_888	0	0	0	0	0	0
122	AF	Acct 889-891 - Main of Meas & Reg Station Equip	EXP_8891	4,163,462	2,494,620	482,148	1,145,231	698	40,765
123	AF	Acct 892-Main of Services Exp	EXP_892	3,610,466	2,974,434	424,881	208,327	339	2,485
124	AF	Acct 893-Maint of Meters & House Regulators Exp	EXP_893	6,767,990	4,510,880	1,564,448	692,640	0	22
125	AF	Acct 894-Maint of Other Equipment	EXP_894	207,897	6,334	1,357	1,711	198,446	50
126	AF								
127	AF	Distr Oper Exp	DISTEXPO	71,400,849	56,744,669	6,769,606	7,677,520	5,413	203,641
128	AF	Distr Maint Exp	DISTEXPM	31,472,549	20,955,051	4,489,107	5,661,476	202,649	164,268
129	AF	Cust Serv & Info Expense	CUSTS_I	4,034,218	3,287,677	493,290	222,739	121	30,392
130	AF	Acct 901-903,905 Cust Acct Exp Excl 904	CACCTEXP	72,712,827	62,301,980	5,905,031	3,203,904	2,373	1,299,538
131	AF	Accts 901-910 Excl 904 - Cust Accts,Serv & Info	CUSTSVSX	76,747,044	65,589,657	6,398,322	3,426,643	2,494	1,329,929
132	AF	Sales Expense	SALESEXP	88,423	70,127	12,936	5,339	2	19

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
133	**AF**	**ALLOCATION FACTOR TABLE CONTINUED**							
134	**AF**	**INTERNALLY DEVELOPED ALLOCATION FACTORS**							
135	AF								
136	AF	Total O&M Expense Excl A&G Expense	TOTOMXAG	242,970,637	189,516,811	23,956,488	27,423,038	210,992	1,863,308
137	AF	Total O&M Expense Excl 904 Expense	TOTOMX904	255,675,994	192,561,588	26,692,312	33,876,943	284,662	2,260,488
138	AF	Total O&M Expense Excl Fuel & 904 Expense	TOMXFUEL904	223,769,120	168,625,830	24,226,594	28,371,547	284,662	2,260,488
139	AF	Tot Admin & Genl Exp xPension/Ben	AGEXP	38,752,071	21,675,904	6,046,494	10,418,767	73,670	537,236
140	AF	Accts 901-905 Cust Accts Exp Excl 904-Uncol	CUSTACCTS	72,712,827	62,301,980	5,905,031	3,203,904	2,373	1,299,538
141	AF	O&M + Capital Additions	EXPENDITURES	1,177,832,467	862,783,854	145,280,879	163,534,840	386,140	5,846,754
142	AF								
143	AF	Depreciation Expense (total)	DEPREXP	203,691,216	146,793,062	25,243,756	30,634,719	42,609	977,070
144	AF								
145	AF	NJ State Income Tax (CBT)	STATEINCTAX	77,634,124	55,792,643	9,859,372	11,624,350	19,881	337,879
146	AF	NJ State Deferred Income Tax	DFSTATEINCTAX	-39,443,958	-33,541,862	-2,805,889	-2,810,775	-20,543	-264,889
147	AF								
148	AF	**Labor Expense Related**							
149	AF	Total Distribution Exp (Oper) Labor	TLABDO	97,081,101	87,477,279	4,424,907	5,043,241	3,614	132,059
150	AF	Total Distribution Exp (Maint) Labor	TLABDM	14,888,885	9,818,123	2,312,389	2,618,038	69,389	70,946
151	AF	Total Labor	LABOR	168,715,063	143,469,817	12,001,731	12,022,629	87,868	1,133,019
152	AF								
153	AF	**REVENUES AND BILLING DETERMINANTS**							
154	AF								
155	AF	Base Rate Sales Revenue	SALESREV	1,401,350,320	1,001,979,781	178,047,445	213,229,775	561,110	7,532,209
156	AF								
157	AF	Residential Service Gas	REVRSG	1,001,979,781	1,001,979,781	0	0	0	0
158	AF	General Service Gas	REVGSG	178,047,445	0	178,047,445	0	0	0
159	AF	Large Volume Service Gas	REVLVG	213,229,775	0	0	213,229,775	0	0
160	AF	Street Light Gas	REVSLG	561,110	0	0	0	561,110	0
161	AF	Firm Transportation Gas Service	REVTSGF	7,532,209	0	0	0	0	7,532,209
162	AF								
163	AF								
164	AF	Total Rev Req @ desired ROR	REVREQ	1,401,350,320	1,001,979,781	178,047,445	213,229,775	561,110	7,532,209
165	AF								
166	AF								
167	AF	**PRESENT REVENUES FROM SALES INPUT**							
168	AF								
169	AF	Total Sales of Gas Revenue Requirement		0	0	0	0	0	0
170	AF	Sales of Gas Revenues - Rates		1,101,761	808,939	129,770	150,330	438	12,284
171	AF	Sales of Gas Revenues - Other		0	0	0	0	0	0
172	AF								
173	AF	**RATE OF RETURN**							
174	AF	Rate of Return (Equalized)	CALCULATED	7.55%	7.55%	7.55%	7.55%	7.55%	7.55%

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
1	AP	**ALLOCATION PROPORTIONS TABLE**							
2	AP	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**							
3	AP								
4	AP	**CAPACITY RELATED**							
5	AP	Peak-Hour Sendout - delivery	PEAKHOUR_04	1.000000	0.624295	0.123994	0.240464	0.000000	0.011247
6	AP								
7	AP	Staff Average and Peak Allocator - delivery	AVGPEAK_04	1.000000	0.599170	0.115805	0.275067	0.000168	0.009791
8	AP	**COMMODITY RELATED**							
9	AP	Annual transported gas @mtr - delivery	TRANSPORT_04	1.000000	0.584197	0.110924	0.295687	0.000267	0.008924
10	AP	Balancing therms - delivery	BALANCE_04	1.000000	0.750176	0.077279	0.172546	0.000000	0.000000
11	AP	Annual transported gas @mtr - access	TRANSPORT_03	1.000000	0.584197	0.110924	0.295687	0.000267	0.008924
12	AP	Annual transported gas @mtr - meters	TRANSPORT_07	1.000000	0.584197	0.110924	0.295687	0.000267	0.008924
13	AP	TEFA $ responsibility W/N - delivery	TEFA_04	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
14	AF								
15	AP	**BILLING DETERMINANTS**							
16	AP	Number of Customers		1.000000	0.912699	0.076817	0.010458	0.000008	0.000017
17	AP	Transported Gas at Meter (calendar)		1.000000	0.584197	0.110924	0.295687	0.000267	0.008924
18	AP								
19	AP								
20	AP	**CUSTOMER RELATED**							
21	AP	G380 services - access	SERVICES_03	1.000000	0.824141	0.117698	0.057480	0.000000	0.000681
22	AP	Cust Installns LDC G879 - delivery	CINST_04	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000
23	AP	Avg Customer Bills - delivery	CUSTAVG_04	1.000000	0.905940	0.076266	0.017728	0.000014	0.000052
24	AP	Avg Customer Bills - cust svs	CUSTAVG_06	1.000000	0.905940	0.076266	0.017728	0.000014	0.000052
25	AP	G381 meters - measurement	SMMETERS_07	1.000000	0.666502	0.231154	0.102341	0.000000	0.000003
26	AP								
27	AP	Billing Function costs - cust svs	BILLING_06	1.000000	0.798708	0.081028	0.079113	0.000070	0.041081
28	AP	Competitive Service work - delivery	COMPSVSWK_04	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000
29	AF								
30	AP	Account Maint - cust svs	ACCTMAINT_06	1.000000	0.906056	0.076906	0.015102	0.000006	0.001930
31	AP	G382 meter install - measurement	MTRINSTAL_07	1.000000	0.911689	0.079972	0.008339	0.000000	0.000001
32	AP	G383 house regulators - access	HOUSEREG_03	1.000000	0.847152	0.103783	0.048988	0.000000	0.000078
33	AP	G384 house reg install - access	HSEREGINST_03	1.000000	0.913683	0.072128	0.014182	0.000000	0.000007
34	AP	G385 lrg regulators - access	LRGREG_03	1.000000	0.012461	0.022443	0.960949	0.000000	0.004147
35	AP	G385 lrg mtrs - measurement	LRGMTR_07	1.000000	0.000000	0.843613	0.130515	0.000000	0.025873
36	AP	G380 services - reserve - access	SERVICESR_03	1.000000	0.835782	0.113287	0.049767	0.000000	0.001164
37	AP	G381 meters - reserve - measurement	SMMETERSR_07	1.000000	0.675682	0.223583	0.100732	0.000000	0.000003
38	AP	G382 meter install - reserve -measurement	MTRINSTALR_07	1.000000	0.923028	0.069968	0.007004	0.000000	0.000000
39	AP	G383 house regulators - reserve - access	HOUSEREGR_03	1.000000	0.841335	0.106022	0.052440	0.000000	0.000203
40	AP	G384 house reg install - reserve - access	HSEREGINSTR_03	1.000000	0.915288	0.070637	0.014054	0.000000	0.000020
41	AP	G385 lrg regulators - reserve - access	LRGREGR_03	1.000000	0.001951	0.023674	0.965781	0.000000	0.008594
42	AP	G385 lrg mtrs - reserve - measurement	LRGMTRR_07	1.000000	0.000000	0.845398	0.101003	0.000000	0.053598
43	AP	Direct LVG - delivery	DIRLVG_04	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
44	AP	Direct LVG - cust svs	DIRLVG_06	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
45	**AP**	**ALLOCATION PROPORTIONS TABLE CONTINUED**							
46	**AP**	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**							
47	AP								
48	AP	Direct SLG - streetlights	DIRSLG_05	1.000000	0.000000	0.000000	0.000000	1.000000	0.000000
49	AP	Meter Reading Costs - measurement	MRCOST_07	1.000000	0.906089	0.076261	0.017650	0.000000	0.000000
50	AP	Other Utility work by Cust Ops - delivery	UTILWORK_04	1.000000	0.793082	0.146292	0.060382	0.000026	0.000218
51	AP	Direct SLG - access	DIRSLG_03	1.000000	0.000000	0.000000	0.000000	1.000000	0.000000
52	AP	Direct Competitive Services - delivery	DIRCOMPSVS_04	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
53	AP	Direct TSG-F - access	DIRTSGF_03	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
54	AP	Direct TSG-F - delivery	DIRTSGF_04	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
55	AP	Direct TSG-F - measurement	DIRTSGF_07	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
56	AP	Direct - RSG - delivery	DIRRSG_04	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
57	AP	Choice - delivery	CHOICE_04	1.000000	0.912699	0.076817	0.010458	0.000008	0.000017
58	AP								
59	AP								
60	AP	Dummy allocator for unused lines	not_used	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
61	AP								
62	AP								
63	AP	**Plant Related**							
64	AP	Acct G301-G303 Intangible Plt	INTANGPLT	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
65	AP	Acct G399.10-23 Oth Tangible Plt	TANGPLT	1.000000	0.850812	0.084313	0.047882	0.000038	0.016955
66	AP	Production Plant Total	PRODPLT	1.000000	0.750176	0.077279	0.172546	0.000000	0.000000
67	AP	Storage Plant Total	STORPLT	1.000000	0.750176	0.077279	0.172546	0.000000	0.000000
68	AP	Transmission Plant Total	TRANPLT	1.000000	0.599170	0.115805	0.275067	0.000168	0.009791
69	AP	Distribution Plant Total	DISTPLT	1.000000	0.717567	0.125751	0.152015	0.000213	0.004454
70	AP	G391-G398 General Plant	GENPLT	1.000000	0.724223	0.115698	0.155317	0.000226	0.004536
71	AP	Common Plant	COMPLT	1.000000	0.820778	0.091862	0.073260	0.000082	0.014018
72	AP	Accts C389-C399, G391-E398 Com & Gen Plt	COMGENPLT	1.000000	0.756796	0.107657	0.127635	0.000177	0.007735
73	AP	Total Prod, Storage, Transmission, & Dist Plant	PSTDPLT	1.000000	0.716637	0.125329	0.153347	0.000211	0.004476
74	AP	Total Plant	TOTPLT	1.000000	0.717949	0.124780	0.152477	0.000210	0.004585
75	AP								
76	AP	Distribution Plant x Meters & Installs	DISTPLTXMTR	1.000000	0.724223	0.115698	0.155317	0.000226	0.004536
77	AP	Acct G374-375 - Land & Structures	PLT_3745	1.000000	0.717567	0.125751	0.152015	0.000213	0.004454
78	AP	Acct G376 - Mains	PLT_376	1.000000	0.599159	0.115801	0.275082	0.000168	0.009791
79	AP	Acct G377 - Compressor Station Equip	PLT_377	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
80	AP	Acct G378-379 - Meas & Regul Station Equip	PLT_3789	1.000000	0.599170	0.115805	0.275067	0.000168	0.009791
81	AP	Acct G380 & 387.2 - Services	SERVICES	1.000000	0.823837	0.117680	0.057701	0.000094	0.000688
82	AP	Acct G376, G380 & 387.2 - Mains & Services	MAIN_SERV	1.000000	0.731870	0.116911	0.146681	0.000124	0.004414
83	AP	Acct G381 - House Meters	PLT_381	1.000000	0.666502	0.231153	0.102342	0.000000	0.000003
84	AP	Acct G382 - Meter Installations	PLT_382	1.000000	0.911685	0.079972	0.008342	0.000000	0.000001
85	AP	Acct G381,382, & 385 - Meters	METERPLT	1.000000	0.608245	0.290870	0.097780	0.000000	0.003104
86	AP	Acct G381-384 - Meters & House Regulators	PLT_3814	1.000000	0.736573	0.185946	0.077473	0.000000	0.000008
87	AP	Acct G382-384 - House Reg & Install & Meter Install	PLT_3824	1.000000	0.900582	0.080134	0.019264	0.000000	0.000019
88	AP	Acct G383-384 - House Reg & Installation	PLT_3834	1.000000	0.896717	0.080190	0.023067	0.000000	0.000026

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				(1)	(2)	(3)	(4)	(5)	(6)
89	**AP**	**ALLOCATION PROPORTIONS TABLE CONTINUED**							
90	**AP**	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**							
91	AP								
92	AP	Acct G385 - Ind & Com Meas & Regul Station Equip	PLT_385	1.000000	0.013336	0.429068	0.542658	0.000003	0.014935
93	AP	Acct G386 - Other Property on Cust Premises	PLT_386	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
94	AP	Acct G387.1 - Other Equipment (St Ltg Posts)	PLT_387_1	1.000000	0.000000	0.000000	0.000000	1.000000	0.000000
95	AP								
96	AP	Total Distribution Plant Reserve	TOTDRESERVE	1.000000	0.719807	0.116913	0.157747	0.000082	0.005451
97	AP	Total Net Plant	TOTPLTNET	1.000000	0.717338	0.127364	0.150745	0.000252	0.004300
98	AP								
99	AP								
100	AP	**Revenue Related**							
101	AP	Total Operating Revenue	TOTREV	1.000000	0.722476	0.123596	0.148344	0.000387	0.005196
102	AP	Intra Dept Rev Req - 5.62% GS / 94.38% LV	INTRAREV	1.000000	0.000000	0.047366	0.952634	0.000000	0.000000
103	AP								
104	AP								
105	AP	**Expense Related**							
106	AP	Manufactured Gas O&M Excl Fuel Expense	MFGO_M	1.000000	0.750176	0.077279	0.172546	0.000000	0.000000
107	AP	Other Storage Plant O&M Expense	STOREXP	1.000000	0.750176	0.077279	0.172546	0.000000	0.000000
108	AP	Transmission Plant O&M Expense	TRANEXP	1.000000	0.599170	0.115805	0.275067	0.000168	0.009791
109	AP	Acct 813-Other Gas Supply Expense	EXP_813	1.000000	0.584197	0.110924	0.295687	0.000267	0.008924
110	AP	Acct 871 - Distribution Load Dispatching	EXP_871	1.000000	0.584197	0.110924	0.295687	0.000267	0.008924
111	AP	Acct 872 - Compressor Station Labor & Expenses	EXP_872	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
112	AP	Acct 874-Mains & Services Expenses	EXP_874	1.000000	0.731870	0.116911	0.146681	0.000124	0.004414
113	AP	Acct 875-877 - Meas & Regulating Station Exp	EXP_8757	1.000000	0.599170	0.115805	0.275067	0.000168	0.009791
114	AP	Acct 878 - Meter & House Regulator Expenses	EXP_878	1.000000	0.736573	0.185946	0.077473	0.000000	0.000008
115	AP	Acct 879 - Customer Installation Expenses	EXP_879	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000
116	AP	Acct 880.0,.1,.2 - Other Expenses	EXP_8801	1.000000	0.794734	0.094811	0.107527	0.000076	0.002852
117	AP	Acct 880.3 - Operation of Street Lighting Exp	EXP_8803	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
118	AP	Acct 881 - Rents	EXP_881	1.000000	0.584197	0.110924	0.295687	0.000267	0.008924
119	AP	Acct 886-Maint of Structures & Improvements Exp	EXP_886	1.000000	0.717567	0.125751	0.152015	0.000213	0.004454
120	AP	Acct 887-Maint of Mains Exp	EXP_887	1.000000	0.599159	0.115801	0.275082	0.000168	0.009791
121	AP	Acct 888-Maint of Compressor Station Equip Exp	EXP_888	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
122	AP	Acct 889-891 - Main of Meas & Reg Station Equip	EXP_8891	1.000000	0.599170	0.115805	0.275067	0.000168	0.009791
123	AP	Acct 892-Main of Services Exp	EXP_892	1.000000	0.823837	0.117680	0.057701	0.000094	0.000688
124	AP	Acct 893-Maint of Meters & House Regulators Exp	EXP_893	1.000000	0.666502	0.231154	0.102341	0.000000	0.000003
125	AP	Acct 894-Maint of Other Equipment	EXP_894	1.000000	0.030466	0.006527	0.008231	0.954537	0.000239
126	AP								
127	AP	Distr Oper Exp	DISTEXPO	1.000000	0.794734	0.094811	0.107527	0.000076	0.002852
128	AP	Distr Maint Exp	DISTEXPM	1.000000	0.665820	0.142636	0.179886	0.006439	0.005219
129	AP	Cust Serv & Info Expense	CUSTS_I	1.000000	0.814948	0.122277	0.055212	0.000030	0.007533
130	AP	Acct 901-903,905 Cust Acct Exp Excl 904	CACCTEXP	1.000000	0.856822	0.081210	0.044062	0.000033	0.017872
131	AP	Accts 901-910 Excl 904 - Cust Accts,Serv & Info	CUSTSVSX	1.000000	0.854621	0.083369	0.044649	0.000032	0.017329
132	AP	Sales Expense	SALESEXP	1.000000	0.793082	0.146292	0.060382	0.000026	0.000218

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				(1)	(2)	(3)	(4)	(5)	(6)
133	AP	Total O&M Expense Excl A&G Expense	TOTOMXAG	1.000000	0.779999	0.098598	0.112866	0.000868	0.007669
134	AP	Total O&M Expense Excl 904 Expense	TOTOMX904	1.000000	0.753147	0.104399	0.132500	0.001113	0.008841
135	AP	Total O&M Expense Excl Fuel & 904 Expense	TOMXFUEL904	1.000000	0.753571	0.108266	0.126789	0.001272	0.010102
136	AP	Tot Admin & Genl Exp xPension/Ben	AGEXP	1.000000	0.559348	0.156030	0.268857	0.001901	0.013863
137	AP	Accts 901-905 Cust Accts Exp Excl 904-Uncol	CUSTACCTS	1.000000	0.856822	0.081210	0.044062	0.000033	0.017872
138	AP	O&M + Capital Additions	EXPENDITURES	1.000000	0.732518	0.123346	0.138844	0.000328	0.004964
139	AP								
140	AP	Depreciation Expense (total)	DEPREXP	1.000000	0.720665	0.123931	0.150398	0.000209	0.004797
141	AP								
142	AP	NJ State Income Tax (CBT)	STATEINCTAX	1.000000	0.718661	0.126998	0.149732	0.000256	0.004352
143	AP	NJ State Deferred Income Tax	DFSTATEINCTAX	1.000000	0.850368	0.071136	0.071260	0.000521	0.006716
144	AP								
145	AP	**Labor Expense Related**							
146	AP	Total Distribution Exp (Oper) Labor	TLABDO	1.000000	0.901074	0.045579	0.051949	0.000037	0.001360
147	AP	Total Distribution Exp (Maint) Labor	TLABDM	1.000000	0.659426	0.155310	0.175838	0.004660	0.004765
148	AP	Total Labor	LABOR	1.000000	0.850368	0.071136	0.071260	0.000521	0.006716
149	AP								
150	AP	**REVENUES AND BILLING DETERMINANTS**							
151	AP								
152	AP	Base Rate Sales Revenue	SALESREV	1.000000	0.715010	0.127054	0.152160	0.000400	0.005375
153	AP								
154	AP	Residential Service Gas	REVRSG	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000
155	AP	General Service Gas	REVGSG	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
156	AP	Large Volume Service Gas	REVLVG	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000
157	AP	Street Light Gas	REVSLG	1.000000	0.000000	0.000000	0.000000	1.000000	0.000000
158	AP	Firm Transportation Gas Service	REVTSGF	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000
159	AP								
160	AP	Total Rev Req @ desired ROR	REVREQ	1.000000	0.715010	0.127054	0.152160	0.000400	0.005375
161	AP								
162	AP	**PRESENT REVENUES FROM SALES INPUT**							
163	AP	Total Sales of Gas Revenue Requirement		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
164	AP	Sales of Gas Revenues - Rates		1.000000	0.734224	0.117784	0.136445	0.000397	0.011149
165	AP	Sales of Gas Revenues - Other		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000

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				(1)	(2)	(3)	(4)	(5)	(6)
1	ADA	**ALLOCATED DIRECT ASSIGNMENTS**							
2	ADA	**DIRECT ASSIGN TO CLASSES W/SALES REV FUNCTIONS**							
3	ADA								
4	ADA	**Account 904 - Uncollectible Accounts**							
5	ADA	Residential Service Gas	REVRSG	1,001,979,781	1,001,979,781	0	0	0	0
6	ADA	General Service Gas	REVGSG	178,047,445	0	178,047,445	0	0	0
7	ADA	Large Volume Service Gas	REVLVG	213,229,775	0	0	213,229,775	0	0
8	ADA	Street Light Gas	REVSLG	561,110	0	0	0	561,110	0
9	ADA	Firm Transportation Gas Service	REVTSGF	7,532,209	0	0	0	0	7,532,209
10	ADA								
11	ADA	Total 904-Uncollectible	EXP_904	1,400,789,210	1,001,979,781	178,047,445	213,229,775	0	7,532,209
12	ADA								
13	ADA	Total 904-Uncollectible	EXP_904	1.000000	0.715297	0.127105	0.152221	0.0	0.005377
14	ADA								
15	ADA	Additional Net Write-Offs at Claimed Rate	EXP_904	0	0	0	0	0	0
16	ADA								
17	ADA	**Rev Req (cal) to Customers Late Payment fees**							
18	ADA	Residential Service Gas	REVRSG	0	0	0	0	0	0
19	ADA	General Service Gas	REVGSG	178,047,445	0	178,047,445	0	0	0
20	ADA	Large Volume Service Gas	REVLVG	213,229,775	0	0	213,229,775	0	0
21	ADA	Street Light Gas	REVSLG	0	0	0	0	0	0
22	ADA	Firm Transportation Gas Service	REVTSGF	0	0	0	0	0	0
23	ADA								
24	ADA	Total Late Payment Fees	REVLATEP	391,277,219	0	178,047,445	213,229,775	0	0
25	ADA								
26	ADA	Total Late Payment Fees	REVLATEP	1.000000	0.0	0.455042	0.544958	0.0	0.0
27	ADA								
28	ADA	**ALLOCATED DIRECT ASSIGNMENTS**							
29	ADA	**DIRECT ASSIGN TO CLASSES W/SALES REV FUNCTIONS**							
30	ADA								
31	ADA	**AVAILABLE**							
32	ADA	Residential Service Gas	REVRSG	0	0	0	0	0	0
33	ADA	General Service Gas	REVGSG	0	0	0	0	0	0
34	ADA	Large Volume Service Gas	REVLVG	0	0	0	0	0	0
35	ADA	Street Light Gas	REVSLG	0	0	0	0	0	0
36	ADA	Firm Transportation Gas Service	REVTSGF	0	0	0	0	0	0
37	ADA								
38	ADA	Total Available	REVAVAIL	0	0	0	0	0	0
39	ADA								
40	ADA	Total Available	REVAVAIL	0.0	0.0	0.0	0.0	0.0	0.0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
1	RRW	**REVENUE REQUIREMENTS**							
2	RRW								
3	RRW	PRESENT RATES							
4	RRW	---							
5	RRW	RATE BASE		8,681,618,581	6,235,276,049	1,106,086,416	1,300,573,328	2,254,181	37,428,607
6	RRW	NET OPER INC (PRESENT RATES)		655,462,203	470,763,342	83,509,524	98,193,286	170,191	2,825,860
7	RRW	RATE OF RETURN (PRES RATES)		7.55%	7.55%	7.55%	7.55%	7.55%	7.55%
8	RRW	RELATIVE RATE OF RETURN		1.00	1.00	1.00	1.00	1.00	1.00
9	RRW	SALES REVENUE (PRE RATES)		1,401,350,320	1,001,979,781	178,047,445	213,229,775	561,110	7,532,209
10	RRW	REVENUE PRES RATES $/THERM		$0.5393	$0.6601	$0.6178	$0.2775	$0.8077	$0.3248
11	RRW	REVENUE REQUIRED - $/MO/CUST		$61.65	$48.30	$101.98	$897.02	$2,922.45	$19,615.13
12	RRW								
13	RRW								
14	RRW	CLAIMED RATE OF RETURN							
15	RRW	---							
16	RRW	CLAIMED RATE OF RETURN		7.55%	7.55%	7.55%	7.55%	7.55%	7.55%
17	RRW	RETURN REQ FOR CLAIMED ROR		655,462,203	470,763,342	83,509,524	98,193,286	170,191	2,825,860
18	RRW	SALES REVENUE REQ CLAIMED ROR		1,401,350,320	1,001,979,781	178,047,445	213,229,775	561,110	7,532,209
19	RRW	REVENUE DEFICIENCY SALES REV		0	0	0	0	0	0
20	RRW	PERCENT INCREASE REQUIRED		0.0	0.0	0.0	0.0	0.0	0.0
21	RRW	ANNUAL BOOKED THERM SALES		2,598,285,838	1,517,910,828	288,213,545	768,279,951	694,743	23,186,772
22	RRW	SALES REV REQUIRED $/THERM		$0.5393	$0.6601	$0.6178	$0.2775	$0.8077	$0.3248
23	RRW	REVENUE DEFICIENCY $/THERM		0.0	0.0	0.0	0.0	0.0	0.0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
1	S	**SUMMARY OF RESULTS**							
2	S	**DEVELOPMENT OF RETURN**							
3	S								
4	S	**RATE BASE**							
5	S	Plant in Service							
6	S	Production Plant 304-320	CALCULATED	52,043,670	0	52,043,670	0	0	0
7	S	Storage Plant 360-363	CALCULATED	19,575,233	0	19,575,233	0	0	0
8	S	Transmission Plant 365-371	CALCULATED	103,544,395	0	103,544,395	0	0	0
9	S	Distribution Plant							
10	S	Land & Structures 374-375	CALCULATED	96,512,525	52,625,554	38,287,314	9,389	0	5,590,267
11	S	Mains 376	CALCULATED	3,775,184,891	0	3,775,184,891	0	0	0
12	S	Compressor Station Equipment 377	CALCULATED	0	0	0	0	0	0
13	S	Meas & Regulating Station Equip 378-379	CALCULATED	285,986,290	0	285,986,290	0	0	0
14	S	Services 380	CALCULATED	5,447,179,699	5,447,179,699	0	0	0	0
15	S	Meters 381	CALCULATED	477,048,047	0	0	0	0	477,048,047
16	S	Meter Installations 382	CALCULATED	52,631,537	0	0	0	0	52,631,537
17	S	House Regulators & Install 383-384	CALCULATED	151,182,537	151,182,537	0	0	0	0
18	S	Industrial Meas & Reg Station Equip 385	CALCULATED	145,614,455	72,807,227	0	0	0	72,807,227
19	S	Other Property on Cust Premises 386	CALCULATED	0	0	0	0	0	0
20	S	Other Equipment (Street Lighting) 387	CALCULATED	1,521,717	509,787	0	1,011,930	0	0
21	S	Asset Retirement Obligation 388	CALCULATED	65,215,073	0	65,215,073	0	0	0
22	S	Total Distribution Plant	CALCULATED	10,498,076,770	5,724,304,805	4,164,673,568	1,021,319	0	608,077,078
23	S	General Plant E389-E399	CALCULATED	200,812,197	116,163,890	84,514,137	20,726	0	113,444
24	S	Common Plant C389-C399	CALCULATED	102,234,955	15,246,506	16,357,253	2,720	57,691,885	12,936,591
25	S	Intangible Plant E301-E303, E399, C303-C390	CALCULATED	16,791,854	283,770	1,334,206	51	12,410,339	2,763,489
26	S	Total Plant in Service	CALCULATED	10,993,079,074	5,855,998,970	4,442,042,462	1,044,816	70,102,224	623,890,602
27	S								
28	S	Less: Reserve for Depreciation and Amorization	CALCULATED	2,718,471,978	1,288,707,941	1,277,621,837	11,318	36,625,623	115,505,260
29	S								
30	S	Plus: Rate Base Additions							
31	S	Working Capital	CALCULATED	645,513,843	319,001,914	235,457,149	139,316	36,066,596	54,848,868
32	S	Capital Stimulas Adjust (Pro Forma #13)	CALCULATED	0	0	0	0	0	0
33	S	Capital Lease Plt & Reserve Deduct	CALCULATED	96,280	14,358	15,405	3	54,332	12,183
34	S	Other Rate Base Additions		1,727,003,584	942,713,147	682,925,226	172,250	620,711	100,572,249
35	S	Plus: Rate Base Deductions							
36	S	Customer Advances	CALCULATED	-24,909,672	-14,713,434	-10,196,237	0	0	0
37	S	Unbilled Revenue	CALCULATED	-256,132,009	-136,441,189	-103,496,869	-24,344	-1,633,339	-14,536,269
38	S	Deferred Income Taxes and Credits	CALCULATED	-1,684,560,542	-896,261,535	-681,950,492	-159,771	-10,723,562	-95,465,181
39	S								
40	S	Other Rate Base Deductions							
41	S	TOTAL RATE BASE		8,681,618,581	4,781,604,291	3,287,174,807	1,160,952	57,861,339	553,817,193
42	S								
43	S								
44	S	**SUMMARY OF RESULTS**							

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
45	S	**DEVELOPMENT OF RETURN**							
46	S								
47	S	**RATE BASE**	CALCULATED	8,681,618,581	4,781,604,291	3,287,174,807	1,160,952	57,861,339	553,817,193
48	S								
49	S	**OPERATING REVENUES**							
50	S	Rate Revenues from Customers	CALCULATED	1,401,350,320	694,848,286	518,377,997	396,637	78,066,852	109,660,548
51	S	Other Operating Revenues	CALCULATED	67,687,036	9,818,488	55,165,609	5,328	1,086,253	1,611,358
52	S	Revenues from Other Sources	CALCULATED	0	0	0	0	0	0
53	S	Less: Provisions for Rate Refunds	CALCULATED	0	0	0	0	0	0
54	S	TOTAL OPERATING REVENUES		1,469,037,356	704,666,774	573,543,606	401,966	79,153,105	111,271,906
55	S								
56	S	**OPERATING EXPENSES**							
57	S	Operation and Maintenance Expense							
58	S	Gas Production and Supply Expense	CALCULATED	31,906,945	0	31,906,945	0	0	0
59	S	Storage Expense	CALCULATED	2,714,605	0	2,714,605	0	0	0
60	S	Transmission Expense	CALCULATED	2,593,507	0	2,593,507	0	0	0
61	S	Distribution Expense	CALCULATED	102,873,398	26,407,965	57,901,140	199,225	0	18,365,069
62	S	Customer Accounts Expense	CALCULATED	98,759,541	12,918,882	12,349,849	0	58,442,460	15,048,351
63	S	Customer Service & Information Expense	CALCULATED	4,034,218	0	2,596,868	0	1,437,350	0
64	S	Sales Expense	CALCULATED	88,423	0	88,423	0	0	0
65	S	Administrative and General Expense	CALCULATED	38,752,071	7,066,337	12,641,434	66,361	12,596,054	6,381,885
66	S	Total Operation and Maintenance Expense	CALCULATED	281,722,708	46,393,184	122,792,771	265,586	72,475,863	39,795,304
67	S	Depreciation Expense	CALCULATED	203,691,216	108,184,098	80,336,675	19,302	3,717,640	11,433,501
68	S	Amortization Expense	CALCULATED	2,351,634	0	1,210,181	0	909,279	232,173
69	S	Taxes Other Than Income Taxes	CALCULATED	-24,480,722	-8,234,607	-11,466,368	-6,462	-2,592,417	-2,180,869
70	S	Proforma Expense Adjustments	CALCULATED	100,619,236	46,208,773	42,531,052	15,737	5,082,769	6,780,904
71	S	State Income Taxes	CALCULATED	77,634,124	42,518,568	29,567,224	10,226	604,895	4,933,212
72	S	Federal Income Taxes	CALCULATED	143,331,440	78,834,379	54,165,406	19,670	1,053,056	9,258,929
73	S	Provision for Deferred Income Taxes	CALCULATED	28,705,516	29,751,254	6,224,968	-9,746	-6,466,512	-794,448
74	S	Income Taxes Deferred in Prior Years	CALCULATED	0	0	0	0	0	0
75	S	Investment Tax Credit Adjustement (Net)	CALCULATED	0	0	0	0	0	0
76	S	TOTAL OPERATING EXPENSES		813,575,153	343,655,650	325,361,908	314,314	74,784,574	69,458,708
77	S								
78	S	**OPERATING INCOME (RETURN)**		655,462,203	361,011,124	248,181,698	87,652	4,368,531	41,813,198
79	S	Plus Operating Income Adjustment	CALCULATED						
80	S	TOTAL NET OPERATING INCOME		655,462,203	361,011,124	248,181,698	87,652	4,368,531	41,813,198
81	S								
82	S	**RATE OF RETURN ON RATE BASE (PRESENT)**		7.55%	7.55%	7.55%	7.55%	7.55%	7.55%
83	S	**INDEX RATE OF RETURN (PRESENT)**		1.00	1.00	1.00	1.00	1.00	1.00
84	S								
85	S								
86	S	**EQUALIZED RETURN AT PROPOSED ROR**							
87	S	**DEVELOPMENT OF RETURN (EQUALIZED RATE LEVELS)**							
88	S								

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
89	S	**RATE BASE**	CALCULATED	8,681,618,581	4,781,604,291	3,287,174,807	1,160,952	57,861,339	553,817,193
90	S								
91	S	**RATE OF RETURN**		7.55%	7.55%	7.55%	7.55%	7.55%	7.55%
92	S								
93	S	**RETURN (RATE BASE * 7.40% ROR)**		655,462,203	361,011,124	248,181,698	87,652	4,368,531	41,813,198
94	S								
95	S	**PLUS:**							
96	S	**OPERATING EXPENSES**							
97	S	Total Operation and Maintenance Expense	CALCULATED	281,722,708	46,393,184	122,792,771	265,586	72,475,863	39,795,304
98	S	Depreciation Expense	CALCULATED	203,691,216	108,184,098	80,336,675	19,302	3,717,640	11,433,501
99	S	Amortization Expense	CALCULATED	2,351,634	0	1,210,181	0	909,279	232,173
100	S	Taxes Other Than Income Taxes	CALCULATED	-24,480,722	-8,234,607	-11,466,368	-6,462	-2,592,417	-2,180,869
101	S	Proforma Expense Adjustments	CALCULATED	100,619,236	46,208,773	42,531,052	15,737	5,082,769	6,780,904
102	S	Income Taxes	CALCULATED	220,965,564	121,352,947	83,732,630	29,896	1,657,951	14,192,142
103	S	Provision for Deferred Income Taxes	CALCULATED	28,705,516	29,751,254	6,224,968	-9,746	-6,466,512	-794,448
104	S	Income Taxes Deferred in Prior Years	CALCULATED	0	0	0	0	0	0
105	S	Investment Tax Credit Adjustement (Net)	CALCULATED						
106	S	**TOTAL OPERATING EXPENSES**		813,575,153	343,655,650	325,361,908	314,314	74,784,574	69,458,708
107	S								
108	S	**EQUALS TOTAL COST OF SERVICE**		1,469,037,356	704,666,774	573,543,606	401,966	79,153,105	111,271,906
109	S								
110	S	**LESS:**							
111	S	Other Operating Revenues	CALCULATED	67,687,036	9,818,488	55,165,609	5,328	1,086,253	1,611,358
112	S	Revenues from Other Sources	CALCULATED	0	0	0	0	0	0
113	S	Plus: Provisions for Rate Refunds	CALCULATED	0	0	0	0	0	0
114	S	**EQUALS:**							
115	S	**BASE RATE SALES @ EQUALIZED ROR 7.40%**		1,401,350,320	694,848,286	518,377,997	396,637	78,066,852	109,660,548
116	S								
117	S	**TOTAL COST OF SERVICE INCREASE/DECREASE**		0	0	0	0	0	0
118	S	**REVENUE INCREASE TO RETAIL REVENUES (%)**		0.00	0.00	0.00	0.00	0.00	0.00

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
1	RBP	**DEVELOPMENT OF RATE BASE**							
2	RBP								
3	RBP	**GAS PLANT IN SERVICE**							
4	RBP								
5	RBP	INTANGIBLE PLANT - G301-G303							
6	RBP	General - AWMS & Misc.	TOTPLT	0	0	0	0	0	0
7	RBP	Choice Progect	not_used	0	0	0	0	0	0
8	RBP	GSMIS - meter related	not_used	0	0	0	0	0	0
9	RBP	- regulator related	not_used	0	0	0	0	0	0
10	RBP	- appliance safety related	not_used	0	0	0	0	0	0
11	RBP	- Comp Svs related	not_used	0	0	0	0	0	0
12	RBP	- Cust Svs related	not_used	0	0	0	0	0	0
13	RBP	TOTAL INTANGIBLE PLANT		0	0	0	0	0	0
14	RBP								
15	RBP	C303 - INTANGIBLE PLANT - CUST SERVICE							
16	RBP	Customer Service	CUSTSVSX	16,301,302	0	1,127,751	0	12,410,339	2,763,212
17	RBP	Measurement	MRCOST_07	0	0	0	0	0	0
18	RBP	Not Used	not_used	0	0	0	0	0	0
19	RBP	G399.1 Asset Retirement Costs of General Plt	GENPLT	490,552	283,770	206,454	51	0	277
20	RBP	Not Used	not_used	0	0	0	0	0	0
21	RBP	TOTAL ACCOUNTS C303-C390.4,G399		16,791,854	283,770	1,334,206	51	12,410,339	2,763,489
22	RBP								
23	RBP	TOTAL INTANGIBLE PLANT		16,791,854	283,770	1,334,206	51	12,410,339	2,763,489
24	RBP								
25	RBP	PRODUCTION PLANT							
26	RBP	G304-G320 - All Land & Equipment	BALANCE_04	52,043,670	0	52,043,670	0	0	0
27	RBP	Not Used	not_used	0	0	0	0	0	0
28	RBP	TOTAL PRODUCTION PLANT		52,043,670	0	52,043,670	0	0	0
29	RBP								
30	RBP	STORAGE PLANT							
31	RBP	G360-G363 - All Land & Equipment	BALANCE_04	19,575,233	0	19,575,233	0	0	0
32	RBP	Not Used	not_used	0	0	0	0	0	0
33	RBP	TOTAL STORAGE PLANT		19,575,233	0	19,575,233	0	0	0
34	RBP								
35	RBP	TRANSMISSION PLANT							
36	RBP	G365 Land & Land Rights	AVGPEAK_04	5,421,128	0	5,421,128	0	0	0
37	RBP	G366 Structures & Improvements	AVGPEAK_04	0	0	0	0	0	0
38	RBP	G367 Mains	AVGPEAK_04	93,786,847	0	93,786,847	0	0	0
39	RBP	G369 Meas. & Reg. Station Equipment	AVGPEAK_04	4,336,420		4,336,420			
40	RBP	TOTAL TRANSMISSION PLANT		103,544,395	0	103,544,395	0	0	0
41	RBP								
42	RBP								
43	RBP								
44	RBP	**GAS PLANT IN SERVICE CONTINUED**							

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
45	RBP								
46	RBP	DISTRIBUTION PLANT							
47	RBP	G374-G375 Land & Structures							
48	RBP	General	DISTPLT	96,512,525	52,625,554	38,287,314	9,389	0	5,590,267
49	RBP	Not Used	not_used	0	0	0	0	0	0
50	RBP	Total Accounts G374-G375		96,512,525	52,625,554	38,287,314	9,389	0	5,590,267
51	RBP								
52	RBP	G376 Mains							
53	RBP	Firm Allocation	AVGPEAK_04	3,772,391,917	0	3,772,391,917	0	0	0
54	RBP	CIG, TSG-NF & CSG Redistribution	TRANSPORT_04	2,792,974	0	2,792,974	0	0	0
55	RBP	Not Used	not_used	0	0	0	0	0	0
56	RBP	Total Account G376		3,775,184,891	0	3,775,184,891	0	0	0
57	RBP								
58	RBP	G377 Compressor Station Equip	DISTPLTXMTR	0	0	0	0	0	0
59	RBP								
60	RBP	G378-G379 Meas & Regulatory Equipment							
61	RBP	Firm Investment	AVGPEAK_04	285,986,290	0	285,986,290	0	0	0
62	RBP	Not Used	not_used	0	0	0	0	0	0
63	RBP	Total Account G378-G379		285,986,290	0	285,986,290	0	0	0
64	RBP								
65	RBP	G380 Services							
66	RBP	Firm Allocation	SERVICES_03	5,442,013,091	5,442,013,091	0	0	0	0
67	RBP	CIG, TSG-NF & CSG Redistribution	TRANSPORT_03	5,166,608	5,166,608	0	0	0	0
68	RBP	Not Used	not_used	0	0	0	0	0	0
69	RBP	Total Account G380		5,447,179,699	5,447,179,699	0	0	0	0
70	RBP								
71	RBP	G381 Meters							
72	RBP	Firm Allocation	SMMETERS_07	477,045,042	0	0	0	0	477,045,042
73	RBP	CIG, TSG-NF & CSG Redistribution	TRANSPORT_07	3,005	0	0	0	0	3,005
74	RBP	Not Used	not_used	0	0	0	0	0	0
75	RBP	Total Account G381		477,048,047	0	0	0	0	477,048,047
76	RBP								
77	RBP	G382 Meter Installations							
78	RBP	Firm Allocation	MTRINSTAL_07	52,630,927	0	0	0	0	52,630,927
79	RBP	CIG, TSG-NF & CSG Redistribution	TRANSPORT_07	609	0	0	0	0	609
80	RBP	Not Used	not_used	0	0	0	0	0	0
81	RBP	Total Account G382		52,631,537	0	0	0	0	52,631,537
82	RBP								
83	RBP								
84	RBP								
85	RBP								
86	RBP								
87	RBP								
88	RBP	**GAS PLANT IN SERVICE CONTINUED**							

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
89	RBP								
90	RBP	DISTRIBUTION PLANT CONTINUED							
91	RBP								
92	RBP	G383 House Regulators & Installation							
93	RBP	Firm Allocation - Regulators - G383	HOUSEREG_03	38,488,025	38,488,025	0	0	0	0
94	RBP	CIG, TSG-NF & CSG Redistribution	TRANSPORT_03	11,098	11,098	0	0	0	0
95	RBP	Not Used	not_used	0	0	0	0	0	0
96	RBP	Total Account G383		38,499,123	38,499,123	0	0	0	0
97	RBP								
98	RBP	G384 House Regulators & Installation		0	0	0	0	0	0
99	RBP	Firm Allocation - Installation - G384	HSEREGINST_03	112,681,544	112,681,544	0	0	0	0
100	RBP	G384 CIG. TSG-NF & CSG Redistribution	TRANSPORT_03	1,870	1,870	0	0	0	0
101	RBP	Total Account G384		112,683,414	112,683,414	0	0	0	0
102	RBP	G385 Industrial Meas and Regul Station Equip							
103	RBP	Firm Allocation - Regulators	LRGREG_03	71,912,204	71,912,204	0	0	0	0
104	RBP	Firm Allocation - Meters	LRGMTR_07	71,912,204	0	0	0	0	71,912,204
105	RBP	CIG, TSG-NF & CSG Redistribution - Regulators	TRANSPORT_03	895,023	895,023	0	0	0	0
106	RBP	CIG, TSG-NF & CSG Redistribution - Meters	TRANSPORT_07	895,023	0	0	0	0	895,023
107	RBP	Not Used	not_used	0	0	0	0	0	0
108	RBP	Total Account G385		145,614,455	72,807,227	0	0	0	72,807,227
109	RBP								
110	RBP	G386 Other Prop on Cust Prem	TRANSPORT_04	0	0	0	0	0	0
111	RBP								
112	RBP	G387-Other Equipment							
113	RBP	G387.1 Other Eqmt - Street Ltg Posts	DIRSLG_05	1,011,930	0	0	1,011,930	0	0
114	RBP	G387.2 Other Eqmt - Street Ltg Services	DIRSLG_03	509,787	509,787	0	0	0	0
115	RBP	Total Accounts G387		1,521,717	509,787	0	1,011,930	0	0
116	RBP								
117	RBP	G388 - Asset Retirement Obligations	PLT_376	65,215,073	0	65,215,073	0	0	0
118	RBP								
119	RBP	TOTAL DISTRIBUTION PLANT		10,498,076,770	5,724,304,805	4,164,673,568	1,021,319	0	608,077,078
120	RBP								
121	RBP								
122	RBP								
123	RBP								
124	RBP								
125	RBP								
126	RBP								
127	RBP								
128	RBP								
129	RBP								
130	RBP								
131	RBP								
132	RBP								

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
133	RBP								
134	RBP								
135	RBP	**GAS PLANT IN SERVICE CONTINUED**							
136	RBP								
137	RBP	GENERAL AND COMMON PLANT							
138	RBP	E390-E398 GENERAL PLANT							
139	RBP	Meter Related	METERPLT	0	0	0	0	0	0
140	RBP	Regulator Plant Related	PLT_3834	0	0	0	0	0	0
141	RBP	Appliance Safety Related	CINST_04	0	0	0	0	0	0
142	RBP	Distribution Delivery	DISTPLTXMTR	200,812,197	116,163,890	84,514,137	20,726	0	113,444
143	RBP	Competitive Service	COMPSVSWK_04	0	0	0	0	0	0
144	RBP	SONP/RNP Related	CUSTAVG_04	0	0	0	0	0	0
145	RBP	Gas Peaking Plant Related	BALANCE_04	0	0	0	0	0	0
146	RBP	Total Accounts E390-E398		200,812,197	116,163,890	84,514,137	20,726	0	113,444
147	RBP								
148	RBP	C389-C399 COMMON PLANT							
149	RBP	ASB Work Related	CINST_04	0	0	0	0	0	0
150	RBP	Meter Plant Related	METERPLT	0	0	0	0	0	0
151	RBP	Not Used	not_used	0	0	0	0	0	0
152	RBP	Customer Service Related	CUSTSVSX	75,768,116	0	5,241,765	0	57,683,000	12,843,352
153	RBP	Distribution Delivery Related	DISTPLTXMTR	25,073,523	14,504,288	10,552,482	2,588	0	14,165
154	RBP	Service & Support Related	UTILWORK_04	0	0	0	0	0	0
155	RBP	Unassigned	TOTPLT	1,393,316	742,218	563,006	132	8,885	79,075
156	RBP	Total Accounts C389-C399		102,234,955	15,246,506	16,357,253	2,720	57,691,885	12,936,591
157	RBP								
158	RBP	TOTAL GENERAL AND COMMON PLANT		303,047,153	131,410,396	100,871,390	23,446	57,691,885	13,050,035
159	RBP								
160	RBP								
161	RBP	**TOTAL GAS PLANT IN SERVICE (101)**		10,993,079,074	5,855,998,970	4,442,042,462	1,044,816	70,102,224	623,890,602

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
1	RBD	**LESS: DEPRECIATION RESERVE & AMORT**							
2	RBD								
3	RBD	G301-G303 - INTANGILE PLANT - RESERVE							
4	RBD	General - AWMS & Misc.	TOTPLT	0	0	0	0	0	0
5	RBD	Choice Progect	not_used	0	0	0	0	0	0
6	RBD	GSMIS - meter related	not_used	0	0	0	0	0	0
7	RBD	- regulator related	not_used	0	0	0	0	0	0
8	RBD	- appliance safety related	not_used	0	0	0	0	0	0
9	RBD	- Comp Svs related	not_used	0	0	0	0	0	0
10	RBD	- Cust Svs related	not_used	0	0	0	0	0	0
11	RBD	Total Accounts E301-E303 Reserve		0	0	0	0	0	0
12	RBD								
13	RBD	C303 - INTANGIBLE PLANT - CUST SERVICE							
14	RBD	Customer Service	CUSTSVSX	9,821,603	0	679,475	0	7,477,281	1,664,847
15	RBD	Measurement	MRCOST_07	0	0	0	0	0	0
16	RBD	Not Used	not_used	0	0	0	0	0	0
17	RBD	G399.1 Asset Retirement Costs of General Plt	GENPLT	0	0	0	0	0	0
18	RBD	Not Used	not_used	0	0	0	0	0	0
19	RBD	TOTAL ACCOUNTS C303-C390.4,G399		9,821,603	0	679,475	0	7,477,281	1,664,847
20	RBD								
21	RBD	TOTAL INTANGIBLE PLANT		9,821,603	0	679,475	0	7,477,281	1,664,847
22	RBD								
23	RBD	PRODUCTION PLANT G304-G320 RESERVE	BALANCE_04	56,077,402	0	56,077,402	0	0	0
24	RBD								
25	RBD	STORAGE PLANT G360-G363 RESERVE	BALANCE_04	9,476,790	0	9,476,790	0	0	0
26	RBD								
27	RBD	TRANSMISSION PLANT G365-G369 RESERVE	TRANPLT	50,246,121	0	50,246,121	0	0	0
28	RBD								
29	RBD	DISTRIBUTION PLANT RESERVE							
30	RBD	G374-G375 Land & Structures Reserve	PLT_3745	432,406	235,779	171,539	42	0	25,046
31	RBD								
32	RBD	G376 Mains Reserve							
33	RBD	Firm Allocation	AVGPEAK_04	1,017,890,245	0	1,017,890,245	0	0	0
34	RBD	CIG, TSG-NF & CSG Redistribution	TRANSPORT_04	759,994	0	759,994	0	0	0
35	RBD	Not Used	not_used	0	0	0	0	0	0
36	RBD	Total Account G376		1,018,650,239	0	1,018,650,239	0	0	0
37	RBD								
38	RBD	G377 Compressor Station Equip Reserve	DISTPLTXMTR						
39	RBD								
40	RBD	G378-G379 Meas & Regulatory Equip Reserve							
41	RBD	Firm Investment	AVGPEAK_04	93,669,010	0	93,669,010	0	0	0
42	RBD	Not Used	not_used	0	0	0	0	0	0
43	RBD	Total Account G378-G379		93,669,010	0	93,669,010	0	0	0
44	RBD	**DEPRECIATION RESERVE & AMORT CONTINUED**							

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
45	RBD								
46	RBD	**DISTRIBUTION PLANT CONTINUED**							
47	RBD								
48	RBD	G380 Services Reserve							
49	RBD	Firm Allocation	SERVICESR_03	1,126,944,013	1,126,944,013	0	0	0	0
50	RBD	CIG, TSG-NF & CSG Redistribution	TRANSPORT_03	2,349,910	2,349,910	0	0	0	0
51	RBD	Not Used	not_used	0	0	0	0	0	0
52	RBD	Total Account G380		1,129,293,923	1,129,293,923	0	0	0	0
53	RBD								
54	RBD	G381 Meters Reserve							
55	RBD	Firm Allocation	SMMETERSR_07	61,006,069	0	0	0	0	61,006,069
56	RBD	CIG, TSG-NF & CSG Redistribution	TRANSPORT_07	1,948	0	0	0	0	1,948
57	RBD	Not Used	not_used	0	0	0	0	0	0
58	RBD	Total Account G381		61,008,018	0	0	0	0	61,008,018
59	RBD								
60	RBD	G382 Meter Installations Reserve							
61	RBD	Firm Allocation	MTRINSTALR_07	33,652,945	0	0	0	0	33,652,945
62	RBD	CIG, TSG-NF & CSG Redistribution	TRANSPORT_07	279	0	0	0	0	279
63	RBD	Not Used	not_used	0	0	0	0	0	0
64	RBD	Total Account G382		33,653,224	0	0	0	0	33,653,224
65	RBD								
66	RBD	G383 House Regulators & Installation Reserve							
67	RBD	Firm Allocation - Regulators - G383	HOUSEREGR_03	25,030,964	25,030,964	0	0	0	0
68	RBD	CIG, TSG-NF & CSG Redistribution	TRANSPORT_03	4,827	4,827	0	0	0	0
69	RBD	Not Used	not_used	0	0	0	0	0	0
70	RBD	Total Account G383		25,035,791	25,035,791	0	0	0	0
71	RBD								
72	RBD	G384 House Regulators & Installation Reserve		0	0	0	0	0	0
73	RBD	Firm Allocation - Installation - G384	HSEREGINSTR_03	58,406,745	58,406,745	0	0	0	0
74	RBD	G384 CIG. TSG-NF & CSG Redistribution	TRANSPORT_03	1,006	1,006	0	0	0	0
75	RBD	Total Account G384		58,407,752	58,407,752	0	0	0	0
76	RBD	G385 Industrial Meas and Regul Sta Equip Reserve							
77	RBD	Firm Allocation - Regulators	LRGREGR_03	12,236,618	12,236,618	0	0	0	0
78	RBD	Firm Allocation - Meters	LRGMTRR_07	12,236,618	0	0	0	0	12,236,618
79	RBD	CIG, TSG-NF & CSG Redistribution - Regulators	TRANSPORT_03	295,977	295,977	0	0	0	0
80	RBD	CIG, TSG-NF & CSG Redistribution - Meters	TRANSPORT_07	295,977	0	0	0	0	295,977
81	RBD	Not Used	not_used	0	0	0	0	0	0
82	RBD	Total Account G385		25,065,190	12,532,595	0	0	0	12,532,595
83	RBD								
84	RBD	G386 Other Prop on Cust Prem	TRANSPORT_04	0	0	0	0	0	0
85	RBD	G387.1 Other Eqmt - Street Ltg Posts	DIRSLG_05	0	0	0	0	0	0
86	RBD	G387.2 Other Eqmt - Street Ltg Services	DIRSLG_03	0	0	0	0	0	0
87	RBD								
88	RBD	TOTAL DISTRIBUTION PLANT RESERVE		2,445,215,554	1,225,505,840	1,112,490,788	42	0	107,218,883

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				(1)	(2)	(3)	(4)	(5)	(6)
89	RBD								
90	RBD	**DEPRECIATION RESERVE & AMORT CONTINUED**							
91	RBD								
92	RBD	GENERAL AND COMMON PLANT RESERVE							
93	RBD								
94	RBD	E390-E398 GENERAL PLANT - RESERVE							
95	RBD	Meter Related	METERPLT	0	0	0	0	0	0
96	RBD	Regulator Plant Related	PLT_3834	0	0	0	0	0	0
97	RBD	Appliance Safety Related	CINST_04	0	0	0	0	0	0
98	RBD	Distribution Delivery	DISTPLTXMTR	94,949,830	54,925,656	39,960,735	9,800	0	53,640
99	RBD	Competitive Service	COMPSVSWK_04	0	0	0	0	0	0
100	RBD	SONP/RNP Related	CUSTAVG_04	0	0	0	0	0	0
101	RBD	Gas Peaking Plant Related	BALANCE_04	0	0	0	0	0	0
102	RBD	Total Accounts E390-E398		94,949,830	54,925,656	39,960,735	9,800	0	53,640
103	RBD								
104	RBD	C389-C399 COMMON PLANT							
105	RBD	ASB Work Related	CINST_04	0	0	0	0	0	0
106	RBD	Not Used	not_used	0	0	0	0	0	0
107	RBD	Customer Service Related	CUSTSVSX	38,276,434	0	2,648,028	0	29,140,219	6,488,187
108	RBD	Distribution Delivery Related	DISTPLTXMTR	13,134,595	7,597,973	5,527,846	1,356	0	7,420
109	RBD	Service & Support Related	UTILWORK_04	0	0	0	0	0	0
110	RBD	Unassigned	TOTPLT	1,273,650	678,472	514,652	121	8,122	72,284
111	RBD	Total Accounts C389-C399 Reserve		52,684,679	8,276,445	8,690,526	1,477	29,148,341	6,567,890
112	RBD								
113	RBD	**TOTAL DEPRECIATION RESERVE & AMORT.**		2,718,471,978	1,288,707,941	1,277,621,837	11,318	36,625,623	115,505,260
114	RBD								
115	RBD								
116	RBD	**NET GAS PLANT IN SERVICE**		8,274,607,096	4,567,291,030	3,164,420,625	1,033,497	33,476,602	508,385,342
117	RBD	Meter Plant Related	METERPLT	0	0	0	0	0	0

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
1	RBO	**ADDITIONS AND DEDUCTIONS TO RATE BASE**							
2	RBO								
3	RBO	**PLUS: ADDITIONS TO RATE BASE**							
4	RBO								
5	RBO	Working Capital							
6	RBO	Materials and Supplies Excl Fuel Stock	PSTDPLT	59,382,049	31,847,963	24,145,283	5,682	0	3,383,121
7	RBO	Fuel Stock & Fuel Stock Expense	not_used	0	0	0	0	0	0
8	RBO	Gas Stored Underground	not_used	0	0	0	0	0	0
9	RBO	Cash (lead/lag)	EXPENDITURES	586,016,094	287,097,269	211,270,154	133,607	36,059,477	51,455,588
10	RBO	Prepayments/Working Funds	EXPENDITURES	115,700	56,683	41,712	26	7,119	10,159
11	RBO	Total Working Capital		645,513,843	319,001,914	235,457,149	139,316	36,066,596	54,848,868
12	RBO	CEF-EC Adjustment	not_used	0	0	0	0	0	0
13	RBO	CEF-EV Adjustment	not_used	0	0	0	0	0	0
14	RBO	Net Plant Adds - Distribution	DISTPLT	1,573,578,886	858,028,130	624,251,712	153,088	0	91,145,957
15	RBO	Capital Stimulas Adjust	DISTPLT	0	0	0	0	0	0
16	RBO	Capital Lease Plant & Reserve Deduction	COMPLT	96,280	14,358	15,405	3	54,332	12,183
17	RBO	Net Plant Adds - General & Other	TOTPLTNET	153,424,698	84,685,018	58,673,514	19,163	620,711	9,426,293
18	RBO	TOTAL ADDITIONS TO RATE BASE		2,372,613,708	1,261,729,420	918,397,780	311,569	36,741,638	155,433,300
19	RBO								
20	RBO	**PLUS: DEDUCTIONS TO RATE BASE**							
21	RBO								
22	RBO	Customer Advances for Construction	MAIN_SERV	-24,909,672	-14,713,434	-10,196,237	0	0	0
23	RBO	IAP Adjustment	not_used	0	0	0	0	0	0
24	RBO	GSMP II EXT Adjustment	TOTPLT	-256,132,009	-136,441,189	-103,496,869	-24,344	-1,633,339	-14,536,269
25	RBO	Deferred Income Taxes and Credits							
26	RBO	ADIT Test/Post year	TOTPLT	0	0	0	0	0	0
27	RBO	Liberalized Depreciation	TOTPLT	35,377,684	18,845,647	14,295,283	3,362	225,601	2,007,791
28	RBO	Liberalized Depreciation - Production	BALANCE_04	-1,955,963	0	-1,955,963	0	0	0
29	RBO	Cost of Removal	TOTPLT	9,569,770	5,097,804	3,866,917	910	61,026	543,114
30	RBO	3% Investment Tax Credit	DISTPLT	0	0	0	0	0	0
31	RBO	Computer Software	TOTPLT	0	0	0	0	0	0
32	RBO	Capitalized Interest	TOTPLTNET	-160,793	-88,752	-61,491	-20	-651	-9,879
33	RBO	NJ Corporate Business Tax	STATEINCTAX	4,194,912	2,297,464	1,597,647	553	32,685	266,563
34	RBO	Defrd Tax & Consolidated Tax Adjustment	TOTPLT	-1,731,586,152	-922,413,698	-699,692,885	-164,575	-11,042,224	-98,272,770
35	RBO	Total Deferred Income Taxes and Credits		-1,684,560,542	-896,261,535	-681,950,492	-159,771	-10,723,562	-95,465,181
36	RBO								
37	RBO	TOTAL DEDUCTIONS TO RATE BASE		-1,965,602,222	-1,047,416,159	-795,643,598	-184,114	-12,356,901	-110,001,450
38	RBO								
39	RBO								
40	RBO	**TOTAL RATE BASE**		8,681,618,581	4,781,604,291	3,287,174,807	1,160,952	57,861,339	553,817,193

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
1	REV	**OPERATING REVENUES**							
2	REV								
3	REV	**SALES REVENUES**							
4	REV	BASE RATE SALES @ EQUALIZED ROR 7.40%		1,401,350,320	694,848,286	518,377,997	396,637	78,066,852	109,660,548
5	REV	Revenue Requirement - Other #1	not_used	0	0	0	0	0	0
6	REV	Revenue Requirement - Other #2	not_used	0	0	0	0	0	0
7	REV	TOTAL SALES OF GAS		1,401,350,320	694,848,286	518,377,997	396,637	78,066,852	109,660,548
8	REV								
9	REV	**OTHER OPERATING REVENUES**							
10	REV	G487-Forfeited Discounts	REVLATEP	1,447,215	477,356	796,541	0	36,991	136,326
11	REV	G488-Miscellaneous Service Revenues	COMPSVSWK_04	40,880,111	0	40,880,111	0	0	0
12	REV	G489-Revenues from Transmission from Others	not_used	0	0	0	0	0	0
13	REV	G493-Rent from Gas Property	TOTPLT	0	0	0	0	0	0
14	REV	G495-Other Gas Revenues							
15	REV	Miscellaneous Gas Revenues	TOTREV	19,473,704	9,341,132	7,602,950	5,328	1,049,261	1,475,031
16	REV	Peak Shaving Revenues	BALANCE_04	5,886,006	0	5,886,006	0	0	0
17	REV	Not Used	not_used	0	0	0	0	0	0
18	REV	Not Used	not_used	0	0	0	0	0	0
19	REV	TOTAL OTHER OPERATING REV		67,687,036	9,818,488	55,165,609	5,328	1,086,253	1,611,358
20	REV								
21	REV	**OTHER REVENUE SOURCES**							
22	REV	Not Used	not_used	0	0	0	0	0	0
23	REV	Not Used	not_used	0	0	0	0	0	0
24	REV	TOTAL OTHER REVENUE SOURCES		0	0	0	0	0	0
25	REV								
26	REV	LESS: E496 Provision for Rate Refunds	TOTREV	0	0	0	0	0	0
27	REV								
28	REV	**TOTAL OPERATING REVENUES**		1,469,037,356	704,666,774	573,543,606	401,966	79,153,105	111,271,906

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
1	E	**OPERATION & MAINTENANCE EXPENSE**							
2	E								
3	E	MANUFACTURED GAS PRODUCTION EXPENSE							
4	E	G710-G718 Production Expenses Incl Labor	BALANCE_04	281,982	0	281,982	0	0	0
5	E	G722-G736 Gas Raw Materials	BALANCE_04	29,792,635	0	29,792,635	0	0	0
6	E	G739-G745 Operation & Maintenance Exp	BALANCE_04	1,832,256	0	1,832,256	0	0	0
7	E	Not Used	not_used	0	0	0	0	0	0
8	E	TOTAL MANUFACTURED GAS PRODUCTION EXP		31,906,873	0	31,906,873	0	0	0
9	E								
10	E	OTHER GAS SUPPLY EXPENSE							
11	E	G801 Natural Gas Field Line Purchases	not_used	0	0	0	0	0	0
12	E	G804 Natural Gas City Gate Purchases	not_used	0	0	0	0	0	0
13	E	G805 Other Gas Purchases	not_used	0	0	0	0	0	0
14	E	G808.1,.2 GasInject & W/D from Storage	not_used	0	0	0	0	0	0
15	E	G812 Gas Used for Other Util Oper	not_used	0	0	0	0	0	0
16	E	G813 Other Gas Supply Expenses							
17	E	Supply Related	not_used	0	0	0	0	0	0
18	E	Distribution Related	TRANSPORT_04	72		72			
19	E	TOTAL OTHER GAS SUPPLY EXPENSE		72		72			
20	E	TOTAL GAS PRODUCTION AND SUPPLY		31,906,945	0	31,906,945	0	0	0
21	E								
22	E	OTHER STORAGE EXPENSE							
23	E	G840-G842 Operation	BALANCE_04	8,906	0	8,906	0	0	0
24	E	G843 Maintenance	BALANCE_04	2,705,699		2,705,699			
25	E	TOTAL OTHER STORAGE EXPENSE		2,714,605	0	2,714,605	0	0	0
26	E								
27	E	TRANSMISSION EXPENSES							
28	E	G850-G867 Transmission Exp	TRANPLT	2,593,507		2,593,507			
29	E	TOTAL TRANSMISSION EXPENSE		2,593,507	0	2,593,507	0	0	0
30	E								
31	E	DISTRIBUTION EXPENSES							
32	E	Operation							
33	E	G870 Operation Supervision & Engineering	TLABDO	0	0	0	0	0	0
34	E	G871 Load Dispatching	TRANSPORT_04	5,839,316	0	5,839,316	0	0	0
35	E	G872 Compressor Station Labor & Expenses	TRANSPORT_04	0	0	0	0	0	0
36	E	G874 Mains & Services	MAIN_SERV	20,733,577	12,246,734	8,486,843	0	0	0
37	E	G875 Meas & Reg Station - General	PLT_3789	2,497,019	0	2,497,019	0	0	0
38	E	G876 Meas & Reg Station - Industrial	PLT_3789	7,594	0	7,594	0	0	0
39	E	G877 Meas & Reg Station - City Gate	PLT_3789	514,539	0	514,539	0	0	0
40	E	G878 Meter & House Reg	PLT_3814	11,492,061	2,551,763	0	0	0	8,940,298
41	E	G879 Customer Installations							
42	E	- Customer Installations	CINST_04	17,355,157	0	17,355,157	0	0	0
43	E	- Competitive Services by ASB	COMPSVSWK_04	0	0	0	0	0	0
44	**E**	**OPERATION & MAINTENANCE EXPENSE CONTINUED**							

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
45	E								
46	E	G880.0,.1,.2 Other Expenses	DISTEXPO	14,050,188	3,625,445	8,234,483	0	0	2,190,260
47	E	G880.3 Operation of Street Lighting	DIRSLG_05	0	0	0	0	0	0
48	E	G881 Rents	TRANSPORT_04	-1,088,602	0	-1,088,602	0	0	0
49	E	Total Distribution Operation		71,400,849	18,423,942	41,846,349	0	0	11,130,558
50	E								
51	E	DISTRIBUTION EXPENSES CONTINUED							
52	E	Maintenance							
53	E	G885 Maint. Supervision & Engineering	TLABDM	0	0	0	0	0	0
54	E	G886 Structures & Improvements	PLT_3745	8,016,449	4,371,143	3,180,191	780	0	464,334
55	E	G887 Mains	PLT_376	8,706,285	0	8,706,285	0	0	0
56	E	G888 Compressor Station Equip	PLT_377	0	0	0	0	0	0
57	E	G889 Meas & Reg Station - General	PLT_3789	1,007,898	0	1,007,898	0	0	0
58	E	G891 Meas & Reg Station - City Gate	PLT_3789	3,155,564	0	3,155,564	0	0	0
59	E	G892 Services	SERVICES	3,610,466	3,610,466	0	0	0	0
60	E	G893 Meters & House Reg							
61	E	G893.1 - Meters	SMMETERS_07	6,767,990	0	0	0	0	6,767,990
62	E	G893.4 - House Regulators	PLT_3834	0	0	0	0	0	0
63	E	Not Used	not_used	0	0	0	0	0	0
64	E	G894 Maint of Other Equipment							
65	E	G894.0 - Maint of Other Equip	DISTEXPM	9,513	2,413	4,853	60	0	2,187
66	E	G894.1 - Maint of Gas Streetlights	DIRSLG_05	198,384	0	0	198,384	0	0
67	E	Total Distribution Maintenance		31,472,549	7,984,022	16,054,791	199,225		7,234,511
68	E	TOTAL DISTRIBUTION PLANT O&M EXPENSES		102,873,398	26,407,965	57,901,140	199,225	0	18,365,069
69	E								
70	E	TOTAL OPER & MAINT EXP (PROD,STOR, TRAN,& DIST)		140,088,455	26,407,965	95,116,197	199,225	0	18,365,069
71	E								
72	E	CUSTOMER ACCOUNTS EXPENSES							
73	E	G901 Supervision	CUSTACCTS	0	0	0	0	0	0
74	E	G902 Meter Reading							
75	E	- Meter Reading Related	MRCOST_07	12,907,838	0	0	0	0	12,907,838
76	E	- Meter O&M Related	METERPLT	38,249	0	0	0	0	38,249
77	E	G903 Customer Records and Collection							
78	E	- SONP/RNP	CUSTAVG_06	526,534	0	0	0	526,534	0
79	E	- Meter O&M Related	METERPLT	0	0	0	0	0	0
80	E	- Meter Reading Related	MRCOST_07	63,202	0	0	0	0	63,202
81	E	- Billing Related	BILLING_06	16,558,655	0	0	0	16,558,655	0
82	E	- Acct Maint Related	ACCTMAINT_06	26,073,286	0	0	0	26,073,286	0
83	E	- Utility Work Related	UTILWORK_04	2,712,621	0	2,712,621	0	0	0
84	E	- Remaining	BILLING_06	13,832,442	0	0	0	13,832,442	0
85	E	Not used	not_used	0	0	0	0	0	0
86	**E**	**OPERATION & MAINTENANCE EXPENSE CONTINUED**							
87	E								
88	E	G904 Uncollectible Accounts	EXP_904	26,046,715	12,918,882	9,637,228	0	1,451,542	2,039,062

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
89	E	G905 Misc Customer Accounts	CUSTACCTS	0	0	0	0	0	0
90	E	TOTAL CUSTOMER ACCTS EXPENSE		98,759,541	12,918,882	12,349,849	0	58,442,460	15,048,351
91	E								
92	E	CUSTOMER SERVICE & INFO EXPENSES							
93	E	G907 & 908 - Customer Service & Information							
94	E	- Billing	BILLING_06	37,379	0	0	0	37,379	0
95	E	- Acct Maint related	ACCTMAINT_06	746,413	0	0	0	746,413	0
96	E	- Utility work related	UTILWORK_04	1,684,915	0	1,684,915	0	0	0
97	E	- Remaining	ACCTMAINT_06	0	0	0	0	0	0
98	E	G909 Info & Instr Advertising	TRANSPORT_04	0	0	0	0	0	0
99	E	G910 - Misc Cust Service & Info							
100	E	- Utility work related	UTILWORK_04	911,953	0	911,953	0	0	0
101	E	- Remaining	BILLING_06	653,558				653,558	
102	E	TOTAL CUSTOMER SERVICE & INFO EXPENSES		4,034,218	0	2,596,868	0	1,437,350	0
103	E								
104	E	SALES EXPENSES							
105	E	G912 - Demonstrating and Selling	UTILWORK_04	88,423	0	88,423	0	0	0
106	E	G913 - Advertising	UTILWORK_04	0	0	0	0	0	0
107	E	G916 - Miscellaneous	UTILWORK_04	0	0	0	0	0	0
108	E								
109	E	SALES EXPENSES TOTAL (ACCT 916)		88,423	0	88,423	0	0	0
110	E								
111	E	TOTAL OPER & MAINT EXCL A&G		242,970,637	39,326,847	110,151,337	199,225	59,879,809	33,413,420
112	E								
113	E	ADMINISTRATIVE & GENERAL EXPENSE							
114	E	G920 A&G Salaries	TOMXFUEL904	6,954,680	1,040,372	2,525,185	8,254	2,207,416	1,173,453
115	E	G921 Office Supplies & Exp	TOMXFUEL904	652,569	97,620	236,942	775	207,125	110,107
116	E	G923 Outside Services Employed							
117	E	- Gas Peaking Plant Related	BALANCE_04	0	0	0	0	0	0
118	E	- Remaining	TOMXFUEL904	61,043,177	9,131,634	22,164,260	72,451	19,375,105	10,299,728
119	E	G924 Property Insurance	TOTPLT	296,480	157,935	119,801	28	1,891	16,826
120	E	G925 Injuries & Damages	LABOR	15,351,785	1,426,237	8,414,798	7,268	3,520,332	1,983,151
121	E	G926 Employee Pension & Benefits							
122	E	- Gas Peaking Plant Related	BALANCE_04	0	0	0	0	0	0
123	E	- Remaining	LABOR	-60,778,346	-5,646,530	-33,314,531	-28,773	-13,937,138	-7,851,375
124	E	G928 Regulatory Comm Exp	TRANSPORT_04	5,147,284	0	5,147,284	0	0	0
125	E	G929 Duplicate Charges - credit	INTRAREV	764,611	181,986	529,739	0	14,392	38,494
126	E	G930.1 General Advertising Expenses	TRANSPORT_04	1,968,152	0	1,968,152	0	0	0
127	E	G930.2 Misc General Expenses	TRANSPORT_04	3,638,524	0	3,638,524	0	0	0
128	E	G931 Rents	AGEXP	3,713,155	677,084	1,211,280	6,359	1,206,932	611,501
129	E	G932 Maint of General Plant	COMGENPLT	0	0	0	0	0	0
130	E	G935 Other A&G Maint	COMGENPLT	0	0	0	0	0	0
131	E	Not Used	not_used	0	0	0	0	0	0
132	E	TOTAL A&G EXPENSE		38,752,071	7,066,337	12,641,434	66,361	12,596,054	6,381,885

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				(1)	(2)	(3)	(4)	(5)	(6)
133	E								
134	E	**TOTAL OPERATION & MAINTENANCE EXPENSES**		281,722,708	46,393,184	122,792,771	265,586	72,475,863	39,795,304
135	E	G890 Meas & Reg Station - Industrial	PLT_3789	0	0	0	0	0	0

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12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
1	DE	**DEPRECIATION AND AMORTIZATION EXPENSES**							
2	DE								
3	DE	G403 DEPRECIATION EXPENSE							
4	DE	Production Plant	BALANCE_04	1,670	0	1,670	0	0	0
5	DE	Storage Plant	BALANCE_04	114,612	0	114,612	0	0	0
6	DE	Transmission Plant	TRANPLT	1,172,631	0	1,172,631	0	0	0
7	DE	Distribution Plant	DISTPLT	182,874,076	99,716,069	72,547,653	17,791	0	10,592,562
8	DE	General and Common Plant	COMGENPLT	19,528,227	8,468,029	6,500,109	1,511	3,717,640	840,939
9	DE	Not Used	not_used	0	0	0	0	0	0
10	DE	TOTAL DEPRECIATION EXPENSE		203,691,216	108,184,098	80,336,675	19,302	3,717,640	11,433,501
11	DE								
12	DE	G404.3 AMORT OF OTHER LIMITED TERM PLANT							
13	DE	Customer Service related	CUSTSVSX	1,194,362	0	82,628	0	909,279	202,455
14	DE	AWMS	DISTPLT	0	0	0	0	0	0
15	DE	Distribution	CHOICE_04	1,127,553	0	1,127,553	0	0	0
16	DE	Metering	METERPLT	29,719	0	0	0	0	29,719
17	DE	All Other	PSTDPLT	0	0	0	0	0	0
18	DE	TOTAL AMORT OF OTHER LIMITED TERM PLT		2,351,634	0	1,210,181	0	909,279	232,173
19	DE								
20	DE	G407 AMORT OF PROPERTY LOSSES							
21	DE	Remediation Adjustment Clause	not_used	0	0	0	0	0	0
22	DE	Excess Cost of Removal	TOTPLT						
23	DE	TOTAL AMORT OF PROPERTY LOSSES		0	0	0	0	0	0
24	DE								
25	DE	TOTAL AMORTIZATION EXPENSE		2,351,634	0	1,210,181	0	909,279	232,173
26	DE								
27	DE	**TOTAL DEPRECIATION AND AMORTIZATION EXPENSES**		206,042,850	108,184,098	81,546,856	19,302	4,626,919	11,665,674

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
1	EO	**OTHER OPERATING EXPENSES**							
2	EO								
3	EO	**G408 TAXES OTHER THAN INCOME TAXES**							
4	EO	Payroll	LABOR	-2,034	-189	-1,115	-1	-466	-263
5	EO	TEFA	TEFA_04	0	0	0	0	0	0
6	EO	Real Estate Taxes	TOTPLT	-13,552,354	-7,219,321	-5,476,185	-1,288	-86,423	-769,137
7	EO	State Unemploy Insur (SUI) Tax	LABOR	0	0	0	0	0	0
8	EO	Fed Insur Contr & UnempTax	LABOR	-60,481	-5,619	-33,152	-29	-13,869	-7,813
9	EO	Fed Insur Contr & UnempTax - Gas Peaking Plts	BALANCE_04	0	0	0	0	0	0
10	EO	FICA	LABOR	-10,865,853	-1,009,477	-5,955,917	-5,144	-2,491,659	-1,403,656
11	EO	Miscellaneous State and Municipal Tax	TOTPLT	0	0	0	0	0	0
12	EO	Federal Environmental Tax	PSTDPLT	0.0	0.0	0.0	0.0	0.0	0.0
13	EO	**TOTAL TAXES OTHER THAN INCOME**		-24,480,722	-8,234,607	-11,466,368	-6,462	-2,592,417	-2,180,869
14	EO								
15	EO	**PROFORMA EXPENSE ADJUSTMENTS**							
16	EO	Amortization of CEF-EC Program Regulatory Assets		0	0	0	0	0	0
17	EO	Amortization of CEF-EV Program Regulatory Assets		0	0	0	0	0	0
18	EO	BGS Administrative Expense Adjustment		0	0	0	0	0	0
19	EO	CIP Revenue Accrual Adjustment	not_used	0	0	0	0	0	0
20	EO	Deferred Compensation & Severance Expense	LABOR	-361,345	-33,570	-198,065	-171	-82,860	-46,679
21	EO	Gas Bad Debt Adjustment	not_used	0	0	0	0	0	0
22	EO	TAC Revenue Accrual Adjustment	not_used	0	0	0	0	0	0
23	EO	Tax Bad Debt Adjustment	SALESREV	2,990,017	1,482,576	1,106,047	846	166,569	233,979
24	EO	TSG-NF Gas Margin Reset	not_used	0	0	0	0	0	0
25	EO	Wage Increases (Rate Year)	LABOR	7,223,753	671,113	3,959,567	3,420	1,656,485	933,168
26	EO	Payroll Taxes (Rate Year)	LABOR	508,958	47,284	278,976	241	116,710	65,747
27	EO	Interest Syncronization	TOTPLTNET	-1,864,683	-1,029,239	-713,102	-233	-7,544	-114,565
28	EO	- add'l tax effects on rev req	TOTPLTNET	-729,117	-402,447	-278,833	-91	-2,950	-44,796
29	EO	Pension & Fringe Benefit (Rate Year)	LABOR	7,091,402	658,817	3,887,022	3,357	1,626,136	916,071
30	EO	Adj #5 - Gas COLI Interest Expense	LABOR	0	0	0	0	0	0
31	EO	- add'l tax effects on rev req	LABOR	0	0	0	0	0	0
32	EO	Postage	CUSTACCTS	0	0	0	0	0	0
33	EO	BPU / Rate Counsel Assessment	TRANSPORT_04	738,301	0	738,301	0	0	0
34	EO	Adj #6 - Weather Normalization	not_used	0	0	0	0	0	0
35	EO	Gains / Losses Normalization	TOTPLT	-207,450	-110,508	-83,826	-20	-1,323	-11,773
36	EO	- add'l tax effects on rev req	TOTPLT	-81,116	-43,210	-32,777	-8	-517	-4,604
37	EO	Test Year Corrections	TOTPLT	0	0	0	0	0	0
38	EO	Customer Information System Amort	CUSTSVSX	0	0	0	0	0	0
39	EO	Real Estate Tax Increases (Rate Year)	TOTPLT	158,827	84,607	64,178	15	1,013	9,014
40	EO	Capital Stimulus (Depreciation)	DISTPLT	0	0	0	0	0	0
41	EO	Insurance Premium Increases (Rate Year)	TOTPLT	237,517	126,525	95,975	23	1,515	13,480
42	EO	Adj #15 - Excess COR Refund Recovery	TOTPLT	0	0	0	0	0	0
43	EO	Test Year Amortization Adjustments	TOTPLT	-5,932,749	-3,160,368	-2,397,283	-564	-37,833	-336,702
44	EO	Adj #11 - TSGNF Margin Sharing	not_used	0	0	0	0	0	0

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				(1)	(2)	(3)	(4)	(5)	(6)
45	EO	Adj #12 - Depreciation Rate Change/Annualization	DEPREXP	0	0	0	0	0	0
46	EO	Capital Stimulus Revenue	DISTPLT	0	0	0	0	0	0
47	EO	ASB Margin	TOTPLT	15,265,290	8,131,800	6,168,342	1,451	97,346	866,352
48	EO	Adj #13 - Storm Cost Amortization	TOTPLTNET	0	0	0	0	0	0
49	EO	Other Regulatory Asset / Liability Amortizations	TOTPLT	0	0	0	0	0	0
50	EO	Rate Case Expenses	TOTPLT	141,376	75,311	57,127	13	902	8,024
51	EO	Tax - Repair Allowance	DISTPLT	0	0	0	0	0	0
52	EO	Tax - Flow Through Items	DISTPLT	0	0	0	0	0	0
53	EO	Adj #14 Post Rate Case Storm Cost Normalization	TOTPLT	0	0	0	0	0	0
54	EO	Recovery of Credit Card Fees	CUSTSVSX	0	0	0	0	0	0
55	EO	Adj #20 - Vacation Accrual	LABOR	0	0	0	0	0	0
56	EO	Energy Strong II / IAP Revenue Adjustment	TOTPLT						
57	EO	Depreciation Rate Change	DEPREXP	74,624,206	39,634,269	29,432,102	7,071	1,361,993	4,188,771
58	EO	TOTAL PROFORMA EXPENSE ADJUSTMENTS		100,619,236	46,208,773	42,531,052	15,737	5,082,769	6,780,904
59	EO								
60	EO	**TOTAL OTHER OPERATING EXPENSES**		76,138,514	37,974,166	31,064,684	9,276	2,490,352	4,600,036
61	EO	COLI Interest Expense Recovery	LABOR	816,048	75,814	447,302	386	187,129	105,417

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
1	TI	**DEVELOPMENT OF INCOME TAXES**							
2	TI								
3	TI	TOTAL OPERATING REVENUES	CALCULATED	1,469,037,356	704,666,774	573,543,606	401,966	79,153,105	111,271,906
4	TI	LESS:							
5	TI	OPERATION & MAINTAINENCE EXPENSE	CALCULATED	281,722,708	46,393,184	122,792,771	265,586	72,475,863	39,795,304
6	TI	DEPRECIATION & AMORTIZATION EXPENSE	CALCULATED	206,042,850	108,184,098	81,546,856	19,302	4,626,919	11,665,674
7	TI	OTHER OPERATING EXPENSES	CALCULATED	76,138,514	37,974,166	31,064,684	9,276	2,490,352	4,600,036
8	TI	NET OPERATING INCOME BEFORE TAXES		905,133,284	512,115,325	338,139,296	107,802	-440,030	55,210,891
9	TI	LESS:							
10	TI	G427 - G431 INTEREST CHARGES	TOTPLTNET	100,820,068	55,649,119	38,556,163	12,592	407,888	6,194,306
11	TI	**TOTAL OPERATING INCOME BEFORE TAXES**		804,313,216	456,466,206	299,583,132	95,210	-847,918	49,016,586
12	TI								
13	TI	**TAX ADJUSTMENTS - FEDERAL**							
14	TI								
15	TI	Assessment by Board of Public Utilities of the State of NJ	TOTPLTNET	56,782	31,342	21,715	7	230	3,489
16	TI	Injuries and Damages ;		0	0	0	0	0	0
17	TI	Bankrupticies & Acc. Prov. For Rents Receivable	TOTPLTNET	52,256	28,843	19,984	7	211	3,211
18	TI	Capitalized interest-Section 263A	TOTPLT	416,892	222,078	168,456	40	2,658	23,660
19	TI	Casualty Loss Deferred O&M & Ins Proceeds	TOTPLTNET	-1,095,802	-604,844	-419,062	-137	-4,433	-67,325
20	TI	Deduction for New Network Meter Equipment		0	0	0	0	0	0
21	TI	Defer Dividend Equivalents/Restricted Stock-Temp.		0	0	0	0	0	0
22	TI	Deferred Depreciation on CIP ll	TOTPLT	8,262	4,401	3,338	1	53	469
23	TI	Deferred Return on CIP ll	TOTPLT	18,055	9,618	7,296	2	115	1,025
24	TI	Diesel Fuel Credit		0	0	0	0	0	0
25	TI	Environmental Accrual		0	0	0	0	0	0
26	TI	FIN48 Reg Asset Reversal		0	0	0	0	0	0
27	TI	FIN48 Services Allocation		0	0	0	0	0	0
28	TI	GainState LILOAudit Refunds not yet received		0	0	0	0	0	0
29	TI	LCAPP		0	0	0	0	0	0
30	TI	Legal Reserves (c & nc)	TOTPLTNET	-418,012	-230,728	-159,858	-52	-1,691	-25,682
31	TI	Material Supplies & Reserves	TOTPLT	78,535	41,836	31,734	7	501	4,457
32	TI	Misc Adj - Permanent		0	0	0	0	0	0
33	TI	Miscellaneous		0	0	0	0	0	0
34	TI	Partnership income/loss per K-1		0	0	0	0	0	0
35	TI	Performance Incentive Plan Adjustment	TOTPLTNET	-455,695	-251,528	-174,269	-57	-1,844	-27,998
36	TI	RAC-Environmental Cleanup Costs		0	0	0	0	0	0
37	TI	Repair Allow Deferral Carrying Charges		0	0	0	0	0	0
38	TI	SBC-Societal Benefits Clause		0	0	0	0	0	0
39	TI	Stock Based Compensation	TOTPLTNET	-325,229	-179,515	-124,376	-41	-1,316	-19,982
40	TI	TAX ADJUSTMENTS - FEDERAL CONTINUED		0	0	0	0	0	0
41	TI	Uncollectible Accounts		0	0	0	0	0	0
42	TI	Utility Commodity Costs		0	0	0	0	0	0
43	TI	Additional Expenses on Rental Property	TOTPLT	0	0	0	0	0	0
44	TI	Additional Rental Income - NJ Properties	TOTPLT	0	0	0	0	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
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12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
45	TI	Amort of Def Gain on Sale of Services Assets	not_used	0	0	0	0	0	0
46	TI	Amort of Deferred Gain on Sale of Generation Assets	not_used	0	0	0	0	0	0
47	TI	Amortization of Limited-Term Utility Plant	TOTPLT	-14	-7	-6	0	0	-1
48	TI	Amortization of Reacquisition of Pref Stock	TOTPLT	7,787	4,148	3,146	1	50	442
49	TI	CECL Reserve	not_used	0	0	0	0	0	0
50	TI	CEF- EC AMI	TOTPLT	0	0	0	0	0	0
51	TI	CEF- EV Deferral	TOTPLT	0	0	0	0	0	0
52	TI	Clause - Demographic Studies	not_used	0	0	0	0	0	0
53	TI	Clause - Navigant Studies	not_used	0	0	0	0	0	0
54	TI	Clause - RAC (Environmental Clean Up)	not_used	0	0	0	0	0	0
55	TI	Clause - Societal Benefits Clause (AAP)	not_used	0	0	0	0	0	0
56	TI	Company Owned Life Insurance - Book	LABOR	-352,245	-32,725	-193,077	-167	-80,774	-45,503
57	TI	Company Owned Life Insurance - Tax	LABOR	-14,570	-1,354	-7,986	-7	-3,341	-1,882
58	TI	COVID Deferrals	not_used	0	0	0	0	0	0
59	TI	Current SHARE -- FT	DEPREXP	-21,771,486	-11,563,231	-8,586,766	-2,063	-397,359	-1,222,067
60	TI	Customer Advances	TOTPLTNET	294,687	162,657	112,696	37	1,192	18,105
61	TI	Customer Connection Fees (Contributions in Aid of Constructi	TOTPLTNET	0	0	0	0	0	0
62	TI	Deduction for Retention Payments (c)	LABOR	-4,379	-407	-2,400	-2	-1,004	-566
63	TI	Deferred Employer ER FICA	LABOR	-5,798,258	-538,679	-3,178,208	-2,745	-1,329,604	-749,022
64	TI	Diesel Fuel Tax Credit	TOTPLT	928	494	375	0	6	53
65	TI	Entertainment (100%)	LABOR	36,298	3,372	19,896	17	8,323	4,689
66	TI	FAS 5 (ASC40) Reserve - Sales Tax	not_used	0	0	0	0	0	0
67	TI	Fed Amort of Deferred Gain on Sale of Generation Assets	not_used	0	0	0	0	0	0
68	TI	Injuries & Damages - FT	TOTPLT	1,044,758	556,541	422,162	99	6,662	59,293
69	TI	Line Pack Adjustment	not_used	0	0	0	0	0	0
70	TI	Plant Related	DEPREXP	-61,904,159	-32,878,422	-24,415,262	-5,866	-1,129,835	-3,474,776
71	TI	Previously Deducted Amort - Reacquired Bonds	not_used	0	0	0	0	0	0
72	TI	Qualified Transportation Fringe	LABOR	139,386	12,949	76,402	66	31,963	18,006
73	TI	R & D Credits CF	not_used	0	0	0	0	0	0
74	TI	R&D Credit - Fed	TOTPLT	-75,718	-40,335	-30,596	-7	-483	-4,297
75	TI	R&D Expenditure	TOTPLT	-16,866	-8,984	-6,815	-2	-108	-957
76	TI	Rabbi Trust	not_used	0	0	0	0	0	0
77	TI	RE - Lease Liability	TOTPLT	-519,350	-276,657	-209,857	-49	-3,312	-29,475
78	TI	RE - ROU Lease Asset	TOTPLT	594,984	316,947	240,419	57	3,794	33,767
79	TI	Reversal of Book Income from Partnerships	TOTPLT	0	0	0	0	0	0
80	TI	Severance Pay (nc)	LABOR	121,791	11,315	66,757	58	27,928	15,733
81	TI	State NOL CF (c)	DEPREXP	7,732,062	4,106,638	3,049,558	733	141,121	434,013
82	TI	Tax Net Bad Debt Writeoffs - FT	TOTPLT	-81,087	-43,195	-32,765	-8	-517	-4,602
83	TI	Unicap book/tax inventory FS	not_used	0	0	0	0	0	0
84	TI	Unrealized G/L on Equity Securities	TOTPLT	142,148	75,722	57,439	14	906	8,067
85	TI	Credits & Adjustments	TOTPLT	0	0	0	0	0	0
86	TI	Repair Allowance	TOTPLT	0	0	0	0	0	0
87	TI	Uncollectible Accounts - Writeoff	REVREQ	0	0	0	0	0	0
88	TI	Injuries and Damages	TOTPLT	0	0	0	0	0	0

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
89	TI	Meals & entertainment	LABOR	-459,207	-42,662	-251,706	-217	-105,301	-59,321
90	TI	Company owned life insurance	LABOR	0	0	0	0	0	0
91	TI	ESOP/401(k) Cash Dividends	TOTPLTNET	-844,650	-466,217	-323,016	-105	-3,417	-51,895
92	TI	Medicare Subsidy		0	0	0	0	0	0
93	TI	Allowable Depreciation	DEPREXP	0	0	0	0	0	0
94	TI	Previously Ded Amort-Reacq Bonds	not_used	0	0	0	0	0	0
95	TI	Amortization of Computer Software	INTANGPLT	0	0	0	0	0	0
96	TI	Amort Def Gain - Sale of Gen Asset	not_used	0	0	0	0	0	0
97	TI	Gain on Sale of Services Corp Asset	not_used	0	0	0	0	0	0
98	TI	AFUDC / IDC	TOTPLT	-345,079	-183,823	-139,438	-33	-2,201	-19,584
99	TI	Cost of removal	TOTPLT	0	0	0	0	0	0
100	TI	*Utility Commodity Costs-Non-Taxable Income	not_used	0	0	0	0	0	0
101	TI	*RAC-Environmental Cleanup Costs - Debit	not_used	0	0	0	0	0	0
102	TI	*SBC-Societal Benefits Clause - Unallow Deductions	not_used	0	0	0	0	0	0
103	TI	Deferred Comp - officers	LABOR	-15,155	-1,408	-8,307	-7	-3,475	-1,958
104	TI	Deduction of Securitizartion	not_used	0	0	0	0	0	0
105	TI	Accrued vacation pay adjustment	LABOR	-257,985	-23,968	-141,410	-122	-59,159	-33,327
106	TI	3rd Party Claims	TOTPLT	-975	-519	-394	0	-6	-55
107	TI	Gain/loss bond reacq	not_used	0	0	0	0	0	0
108	TI	Amortization of Call Option Sale	LABOR	0	0	0	0	0	0
109	TI	Contribution in Aid of Construct	TOTPLTNET	0	0	0	0	0	0
110	TI	Pension Accrual Adjustment	LABOR	-7,780,352	-722,823	-4,264,657	-3,683	-1,784,120	-1,005,069
111	TI	Unallowable OPEB Amortization	LABOR	47,224,310	4,387,311	25,885,135	22,356	10,829,050	6,100,458
112	TI	NJ BPU assessment	TOTPLTNET	0	0	0	0	0	0
113	TI	Unicap book/tax inventory	TOTPLTNET	0	0	0	0	0	0
114	TI	W-2 Earnings Exceeding $1,000,000	LABOR	1,506,831	139,990	825,942	713	345,533	194,653
115	TI	Diesel Fuel Tax Credit	not_used	0	0	0	0	0	0
116	TI	Deferred Depreciation & Return on CIP II	TOTPLTNET	0	0	0	0	0	0
117	TI	Capitalized Interest - Section 263A	TOTPLT	0	0	0	0	0	0
118	TI	Clause - Deferred Fuel	not_used	0	0	0	0	0	0
119	TI	Restricted Stock - Permanent	LABOR	-67,594	-6,280	-37,051	-32	-15,500	-8,732
120	TI	Materials & Supplies Reserve	TOTPLT	0	0	0	0	0	0
121	TI	Amortization of Reacquisition of Pref Stock	TOTPLTNET	0	0	0	0	0	0
122	TI	Lobbying Expenses	LABOR	0	0	0	0	0	0
123	TI	Penalties	not_used	0	0	0	0	0	0
124	TI	Dividends Received Deduction	TOTPLTNET	0	0	0	0	0	0
125	TI	Real Estate Taxes	TOTPLTNET	-1,021,308	-563,726	-390,574	-128	-4,132	-62,748
126	TI	Line Pack Adjustment	TOTPLTNET	0	0	0	0	0	0
127	TI	Legal Reserves	TOTPLTNET	0	0	0	0	0	0
128	TI	Casualty Insurance Proceeds	TOTPLT	0	0	0	0	0	0
129	TI	Miscellaneous (R&D Exp., Limit Term Util Plant, ARO Fin 47, F	TOTPLT	0	0	0	0	0	0
130	TI	**TOTAL TAX ADJUSTMENTS - FEDERAL**		-44,148,425	-38,545,834	-12,085,406	8,683	6,467,366	6,766
131	TI								
132	TI								

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
133	TI	**DEVELOPMENT OF INCOME TAXES CONTINUED**							
134	TI								
135	TI	**TAX ADJUSTMENTS - STATE**							
136	TI	Reverse TEFA	TEFA_04	0	0	0	0	0	0
137	TI	Federal Depreciation Reversal	TOTPLT	64,677,176	34,453,448	26,134,512	6,147	412,443	3,670,626
138	TI	State Tax Depreciation	DEPREXP	37,759,415	20,054,710	14,892,472	3,578	689,160	2,119,494
139	TI	Amortization of Service's Asset Sale	TOTPLTNET	0	0	0	0	0	0
140	TI	NOL Utilization	TOTPLTNET	0	0	0	0	0	0
141	TI	**TOTAL TAX ADJUSTMENTS - STATE**		102,436,591	54,508,158	41,026,985	9,725	1,101,603	5,790,120
142	TI								
143	TI	**TAXABLE NET INCOME - STATE**		862,601,382	472,428,530	328,524,711	113,618	6,721,051	54,813,472
144	TI	State Tax Liability		77,634,124	42,518,568	29,567,224	10,226	604,895	4,933,212
145	TI	Prior Year Adjustment & State Credit	TOTPLTNET	0	0	0	0	0	0
146	TI	**TOTAL STATE INCOME TAX LIABILITY**		77,634,124	42,518,568	29,567,224	10,226	604,895	4,933,212
147	TI								
148	TI	**TAXABLE NET INCOME - FEDERAL**		682,530,667	375,401,805	257,930,503	93,667	5,014,553	44,090,139
149	TI	Federal Tax Liability		143,331,440	78,834,379	54,165,406	19,670	1,053,056	9,258,929
150	TI	Prior Yr & Oth Adjustments	TOTPLTNET	0	0	0	0	0	0
151	TI	Not Used	not_used	0	0	0	0	0	0
152	TI	**TOTAL FEDERAL INCOME TAX LIABILITY**		143,331,440	78,834,379	54,165,406	19,670	1,053,056	9,258,929
153	TI								
154	TI	**TOTAL INCOME TAX EXPENSE**		220,965,564	121,352,947	83,732,630	29,896	1,657,951	14,192,142
155	TI								
156	TI	**TAX RATES**							
157	TI	FEDERAL TAX RATE - CURRENT		21.000%					
158	TI	NEW JERSEY CORP BUSINESS TAX RATE		9.000%					
159	TI	CUSTOMER ACCT UNCOLLECTIBLE RATE		0.000					
160	TI	EFFECTIVE TAX RATE		28.110%					
161	TI	COMPOSITE RATE		28.110%					
162	TI	1 - EFFECTIVE TAX RATE		71.89000%					
163	TI								
164	TI	**DEVELOPMENT OF OPERATING INCOME ADJUSTED**							
165	TI								
166	TI	**G410 + G411- PROVISION FOR DEFERRED INCOME TAX**							
167	TI	Additional Rental Income - NJ Properties	TOTPLT	0	0	0	0	0	0
168	TI	Amort of Def Gain on Sale of Services Assets	not_used	0	0	0	0	0	0
169	TI	Amort of Deferred Gain on Sale of Generation Assets	not_used	0	0	0	0	0	0
170	TI	Amortization of Limited-Term Utility Plant	TOTPLT	14	7	6	0	0	1
171	TI	Bankruptcies and Accum Provision for Rent Receivable	TOTPLT	-31,746	-16,911	-12,828	-3	-202	-1,802
172	TI	Casualty Loss Deferred O&M	TOTPLTNET	1,095,802	604,844	419,062	137	4,433	67,325
173	TI	CECL Reserve	not_used	0	0	0	0	0	0
174	TI	CEF- EC AMI	TOTPLT	0	0	0	0	0	0
175	TI	CEF- EV Deferral	TOTPLT	0	0	0	0	0	0
176	TI	Clause - Demographic Studies	not_used	0	0	0	0	0	0

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				(1)	(2)	(3)	(4)	(5)	(6)
177	TI	Clause - Navigant Studies	not_used	0	0	0	0	0	0
178	TI	Clause - RAC (Environmental Clean Up)	not_used	0	0	0	0	0	0
179	TI	Clause - Societal Benefits Clause (AAP)	not_used	0	0	0	0	0	0
180	TI	COVID Deferrals	not_used	0	0	0	0	0	0
181	TI	Current SHARE -- FT	DEPREXP	5,506,769	2,924,745	2,171,893	522	100,506	309,103
182	TI	Customer Advances	TOTPLTNET	-294,687	-162,657	-112,696	-37	-1,192	-18,105
183	TI	Deduction for Retention Payments (c)	LABOR	4,379	407	2,400	2	1,004	566
184	TI	Deferred Employer ER FICA	LABOR	5,798,258	538,679	3,178,208	2,745	1,329,604	749,022
185	TI	FAS 5 (ASC40) Reserve - Sales Tax	not_used	0	0	0	0	0	0
186	TI	Fed Amort of Deferred Gain on Sale of Generation Assets	not_used	0	0	0	0	0	0
187	TI	Injuries & Damages - FT	TOTPLT	-264,256	-140,769	-106,780	-25	-1,685	-14,997
188	TI	Line Pack Adjustment	not_used	0	0	0	0	0	0
189	TI	Medicare Subsidy	not_used	0	0	0	0	0	0
190	TI	Partnership Income/Loss (nc)	TOTPLT	0	0	0	0	0	0
191	TI	Plant Related	DEPREXP	62,706,788	33,304,712	24,731,822	5,942	1,144,484	3,519,828
192	TI	Previously Deducted Amort - Reacquired Bonds	not_used	0	0	0	0	0	0
193	TI	R & D Credits CF	TOTPLT	-67,859	-36,148	-27,420	-6	-433	-3,851
194	TI	RE - Lease Liability	TOTPLT	519,350	276,657	209,857	49	3,312	29,475
195	TI	RE - ROU Lease Asset	TOTPLT	-594,984	-316,947	-240,419	-57	-3,794	-33,767
196	TI	Real Estate Taxes (nc)	TOTPLT	1,021,308	544,049	412,686	97	6,513	57,962
197	TI	Reversal of Book Income from Partnerships	TOTPLT	0	0	0	0	0	0
198	TI	Severance Pay (nc)	LABOR	-121,791	-11,315	-66,757	-58	-27,928	-15,733
199	TI	State NOL CF (c)	DEPREXP	-7,732,062	-4,106,638	-3,049,558	-733	-141,121	-434,013
200	TI	Unrealized G/L on Equity Securities	TOTPLT	-142,148	-75,722	-57,439	-14	-906	-8,067
201	TI	Previously Ded Amort-Reacq Bonds	not_used	0	0	0	0	0	0
202	TI	Clause - Deferred Fuel	not_used	0	0	0	0	0	0
203	TI	Gain on Sale of Services Corp Asset	not_used	0	0	0	0	0	0
204	TI	AFUDC / IDC	TOTPLT	345,079	183,823	139,438	33	2,201	19,584
205	TI	Capitalized interest-Section 263A	TOTPLT	-416,892	-222,078	-168,456	-40	-2,658	-23,660
206	TI	Cost of removal	TOTPLT	0	0	0	0	0	0
207	TI	Deferred Comp - officers	LABOR	15,155	1,408	8,307	7	3,475	1,958
208	TI	Deduction of Securitizartion	not_used	0	0	0	0	0	0
209	TI	Accrued vacation pay adjustment	LABOR	257,985	23,968	141,410	122	59,159	33,327
210	TI	Gain/loss bond reacq	not_used	0	0	0	0	0	0
211	TI	Amortization of Call Option Sale	LABOR	0	0	0	0	0	0
212	TI	Defer Dividend Equivalents/Restricted Stock-Temp.	LABOR	0	0	0	0	0	0
213	TI	Contribution in Aid of Construct	TOTPLTNET	0	0	0	0	0	0
214	TI	Pension Accrual Adjustment	LABOR	7,780,352	722,823	4,264,657	3,683	1,784,120	1,005,069
215	TI	Unallowable OPEB Amortization	LABOR	-47,224,310	-4,387,311	-25,885,135	-22,356	-10,829,050	-6,100,458
216	TI	Fin Def-Energy Competition Act Ct	TOTPLT	0	0	0	0	0	0
217	TI	Rabbi Trust Unrealized Losses		0	0	0	0	0	0
218	TI	Additional Real Estate Taxes	TOTPLT	0	0	0	0	0	0
219	TI	PIP Adjustment	LABOR	455,695	42,336	249,781	216	104,496	58,867
220	TI	Deferred NJ Corp Bus Tax(Net of FIT)	TOTPLTNET	0	0	0	0	0	0

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
221	TI	Misc	TOTPLT	0	0	0	0	0	0
222	TI	Construction Period Interest	TOTPLTNET	0	0	0	0	0	0
223	TI	Deferred Return on CIP ll	TOTPLT	-18,055	-9,618	-7,296	-2	-115	-1,025
224	TI	Deferred Depreciation on CIP ll	TOTPLT	-8,262	-4,401	-3,338	-1	-53	-469
225	TI	Investment Tax Credit	TOTPLT	-493,265	-262,762	-199,317	-47	-3,146	-27,994
226	TI	Assessment by Board of Public Utilities of the State of NJ	TOTPLTNET	-56,782	-31,342	-21,715	-7	-230	-3,489
227	TI	3rd Party Claims	TOTPLT	975	519	394	0	6	55
228	TI	Customer Connections Fees		0	0	0	0	0	0
229	TI	Legal Reserves (nc)	TOTPLTNET	418,012	230,728	159,858	52	1,691	25,682
230	TI	Material Supplies & Reserves	TOTPLTNET	-78,535	-43,349	-30,034	-10	-318	-4,825
231	TI	Stock Based Compensation	TOTPLTNET	325,229	179,515	124,376	41	1,316	19,982
232	TI	**TOTAL DEFERRED INCOME TAX**		28,705,516	29,751,254	6,224,968	-9,746	-6,466,512	-794,448
233	TI								
234	TI	**This Section is not used at this time**							
235	TI	**PROFORMA OPERATING INCOME ADJUSTMENTS**							
236	TI	Not Used	not_used	0	0	0	0	0	0
237	TI	Not Used	not_used	0	0	0	0	0	0
238	TI	Not Used	not_used	0	0	0	0	0	0
239	TI	**OPERATING INCOME ADJUSTED**		655,462,203	361,011,124	248,181,698	87,652	4,368,531	41,813,198

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
1	LR	**DEVELOPMENT OF LABOR ALLOCATION FACTOR**							
2	LR	Labor portion included in O&M Expense							
3	LR								
4	LR	**G700-G742 MANUFACTURED GAS LABOR EXP**	MFGO_M	778,312	0	778,312	0	0	0
5	LR	**G813 GAS SUPPLY LABOR EXPENSE**	EXP_813	0	0	0	0	0	0
6	LR	**G840-G843 STORAGE PLANT LABOR EXP**	STOREXP	407,976	0	407,976	0	0	0
7	LR	**G850-G867 TRANSMISSION LABOR EXP**	TRANEXP	483,267	0	483,267	0	0	0
8	LR								
9	LR	**DISTRIBUTION LABOR EXPENSE**							
10	LR	Operation							
11	LR	G870 Operation Supervision & Engineering	TLABDO	0	0	0	0	0	0
12	LR	G871 Load Dispatching	EXP_871	4,522,112	0	4,522,112	0	0	0
13	LR	G872 Compressor Station Labor & Expenses	EXP_872	0	0	0	0	0	0
14	LR	G874 Mains & Services	EXP_874	14,351,672	8,477,124	5,874,548	0	0	0
15	LR	G875-877 Meas & Reg Station	EXP_8757	1,368,583	0	1,368,583	0	0	0
16	LR	G878 Meter & House Reg	EXP_878	8,562,092	1,901,176	0	0	0	6,660,916
17	LR	G879 Customer Installations - Total	EXP_879	63,057,319	0	63,057,319	0	0	0
18	LR	G880.1 Miscellaneous Dist Exp	EXP_8801	5,219,383	1,346,785	3,058,957	0	0	813,641
19	LR	G880.3 Operation of Street Lighting	EXP_8803	0	0	0	0	0	0
20	LR	G881 Rents	EXP_881	-60	0	-60	0	0	0
21	LR	Total Operation		97,081,101	11,725,086	77,881,458	0	0	7,474,557
22	LR								
23	LR	Maintenance							
24	LR	G885 Maint. Supervision & Engineering	TLABDM	0	0	0	0	0	0
25	LR	G886 Structures & Improvements	EXP_886	1,015,469	553,706	402,845	99	0	58,819
26	LR	G887 Mains	EXP_887	4,445,965	0	4,445,965	0	0	0
27	LR	G888 Compressor Station Equip	EXP_888	0	0	0	0	0	0
28	LR	G889-891 Meas & Reg Station	EXP_8891	2,185,363	0	2,185,363	0	0	0
29	LR	G892 Services	EXP_892	2,126,460	2,126,460	0	0	0	0
30	LR	G893 Meters & House Reg	EXP_893	5,044,535	0	0	0	0	5,044,535
31	LR	G894 Maint of Other Equipment - Total	EXP_894	71,094	825	1,659	67,862	0	748
32	LR	Not Used	not_used	0	0	0	0	0	0
33	LR	Total Maintenance		14,888,885	2,680,991	7,035,832	67,960		5,104,101
34	LR	TOTAL DISTRIBUTION LABOR EXPENSE		111,969,986	14,406,077	84,917,290	67,960	0	12,578,658
35	LR								
36	LR	**G901-G903,G905 CUST ACCOUNTS EXPENSE**	CUSTACCTS	45,109,566	0	1,682,855	0	35,356,012	8,070,699
37	LR	**G907-G910, xDSM CUST SERV & INFO EXP**	CUSTS_I	3,007,750	0	1,936,120	0	1,071,630	0
38	LR	**G911-G916 SALES EXPENSE**	SALESEXP	3,526	0	3,526	0	0	0
39	LR	**ADMIN & GENERAL EXP ACCOUNTS xG926**	AGEXP	6,954,680	1,268,167	2,268,708	11,910	2,260,564	1,145,331
40	LR	**Employee Pension/Benefits Acct G926**	LABOR	0	0	0	0	0	0
41	LR								
42	LR	**TOTAL OPERATION & MAINT LABOR EXPENSE**		168,715,063	15,674,245	92,478,054	79,870	38,688,206	21,794,689

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
1	CA	**DEVELOPMENT OF CAPITAL ADDITIONS ALLOCATION F/**							
2	CA								
3	CA	**INTANGIBLE PLANT - G301-G303**	INTANGPLT	0	0	0	0	0	0
4	CA	**PRODUCTION PLANT - G304-G347**	PRODPLT	-2,267,387	0	-2,267,387	0	0	0
5	CA	**STORAGE PLANT - G360-G363**	STORPLT	8,371,561	0	8,371,561	0	0	0
6	CA	TRANSMISSION PLANT - G365-G371	TRANPLT	11	0	11	0	0	0
7	CA								
8	CA	**DISTRIBUTION PLANT**							
9	CA	G374 Land and Land Rights & G375 Structure & Improveme	PLT_3745	2,620,552	1,428,913	1,039,595	255	0	151,789
10	CA	G376 Mains	PLT_376	226,633,216	0	226,633,216	0	0	0
11	CA	G377 Compressor Station Equipment	PLT_377	0	0	0	0	0	0
12	CA	G378-G379 Meas & Regul Eqmt	PLT_3789	57,069,064	0	57,069,064	0	0	0
13	CA	G380 Services	SERVICES	505,466,924	505,466,924	0	0	0	0
14	CA	G381 Meters	PLT_381	58,899,779	0	0	0	0	58,899,779
15	CA	G382 Meter Installations	PLT_382	-1,810,761	0	0	0	0	-1,810,761
16	CA	G383-384 House Regulators & Install	PLT_3834	2,268,333	2,268,333	0	0	0	0
17	CA	G385 Ind Reg & Meas Eqmt	PLT_385	12,739,212	6,369,606				6,369,606
18	CA	TOTAL DISTRIBUTION PLANT		863,886,319	515,533,776	284,741,875	255	0	63,610,413
19	CA								
20	CA	**COMMON PLANT**	COMPLT	0	0	0	0	0	0
21	CA	**GENERAL PLANT EXCL INTANGIBLE PLT**	GENPLT	26,119,255	15,109,213	10,992,591	2,696	0	14,755
22									
23	CA	**TOTAL CAPITAL ADDITIONS**		896,109,759	530,642,989	301,838,650	2,951	0	63,625,169

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
1	AF	**ALLOCATION FACTOR TABLE**							
2	AF	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**							
3	AF								
4	AF	**CAPACITY RELATED**							
5	AF	Peak-Hour Sendout - delivery	PEAKHOUR_04	124,747	0	124,747	0	0	0
6	AF								
7	AF	Staff Average and Peak Allocator - delivery	AVGPEAK_04	1	0	1	0	0	0
8	AF	**COMMODITY RELATED**							
9	AF	Annual transported gas @mtr - delivery	TRANSPORT_04	2,598,285,838	0	2,598,285,838	0	0	0
10	AF	Balancing therms - delivery	BALANCE_04	1,793,060	0	1,793,060	0	0	0
11	AF	Annual transported gas @mtr - access	TRANSPORT_03	2,598,285,838	2,598,285,838	0	0	0	0
12	AF	Annual transported gas @mtr - meters	TRANSPORT_07	2,598,285,838	0	0	0	0	2,598,285,838
13	AF	TEFA $ responsibility W/N - delivery	TEFA_04						
14	AF								
15	AF	**BILLING DETERMINANTS**							
16	AF	Number of Customers		1,894,095	1,894,095	1,894,095	1,894,095	1,894,095	1,894,095
17	AF	Transported Gas at Meter (calendar)		2,598,285,838	2,598,285,838	2,598,285,838	2,598,285,838	2,598,285,838	2,598,285,838
18	AF								
19	AF								
20	AF	**CUSTOMER RELATED**							
21	AF	G380 services - access	SERVICES_03	1,215,746,207	1,215,746,207	0	0	0	0
22	AF	Cust Installns LDC G879 - delivery	CINST_04	100	0	100	0	0	0
23	AF	Avg Customer Bills - delivery	CUSTAVG_04	661,048	0	661,048	0	0	0
24	AF	Avg Customer Bills - cust svs	CUSTAVG_06	661,048	0	0	0	661,048	0
25	AF	G381 meters - measurement	SMMETERS_07	95,373,410	0	0	0	0	95,373,410
26	AF								
27	AF	Billing Function costs - cust svs	BILLING_06	20,835,825	0	0	0	20,835,825	0
28	AF	Competitive Service work - delivery	COMPSVSWK_04	100	0	100	0	0	0
29	AF								
30	AF	Account Maint - cust svs	ACCTMAINT_06	67,192,728	0	0	0	67,192,728	0
31	AF	G382 meter install - measurement	MTRINSTAL_07	149,490,256	0	0	0	0	149,490,256
32	AF	G383 house regulators - access	HOUSEREG_03	27,726,351	27,726,351	0	0	0	0
33	AF	G384 house reg install - access	HSEREGINST_03	49,550,462	49,550,462	0	0	0	0
34	AF	G385 lrg regulators - access	LRGREG_03	42,370,365	42,370,365	0	0	0	0
35	AF	G385 lrg mtrs - measurement	LRGMTR_07	6,790,868	0	0	0	0	6,790,868
36	AF	G380 services - reserve - access	SERVICESR_03	302,262,539	302,262,539	0	0	0	0
37	AF	G381 meters - reserve - measurement	SMMETERSR_07	39,637,552	0	0	0	0	39,637,552
38	AF	G382 meter install - reserve -measurement	MTRINSTALR_07	70,947,597	0	0	0	0	70,947,597
39	AF	G383 house regulators - reserve - access	HOUSEREGR_03	4,745,170	4,745,170	0	0	0	0
40	AF	G384 house reg install - reserve - access	HSEREGINSTR_03	9,880,504	9,880,504	0	0	0	0
41	AF	G385 lrg regulators - reserve - access	LRGREGR_03	6,940,251	6,940,251	0	0	0	0
42	AF	G385 lrg mtrs - reserve - measurement	LRGMTRR_07	1,112,795	0	0	0	0	1,112,795
43	AF	Direct LVG - delivery	DIRLVG_04	0	0	0	0	0	0
44	AF	Direct LVG - cust svs	DIRLVG_06	0	0	0	0	0	0

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				(1)	(2)	(3)	(4)	(5)	(6)
45	AF	ALLOCATION FACTOR TABLE							
46	AF	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**							
47	AF								
48	AF	Direct SLG - streetlights	DIRSLG_05	1	0	0	1	0	0
49	AF	Meter Reading Costs - measurement	MRCOST_07	16,284,753	0	0	0	0	16,284,753
50	AF	Other Utility work by Cust Ops - delivery	UTILWORK_04	6,776,917	0	6,776,917	0	0	0
51	AF	Direct SLG - access	DIRSLG_03	1	1	0	0	0	0
52	AF	Direct Competitive Services - delivery	DIRCOMPSVS_04	0	0	0	0	0	0
53	AF	Direct TSG-F - access	DIRTSGF_03	0	0	0	0	0	0
54	AF	Direct TSG-F - delivery	DIRTSGF_04	0	0	0	0	0	0
55	AF	Direct TSG-F - measurement	DIRTSGF_07	0	0	0	0	0	0
56	AF	Direct - RSG - delivery	DIRRSG_04	0	0	0	0	0	0
57	AF	Choice - delivery	CHOICE_04	1,894,095	0	1,894,095	0	0	0
58	AF								
59	AF								
60	AF	Dummy allocator for unused lines	not_used	0	0	0	0	0	0
61	AF								
62	AF								
63	AF	**Plant Related**							
64	AF	Acct G301-G303 Intangible Plt	INTANGPLT	0	0	0	0	0	0
65	AF	Acct G399.10-23 Oth Tangible Plt	TANGPLT	16,791,854	283,770	1,334,206	51	12,410,339	2,763,489
66	AF	Production Plant Total	PRODPLT	52,043,670	0	52,043,670	0	0	0
67	AF	Storage Plant Total	STORPLT	19,575,233	0	19,575,233	0	0	0
68	AF	Transmission Plant Total	TRANPLT	103,544,395	0	103,544,395	0	0	0
69	AF	Distribution Plant Total	DISTPLT	10,498,076,770	5,724,304,805	4,164,673,568	1,021,319	0	608,077,078
70	AF	G391-G398 General Plant	GENPLT	200,812,197	116,163,890	84,514,137	20,726	0	113,444
71	AF	Common Plant	COMPLT	102,234,955	15,246,506	16,357,253	2,720	57,691,885	12,936,591
72	AF	Accts C389-C399, G391-E398 Com & Gen Plt	COMGENPLT	303,047,153	131,410,396	100,871,390	23,446	57,691,885	13,050,035
73	AF	Total Prod, Storage, Transmission, & Dist Plant	PSTDPLT	10,673,240,067	5,724,304,805	4,339,836,866	1,021,319	0	608,077,078
74	AF	Total Plant	TOTPLT	10,993,079,074	5,855,998,970	4,442,042,462	1,044,816	70,102,224	623,890,602
75	AF								
76	AF	Distribution Plant x Meters & Installs	DISTPLTXMTR	9,895,589,959	5,724,304,805	4,164,673,568	1,021,319	0	5,590,267
77	AF	Acct G374-375 - Land & Structures	PLT_3745	96,512,525	52,625,554	38,287,314	9,389	0	5,590,267
78	AF	Acct G376 - Mains	PLT_376	3,775,184,891	0	3,775,184,891	0	0	0
79	AF	Acct G377 - Compressor Station Equip	PLT_377	0	0	0	0	0	0
80	AF	Acct G378-379 - Meas & Regul Station Equip	PLT_3789	285,986,290	0	285,986,290	0	0	0
81	AF	Acct G380 & 387.2 - Services	SERVICES	5,447,689,486	5,447,689,486	0	0	0	0
82	AF	Acct G376, G380 & 387.2 - Mains & Services	MAIN_SERV	9,222,874,377	5,447,689,486	3,775,184,891	0	0	0
83	AF	Acct G381 - House Meters	PLT_381	477,048,047	0	0	0	0	477,048,047
84	AF	Acct G382 - Meter Installations	PLT_382	52,631,537	0	0	0	0	52,631,537
85	AF	Acct G381,382, & 385 - Meters	METERPLT	602,486,811	0	0	0	0	602,486,811
86	AF	Acct G381-384 - Meters & House Regulators	PLT_3814	680,862,120	151,182,537	0	0	0	529,679,583
87	AF	Acct G382-384 - House Reg & Install & Meter Install	PLT_3824	203,814,074	151,182,537	0	0	0	52,631,537
88	AF	Acct G383-384 - House Reg & Installation	PLT_3834	151,182,537	151,182,537	0	0	0	0

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				(1)	(2)	(3)	(4)	(5)	(6)
89	**AF**	**ALLOCATION FACTOR TABLE CONTINUED**							
90	**AF**	**INTERNALLY DEVELOPED ALLOCATION FACTORS**							
91	AF								
92	AF	Acct G385 - Ind & Com Meas & Regul Station Equip	PLT_385	145,614,455	72,807,227	0	0	0	72,807,227
93	AF	Acct G386 - Other Property on Cust Premises	PLT_386	0	0	0	0	0	0
94	AF	Acct G387.1 - Other Equipment (St Ltg Posts)	PLT_387_1	1,011,930	0	0	1,011,930	0	0
95	AF								
96	AF	Total Distribution Plant Reserve	TOTDRESERVE	2,718,471,978	1,288,707,941	1,277,621,837	11,318	36,625,623	115,505,260
97	AF	Total Net Plant	TOTPLTNET	8,274,607,096	4,567,291,030	3,164,420,625	1,033,497	33,476,602	508,385,342
98	AF								
99	AF								
100	AF	**Revenue Related**							
101	AF	Total Operating Revenue	TOTREV	1,469,037,356	704,666,774	573,543,606	401,966	79,153,105	111,271,906
102	AF	Intra Dept Rev Req - 5.62% GS / 94.38% LV	INTRAREV	211,252,528	50,280,524	146,360,289	0	3,976,366	10,635,348
103	AF								
104	AF								
105	AF	**Expense Related**							
106	AF	Manufactured Gas O&M Excl Fuel Expense	MFGO_M	2,114,238	0	2,114,238	0	0	0
107	AF	Other Storage Plant O&M Expense	STOREXP	2,714,605	0	2,714,605	0	0	0
108	AF	Transmission Plant O&M Expense	TRANEXP	2,593,507	0	2,593,507	0	0	0
109	AF	Acct 813-Other Gas Supply Expense	EXP_813	72	0	72	0	0	0
110	AF	Acct 871 - Distribution Load Dispatching	EXP_871	5,839,316	0	5,839,316	0	0	0
111	AF	Acct 872 - Compressor Station Labor & Expenses	EXP_872	0	0	0	0	0	0
112	AF	Acct 874-Mains & Services Expenses	EXP_874	20,733,577	12,246,734	8,486,843	0	0	0
113	AF	Acct 875-877 - Meas & Regulating Station Exp	EXP_8757	3,019,152	0	3,019,152	0	0	0
114	AF	Acct 878 - Meter & House Regulator Expenses	EXP_878	11,492,061	2,551,763	0	0	0	8,940,298
115	AF	Acct 879 - Customer Installation Expenses	EXP_879	17,355,157	0	17,355,157	0	0	0
116	AF	Acct 880.0,.1,.2 - Other Expenses	EXP_8801	14,050,188	3,625,445	8,234,483	0	0	2,190,260
117	AF	Acct 880.3 - Operation of Street Lighting Exp	EXP_8803	0	0	0	0	0	0
118	AF	Acct 881 - Rents	EXP_881	-1,088,602	0	-1,088,602	0	0	0
119	AF	Acct 886-Maint of Structures & Improvements Exp	EXP_886	8,016,449	4,371,143	3,180,191	780	0	464,334
120	AF	Acct 887-Maint of Mains Exp	EXP_887	8,706,285	0	8,706,285	0	0	0
121	AF	Acct 888-Maint of Compressor Station Equip Exp	EXP_888	0	0	0	0	0	0
122	AF	Acct 889-891 - Main of Meas & Reg Station Equip	EXP_8891	4,163,462	0	4,163,462	0	0	0
123	AF	Acct 892-Main of Services Exp	EXP_892	3,610,466	3,610,466	0	0	0	0
124	AF	Acct 893-Maint of Meters & House Regulators Exp	EXP_893	6,767,990	0	0	0	0	6,767,990
125	AF	Acct 894-Maint of Other Equipment	EXP_894	207,897	2,413	4,853	198,445	0	2,187
126	AF								
127	AF	Distr Oper Exp	DISTEXPO	71,400,849	18,423,942	41,846,349	0	0	11,130,558
128	AF	Distr Maint Exp	DISTEXPM	31,472,549	7,984,022	16,054,791	199,225	0	7,234,511
129	AF	Cust Serv & Info Expense	CUSTS_I	4,034,218	0	2,596,868	0	1,437,350	0
130	AF	Acct 901-903,905 Cust Acct Exp Excl 904	CACCTEXP	72,712,827	0	2,712,621	0	56,990,917	13,009,288
131	AF	Accts 901-910 Excl 904 - Cust Accts,Serv & Info	CUSTSVSX	76,747,044	0	5,309,489	0	58,428,267	13,009,288
132	AF	Sales Expense	SALESEXP	88,423	0	88,423	0	0	0

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				(1)	(2)	(3)	(4)	(5)	(6)
133	**AF**	**ALLOCATION FACTOR TABLE CONTINUED**							
134	**AF**	**INTERNALLY DEVELOPED ALLOCATION FACTORS**							
135	AF								
136	AF	Total O&M Expense Excl A&G Expense	TOTOMXAG	242,970,637	39,326,847	110,151,337	199,225	59,879,809	33,413,420
137	AF	Total O&M Expense Excl 904 Expense	TOTOMX904	255,675,994	33,474,302	113,155,543	265,586	71,024,321	37,756,242
138	AF	Total O&M Expense Excl Fuel & 904 Expense	TOMXFUEL904	223,769,120	33,474,302	81,248,670	265,586	71,024,321	37,756,242
139	AF	Tot Admin & Genl Exp xPension/Ben	AGEXP	38,752,071	7,066,337	12,641,434	66,361	12,596,054	6,381,885
140	AF	Accts 901-905 Cust Accts Exp Excl 904-Uncol	CUSTACCTS	72,712,827	0	2,712,621	0	56,990,917	13,009,288
141	AF	O&M + Capital Additions	EXPENDITURES	1,177,832,467	577,036,173	424,631,421	268,536	72,475,863	103,420,473
142	AF								
143	AF	Depreciation Expense (total)	DEPREXP	203,691,216	108,184,098	80,336,675	19,302	3,717,640	11,433,501
144	AF								
145	AF	NJ State Income Tax (CBT)	STATEINCTAX	77,634,124	42,518,568	29,567,224	10,226	604,895	4,933,212
146	AF	NJ State Deferred Income Tax	DFSTATEINCTAX	-39,443,958	-3,664,488	-21,620,479	-18,673	-9,044,930	-5,095,389
147	AF								
148	AF	**Labor Expense Related**							
149	AF	Total Distribution Exp (Oper) Labor	TLABDO	97,081,101	11,725,086	77,881,458	0	0	7,474,557
150	AF	Total Distribution Exp (Maint) Labor	TLABDM	14,888,885	2,680,991	7,035,832	67,960	0	5,104,101
151	AF	Total Labor	LABOR	168,715,063	15,674,245	92,478,054	79,870	38,688,206	21,794,689
152	AF								
153	AF	**REVENUES AND BILLING DETERMINANTS**							
154	AF								
155	AF	Base Rate Sales Revenue	SALESREV	1,401,350,320	694,848,286	518,377,997	396,637	78,066,852	109,660,548
156	AF								
157	AF	Residential Service Gas	REVRSG	1,001,979,781	565,279,018	297,800,015	0	66,286,822	72,613,926
158	AF	General Service Gas	REVGSG	178,047,445	80,584,730	64,098,648	0	6,154,493	27,209,573
159	AF	Large Volume Service Gas	REVLVG	213,229,775	48,476,014	151,258,683	0	3,846,666	9,648,411
160	AF	Street Light Gas	REVSLG	561,110	72,338	89,022	396,637	3,088	24
161	AF	Firm Transportation Gas Service	REVTSGF	7,532,209	436,185	5,131,629	0	1,775,782	188,613
162	AF								
163	AF								
164	AF	Total Rev Req @ desired ROR	REVREQ	1,401,350,320	694,848,286	518,377,997	396,637	78,066,852	109,660,548
165	AF								
166	AF								
167	AF	**PRESENT REVENUES FROM SALES INPUT**							
168	AF								
169	AF	Total Sales of Gas Revenue Requirement		0	0	0	0	0	0
170	AF	Sales of Gas Revenues - Rates		1,101,761	1,101,761	1,101,761	1,101,761	1,101,761	1,101,761
171	AF	Sales of Gas Revenues - Other		0	0	0	0	0	0
172	AF								
173	AF	**RATE OF RETURN**							
174	AF	Rate of Return (Equalized)	CALCULATED	7.55%	7.55%	7.55%	7.55%	7.55%	7.55%

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LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
1	AP	**ALLOCATION PROPORTIONS TABLE**							
2	AP	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**							
3	AP								
4	AP	**CAPACITY RELATED**							
5	AP	Peak-Hour Sendout - delivery	PEAKHOUR_04	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
6	AP								
7	AP	Staff Average and Peak Allocator - delivery	AVGPEAK_04	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
8	AP	**COMMODITY RELATED**							
9	AP	Annual transported gas @mtr - delivery	TRANSPORT_04	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
10	AP	Balancing therms - delivery	BALANCE_04	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
11	AP	Annual transported gas @mtr - access	TRANSPORT_03	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000
12	AP	Annual transported gas @mtr - meters	TRANSPORT_07	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000
13	AP	TEFA $ responsibility W/N - delivery	TEFA_04	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
14	AF								
15	AP	**BILLING DETERMINANTS**							
16	AP	Number of Customers		1.000000	1.000000	1.000000	1.000000	1.000000	1.000000
17	AP	Transported Gas at Meter (calendar)		1.000000	1.000000	1.000000	1.000000	1.000000	1.000000
18	AP								
19	AP								
20	AP	**CUSTOMER RELATED**							
21	AP	G380 services - access	SERVICES_03	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000
22	AP	Cust Installns LDC G879 - delivery	CINST_04	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
23	AP	Avg Customer Bills - delivery	CUSTAVG_04	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
24	AP	Avg Customer Bills - cust svs	CUSTAVG_06	1.000000	0.000000	0.000000	0.000000	1.000000	0.000000
25	AP	G381 meters - measurement	SMMETERS_07	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000
26	AP								
27	AP	Billing Function costs - cust svs	BILLING_06	1.000000	0.000000	0.000000	0.000000	1.000000	0.000000
28	AP	Competitive Service work - delivery	COMPSVSWK_04	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
29	AF								
30	AP	Account Maint - cust svs	ACCTMAINT_06	1.000000	0.000000	0.000000	0.000000	1.000000	0.000000
31	AP	G382 meter install - measurement	MTRINSTAL_07	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000
32	AP	G383 house regulators - access	HOUSEREG_03	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000
33	AP	G384 house reg install - access	HSEREGINST_03	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000
34	AP	G385 lrg regulators - access	LRGREG_03	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000
35	AP	G385 lrg mtrs - measurement	LRGMTR_07	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000
36	AP	G380 services - reserve - access	SERVICESR_03	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000
37	AP	G381 meters - reserve - measurement	SMMETERSR_07	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000
38	AP	G382 meter install - reserve -measurement	MTRINSTALR_07	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000
39	AP	G383 house regulators - reserve - access	HOUSEREGR_03	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000
40	AP	G384 house reg install - reserve - access	HSEREGINSTR_03	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000
41	AP	G385 lrg regulators - reserve - access	LRGREGR_03	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000
42	AP	G385 lrg mtrs - reserve - measurement	LRGMTRR_07	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000
43	AP	Direct LVG - delivery	DIRLVG_04	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
44	AP	Direct LVG - cust svs	DIRLVG_06	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000

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				(1)	(2)	(3)	(4)	(5)	(6)
45	**AP**	**ALLOCATION PROPORTIONS TABLE CONTINUED**							
46	**AP**	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**							
47	AP								
48	AP	Direct SLG - streetlights	DIRSLG_05	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000
49	AP	Meter Reading Costs - measurement	MRCOST_07	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000
50	AP	Other Utility work by Cust Ops - delivery	UTILWORK_04	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
51	AP	Direct SLG - access	DIRSLG_03	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000
52	AP	Direct Competitive Services - delivery	DIRCOMPSVS_04	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
53	AP	Direct TSG-F - access	DIRTSGF_03	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
54	AP	Direct TSG-F - delivery	DIRTSGF_04	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
55	AP	Direct TSG-F - measurement	DIRTSGF_07	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
56	AP	Direct - RSG - delivery	DIRRSG_04	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
57	AP	Choice - delivery	CHOICE_04	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
58	AP								
59	AP								
60	AP	Dummy allocator for unused lines	not_used	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
61	AP								
62	AP								
63	AP	**Plant Related**							
64	AP	Acct G301-G303 Intangible Plt	INTANGPLT	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
65	AP	Acct G399.10-23 Oth Tangible Plt	TANGPLT	1.000000	0.016899	0.079456	0.000003	0.739069	0.164573
66	AP	Production Plant Total	PRODPLT	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
67	AP	Storage Plant Total	STORPLT	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
68	AP	Transmission Plant Total	TRANPLT	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
69	AP	Distribution Plant Total	DISTPLT	1.000000	0.545272	0.396708	0.000097	0.000000	0.057923
70	AP	G391-G398 General Plant	GENPLT	1.000000	0.578470	0.420862	0.000103	0.000000	0.000565
71	AP	Common Plant	COMPLT	1.000000	0.149132	0.159997	0.000027	0.564307	0.126538
72	AP	Accts C389-C399, G391-E398 Com & Gen Plt	COMGENPLT	1.000000	0.433630	0.332857	0.000077	0.190373	0.043063
73	AP	Total Prod, Storage, Transmission, & Dist Plant	PSTDPLT	1.000000	0.536323	0.406609	0.000096	0.000000	0.056972
74	AP	Total Plant	TOTPLT	1.000000	0.532699	0.404076	0.000095	0.006377	0.056753
75	AP								
76	AP	Distribution Plant x Meters & Installs	DISTPLTXMTR	1.000000	0.578470	0.420862	0.000103	0.000000	0.000565
77	AP	Acct G374-375 - Land & Structures	PLT_3745	1.000000	0.545272	0.396708	0.000097	0.000000	0.057923
78	AP	Acct G376 - Mains	PLT_376	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
79	AP	Acct G377 - Compressor Station Equip	PLT_377	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
80	AP	Acct G378-379 - Meas & Regul Station Equip	PLT_3789	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
81	AP	Acct G380 & 387.2 - Services	SERVICES	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000
82	AP	Acct G376, G380 & 387.2 - Mains & Services	MAIN_SERV	1.000000	0.590672	0.409328	0.000000	0.000000	0.000000
83	AP	Acct G381 - House Meters	PLT_381	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000
84	AP	Acct G382 - Meter Installations	PLT_382	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000
85	AP	Acct G381,382, & 385 - Meters	METERPLT	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000
86	AP	Acct G381-384 - Meters & House Regulators	PLT_3814	1.000000	0.222046	0.000000	0.000000	0.000000	0.777954
87	AP	Acct G382-384 - House Reg & Install & Meter Install	PLT_3824	1.000000	0.741767	0.000000	0.000000	0.000000	0.258233
88	AP	Acct G383-384 - House Reg & Installation	PLT_3834	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000

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89	**AP**	**ALLOCATION PROPORTIONS TABLE CONTINUED**							
90	**AP**	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**							
91	AP								
92	AP	Acct G385 - Ind & Com Meas & Regul Station Equip	PLT_385	1.000000	0.500000	0.000000	0.000000	0.000000	0.500000
93	AP	Acct G386 - Other Property on Cust Premises	PLT_386	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
94	AP	Acct G387.1 - Other Equipment (St Ltg Posts)	PLT_387_1	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000
95	AP								
96	AP	Total Distribution Plant Reserve	TOTDRESERVE	1.000000	0.474056	0.469978	0.000004	0.013473	0.042489
97	AP	Total Net Plant	TOTPLTNET	1.000000	0.551965	0.382425	0.000125	0.004046	0.061439
98	AP								
99	AP								
100	AP	**Revenue Related**							
101	AP	Total Operating Revenue	TOTREV	1.000000	0.479679	0.390421	0.000274	0.053881	0.075745
102	AP	Intra Dept Rev Req - 5.62% GS / 94.38% LV	INTRAREV	1.000000	0.238011	0.692821	0.000000	0.018823	0.050344
103	AP								
104	AP								
105	AP	**Expense Related**							
106	AP	Manufactured Gas O&M Excl Fuel Expense	MFGO_M	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
107	AP	Other Storage Plant O&M Expense	STOREXP	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
108	AP	Transmission Plant O&M Expense	TRANEXP	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
109	AP	Acct 813-Other Gas Supply Expense	EXP_813	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
110	AP	Acct 871 - Distribution Load Dispatching	EXP_871	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
111	AP	Acct 872 - Compressor Station Labor & Expenses	EXP_872	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
112	AP	Acct 874-Mains & Services Expenses	EXP_874	1.000000	0.590672	0.409328	0.000000	0.000000	0.000000
113	AP	Acct 875-877 - Meas & Regulating Station Exp	EXP_8757	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
114	AP	Acct 878 - Meter & House Regulator Expenses	EXP_878	1.000000	0.222046	0.000000	0.000000	0.000000	0.777954
115	AP	Acct 879 - Customer Installation Expenses	EXP_879	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
116	AP	Acct 880.0,.1,.2 - Other Expenses	EXP_8801	1.000000	0.258035	0.586076	0.000000	0.000000	0.155888
117	AP	Acct 880.3 - Operation of Street Lighting Exp	EXP_8803	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
118	AP	Acct 881 - Rents	EXP_881	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
119	AP	Acct 886-Maint of Structures & Improvements Exp	EXP_886	1.000000	0.545272	0.396708	0.000097	0.000000	0.057923
120	AP	Acct 887-Maint of Mains Exp	EXP_887	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
121	AP	Acct 888-Maint of Compressor Station Equip Exp	EXP_888	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
122	AP	Acct 889-891 - Main of Meas & Reg Station Equip	EXP_8891	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
123	AP	Acct 892-Main of Services Exp	EXP_892	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000
124	AP	Acct 893-Maint of Meters & House Regulators Exp	EXP_893	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000
125	AP	Acct 894-Maint of Other Equipment	EXP_894	1.000000	0.011608	0.023342	0.954532	0.000000	0.010518
126	AP								
127	AP	Distr Oper Exp	DISTEXPO	1.000000	0.258035	0.586076	0.000000	0.000000	0.155888
128	AP	Distr Maint Exp	DISTEXPM	1.000000	0.253682	0.510120	0.006330	0.000000	0.229867
129	AP	Cust Serv & Info Expense	CUSTS_I	1.000000	0.000000	0.643710	0.000000	0.356290	0.000000
130	AP	Acct 901-903,905 Cust Acct Exp Excl 904	CACCTEXP	1.000000	0.000000	0.037306	0.000000	0.783781	0.178913
131	AP	Accts 901-910 Excl 904 - Cust Accts,Serv & Info	CUSTSVSX	1.000000	0.000000	0.069182	0.000000	0.761310	0.169509
132	AP	Sales Expense	SALESEXP	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000

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133	AP	Total O&M Expense Excl A&G Expense	TOTOMXAG	1.000000	0.161858	0.453352	0.000820	0.246449	0.137520
134	AP	Total O&M Expense Excl 904 Expense	TOTOMX904	1.000000	0.130925	0.442574	0.001039	0.277790	0.147672
135	AP	Total O&M Expense Excl Fuel & 904 Expense	TOMXFUEL904	1.000000	0.149593	0.363092	0.001187	0.317400	0.168729
136	AP	Tot Admin & Genl Exp xPension/Ben	AGEXP	1.000000	0.182347	0.326213	0.001712	0.325042	0.164685
137	AP	Accts 901-905 Cust Accts Exp Excl 904-Uncol	CUSTACCTS	1.000000	0.000000	0.037306	0.000000	0.783781	0.178913
138	AP	O&M + Capital Additions	EXPENDITURES	1.000000	0.489914	0.360519	0.000228	0.061533	0.087806
139	AP								
140	AP	Depreciation Expense (total)	DEPREXP	1.000000	0.531118	0.394404	0.000095	0.018251	0.056132
141	AP								
142	AP	NJ State Income Tax (CBT)	STATEINCTAX	1.000000	0.547679	0.380853	0.000132	0.007792	0.063544
143	AP	NJ State Deferred Income Tax	DFSTATEINCTAX	1.000000	0.092904	0.548132	0.000473	0.229311	0.129180
144	AP								
145	AP	**Labor Expense Related**							
146	AP	Total Distribution Exp (Oper) Labor	TLABDO	1.000000	0.120776	0.802231	0.000000	0.000000	0.076993
147	AP	Total Distribution Exp (Maint) Labor	TLABDM	1.000000	0.180067	0.472556	0.004565	0.000000	0.342813
148	AP	Total Labor	LABOR	1.000000	0.092904	0.548132	0.000473	0.229311	0.129180
149	AP								
150	AP	**REVENUES AND BILLING DETERMINANTS**							
151	AP								
152	AP	Base Rate Sales Revenue	SALESREV	1.000000	0.495842	0.369913	0.000283	0.055708	0.078253
153	AP								
154	AP	Residential Service Gas	REVRSG	1.000000	0.564162	0.297212	0.000000	0.066156	0.072470
155	AP	General Service Gas	REVGSG	1.000000	0.452603	0.360009	0.000000	0.034567	0.152822
156	AP	Large Volume Service Gas	REVLVG	1.000000	0.227342	0.709369	0.000000	0.018040	0.045249
157	AP	Street Light Gas	REVSLG	1.000000	0.128920	0.158654	0.706879	0.005503	0.000043
158	AP	Firm Transportation Gas Service	REVTSGF	1.000000	0.057909	0.681291	0.000000	0.235758	0.025041
159	AP								
160	AP	Total Rev Req @ desired ROR	REVREQ	1.000000	0.495842	0.369913	0.000283	0.055708	0.078253
161	AP								
162	AP	**PRESENT REVENUES FROM SALES INPUT**							
163	AP	Total Sales of Gas Revenue Requirement		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
164	AP	Sales of Gas Revenues - Rates		1.000000	1.000000	1.000000	1.000000	1.000000	1.000000
165	AP	Sales of Gas Revenues - Other		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000

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				(1)	(2)	(3)	(4)	(5)	(6)
1	ADA	**ALLOCATED DIRECT ASSIGNMENTS**							
2	ADA	**DIRECT ASSIGN TO CLASSES W/SALES REV FUNCTIONS**							
3	ADA								
4	ADA	**Account 904 - Uncollectible Accounts**							
5	ADA	Residential Service Gas	REVRSG	1,001,979,781	565,279,018	297,800,015	0	66,286,822	72,613,926
6	ADA	General Service Gas	REVGSG	178,047,445	80,584,730	64,098,648	0	6,154,493	27,209,573
7	ADA	Large Volume Service Gas	REVLVG	213,229,775	48,476,014	151,258,683	0	3,846,666	9,648,411
8	ADA	Street Light Gas	REVSLG	561,110	72,338	89,022	396,637	3,088	24
9	ADA	Firm Transportation Gas Service	REVTSGF	7,532,209	436,185	5,131,629	0	1,775,782	188,613
10	ADA								
11	ADA	Total 904-Uncollectible	EXP_904	1,400,789,210	694,775,947	518,288,975	0	78,063,764	109,660,524
12	ADA								
13	ADA	Total 904-Uncollectible	EXP_904	1.000000	0.495989	0.369998		0.055728	0.078285
14	ADA								
15	ADA	Additional Net Write-Offs at Claimed Rate	EXP_904	0	0	0	0	0	0
16	ADA								
17	ADA	**Rev Req (cal) to Customers Late Payment fees**							
18	ADA	Residential Service Gas	REVRSG	0	0	0	0	0	0
19	ADA	General Service Gas	REVGSG	178,047,445	80,584,730	64,098,648	0	6,154,493	27,209,573
20	ADA	Large Volume Service Gas	REVLVG	213,229,775	48,476,014	151,258,683	0	3,846,666	9,648,411
21	ADA	Street Light Gas	REVSLG	0	0	0	0	0	0
22	ADA	Firm Transportation Gas Service	REVTSGF	0	0	0	0	0	0
23	ADA								
24	ADA	Total Late Payment Fees	REVLATEP	391,277,219	129,060,744	215,357,331	0	10,001,160	36,857,984
25	ADA								
26	ADA	Total Late Payment Fees	REVLATEP	1.000000	0.329845	0.550396		0.025560	0.094199
27	ADA								
28	ADA	**ALLOCATED DIRECT ASSIGNMENTS**							
29	ADA	**DIRECT ASSIGN TO CLASSES W/SALES REV FUNCTIONS**							
30	ADA								
31	ADA	**AVAILABLE**							
32	ADA	Residential Service Gas	REVRSG	0	0	0	0	0	0
33	ADA	General Service Gas	REVGSG	0	0	0	0	0	0
34	ADA	Large Volume Service Gas	REVLVG	0	0	0	0	0	0
35	ADA	Street Light Gas	REVSLG	0	0	0	0	0	0
36	ADA	Firm Transportation Gas Service	REVTSGF	0	0	0	0	0	0
37	ADA								
38	ADA	Total Available	REVAVAIL	0	0	0	0	0	0
39	ADA								
40	ADA	Total Available	REVAVAIL	0.0	0.0	0.0	0.0	0.0	0.0

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12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
1	RRW	**REVENUE REQUIREMENTS**							
2	RRW								
3	RRW	PRESENT RATES							
4	RRW	--							
5	RRW	RATE BASE		8,681,618,581	4,781,604,291	3,287,174,807	1,160,952	57,861,339	553,817,193
6	RRW	NET OPER INC (PRESENT RATES)		655,462,203	361,011,124	248,181,698	87,652	4,368,531	41,813,198
7	RRW	RATE OF RETURN (PRES RATES)		7.55%	7.55%	7.55%	7.55%	7.55%	7.55%
8	RRW	RELATIVE RATE OF RETURN		1.00	1.00	1.00	1.00	1.00	1.00
9	RRW	SALES REVENUE (PRE RATES)		1,401,350,320	694,848,286	518,377,997	396,637	78,066,852	109,660,548
10	RRW	REVENUE PRES RATES $/THERM		$0.5393	$0.2674	$0.1995	$0.0002	$0.0300	$0.0422
11	RRW	REVENUE REQUIRED - $/MO/CUST		$61.65	$30.57	$22.81	$0.02	$3.43	$4.82
12	RRW								
13	RRW								
14	RRW	CLAIMED RATE OF RETURN							
15	RRW	--							
16	RRW	CLAIMED RATE OF RETURN		7.55%	7.55%	7.55%	7.55%	7.55%	7.55%
17	RRW	RETURN REQ FOR CLAIMED ROR		655,462,203	361,011,124	248,181,698	87,652	4,368,531	41,813,198
18	RRW	SALES REVENUE REQ CLAIMED ROR		1,401,350,320	694,848,286	518,377,997	396,637	78,066,852	109,660,548
19	RRW	REVENUE DEFICIENCY SALES REV		0	0	0	0	0	0
20	RRW	PERCENT INCREASE REQUIRED		0.0	0.0	0.0	0.0	0.0	0.0
21	RRW	ANNUAL BOOKED THERM SALES		2,598,285,838	2,598,285,838	2,598,285,838	2,598,285,838	2,598,285,838	2,598,285,838
22	RRW	SALES REV REQUIRED $/THERM		$0.5393	$0.2674	$0.1995	$0.0002	$0.0300	$0.0422
23	RRW	REVENUE DEFICIENCY $/THERM		0.0	0.0	0.0	0.0	0.0	0.0

Based on 12 months actual

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

line #	FUNCTIONAL SEGMENTS REV REQ	Total Company (1)	RSG (2)	GSG (3)	LVG (4)	SLG (5)	TSG-F (6)
1	Distribution Access	$694,848,286	$565,279,018	$80,584,730	$48,476,014	$72,338	$436,185
2	Distribution Delivery	$518,377,997	$297,800,015	$64,098,648	$151,258,683	$89,022	$5,131,629
3	Street Lighting	$396,637	0	0	0	$396,637	0
4	Customer Service	$78,066,852	$66,286,822	$6,154,493	$3,846,666	$3,088	$1,775,782
5	Measurement	$109,660,548	$72,613,926	$27,209,573	$9,648,411	$24	$188,613
6	Total	$1,401,350,320	$1,001,979,781	$178,047,445	$213,229,775	$561,110	$7,532,209

Service Charge Calculations

line #	(1) Rate Schedule	(2) Distribution Access Rev Req (in $1,000)	(3) Customer Service Rev Req (in $1,000)	(4) Measurement Rev Req (in $1,000)	(5) COS Indicated Total Rev Req (in $1,000)	(6) # of Customers	(7) Cost Based Monthly Service Charge ($/month)	(8) Current Monthly Service Charge ($/month)	(9) Proposed Limited Monthly Service Charge ($/month)	Notes:
1		Average Distribution Increase =			34.671%					Schedule SS-G8 , page 1, line 4
2	RSG	631,784	75,518	81,267	788,570	1,714,741	$ 38.32	$ 8.08	$ 12.28	move to costs, limited @ 1.5 times overall avg Distribution % increase
3	GSG	87,462	6,898	29,537	123,898	140,142	$ 73.67	$ 18.97	$ 28.84	move to costs, limited @ 1.5 times overall avg Distribution % increase
4	LVG	54,107	4,566	10,785	69,458	19,609	$ 295.18	$ 168.50	$ 256.13	move to costs, limited @ 1.5 times overall avg Distribution % increase
5	TSG-F	436	1,776	189	2,401	64	$ 3,125.76	$ 902.42	$ 1,371.74	move to costs, limited @ 1.5 times overall avg Distribution % increase
6	TSG-NF							$ 902.42	$ 1,371.74	set equal to new TSG-F Service Charge
7	CIG							$ 199.11	$ 268.14	increase current @ average Distribution % increase
8	CSG							$ 902.42	$ 1,371.74	set equal to new TSG-F Service Charge
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	
Notes:		values for RSG, GSG & LVG for Cols 2, 3, & 4 from SS-G7, pg 2, lines 20, 23 & 24 values for TSG-F for Cols 2, 3 & 4 from SS-G7, pg 1, lines 1, 4 & 5			= (2) + (3) + (4)	RSG, GSG & LVG from SS-G7, page 2, line 1 TSG-F from COS workpapers	= Col 5 * 1000 / Col 6 / 12 rounded to $.01	SS-G11	based on methodology described	

Exhibit P-9 R-1
Schedule SS-TAC-1 R-1

PSE&G 2024 Tax Adjustment Credit (TACs) Proposed Rate Calculations

Actual results through: 2/29/2024

($'s Unless Specified)

SUT Rate 6.625%

Line	Date(s)		Electric	Gas	Total	Source/Description
1	Sept24 - Dec25	Net Revenue Requirements	(173,752,029)	(238,342,010)	(412,094,040)	SS-2E/G, Col 26
2	Aug-24	(Over) / Under Recovered Balance	11,539,842	(12,347,262)	(807,420)	- SS-3E/G, Col 5
3	Aug-24	Cumulative Interest Exp / (Credit)	342,718	(166,949)	175,769	- SS-3E/G, Col 10
4	Sept24 - Dec25	Total Target Rate Revenue	(161,869,469)	(250,856,221)	(412,725,691)	ln 1 + ln 2 + ln 3
5	Sept24 - Dec25	Revenue at Proposed 2024 TAC rates	(45,641,003)	(126,374,904)	(172,015,907)	SS-6E/G, ln 19
6	Sept24 - Dec25	Proposed TAC Increase / (Decrease)	(116,228,466)	(124,481,317)	(240,709,783)	Ln 4 - ln 5
7	Sep24 - Aug25	Annualized Target Rate Revenue	(122,965,082)	(196,974,806)	(319,939,887)	SS-6E/G, ln 15
8	Sep24 - Aug25	Annualized Revenue at Proposed 2024 TAC rates	(34,665,734)	(99,013,932)	(133,679,666)	SS-6E/G, ln 17
9	Sep24 - Aug25	Annualized TAC Increase / (Decrease)	(88,299,348)	(97,960,874)	(186,260,221)	Ln 7 - ln 8

PSE&G 2024 TAX ADJUSTMENT CREDIT
GTAC Net Revenue Requirement
$000

	1	2	3	4	5	6	1	2	3	4	5	6	7	8	9	10	11	12
	1. Return Excess Income Tax Expense						1. Return Historic ADIT											
							Unprotected Excess			Protected Excess			SHARE			Mixed Service Cost		
	Beginning Excess Income Tax Balance	Excess Income Tax	Excess Income Tax	Ending Excess Income Tax Balance	Short-Term Interest Rate	Interest On Excess Income Tax Balance	Beginning Balance	Amortization to Customers	Ending Balance	Beginning Balance	Amortization to Customers	Ending Balance	Beginning Balance	Amortization to Customers	Ending Balance	Beginning Balance	Amortization to Customers	Ending Balance
Jan-23	-	-	-	-	0.16%	-	74,787	(5,651)	69,136	282,517	(618)	281,899	209,996	(1,544)	208,452	-	-	-
Feb-23	-	-	-	-	4.64%	-	69,136	(5,651)	63,486	281,899	(618)	281,280	208,452	(1,544)	206,908	-	-	-
Mar-23	-	-	-	-	4.78%	-	63,486	(10,813)	52,673	281,280	(397)	280,884	206,908	(2,955)	203,954	-	-	-
Apr-23	-	-	-	-	5.32%	-	52,673	(3,940)	48,733	280,884	(291)	280,593	203,954	(1,077)	202,877	-	-	-
May-23	-	-	-	-	5.32%	-	48,733	(3,669)	45,064	280,593	(271)	280,322	202,877	(1,003)	201,874	-	-	-
Jun-23	-	-	-	-	5.54%	-	45,064	(5,746)	39,318	280,322	(424)	279,897	201,874	(1,570)	200,304	-	-	-
Jul-23	-	-	-	-	5.25%	-	39,318	(7,304)	32,014	279,897	(539)	279,358	200,304	(1,996)	198,308	-	-	-
Aug-23	-	-	-	-	5.21%	-	32,014	(6,498)	25,516	279,358	(480)	278,878	198,308	(1,776)	196,533	-	-	-
Sep-23	-	-	-	-	5.21%	-	25,516	(3,550)	21,966	278,878	(262)	278,616	196,533	(970)	195,563	-	-	-
Oct-23	-	-	-	-	5.49%	-	21,966	(3,986)	17,980	278,616	(16)	278,600	195,563	(1,089)	194,474	-	-	-
Nov-23	-	-	-	-	5.43%	-	17,980	(5,318)	12,663	278,600	(354)	278,246	194,474	(1,453)	193,021	-	-	-
Dec-23	-	-	-	-	5.49%	-	12,663	(5,684)	6,978	278,246	(80)	278,166	193,021	(1,553)	191,467	-	-	-
Jan-24		-	-	-	5.52%	-	6,978	(916)	6,062	278,166	(974)	277,192	191,467	(5,028)	186,440	-	-	-
Feb-24		-	-	-	5.49%	-	6,062	(811)	5,251	277,192	(862)	276,330	186,440	(4,450)	181,990	-	-	-
Mar-24		-	-	-	5.49%	-	5,251	(526)	4,725	276,330	(559)	275,771	181,990	(2,886)	179,104	-	-	-
Apr-24		-	-	-	5.49%	-	4,725	(465)	4,261	275,771	(494)	275,278	179,104	(2,549)	176,555	-	-	-
May-24		-	-	-	5.49%	-	4,261	(486)	3,775	275,278	(517)	274,761	176,555	(2,667)	173,888	-	-	-
Jun-24		-	-	-	5.49%	-	3,775	(591)	3,184	274,761	(628)	274,133	173,888	(3,244)	170,644	-	-	-
Jul-24		-	-	-	5.49%	-	3,184	(710)	2,474	274,133	(755)	273,378	170,644	(3,895)	166,749	-	-	-
Aug-24		-	-	-	5.49%	-	2,474	(657)	1,817	273,378	(698)	272,680	166,749	(3,603)	163,146	-	-	-
Sep-24		-	-	-	5.49%	-	1,817	(525)	1,293	272,680	(558)	272,122	163,146	(2,879)	160,267	-	-	-
Oct-24		-	-	-	5.49%	-	1,293	(373)	920	272,122	(396)	271,726	160,267	(2,044)	158,222	-	-	-
Nov-24		-	-	-	5.49%	-	920	(472)	448	271,726	(502)	271,224	158,222	(2,592)	155,631	-	-	-
Dec-24		-	-	-	5.49%	-	448	(448)	(0)	271,224	(476)	270,749	155,631	(2,457)	153,174	-	-	175,180
Jan-25		-	-	-	5.49%	-	(0)	-	(0)	270,749	(897)	269,852	153,174	(5,028)	148,146	175,180	(10,503)	164,677
Feb-25		-	-	-	5.49%	-	(0)	-	(0)	269,852	(794)	269,058	148,146	(4,450)	143,696	164,677	(9,297)	155,380
Mar-25		-	-	-	5.49%	-	(0)	-	(0)	269,058	(515)	268,543	143,696	(2,886)	140,810	155,380	(6,029)	149,351
Apr-25		-	-	-	5.49%	-	(0)	-	(0)	268,543	(455)	268,089	140,810	(2,549)	138,262	149,351	(5,325)	144,026
May-25		-	-	-	5.49%	-	(0)	-	(0)	268,089	(476)	267,613	138,262	(2,667)	135,594	144,026	(5,572)	138,454
Jun-25		-	-	-	5.49%	-	(0)	-	(0)	267,613	(579)	267,035	135,594	(3,244)	132,351	138,454	(6,776)	131,678
Jul-25		-	-	-	5.49%	-	(0)	-	(0)	267,035	(695)	266,340	132,351	(3,895)	128,455	131,678	(8,138)	123,540
Aug-25		-	-	-	5.49%	-	(0)	-	(0)	266,340	(643)	265,697	128,455	(3,603)	124,853	123,540	(7,527)	116,013
Sep-25		-	-	-	5.49%	-	(0)	-	(0)	265,697	(513)	265,184	124,853	(2,879)	121,973	116,013	(6,015)	109,998
Oct-25		-	-	-	5.49%	-	(0)	-	(0)	265,184	(365)	264,819	121,973	(2,044)	119,929	109,998	(4,271)	105,727
Nov-25		-	-	-	5.49%	-	(0)	-	(0)	264,819	(462)	264,357	119,929	(2,592)	117,337	105,727	(5,414)	100,312
Dec-25		-	-	-	5.49%	-	(0)	-	(0)	264,357	(438)	263,919	117,337	(2,457)	114,881	100,312	(5,132)	95,180
	= Prev Col 1	Input	Input	= Col 1 + Col 2 + Col 3	Input	= (Prev Col 4 + Col 4)/2 * Col 5 / 12	= Prev Col 3 + Col 1 & 2 of "Balances" Wkst	Input	= Col 1 + Col 2	= Prev Col 6 + Col 3 of "Balances" Wkst	Input	= Col 4 + Col 5	= Prev Col 9 + Col 4 of "Balances" Wkst	Input	= Col 7 + Col 8	= Prev Col 12 + Col 11 of "Balances" Wkst	Input	= Col 10 + Col 11
Annual																		
2023			-			-		(67,809)			(4,351)			(18,529)			-	
2024			-			-		(6,978)			(7,418)			(38,293)			-	
2025			-			-		-			(6,830)			(38,293)			(80,000)	
2026			-			-		-			(6,830)			(38,293)			(45,000)	
2027								-			(6,830)			(38,293)			(25,000)	
2028								-			(6,830)			(38,293)			(5,000)	
2029								-			(6,830)			-			(20,180)	

PSE&G 2024 TAX ADJUSTMENT CREDIT
GTAC Net Revenue Requirement
$000

	Monthly After Tax WACC Post -2023 BRC:		0.587%						Monthly After Tax WACC Post -2023 BRC:		0.587%						
	Monthly After Tax WACC Pre-2023 BRC:		0.540%						Monthly After Tax WACC Pre-2023 BRC:		0.540%	ederal Tax Rate =	21.00%			Revenue Factor =	1.3947
13	14	15	16	17	18	19	20`	21	22	23	24	25	26	27	28	29	30
1. Return Historic ADIT (cont.)								1a. Return Historic ADIT (cont.)				2. Current ESHARE Deduciton	2a. Current Mixed Srv & IDD	3. Other			
Return on Rate Base				Corporate Alternative Minimum Tax (CAMT)				Return on Non Rate Base									
Unprotected Excess ADIT Rate Base Related %	Rate Base Related Portion of Unprotected Excess ADIT Amortizaiton to Customers	Cumulative Change in Rate Base	After-Tax Return on Cumulative Change in Rate Base	Beginning Balance	Amortization to Customers	Cumulative Change in Rate Base	After-Tax Return on Cumulative Change in Rate Base	Beginning Non-Rate Base Related Portion of Unprotected Excess	Non-Rate Base Related Portion of Unprotected Excess ADIT Amortizaiton to Customers	Ending Non-Rate Base Related Portion of Unprotected Excess	After-Tax Interest to Customers	Actual SHARE Deduction Flow-Through	Actual SHARE Deduction Flow-Through	IRS ESHARE Deduction Audit Adjustments	Other Major Tax Adjustments	Net Tax Adjustment	**Net Revenue Requirement**
79%	(4,481)	290,131	1,544	-	-	-	-	14,038	(1,170)	12,868	(73)	(4,156)	-	-	-	(10,497)	**(14,879)**
79%	(4,481)	296,676	1,585	-	-	-	-	12,868	(1,170)	11,698	(66)	(4,156)	-	-	-	(10,450)	**(14,812)**
79%	(8,574)	302,713	1,619	-	-	-	-	11,698	(2,238)	9,460	(57)	(4,225)	-	-	(3)	(16,830)	**(23,854)**
79%	(3,125)	309,019	1,652	-	-	-	-	9,460	(816)	8,644	(49)	(2,234)	-	-	(5)	(5,943)	**(8,424)**
79%	(2,909)	315,290	1,686	-	-	-	-	8,644	(760)	7,884	(45)	(2,080)	-	-	(3)	(5,383)	**(7,630)**
79%	(4,556)	321,526	1,720	-	-	-	-	7,884	(1,190)	6,695	(39)	(3,257)	-	-	(2)	(9,319)	**(13,209)**
79%	(5,792)	327,727	1,754	-	-	-	-	6,695	(1,512)	5,183	(32)	(4,141)	-	-	(3)	(12,261)	**(17,379)**
79%	(5,152)	333,893	1,787	-	-	-	-	5,183	(1,345)	3,838	(24)	(3,684)	-	-	(4)	(10,678)	**(15,135)**
79%	(2,815)	340,024	1,820	-	-	-	-	3,838	(735)	3,103	(19)	(2,013)	-	-	(3)	(4,997)	**(7,082)**
79%	(3,161)	346,120	1,853	-	-	-	-	3,103	(825)	2,278	(15)	(4,992)	-	-	(1)	(8,245)	**(11,686)**
79%	(4,217)	352,182	1,886	-	-	-	-	2,278	(1,101)	1,177	(9)	(3,375)	-	-	(0)	(8,623)	**(12,222)**
79%	(4,508)	358,208	1,919	-	-	-	-	1,177	(1,177)	0	(3)	(6,463)	-	-	0	(11,865)	**(16,818)**
100%	(916)	365,186	1,954	-	-	-	-	0	-	0	(0)	(3,695)	-	-	0	(8,658)	**(12,272)**
100%	(811)	369,478	1,984	-	-	-	-	0	-	0	(0)	(2,835)	-	-	0	(6,973)	**(9,884)**
100%	(526)	373,716	2,008	-	-	-	-	0	-	0	(0)	(2,462)	-	-	-	(4,425)	**(6,272)**
100%	(465)	377,905	2,030	-	-	-	-	0	-	0	(0)	(1,602)	-	-	-	(3,079)	**(4,364)**
100%	(486)	382,040	2,053	-	-	-	-	0	-	0	(0)	(1,492)	-	-	-	(3,109)	**(4,407)**
100%	(591)	386,125	2,075	-	-	-	-	0	-	0	(0)	(2,336)	-	-	-	(4,724)	**(6,696)**
100%	(710)	390,158	2,097	-	-	-	-	0	-	0	(0)	(2,970)	-	-	-	(6,233)	**(8,834)**
100%	(657)	394,139	2,119	-	-	-	-	0	-	0	(0)	(2,642)	-	-	-	(5,480)	**(7,768)**
100%	(525)	15,248	1,203	-	-	-	-	0	-	0	(0)	(1,443)	-	-	-	(4,202)	**(5,861)**
100%	(373)	19,125	101	-	-	-	-	0	-	0	(0)	(1,620)	-	-	-	(4,333)	**(6,043)**
100%	(472)	22,952	124	-	-	-	-	0	-	0	(0)	(2,162)	-	-	-	(5,604)	**(7,817)**
100%	(448)	26,726	146	-	-	-	-	0	-	0	(0)	(2,311)	-	-	-	(5,545)	**(7,734)**
0%	-	47,090	217	-	-	-	-	0	-	0	(0)	(3,151)	(1,182)	-	-	(20,544)	**(28,652)**
0%	-	61,504	319	-	-	-	-	0	-	0	(0)	(2,789)	(1,046)	-	-	(18,056)	**(25,183)**
0%	-	70,808	389	-	-	-	-	0	-	0	(0)	(1,809)	(678)	-	-	(11,527)	**(16,077)**
0%	-	78,988	440	-	-	-	-	0	-	0	(0)	(1,597)	(599)	-	-	(10,085)	**(14,065)**
0%	-	87,508	489	-	-	-	-	0	-	0	(0)	(1,672)	(627)	-	-	(10,525)	**(14,679)**
0%	-	97,821	544	-	-	-	-	0	-	0	(0)	(2,033)	(762)	-	-	(12,849)	**(17,921)**
0%	-	110,147	611	-	-	-	-	0	-	0	(0)	(2,441)	(916)	-	-	(15,474)	**(21,582)**
0%	-	121,493	680	-	-	-	-	0	-	0	(0)	(2,258)	(847)	-	-	(14,196)	**(19,800)**
0%	-	130,518	740	-	-	-	-	0	-	0	(0)	(1,804)	(677)	-	-	(11,148)	**(15,549)**
0%	-	136,896	785	-	-	-	-	0	-	0	(0)	(1,281)	(481)	-	-	(7,657)	**(10,679)**
0%	-	144,942	828	-	-	-	-	0	-	0	(0)	(1,624)	(609)	-	-	(9,874)	**(13,771)**
0%	-	152,533	874	-	-	-	-	0	-	0	(0)	(1,540)	(577)	-	-	(9,270)	**(12,929)**
= Col 14 / Col 2	Input	See "RateBase-G", Col 9	= (Prev Col 15 + Col 15) / 2 * Monthly AT WACC	= Prev Col 19	Input	= Col 17 + Col 18	= (Prev Col 19 + Col 19) / 2 * Monthly AT WACC	Previous Col 23 + Col 1 of "Balances" Wkst	Input	= (Prev Col 21 - Col 22)	= (Prev Col 23 + Col 23) / 2 * Monthly AT WACC	= Input * Fed Tax Rate	= Input * Fed Tax Rate	Input	Input	= Col 2 + Col 5 + Col 8 + Col 11 + Col 16 + Col 18+ Col 20+ Col 25+ Col 25 + Col 26+ Col 28	= Col 29 * Rev Fct + Col 3 + Col 6
	(53,771)		20,827						(14,038)		(431)	(44,775)	-	-	(24)	(115,091)	**(163,130)**
	(6,978)		17,893						-		(0)	(27,569)	-	-	0	(62,366)	**(87,951)**
	-		6,917						-		(0)	(24,000)	(9,000)	-	-	(151,206)	**(210,888)**
	-		14,383						-		(0)	(24,000)	(9,000)	-	-	(108,740)	**(151,660)**
	-		19,961						-		(0)	(24,000)	(9,000)	-	-	(83,162)	**(115,986)**
	-		24,129						-		(0)	(24,000)	(9,000)	-	-	(58,994)	**(82,279)**
	-		26,766						-		(0)	(24,000)	(9,000)	-	-	(33,243)	**(46,364)**

PSE&G 2024 TAX ADJUSTMENT CREDIT
Gas Over/(Under) Calculation

2/29/2024

Reflects a tax rate of	28.11%

Monthly Calculation	(1) Over / (Under) Recovery Beginning Balance	(2) Gas Revenues	(3) Revenue Requirement Excluding WACC Cost	(4) Over / (Under) Recovery	(5) Over / (Under) Recovery Ending Balance	(6) Over / (Under) Average Monthly Balance	(7) Interest Rate (Annualized)	(8) Interest On Over / (Under) Average Monthly Balance	(9) Interest Roll-In	(10) Cumulative Interest
Jan-23	(36,306,427)	(13,096,988)	(14,878,963)	1,781,975	(34,524,452)	(35,415,440)	0.16%	(3,395)	-	(27,117)
Feb-23	(34,524,452)	(13,235,538)	(14,812,316)	1,576,779	(32,947,674)	(33,736,063)	4.64%	(93,778)	-	(120,895)
Mar-23	(32,947,674)	(12,211,930)	(23,854,270)	11,642,340	(21,305,333)	(27,126,504)	4.78%	(77,680)	-	(198,575)
Apr-23	(21,305,333)	(5,842,578)	(8,423,563)	2,580,985	(18,724,349)	(20,014,841)	5.32%	(63,790)	-	(262,365)
May-23	(18,724,349)	(3,871,963)	(7,630,464)	3,758,501	(14,965,848)	(16,845,098)	5.32%	(53,687)	-	(316,052)
Jun-23	(14,965,848)	(2,577,268)	(13,208,659)	10,631,391	(4,334,457)	(9,650,152)	5.54%	(32,028)	-	(348,080)
Jul-23	(4,334,457)	(2,383,298)	(17,378,660)	14,995,362	10,660,906	3,163,224	5.25%	9,949	-	(338,131)
Aug-23	10,322,774	(3,132,098)	(15,134,652)	12,002,554	22,325,328	16,324,051	5.21%	50,980	(338,131)	50,980
Sep-23	22,325,328	(3,444,610)	(7,082,188)	3,637,578	25,962,906	24,144,117	5.21%	75,403	-	126,383
Oct-23	25,962,906	(5,826,423)	(11,686,055)	5,859,632	31,822,538	28,892,722	5.49%	94,941	-	221,324
Nov-23	31,822,538	(14,259,480)	(12,222,234)	(2,037,246)	29,785,292	30,803,915	5.43%	100,132	-	321,456
Dec-23	29,785,292	(18,013,458)	(16,817,695)	(1,195,762)	28,589,530	29,187,411	5.49%	95,909	-	417,365
Jan-24	29,006,895	(23,089,715)	(12,272,354)	(10,817,361)	18,189,534	23,598,214	5.52%	78,010	417,365	78,010
Feb-24	18,189,534	(20,224,219)	(9,883,955)	(10,340,264)	7,849,270	13,019,402	5.49%	42,813	-	120,822
Mar-24	7,849,270	(13,222,206)	(6,271,509)	(6,950,697)	898,573	4,373,921	5.49%	14,383	-	135,205
Apr-24	898,573	(7,643,680)	(4,363,905)	(3,279,775)	(2,381,202)	(741,315)	5.49%	(2,438)	-	132,768
May-24	(2,381,202)	(4,745,002)	(4,406,692)	(338,310)	(2,719,512)	(2,550,357)	5.49%	(8,387)	-	124,381
Jun-24	(2,719,512)	(2,923,482)	(6,696,151)	3,772,669	1,053,157	(833,178)	5.49%	(2,740)	-	121,641
Jul-24	1,053,157	(2,809,145)	(8,834,006)	6,024,861	7,078,018	4,065,587	5.49%	13,369	-	135,010
Aug-24	7,078,018	(2,498,658)	(7,767,902)	5,269,244	12,347,262	9,712,640	5.49%	31,939	-	166,949
Sep-24	12,514,211	(5,043,051)	(5,860,996)	817,945	13,332,156	12,923,184	5.49%	42,496	166,949	42,496
Oct-24	13,332,156	(9,721,486)	(6,042,652)	(3,678,834)	9,653,322	11,492,739	5.49%	37,792	-	80,289
Nov-24	9,653,322	(18,944,451)	(7,816,560)	(11,127,892)	(1,474,570)	4,089,376	5.49%	13,447	-	93,736
Dec-24	(1,474,570)	(28,392,540)	(7,734,236)	(20,658,305)	(22,132,874)	(11,803,722)	5.49%	(38,815)	-	54,921
Jan-25	(22,132,874)	(33,133,711)	(28,652,300)	(4,481,411)	(26,614,285)	(24,373,580)	5.49%	(80,149)	-	(25,228)
Feb-25	(26,614,285)	(29,420,772)	(25,183,317)	(4,237,455)	(30,851,740)	(28,733,013)	5.49%	(94,485)	-	(119,713)
Mar-25	(30,851,740)	(25,043,485)	(16,076,840)	(8,966,645)	(39,818,385)	(35,335,063)	5.49%	(116,195)	-	(235,908)
Apr-25	(39,818,385)	(14,477,493)	(14,065,459)	(412,034)	(40,230,419)	(40,024,402)	5.49%	(131,615)	-	(367,523)
May-25	(40,230,419)	(8,987,258)	(14,679,153)	5,691,895	(34,538,524)	(37,384,471)	5.49%	(122,934)	-	(490,457)
Jun-25	(34,538,524)	(5,537,214)	(17,921,007)	12,383,793	(22,154,731)	(28,346,628)	5.49%	(93,214)	-	(583,671)
Jul-25	(22,154,731)	(5,320,654)	(21,581,884)	16,261,230	(5,893,502)	(14,024,116)	5.49%	(46,116)	-	(629,787)
Aug-25	(5,893,502)	(4,732,576)	(19,799,591)	15,067,015	9,173,513	1,640,006	5.49%	5,393	-	(624,394)
Sep-25	9,173,513	(5,043,051)	(15,548,502)	10,505,450	19,678,964	14,426,238	5.49%	47,439	-	(576,956)
Oct-25	19,678,964	(9,721,486)	(10,678,661)	957,174	20,636,138	20,157,551	5.49%	66,285	-	(510,670)
Nov-25	20,636,138	(18,944,451)	(13,771,379)	(5,173,072)	15,463,066	18,049,602	5.49%	59,354	-	(451,316)
Dec-25	15,463,066	(28,392,540)	(12,929,475)	(15,463,066)	(0)	7,731,533	5.49%	25,424	-	(425,892)
	(Prior Col 5) + (Col 9)	Forecasted Therms * Proposed Rate	See Revenue Requirements Schedule for Details	Col 2 - Col 3	Col 1 + Col 4	(Col 1 + Col 5) / 2	Input	(Col 6 * (Col 7) / 12)*net of tax rate		Prior Month + Col 8 - Col 9

Exhibit P-9 R-1

Schedule SS-TAC-4 R-1

PSE&G 2024 TAX ADJUSTMENT CREDIT
Weighted Average Cost of Capital

	Percent	Embedded Cost	Weighted Cost	Pre-Tax Weighted Cost	After-Tax Weighted Cost
Long-Term Debt	45.53%	3.96%	1.80%	1.80%	1.30%
Customer Deposits	0.47%	0.87%	0.00%	0.00%	0.00%
Common Equity	54.00%	9.60%	5.18%	7.21%	5.18%
Total	100.00%		6.99%	9.02%	6.48%

Federal Tax Rate	21.00%
State Tax Rate	9.00%
Fed Benefit of State Tax Deduction	-1.89%
Effective Tax Rate	28.11%

PSE&G 2024 TAX ADJUSTMENT CREDIT
Revenue Factor

	ELECTRIC	GAS
Revenue Increase	100.0000	100.0000
Uncollectible Rate		0.0000
BPU Assessment Rate	0.2176	0.2176
Rate Counsel Assessment Rate	0.0455	0.0455
Income before State of NJ Bus. Tax	99.7369	99.7369
State of NJ Bus. Income Tax	8.9763	8.9763
Income Before Federal Income Taxes	90.7606	90.7606
Federal Income Taxes	19.0597	19.0597
Return	71.7008	71.7008
Revenue Factor	**1.3947**	**1.3947**

Exhibit P-9 R-1

Schedule SS-TAC-6G R-1

PSE&G 2024 TAX ADJUSTMENT CREDIT

Proposed GTAC Calculation

($'s Unless Specified)

Current SUT Rate 6.625%

Line		Gas									Source/Description
		RSG	GSG	LVG	SLG	TSG-F	TSG-NF	CIG	CSG	Total	
1	2024 Sales (Therms)	1,543,180	293,032	762,138	712	22,111	132,909	25,998	756,546	3,536,626	Input
2	Rate Class Allocation[1]	71.80%	11.57%	14.07%	0.05%	0.37%	1.12%	0.32%	0.70%	100.00%	CreditCalc-G TAC 2023
3	Revenue Requirements	(71,551,609)	(11,531,277)	(14,025,734)	(48,580)	(367,156)	(1,115,024)	(319,281)	(698,133)	(99,656,794)	CreditCalc-G TAC 2023
4	Proposed Rate w/o SUT ($/Therms)	(0.046366)	(0.039352)	(0.018403)	(0.068269)	(0.016605)	(0.008389)	(0.012281)	(0.000923)		CreditCalc-G TAC 2023
5	Public Notice Rate w/o SUT ($/Therms)	(0.046366)	(0.039352)	(0.018403)	(0.068269)	(0.016605)	(0.008389)	(0.012281)	(0.000923)		CreditCalc-G TAC 2023
6	Proposed Rate w/ SUT ($/Therms)	(0.049438)	(0.041959)	(0.019622)	(0.072792)	(0.017705)	(0.008945)	(0.013095)	(0.000984)		CreditCalc-G TAC 2023
7	Sep-24 to Dec-25 Sales (Therms)	2,018,198	382,237	996,561	922	30,182	169,761	38,388	1,033,497	4,669,747	
8	Rate Class Allocation	73.65%	11.87%	14.44%	0.05%					100.00%	Line 2 / Sum Line 2
9	Revenue Requirements	(184,743,551)	(29,773,322)	(36,213,916)	(125,433)	0	0	0	0	(250,856,221)	(SS-TAC-1, ln 4 [Gas]) * Line 8 * 1000
10	Proposed Rate w/o SUT ($/Therms)	(0.091539)	(0.077892)	(0.036339)	(0.135989)	0.000000	0.000000	0.000000	0.000000		(Line 7 / (Line 9 * 1,000)) [Rnd 6]
11	Public Notice Rate w/o SUT ($/Therms)										
12	Proposed Rate w/ SUT ($/Therms)	(0.097603)	(0.083052)	(0.038746)	(0.144998)	0.000000	0.000000	0.000000	0.000000		(Line 10 * (1 + SUT Rate)) [Rnd 6]
13	Jun-23 to May 24 Sales (Therms)	1,584,498	302,113	778,914	695	22,584	124,946	27,874	702,392	3,544,017	Input
14	Annulization Factor	78.51%	79.04%	78.16%	75.39%						(Line 7) / (Line 13)
15	Annualized Revenue Requirements	(145,043,157)	(23,532,228)	(28,304,853)	(94,567)					(196,974,806)	(Line 9) * (Line 14)
16	Filed Rates 2024	(0.044386)	(0.039352)	(0.018403)	(0.068269)	(0.016605)	(0.008389)	(0.012281)	(0.000923)		Line 4
17	Test Year Revenue Requirements at Filed Rates 2024	(70,329,549)	(11,888,740)	(14,334,346)	(47,475)	(375,012)	(1,048,176)	(342,326)	(648,308)	(99,013,932)	(Line 13 * Line 16)*1000
18	Annualized Change	(74,713,608)	(11,643,487)	(13,970,508)	(47,093)	375,012	1,048,176	342,326	648,308	(97,960,874)	Line 15 - Line 17
19	16 Month Revenue Requiremnets at Filed 2024 Rates	(89,579,756)	(15,041,810)	(18,339,710)	(62,970)	(501,179)	(1,424,126)	(471,437)	(953,918)	(126,374,904)	(Line 7 * Line 16)*1000

[1]Rate Class Allocation remains the same and stays in effect until the conclusion of the Company's next Base Rate Case

PSE&G Gas - Storm Recovery Charge
SRC Gas Rate Calculation
($'s - Unless noted)

Line No.	Calculation	Description	
1		Deferred Storm Cost Balance as of 9/1/24	3,746,979
2		Estimated Interest Expenses	297,041
3	=(1+2)/3 Years	Estimated Annual Revenue Requirement	1,348,007
4		Forecasted Annual Therms	2,749,512,775
5	=3/4	Proposed SRC (per therm excluding Sales & Use Tax)	0.000490
6	=5*(1+SUT%)	Proposed SRC (per therm Including Sales and Use Tax)	0.000522
7		Existing SRC (per therm Including Sales & Use Tax)	0.000000
8	=(5-7)*4	Storm Recovery Charge Increase / (Decrease)	1,347,261

PSE&G Gas - Storm Recovery Charge
Balance Over/(Under) and Interest Calculation

($'s - Unless noted)

	(1)	(2)	(3)	(4)	(5)	(6)
	Input	Input	Prior Col 6 - Col 1 + Col 2	Input	(Prior Col 6 + Col 3) / 2 * (Col 4 / 12)	Col 3 + Col 5
Month	SRC Revenue	Incremental Deferred Major Storm Expenses	Prior Month (Over)/Under Balance + Monthly Activity)	Annual Interest Rate	Interest Expense	SRC Balance - (Over)/Under
Aug-24						3,746,979
Sep-24	35,782	-	3,711,197	5.43%	16,862	3,728,059
Oct-24	67,758	-	3,660,300	5.43%	16,704	3,677,004
Nov-24	144,466	-	3,532,539	5.43%	16,300	3,548,838
Dec-24	201,279	-	3,347,559	5.43%	15,592	3,363,151
Jan-25	240,101	-	3,123,050	5.43%	14,664	3,137,714
Feb-25	211,283	-	2,926,432	5.43%	13,710	2,940,142
Mar-25	181,433	-	2,758,708	5.43%	12,884	2,771,592
Apr-25	104,854	-	2,666,738	5.43%	12,295	2,679,033
May-25	63,937	-	2,615,096	5.43%	11,969	2,627,065
Jun-25	41,017	-	2,586,048	5.43%	11,786	2,597,834
Jul-25	34,804	-	2,563,030	5.43%	11,668	2,574,698
Aug-25	34,294	-	2,540,403	5.43%	11,564	2,551,968
Sep-25	35,274	-	2,516,694	5.43%	11,459	2,528,154
Oct-25	67,765	-	2,460,388	5.43%	11,278	2,471,667
Nov-25	145,018	-	2,326,649	5.43%	10,848	2,337,497
Dec-25	199,730	-	2,137,767	5.43%	10,118	2,147,884
Jan-26	235,665	-	1,912,219	5.43%	9,179	1,921,399
Feb-26	207,959	-	1,713,440	5.43%	8,218	1,721,658
Mar-26	178,688	-	1,542,969	5.43%	7,381	1,550,350
Apr-26	102,902	-	1,447,448	5.43%	6,778	1,454,225
May-26	64,059	-	1,390,167	5.43%	6,431	1,396,597
Jun-26	40,112	-	1,356,486	5.43%	6,224	1,362,710
Jul-26	34,301	-	1,328,409	5.43%	6,084	1,334,493
Aug-26	33,555	-	1,300,938	5.43%	5,958	1,306,896
Sep-26	34,789	-	1,272,107	5.43%	5,831	1,277,938
Oct-26	66,996	-	1,210,942	5.43%	5,627	1,216,569
Nov-26	144,727	-	1,071,841	5.43%	5,174	1,077,015
Dec-26	196,255	-	880,760	5.43%	4,426	885,187
Jan-27	234,469	-	650,718	5.43%	3,472	654,190
Feb-27	206,055	-	448,136	5.43%	2,492	450,628
Mar-27	176,755	-	273,872	5.43%	1,638	275,510
Apr-27	102,255	-	173,256	5.43%	1,015	174,270
May-27	63,677	-	110,593	5.43%	644	111,237
Jun-27	39,088	-	72,149	5.43%	415	72,564
Jul-27	33,771	-	38,793	5.43%	252	39,045
Aug-27	32,848	-	6,197	5.43%	102	6,299

PSE&G Electric - Storm Recovery Charge
Over/(Under) Balance and Interest Calculation
($'s - Unless noted)

(1)	(2)	(3)
Input	Input	[Schedule SS-SRC-1G R-1] Line 5 x Col 2
Rate Class	**Annual Therms**	**Annual Revenue**
RSG	1,529,513,058	749,461
GSG	289,505,767	141,858
LVG	757,509,975	371,180
SLG	678,864	333
TSG-F	20,993,520	10,287
TSG-NF	126,216,004	61,846
CIG	25,095,588	12,297
Total	2,749,512,775	1,347,261

PSE&G Societal Benefits Charge
Calculation of Cost Recovery - Gas Social Programs
($000)

Exhibit P-9G R-1
Schedule SS-SBC-1 R-1

CALCULATION OF COST RECOVERY FACTOR

GAS **($000's)**

	PERIOD	SOCIAL PROGRAMS	
BEGINNING OVER/(UNDER) BALANCE INCLUDING INTEREST	8/31/2024	$0	
ACTUAL REVENUES	N/A	$0	
ACTUAL EXPENSES	N/A	$0	
INTEREST	N/A	$0	
OVER/(UNDER) BALANCE INCLUDING INTEREST	N/A	$0	
FORECAST REVENUES	N/A	$0	
FORECAST EXPENSES	N/A	$0	
INTEREST	N/A	$0	
OVER/(UNDER) BALANCE INCLUDING INTEREST	8/31/2024	$0	
BALANCE TO BE COLLECTED/(RETURNED) TO CUSTOMERS	8/31/2024	$0	
ESTIMATED EXPENSES TO BE COLLECTED	9/1/24 - 8/31/25	$34,459	
TOTAL TO BE COLLECTED/(RETURNED) TO CUSTOMERS	9/1/24 - 8/31/25	$34,459	
THERM SALES (9/1/2024-8/31/2025)		2,749,513	therm sales from current GAS SBC filing
DOLLAR PER THERM		$0.012533	
REVENUE IMPACT (9/1/2024-8/31/2025)		$34,459.6436	

CALCULATION OF REVENUE IMPACT
($000's)

	SOCIAL
REVISED RATE PER THERM	0.012533
CURRENT RATE PER THERM	0.000000
DIFFERENCE	0.012533
THERM SALES (000s) (03/01/23 - 2/29/24)	2,749,513
REVENUE IMPACT (9/01/24 - 8/31/25)	$34,460

	estimate	estimate	estimate	estimate	estimate
SOCIAL PROGRAMS	**Sep-24**	**Oct-24**	**Nov-24**	**Dec-24**	**Jan-25**
BEGINNING BALANCE	$0	($2,829)	($2,648)	($2,746)	($3,184)
REVENUES RECOVERY	$906	$1,716	$3,658	$5,096	$6,079
BAD DEBT EXPENSE	($3,735)	($1,535)	($3,755)	($5,534)	($3,413)
OVER/(UNDER) COLLECTED	($2,829)	$181	($97)	($438)	$2,667
ACCUMULATED BALANCE	**($2,829)**	**($2,648)**	**($2,746)**	**($3,184)**	**($517)**
INTEREST CALCULATION:					
PRIOR BALANCE	$0	($2,829)	($2,648)	($2,746)	($3,184)
CURRENT BALANCE	($2,829)	($2,648)	($2,746)	($3,184)	($517)
(PRIOR BAL + CURRENT BAL)/2	($1,415)	($2,739)	($2,697)	($2,965)	($1,850)
INTEREST	($5)	($9)	($9)	($10)	($6)
INTEREST RATE	5.52%	5.52%	5.52%	5.52%	5.52%
CUMULATIVE INTEREST	**($5)**	**($14)**	**($23)**	**($32)**	**($39)**

PSE&G Societal Benefits Charge
Over / (Under) Balance

Exhibit P-9G R-1
Schedule SS-SBC-2 R-1

	estimate	estimate	estimate	estimate	estimate
SOCIAL PROGRAMS	**Feb-25**	**Mar-25**	**Apr-25**	**May-25**	**Jun-25**
BEGINNING BALANCE	($517)	$3,420	$6,901	$7,443	$6,450
REVENUES RECOVERY	$5,350	$4,594	$2,655	$1,619	$1,039
BAD DEBT EXPENSE	($1,413)	($1,113)	($2,113)	($2,613)	($2,213)
OVER/(UNDER) COLLECTED	$3,937	$3,481	$542	($994)	($1,174)
ACCUMULATED BALANCE	**$3,420**	**$6,901**	**$7,443**	**$6,450**	**$5,276**
INTEREST CALCULATION:					
PRIOR BALANCE	($517)	$3,420	$6,901	$7,443	$6,450
CURRENT BALANCE	$3,420	$6,901	$7,443	$6,450	$5,276
(PRIOR BAL + CURRENT BAL)/2	$1,451	$5,161	$7,172	$6,947	$5,863
INTEREST	$5	$17	$24	$23	$19
INTEREST RATE	5.52%	5.52%	5.52%	5.52%	5.52%
CUMULATIVE INTEREST	**($34)**	**($17)**	**$7**	**$30**	**$49**

PSE&G Societal Benefits Charge
Over / (Under) Balance

Exhibit P-9G R-1
Schedule SS-SBC-2 R-1

	estimate	estimate
SOCIAL PROGRAMS	**Jul-25**	**Aug-25**
BEGINNING BALANCE	$5,276	$2,045
REVENUES RECOVERY	$881	$868
BAD DEBT EXPENSE	($4,113)	($2,913)
OVER/(UNDER) COLLECTED	($3,231)	($2,044)
ACCUMULATED BALANCE	**$2,094**	**$0**
INTEREST CALCULATION:		
PRIOR BALANCE	$5,276	$2,045
CURRENT BALANCE	$2,094	$0
(PRIOR BAL + CURRENT BAL)/2	$3,685	$1,022
INTEREST	$12	$3
INTEREST RATE	5.52%	5.52%
CUMULATIVE INTEREST	**$62**	**$65**

PSE&G Societal Benefits Charge
Revenue Change By Rate Schedule

Exhibit P-9G R-1
Schedule SS-SBC-3 R-1

($'s - Unless noted)

(1)	(2)	(3)
Input	Input	[Schedule SS-SRC-1G] Line 5 x Col 2
Rate Schedule	**Annual Therms**	**Annual Revenue**
RSG	1,529,513,058	19,169,387
GSG	289,505,767	3,628,376
LVG	757,509,975	9,493,873
SLG	678,864	8,508
TSG-F	20,993,520	263,112
TSG-NF	126,216,004	1,581,865
CIG	25,095,588	314,523
Total	2,749,512,775	34,459,644

STATE OF NEW JERSEY

BOARD OF PUBLIC UTILITIES

**In the Matter of the Petition of
Public Service Electric and Gas Company
for Approval of an Increase in Electric and Gas
Rates and for Changes in the Tariffs for
Electric and Gas Service, B.P.U.N.J.
No. 17 Electric and B.P.U.N.J. No. 17
Gas, and for Changes in Depreciation Rates,
Pursuant to N.J.S.A. 48:2-18,
N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1, and
for Other Appropriate Relief**

BPU Docket Nos. ER23120924 and GR23120925

DIRECT TESTIMONY

OF

AHMAD FARUQUI

PRINCIPAL EMERITUS

THE BRATTLE GROUP

April 15, 2024
P-10 R-1

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
DIRECT TESTIMONY
OF
AHMAD FARUQUI
PRINCIPAL EMERITUS - THE BRATTLE GROUP

Q. What is your name?

A. Ahmad Faruqui.

Q. What is your affiliation?

A. I am a Principal Emeritus with The Brattle Group.

Q. What are your qualifications?

A. I am an economist by training and have advised utilities, regulatory bodies, governments and legislative councils on all six continents. My CV is appended as Schedule AF-1.

Q. What is the topic of your testimony?

A. I am testifying in support of PSE&G's application for developing new time-of-use (TOU) rates for residential customers.

Q. What issues will you address in your testimony?

A. In my testimony, I provide the rationale for why TOU rates are more desirable than flat or inclining block rates, followed by a national overview of the state of TOU deployment. Then, I explain how PSE&G developed its TOU rates and discuss how it intends to deploy them.

Q. Why should rates be aligned with cost causation?

A. Cost causation is one of the fundamental tenets of rate design. It helps to promote economic efficiency and also promotes equity. It's mentioned in Professor Bonbright's widely cited text on public utility regulation.

Q. Why are TOU rates better aligned with cost causation than flat rates or inclining block rates?

A. Consumers don't consume the same amount of electricity around the clock. Electricity consumption varies by day, by month, and by season. In summer peaking utilities, air conditioning load creates a pattern of use that rises with temperature. Often, loads begin to rise in the afternoon and linger on into the evening hours. Load shapes are also driven by customer lifestyles. Since electricity cannot yet be stored in sufficient quantities, extra generation capacity has to be kept in reserve to meet peak loads. It stays idle most of the time and is expensive to install and operate. With flat rates, consumers have no incentive to conserve electricity during peak hours and to use more during off-peak hours. TOU rates provide customers an incentive to reduce peak load and to shift it to off-peak hours.

Q. What is the status of TOU rates in the US?

A. According to the US Energy Information Administration (EIA)[1], as of the year 2022, 380 utilities were offering time-varying rates including TOU rates and dynamic pricing rates to their residential customers. There were 13.1 million customers on these rates, representing 9% of all customers in the nation. However, it's worth noting that the average participant rate is skewed upwards by a few utilities. Nearly 60% of investor-owned utilities offering TOU rates have enrollment rates of less than 1% while some 15% of utilities have participation rates that exceed

[1] Annual Electric Power Industry Report, Form EIA-861, accessed at https://www.eia.gov/electricity/data/eia861/.

15%. Reasons for low enrollment at utilities include poor marketing of the TOU rate, inconvenient design (i.e., long peak period), and/or additional charges to cover the cost of an interval meter (where smart metering has not been deployed).

One of the primary reasons why TOU rate offerings are going up is the widespread deployment of smart meters. According to EIA[2], U.S. electric utilities had about 111 million advanced smart metering infrastructure (AMI) installations, representing 80% of all residential electric customers in 2021.

Q. How many pricing periods are typically to be found in a TOU rate?

A. About two-thirds of the utilities offer TOU rates with two periods and the remaining one-third offer TOU rates with three or more periods.

Q. What is the ratio of peak to off-peak prices in TOU rates?

A. According to the OpenEI database,[3] 85% of TOU rates have a price ratio greater than 2-to-1, with the mean value being 3-to-1. The mean differential between peak and off-peak rates is 12 cents/kWh. TOU rates with three periods have a similar price ratio as those with two period TOU rates and a similar differential.

Q. Based on your experience working with a wide range of utilities in the US and abroad and your review of the literature, why do utilities offer TOU rates?

A. In my view, the foremost reason why utilities offer TOU rates is to help customers manage their energy bills. Customers want choice and offering a TOU rate to them in addition to the existing rate (which could be flat or have an inclining block structure) accommodates that desire.

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[2] US Energy Information Administration, accessed at https://www.eia.gov/tools/faqs/faq.php?id=108&t=3#:~:text=In%202021%2C%20U.S.%20electric%20utilities,electric%20meters%20were%20AMI%20meters.

[3] Utility Rate Database, accessed at https://openei.org/wiki/Utility_Rate_Database.

TOU rates encourage customers to shift their load away from the peak period and helps reduce costs for all customers over the long run. They also encourage off-peak usage which enhances the affordability of newly emerging, climate-friendly technologies, such as electric vehicles (EVs). Well-designed TOU rates represent a win-win situation for customers and their utilities.

Q. What is the typical duration of the peak period?

A. For a long time, utilities developed the duration of the peak period based on a review of prices in the wholesale market. The peak hours used to be 16 hours long and did not appeal to customers. Newer TOU rates, primarily designed to appeal to EV drivers, have much shorter peak periods, typically ranging from 4 to 6 hours. Peak periods used to cover the early afternoon hours, such as noon to 6 pm. Now they occur much later in the afternoon, and often range from 4 pm to 9 pm.

Q. How are the pricing periods developed?

A. Utilities typically develop pricing periods by reviewing recent data on annual hourly load shapes for system marginal costs and annual hourly load shapes for the system as a whole. Sometimes, they also review annual hourly load shapes for the residential class.

Q. How are prices developed by period?

A. Utilities typically develop them by reviewing hourly marginal energy costs and capacity costs for supply (capacity, energy, transmission and distribution). In this proceeding, PSE&G is only proposing changes in the distribution portion of rates. Since customers pay a single amount that includes generation, transmission and distribution, we have developed illustrative rates that include all these components. It's my understanding that the final version of TOU rates will be developed in future Basic Generation Service ("BGS") proceedings.

Q. Are system costs based on embedded or marginal costs?

A. In nearly every case that I am aware of, utilities base their rates on an embedded cost of service study. TOU rates are designed to be revenue-neutral for the class as a whole. Thus, a customer whose load shape resembles that of the class as a whole will see no change in their bill unless they change their load shape. If they lower their peak load and/or shift it to the off-peak period, they will realize bill savings. Peakier-than-average customers will see higher bills unless they reduce their peak load. Customers who are less peaky than the class average will realize immediate savings by choosing a TOU rate and if they lower their peak load, will realize even higher savings.

In a few cases, utilities also review a marginal cost of service study. However, these are only used to determine the ratio between peak and off-peak period charges. The absolute values are still based on an embedded cost of service study.[4]

Q. What are the different ways in which utilities deploy TOU rates to customers?

A. There are three modes of deployment: opt-in, opt-out and mandatory. Opt-in means the rate is offered to all customers. Any customer who wants to take it can sign up for it. Those customers who don't take the optional rate stay on their existing rate. Opt-out means that all customers are rolled over to the rate but any customer who does not want to stay on it can opt-out to another rate, which may be the prior rate or a new rate. Mandatory means that all customers are rolled over to the TOU rate and they have no choice. In Michigan, which has moved all customers to a default TOU rate, customers do have a choice to switch to other rates but they are also TOU rates.

[4] This method of developing rate is also called the equiproportional marginal cost method.

Q. How many TOU rates are deployed on an opt-in basis?

A. Most TOU deployments are on an opt-in basis.

Q. How many TOU rates are deployed on an opt-out basis?

A. In the US, California and Colorado have rolled out TOU rates as the default rate. In California, this was first done by a municipal utility, SMUD, which serves more than half a million customers in Sacramento and surrounding areas. It was then followed by all three large investor-owned utilities which serve 12 million customers. In Canada, the province of Ontario with some four million customers has rolled out TOU rates but they only apply to the energy portion of the rate.

Q. How many TOU rates are deployed on a mandatory basis?

A. The first utility to deploy TOU rates on a mandatory basis was Fort Collins, which serves nearly 69,000 customers. In Michigan, the two large investor-owned utilities, Consumers Energy and DTE, have deployed a TOU rate as the default and given customers a choice to opt-out to other TOU rates.

Q. Are pilots a pre-requisite for deploying TOU rates?

A. No. There have been scores of pilots around the US and many others around the globe. Utilities can safely proceed with offering opt-in TOU rates based on the experiences of other utilities, supplemented with insights gathered by conducting focus groups with their own customers. However, default and mandatory deployments should ideally be preceded by pilots. That has been the case in California, Colorado and Michigan.

Q. Is seasonal variation often found in TOU rates?

A. Yes, it's quite common, particularly in utilities where system load shapes vary across the seasons because of climatic factors, and this causes variation in the cost of service across seasons.

Q. What are the main features of well-designed TOU rates?

A. Well-designed TOU rates are customer-friendly and have short peak periods. They provide customers with an opportunity to save money by shifting their usage during the peak period to off-peak periods. Utilities provide videos on their web portal to educate customers on how they benefit by reducing peak loads and shifting energy consumption to the off-peak period. They often provide a bill calculator that allows customers to find the lowest cost rate that is consistent with their lifestyle. A single individual may have a different lifestyle than a young couple with no children or a family with young children or empty nesters.

Q. How can customers take advantage of TOU rates?

A. The penetration of EVs is growing fast. EVs are often the biggest load in a customer's house. Customers with EVs can set them to charge after midnight, when electricity costs are lowest. Customers with central air conditioning can precool their homes during the off-peak period by lowering their thermostat by a couple of degrees and raising it by a couple of degrees during the peak period. These days, most homes have programmable thermostats that make this a relatively easy task. Since central air conditioning is a big load in the house, this can yield substantial savings by itself. They can do their laundry during the off-peak hours. In addition, they can set the delay button on their dishwasher so it runs after midnight, which usually falls within the off-peak period.

Q. What utilities have successfully deployed opt-in TOU rates?

A. OGE in Oklahoma and APS and SRP in Arizona have successfully recruited large numbers of customers to TOU rates for years. They offer a choice of several TOU rates to their customers. In the past few years, utilities in Georgia, Missouri and New York have begun offering similarly well-designed rates to their customers on an opt-in basis. For additional details on the status of TOU rates in the US, please consult Schedule AF-2.

Q. Why is PSE&G planning to deploy TOU rates?

A. The primary purpose is to better reflect the cost of service. As noted earlier, this will promote economic efficiency and equity. There is a national trend toward TOU rates. This is being driven by a desire to combat climate change via electrification of buildings and transportation, and to manage the cost and operational challenges of that transition. EV deployment is rising fast. It's going to be potentially the biggest user of electricity in homes. Unless customers charge their EVs during off-peak and night time periods, they will end up creating a serious challenge to the grid. With TOU rates, they will be able to lower their charging costs and also reduce the strain on the grid. Of course, as noted earlier, smart meters are a pre-requisite to the widespread deployment of TOU rates.

Additionally, the Residential TOU Program meets PSE&G's commitment set forth in the BPU's CEF-EV Order to address rates for residential EV charging.[5]

Q. What specific TOU rates is PSE&G planning to deploy?

A. PSE&G is planning to offer two TOU rates to its residential customers. One TOU rate is going to be a two-period rate that modifies the existing Residential Load Management ("RLM")

[5] CEF-EV Order at 13 (Stipulation of Settlement, paragraph 33).

rate by shortening the peak period and enhancing the discount during the off-peak period. The other TOU rate will be a three-period TOU rate with a specially discounted night time rate to encourage night-time charging of EVs.

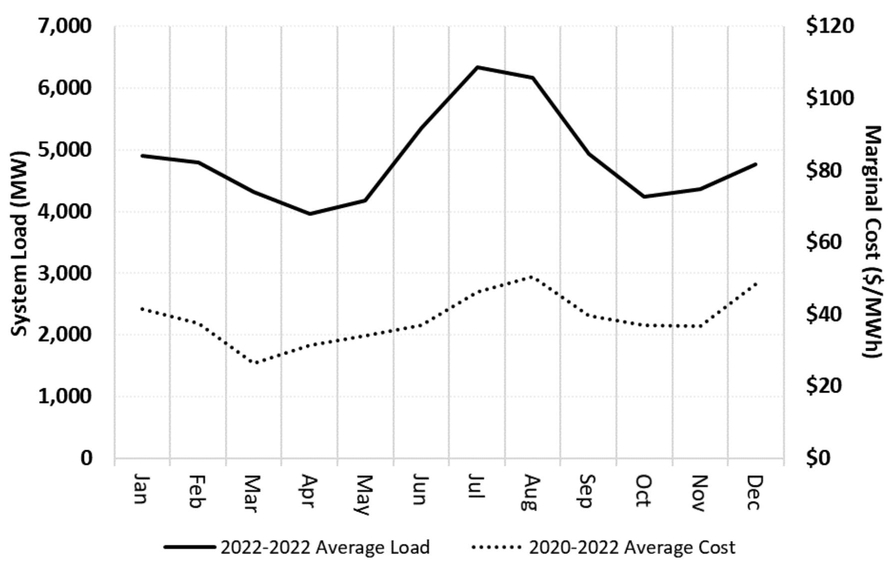
Q. Why is more than one TOU rate being offered?

A. To give customers choice, especially to those who drive EVs.

Q. How were they developed?

A. PSE&G is proposing to develop TOU rates focused on distribution costs in this proceeding. In a later filing, it will develop TOU rates focused on generation energy and capacity costs, transmission costs and all other costs. However, since customers pay a total bill, and not a separate distribution bill, in this testimony I have developed all-in TOU rates. We developed TOU pricing periods by reviewing data on hourly system load shapes, and hourly system marginal costs (equal to Day Ahead Locational Marginal Pricing ("LMPs")). These are summarized in Figure 1. System loads are shown on the vertical axis on the left and marginal costs on the vertical axis on the right.

Figure 1 Average System Load and Marginal Cost by Month (2020-2022)



The figure shows two distinct patterns across the year: winter and summer. Winter has eight months, which goes from October through December and January through May. Summer has four months, from June through September. This also aligns with PSE&G's gas season definition.

Figure 2 Typical Summer Weekday Profile (2020-2022)

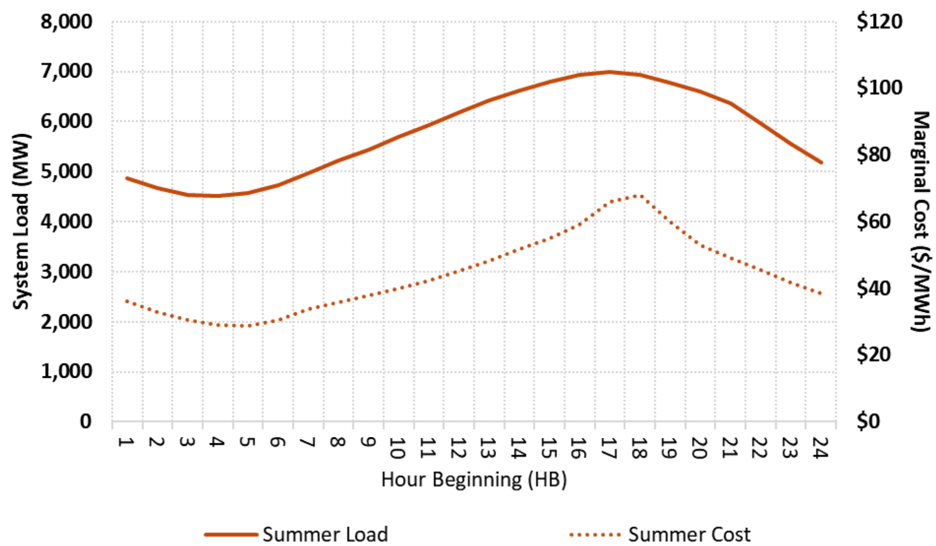
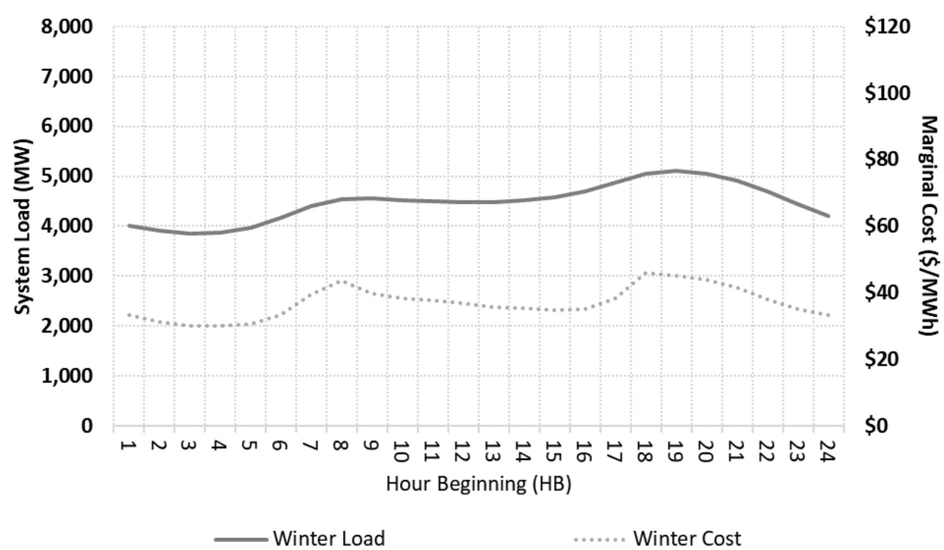


Figure 3 Typical Winter Weekday Profile (2020-2022)



Winter features bimodal peaks with pronounced evening peak while summer features one pronounced evening peak. For simplicity and better customer experience, we propose adopting the same pricing period definitions for all seasons. The two-period TOU rate will have an on-peak time period that runs from 4 P.M. to 9 P.M. (EST) Monday through Friday, which is significantly shorter than the peak period in the existing TOU rate, and very much in line with the newer generation of TOU rates that are being offered in the US.[6] The three-period TOU rate will have the same on-peak period as the two-period TOU rate and will run from 4 P.M. to 9 P.M. (EST) Monday through Friday. In addition, it will have an off-peak period from 12 A.M. to 6 A.M. (EST) in all days that should appeal to EV drivers. All other hours shall constitute the Mid-Peak period.

Q. How did you design the two-period TOU rate?

A. The TOU rates were developed in close concert with Stephen Swetz of PSE&G and were designed to be revenue neutral with the RS rate class. As a starting point, Witness Swetz used PSE&G's embedded cost study for the Residential ("RS"), to develop TOU distribution rates. We designed generation rates to be revenue neutral to current the current RS default generation rates or Basic Generation Service ("BGS") RS rates. We used the Day-Ahead LMPs from PJM as a proxy for the marginal energy cost of generation. For other generation costs, we used costs that were used to develop BGS rates, then adjusted the results to ensure revenue neutrality. We designed transmission rates to be revenue neutral to the RS transmission rates but set rates to recover costs via certain TOU rate periods to better align with cost causation.

For the two-period TOU rate, we first calculated the summer and non-summer peak rates to reflect the generation, transmission, and distribution capacity and the generation energy costs. We allocated the remaining costs (net of revenue from peak hours and revenue from fixed

[6] The definition of current RLM on-peak period is 7 A.M. to 9 P.M. (EST) Monday through Friday during Daylight Savings Time. All other hours are considered as off-peak period.

charges) equally across the off-peak periods, solving for the corresponding rates to ensure revenue neutrality.

The current RS rate varies by season and is a two-tiered, inclining block rate. Under PSE&G's rate proposal, the average residential customer on the RS rate would pay 23 cents/kWh in the summer and 18 cents/kWh in the winter months. This reflects an increase of 24% in summer and an increase of 13% in winter compared to the current RS rate. Both rates are shown in the figure below.

Figure 4 Summary of Current and Proposed RS Rate

		Current RS Rate		Proposed RS Rate	
		Summer	Winter	Summer	Winter
Generation ($/kWh)	0-600	$0.077023	$0.080531	$0.090186	$0.093408
	Over 600	$0.086772		$0.099714	
Distribution ($/kWh)	0-600	$0.047449	$0.035553	$0.080977	$0.047232
	Over 600	$0.051523		$0.085052	
Transmission ($k/kWh)		$0.061233	$0.061233	$0.060495	$0.060495
Average Total Rate ($/kWh)		**$0.187680**	**$0.160734**	**$0.233601**	**$0.181044**
Monthly Charge ($/Month)		$4.95		$8.06	

Figure 5 Summary of Proposed Two-Period TOU Rate

	Two Period TOU			
	Summer		Winter	
	On Peak	Off Peak	On Peak	Off Peak
Generation ($/kWh)	$0.148113	$0.076570	$0.152283	$0.084049
Transmission ($/kWh)	$0.138172	$0.052115	$0.069086	$0.052115
Distribution ($/kWh)	$0.207875	$0.036604	$0.152494	$0.036604
Final Rate ($/kWh)	**$0.494159**	**$0.165289**	**$0.373863**	**$0.172769**
Monthly Charge ($/Month)	$8.06			

Under PSE&G's rate proposal, the average residential customer on the two-period TOU rate would pay 49 cents/kWh during the peak period and 17 cents/kWh during the off-peak period in the summer; in the winter, the corresponding values would be 37 cents/kWh during the peak period and 17 cents/kWh during the off-peak period.

Q. Why did you design a three-period TOU rate in addition to a two-period TOU rate?

A. The three-period TOU rate is designed to appeal to PSE&G's customers that drive electric vehicles ("EVs") but it would be made available to all residential customers.

Q. How did you design the three-period TOU rates?

A. Our methodology is like that of the two-period TOU rate. Like the two-period TOU rate, the three-period TOU rate is also revenue neutral, meaning that it collects the same amount of revenue for the class, before any load shifting.

Figure 6 Summary of Proposed Three-Period TOU Rate

	Three Period TOU					
	Summer			Winter		
	On Peak	**Mid Peak**	**Off Peak**	**On Peak**	**Mid Peak**	**Off Peak**
Generation ($/kWh)	$0.148113	$0.081894	$0.057873	$0.152283	$0.087528	$0.074252
Transmission ($/kWh)	$0.138172	$0.069086	-	$0.069086	$0.069086	-
Distribution ($/kWh)	$0.207875	$0.041730	$0.020864	$0.152494	$0.041730	$0.020864
Final Rate ($/kWh)	**$0.494159**	**$0.192709**	**$0.078738**	**$0.373863**	**$0.198344**	**$0.095116**
Monthly Charge ($/Month)	$8.06					

Under the three-period TOU rate, the average residential customer would pay 49 cents/kWh during the peak period, which is the same as the peak period price in the two-period TOU rate, 19 cents/kWh during the mid-peak period, and 8 cents/kWh during the off-peak period in the summer. In the winter, the corresponding values would be 37 cents/kWh during the peak period, 20 cents/kWh during the mid-peak period and 10 cents/kWh during the off-peak period. The figures below provide graphical illustrations of the rate.

Figure 7 Graphic Illustration of Two-Period TOU Rates (Summer)

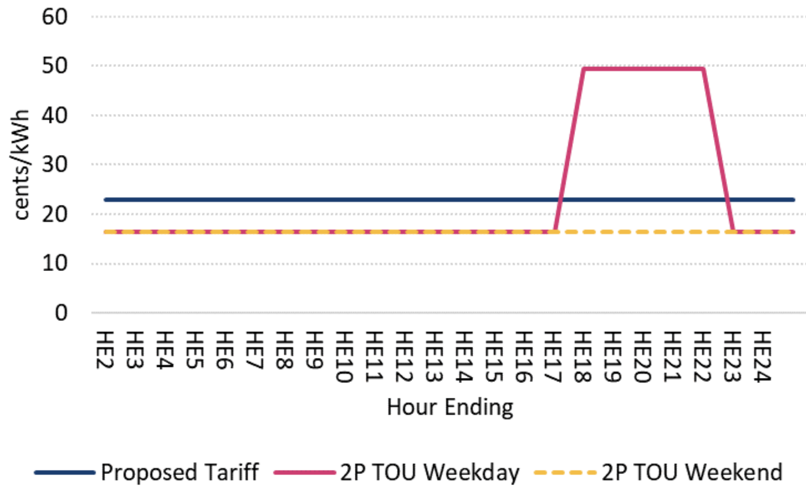
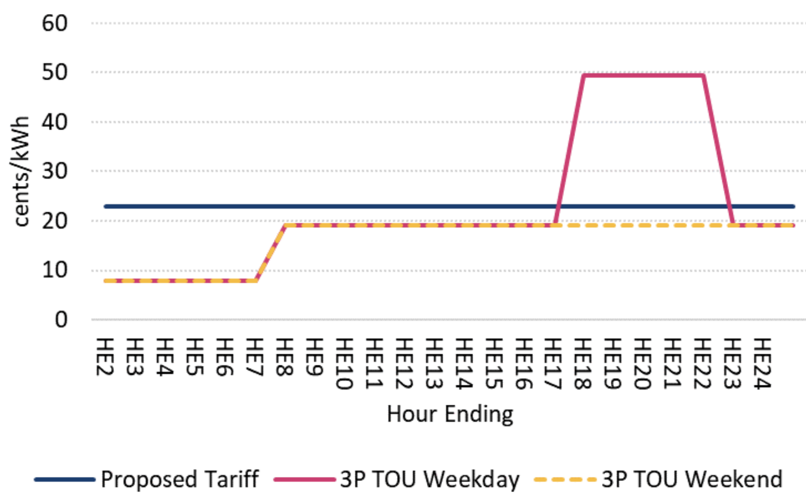


Figure 8 Graphic Illustration of Three-Period TOU Rates (Summer)



Q. How do the proposed TOU rates compare with those being offered by other utilities?

A. Structurally, they are quite similar. Since California has the largest number of customers on TOU rates, and since it also has the largest number of customers with EVs, I have compared PSE&G's rates with those being offered by PG&E, one of the largest investor-owned utilities in the US. It serves some 5 million electric customers in northern California and has a long history of offering TOU rates. It is also the utility which serves my residence. I have been taking service on TOU rates for three decades and drive an EV.

Figure 9 shows the two-period TOU rates for the two utilities and Figure 10 shows their three-period TOU rates. Structurally, the TOU rates are similar but since the average rate levels differ significantly for the two utilities (approximately 23 cents/kWh for PSE&G and approximately 38 cents/kWh for PG&E[7]), PSE&G's customers are always going to be paying less per kWh than PG&E's customers.

Figure 9: Comparison of PSE&G's Two-Period TOU rate with PG&E's

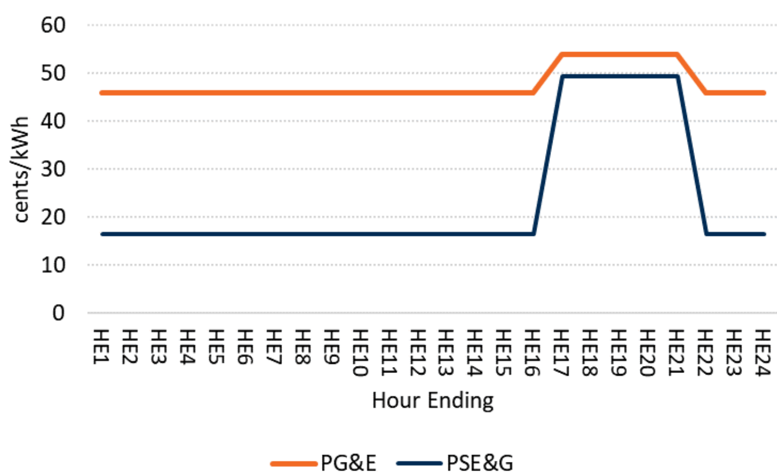
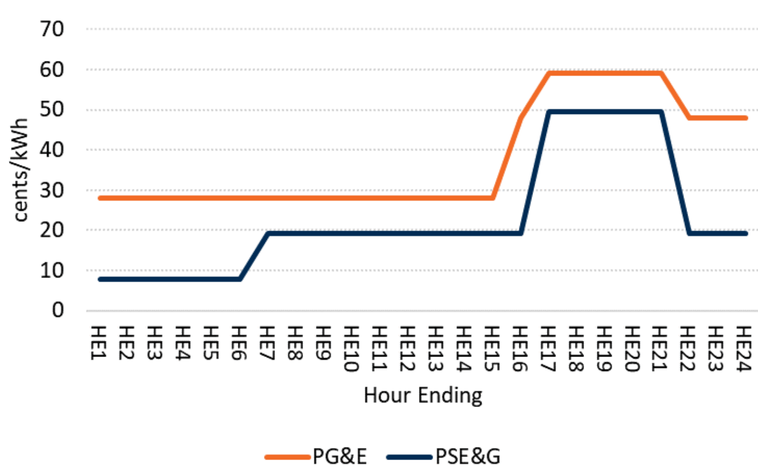


Figure 10: Comparison of PSE&G's Three-Period TOU rate with PG&E's



[7] As of April 1, 2024, PG&E's average rate has risen to 46.9 cents/kWh. The TOU rates have risen accordingly.

Q. Will the pricing periods in the TOU rates change at some point in the future?

A. Yes, they may change in the future if significant changes take place in the time pattern of system loads and system marginal energy and capacity costs. Such changes have occurred in utilities that have had TOU rates in place for decades. I have been on PG&E's TOU rates since the early 1990's. Back then, the on-peak period ran from noon to 6 pm. A decade or two later, it was changed and ran from 2 pm to 7 pm. Now it runs from 4 pm to 9 pm.

Q. Will the levels of the TOU rates change over time?

A. Yes, they may also change over time as significant changes take place in energy and capacity costs by time period.

Q. Are the rates designed to be revenue-neutral for the residential class?

A. Yes, they are. I have estimated the impact of the TOU rates on the average customer in a sample of 170 customers that was provided to me by PSE&G. The results are shown below in Figures 11 and 12, first for the two-period TOU rate, then for the three-period TOU rate. In the figures, positive numbers indicate bill savings and negative numbers indicate bill increases.

Figure 11 Average Bill Impact – Two-Period TOU

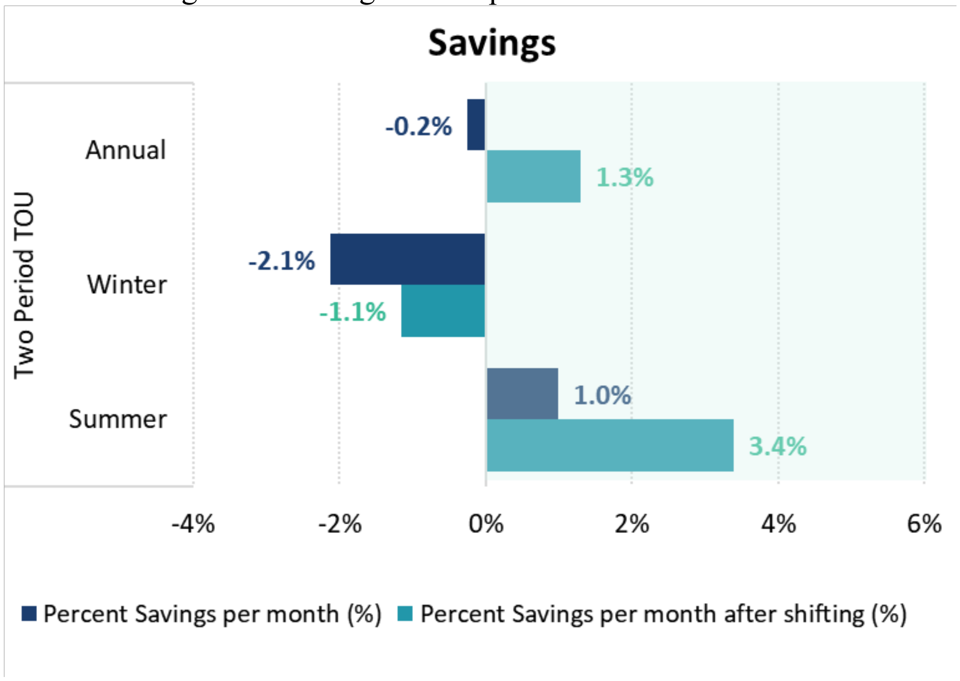
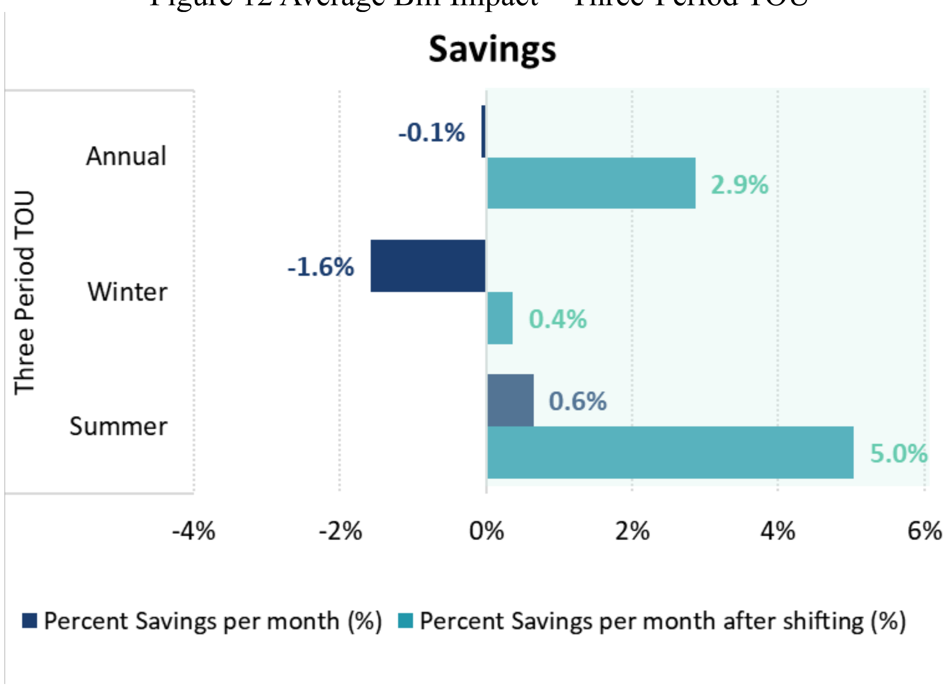


Figure 12 Average Bill Impact – Three-Period TOU



Q. What will be the likely impact of the TOU rates on customer bills?

A. Working with the sample of 170 customers, I estimated how each customer's bill will change if they were to move from the RS to each of the two TOU rates. For each rate, I rank ordered the bill impacts by customer so that the biggest drop in bills occur to the left of the chart and the highest rise in bills occur to the right of the chart. This creates the “propeller charts” that are shown below in Figures 13 and 14. These charts show how the two TOU rates will affect customer bills before they engage in any load shifting. Approximately half of the customers save money simply by switching to the TOU rates, even in the absence of load shifting: 49% in the case of the two-period rate and 48% in the case of the three-period rate.

Figure 13 Monthly Bill Impact on Sample Customers (Two Period TOU, without load shifting)

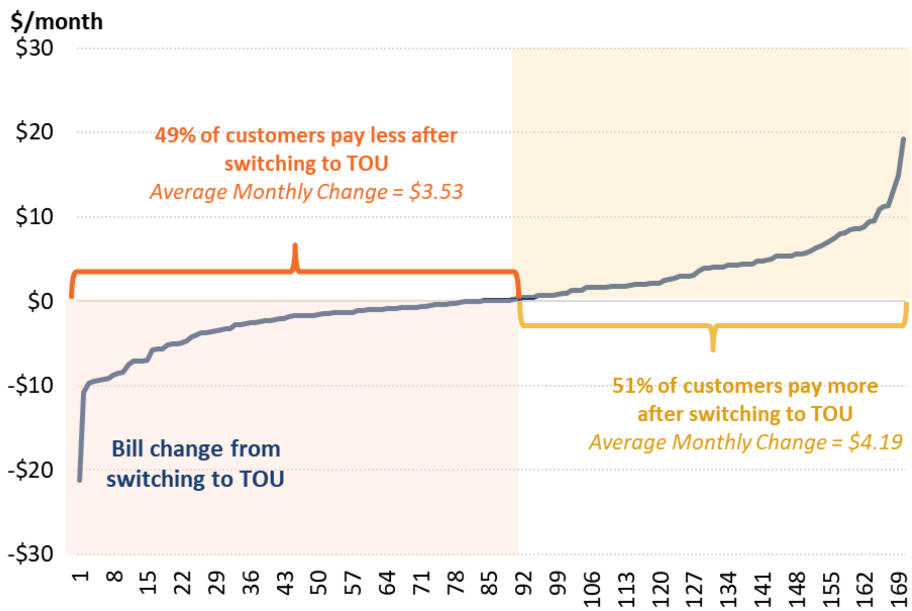
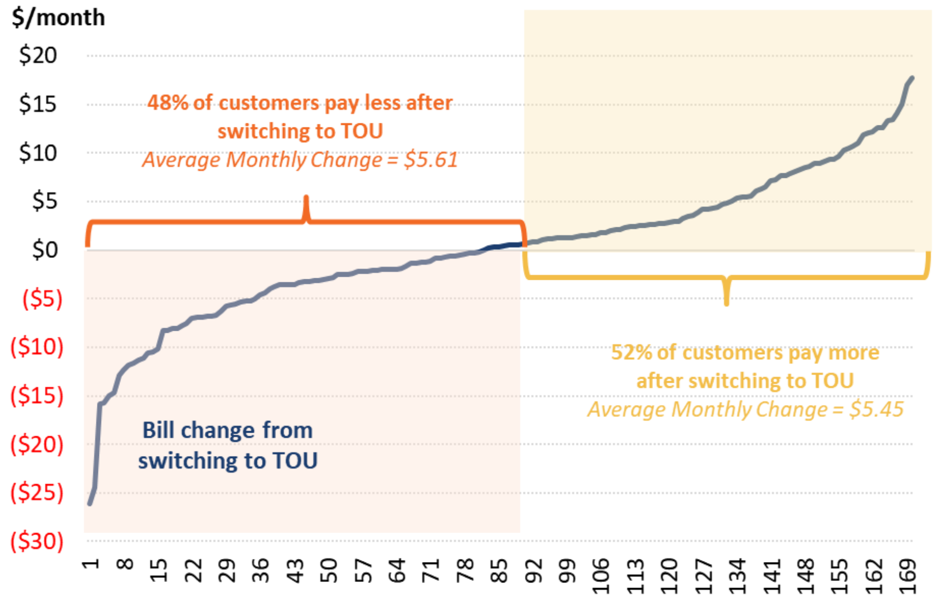


Figure 14 Monthly Bill Impact on Sample Customers (Three Period TOU, without load shifting)



Q. How strong is the incentive to shift loads away from the peak period?

A. Strong price signals exist for shifting load away from the peak period in both the two-period and the three-period TOU rates. For the two-period TOU rate, the peak to off-peak price ratio is about 3:1 to one in summer months, and 2.2:1 for non-summer months. The three-period TOU rate has an even stronger price signal, with a 6.3:1 price ratio during the summer months between on-peak and off-peak period.

Figure 15 Summary of the On-Peak to Off-Peak Ratio

		Residential 2P TOU	Residential 3P TOU
Summer			
On-Peak	$/kWh	$0.494159	$0.494159
Mid-Peak	$/kWh	-	$0.192709
Off-Peak	$/kWh	$0.165289	$0.078738
Winter			
On-Peak	$/kWh	$0.373863	$0.373863
Mid-Peak	$/kWh	-	$0.198344
Off-Peak	$/kWh	$0.172769	$0.095117
On-Peak : (Mid-Peak): Off-Peak Ratios			
Summer		3 :1	6.3 :2.4 :1
Winter		2.2 :1	3.9 :2.1 :1

Q. As a result of the price incentives offered by these two TOU rates, how much will customers lower their peak demand?

A. Customers will have a strong incentive to reduce their peak loads in response to these two TOU rates and to shift that load to the non-peak periods. Using the analytical charts in Arcturus, a Brattle database that contains a meta-analysis of results from more than 400 deployments of time-varying rates around the globe, I would expect to see the following pattern of results for the two TOU rates.[8] In the summer, the two-period TOU rate would induce a drop of 10% in peak load and a drop of 7% in the winter. As for the three-period TOU rate, in the summer it would induce a drop of 16% in peak load and a drop of 12% in the winter.

[8] For the purposes of this testimony, the analysis is carried out using 127 observations pertaining to opt-in deployment of TOU rates from the Arcturus database. For background on Arcturus, please consult: https://www.brattle.com/wp-content/uploads/2023/02/Do-Customers-Respond-to-Time-Varying-Rates-A-Preview-of-Arcturus-3.0.pdf.

Figure 16 The Arc of Price Responsiveness – Two-Period TOU

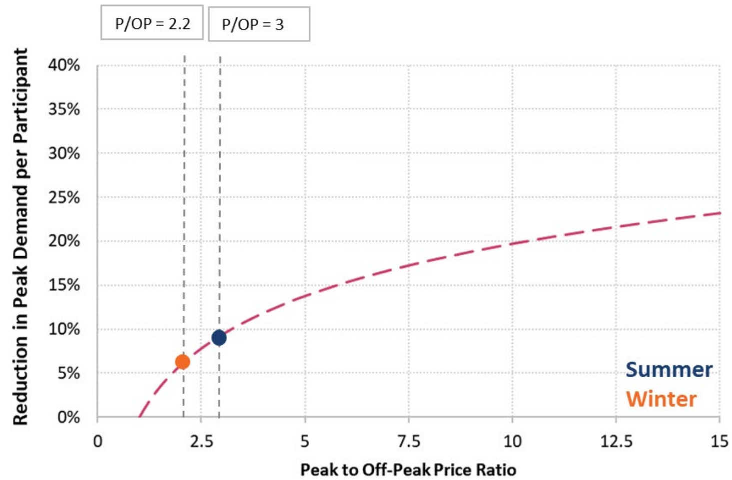
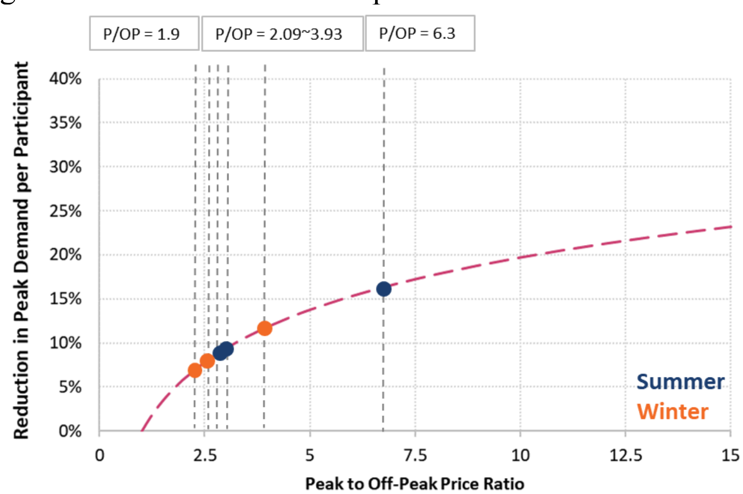


Figure 17 The Arc of Price Responsiveness – Three-Period TOU



Q. When customers respond to TOU rates by reducing their peak loads, will their bills go down?

A. Yes, I would expect them to go down as they shift their usage from a costlier period to the less costly off-peak period in the case of the two-period TOU rate and to the less-costlier mid-peak and off-peak periods in the case of the three-period TOU rate. The propeller charts which include the effect of load shifting away from the peak period are shown below. They show that a greater percentage of customers will see lower bills than the results shown in the previous figures which assumed no load shifting. For the two-period rate, 69% of customers save money, compared to 49% in the absence of load shifting. For the three-period rate, 78% save money, compared to 48% in the absence of load shifting.

Figure 18 Monthly Bill Impact on Sample Customers (Two Period TOU, with load shifting)

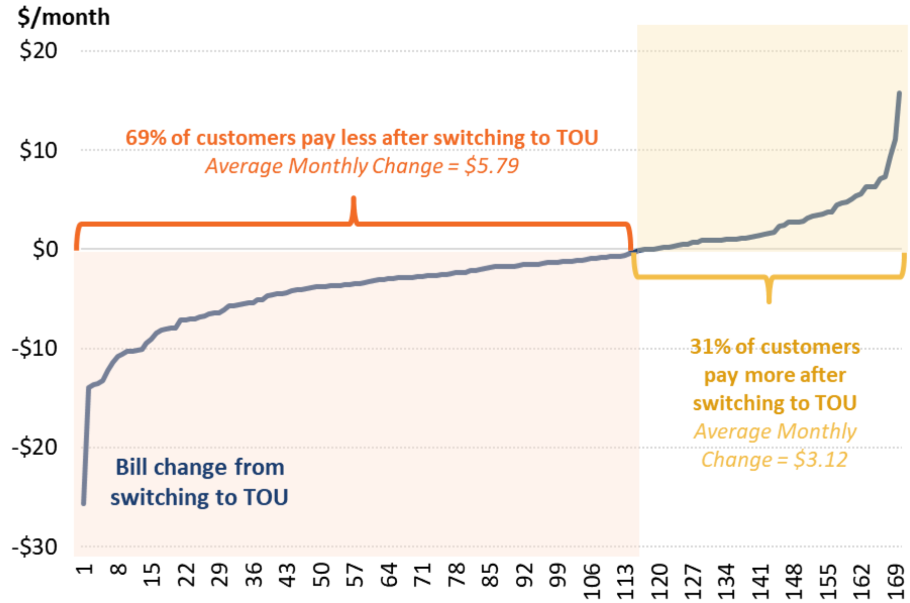
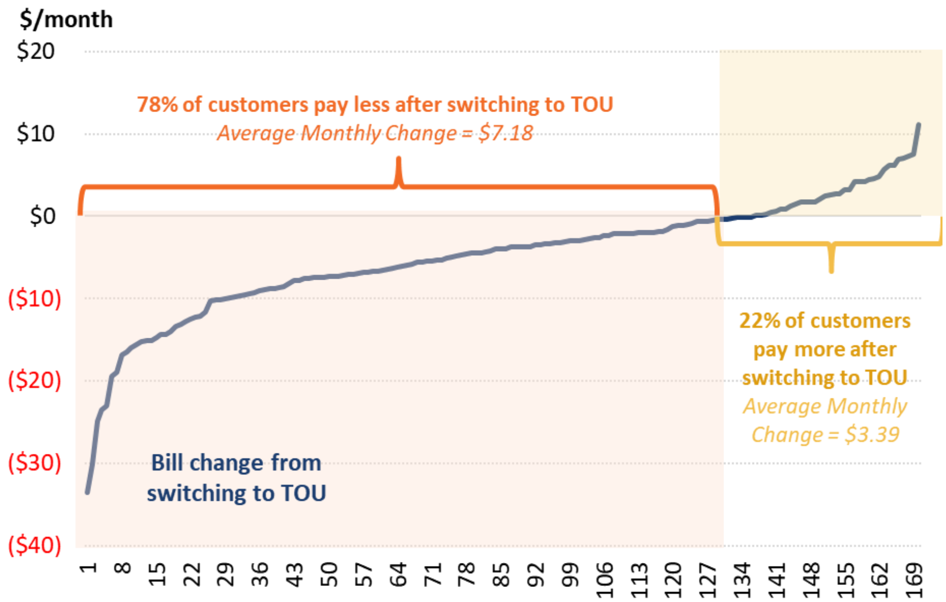


Figure 19 Monthly Bill Impact on Sample Customers (Three Period TOU, with load shifting)



Q. Will any customer be harmed by switching to TOU rates?

A. No. PSE&G will provide bill protection for the first year that a customer is on a TOU rate. They will not see a bill increase. If their bill goes down, they will get to keep the savings. Also, if they don't like the TOU rate for any reason, they will be able to opt-out of it. Additionally, PSE&G will provide ideas on its web portal to help customers modify their pattern of consuming energy to maximize their bill savings.

Q. What is your general assessment of the two TOU rates that PSE&G is proposing to offer its residential customers?

A. PSE&G's TOU rates recognize that customers have diverse tastes and preferences. Some customers want simplicity in their tariffs, others value comfort, while others want to closely monitor their usage and lower their bills by changing the way they consume energy. PSE&G will continue to offer its existing RS Rate Schedule as the default residential rate. The two TOU tariffs will be complementary to the RS Rate Schedule. They will appeal to customers who want to lower their bills by reducing their usage during the peak period and shifting it to the off-peak period.

Q. What is your opinion of the two-period TOU rate?

A. The rate features a discount of 12% compared to the existing tariff in the off-peak period, and a premium of 163% compared to the price in the on-peak period in summer. Customers who are able to shift energy consumption from the on-peak period (which is 5 hours long) to the off-period (which is 19 hours long) in the summer will save 67% on each kWh that is shifted in summer and 54% on each kWh in winter. In my opinion, this rate will appeal to those customers who are able to shift significant end use loads from the on-peak to the off-peak period. For example, they could load their dishes in the dishwasher and set its timer to start operating at 9 p.m. They could program their thermostat so it's a few degrees lower during the off-peak hours in the summer months. If their normal setting is 74 degrees, they could raise it to 75 degrees during the on-peak hours and lower it to 73 degrees during the off-peak hours. The greater the differential in the temperature setting between the off-peak and on-peak periods, the more they will save.

Q. What is your opinion of the three-period TOU rate?

A. This rate features three pricing periods to provide a greater discount during the night time. Based on what I have observed in other jurisdictions where three-period TOU rates are being offered, it should appeal to customers who drive electric vehicles (EVs). They can simply set the timer in their cars to charge the battery during the off-peak hours. Most EVs can be fully charged in six hours and most drivers don't always fully charge their EVs. For each summer kWh shifted from the on-peak to the off-peak period, they will save 84%. For each summer kWh they shift from the on-peak to the mid-peak period, they will save 61%. For winter, the percentage savings are 75% and 47% from the on-peak to the off-peak and mid-peak period, respectively. In my opinion, this rate will appeal to customers who are seriously interested in saving money by moving significant portions of their load out of the on-peak period to the mid-peak and off-peak periods. This rate exemplifies the trends in modern rate designs: allowing customers to create significant savings opportunities by lowering demand when the grid is stressed. This would help PSE&G keep rates lower for customers in the long run by avoiding the need to invest in distribution infrastructure upgrades to meet higher peak demands.

Q. Is a shorter peak period likely to attract more customers than a longer peak period?

A. Yes. A shorter peak period is easier for customers to cope with than a longer peak period. Another advantage of the shorter peak period is that the price differential between on-peak and off-peak hours can be higher than with a longer peak period. Customers would save more for each kWh that is reduced and/or shifted to the off-peak period. In sum, a shorter on-peak period is easier for customers to cope with and also more rewarding. Thus, I would expect it to attract more customers.

Q. Should the TOU rate structure stay constant or change over time?

A. Over time, I would expect system load shapes and costs to change, due to changes in the mix of generation resources and in the manner that customers use electricity, driven by the increasing penetration of EVs and distributed energy resources, such as solar panels and battery storage. As such changes occur, the rate structure should change which may involve changing the duration of the pricing periods as well as the prices within the periods. However, the rates should not be changed every year.

Q. What is the optimal frequency for changing rates?

A. In my view, rate structures and parameters should not be changed too frequently to prevent customer confusion and frustration. Ideally, the structure of the rates and its key parameters should be kept constant over a five-year period. Of course, the price levels in each period may change during this period to reflect changes in the cost of service, market prices and other factors. But the price ratios and period definitions should not be changed too frequently.

Q. Would you expect the proposed TOU rates to be well received by customers?

A. Yes, I would. Customers are likely to appreciate being given more choices to lower their bills by making slight modifications in their lifestyle. All of them will have an opportunity to try out the new TOU rates and see if they can lower their bills. They will have bill protection for the first year and will only pay the lower of the TOU bill or the bill they would have paid with the standard rate. If are not able to lower their bill, they will have the option to get off the TOU rate at the end of their initial 12-month period.

Q. Does that conclude your testimony?

A. Yes.

STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

In the Matter of the Petition of
Public Service Electric and Gas Company
for Approval of an Increase in Electric and Gas
Rates and for Changes in the Tariffs for
Electric and Gas Service, B.P.U.N.J.
No. 17 Electric and B.P.U.N.J. No. 17
Gas, and for Changes in Depreciation Rates,
Pursuant to N.J.S.A. 48:2-18,
N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1, and
for Other Appropriate Relief

BPU Docket Nos. ER23120924 and GR23120925

DIRECT TESTIMONY
OF
KAREN REIF
9+3 UPDATE

VICE PRESIDENT OF RENEWABLES AND ENERGY SOLUTIONS

April 15, 2024
P-11 R-1

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
DIRECT TESTIMONY
OF
KAREN REIF
VICE PRESIDENT OF RENEWABLES AND ENERGY SOLUTIONS

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Karen Reif. My business address is 80 Park Plaza, Newark, New Jersey, 07102.

Q. In what capacity are you employed?

A. I am currently employed by Public Service Electric and Gas Company ("PSE&G" or "Company") as Vice President of Renewables and Energy Solutions. I have been employed by PSE&G for 28 years in a number of positions in trading, deregulated subsidiaries, information technology, and continuous improvement. I have held my present position since 2018. My credentials are set forth in Schedule KR-1.

Q. What is the purpose of your testimony?

A. As part of PSE&G's 2023 base rate filing with the New Jersey Board of Public Utilities ("BPU" or "Board"), the purpose of my testimony is to provide information regarding the PSE&G Clean Energy Future – Electric Vehicles ("CEF-EV") program that will support a finding by the Board that the investments and expenditures made by the program are prudent and reasonable. The Company should be permitted to establish rates in this proceeding that will permit recovery of both the CEF-EV costs that the Company proposes to include in to rates and the regulatory asset balances of CEF-EV capital and operation and maintenance ("O&M") costs that have been established in accordance with the Board's January 27, 2021 Order in BPU Docket No.

EO18101111.[1] My testimony will describe the programs and their implementation as well as costs and investments to date and expected during the test period. The details of the Company's accounting and cost recovery are presented in the testimony of witness Michael McFadden. The template for rate adjustments after this rate case proceeding as allowed in the CEF-EV Order are presented in the testimony of witness Mr. Stephen Swetz.

Q. Do you sponsor any schedules as part of your direct testimony?

A. Yes. I sponsor the following schedules that were prepared or compiled under my direction and supervision.

(1) Schedule KR-1 sets forth my credentials;

(3) Schedule KR-2 R-1 includes the Company's CEF-EV semi-annual reports as required by the CEF-EV Order. Revision R-1 of Schedule KR-2 adds the most recent semi-annual report (dated March 1, 2024), and adds the cover letter that accompanied each semi-annual report.

II. <u>THE COMPANY'S CEF-EV PROGRAMS</u>

Q. Please describe the Company's CEF-EV Program that was approved by the Board in its CEF-EV Order.

A. In 2018, in light of legislative and executive actions in New Jersey supporting electric vehicles, PSE&G filed its CEF-EV program in conjunction with a proposal for energy storage. [2]

[1] *I/M/O The Petition Of Public Service Electric and Gas Company For Approval Of Its Clean Energy Future – Electric Vehicle And Energy Storage ("CEF-EVES") Program On A Regulated Basis*, BPU Docket No. EO18101111, "Decision and Order Approving Stipulation" (January 27, 2021) ("CEF-EV Order"). The cost recovery mechanism established in that Board Order is discussed in the testimony of Michael McFadden.

[2] New Jersey's 2018 Clean Energy Law (P.L. 2018, c. 17, § 1(a)(2), directed the Board to conduct an analysis of whether implementation of energy storage systems would promote the use of electric vehicles, and Executive Order 28 called for the development of a revised Energy Master Plan to include exploration of methods to incentivize transportation electrification. Additionally at that time New Jersey had recently become a partner in California's zero-emission vehicle program that stipulated that large volume automobile manufacturers achieve a certain percentage of sales from EVs.

Subsequently, while PSE&G's program was pending approval, the legislature passed the Plug In Vehicle Act of 2020 directing the Board to adopt policies and programs to advance the adoption of EVs, and the Board issued an order implementing the Act establishing requirements for utility files for light-duty EV charging infrastructure.[3]

In 2021, the CEF-EV Order authorized PSE&G to invest up to $166.2 million in facilities associated with its CEF-EV programs and to incur up to $39 million of incremental O&M expenses, including administrative costs, to support the program. The CEF-EV programs consist of the following three subprograms: (i) a Residential Smart Charging program; (ii) a Level 2 Mixed Use Commercial Charging program; and (iii) a Public Direct Current ("DC") Fast Charging program.[4] The CEF-EV program also provides for cross-program investments for Information Technology ("IT") system upgrades and modifications that support administration of the program.

Q. Please describe the Residential Smart Charging subprogram.

A. The Residential Smart Charging program permits the Company to provide utility incentives to individual residential sites to offset up to $1,500 of the costs of electric facilities required between the utility electric meter and the EV charging stub. The program budget of $60 million is designed to provide make-ready costs for up to 40,000 charging stubs. The Make-Ready work from the meter to the charging station includes the pre-wiring of electrical infrastructure at a parking space or a set of parking spaces to facilitate easy and cost-efficient installation of EV Service Equipment. This program also permits the Company to provide utility incentives of up to $5,000 to offset the costs of making a site Charger-Ready from the utility pole to the meter. This

[3] PIV Act, P.L. 2019, c.362, codified at N.J.S.A. 48:25-1, *et seq*; *In the Matter of Straw Proposal on Electric Vehicle Infrastructure Build Out*, B.P.U. Docket No. QO20050357 (Order Adopting the Minimum Filing Requirements for Light-Duty, Publicly-Accessible Electric Vehicle Charging, September 23, 2020.

[4] The CEF-EV order holds PSE&G's energy storage proposal and a medium-heavy duty EV program in abeyance pending the Board's consideration of energy storage policy issues and policy for medium-heavy-duty EV charging infrastructure.

pole-to-meter work includes activities and facilities needed to upgrade an electric service to accommodate EV service equipment. The budget for this portion of the subprogram is $20 million and is designed to enable the Company to provide incentives at up to 4,000 locations.

Q. Please describe the Mixed Use Commercial Level 2 subprogram.

A. This subprogram is designed to incentivize the installation of 3,500 chargers at 875 sites that include multi-family unit developments, government facilities and public facilities. Under the program PSE&G will provide (i) utility incentives up to $7,500 per charger to cover the make-ready costs of serving up to 3,500 charger stubs up to a total investment of $26.25 million, and (ii) utility incentives to offset up to $10,000 of make-ready electric service upgrades for up to 875 locations, up to a total investment of $8.75 million.

Q. Please describe the Public DC Fast-Charging subprogram.

A. Under this subprogram, PSE&G will provide (i) utility incentives of up to $25,000 per charger of make-ready utility meter to charger stub costs for up to 1,200 fast charger stations, up to a total investment of $30 million, and (ii) utility incentives to offset up to $50,000 of make-ready electric service upgrade costs for up to 300 locations, up to a total investment of $15 million. Of the total $30 million of investments for make-ready utility meter to charger stub work, $5 million is being used to provide demand charge rebates to customers under Rate Schedules GLP and LPL.

Q. Did the CEF-EV Order authorize PSE&G to invest any other EV-related costs in addition to those associated with the three subprograms?

A. Yes. The Company was authorized to invest up to $6.2 million for EV-related IT upgrades.

Q. Did the CEF-EV Order authorize PSE&G to incur any incremental O&M costs?

A. Yes. The Board authorized the Company to incur and defer for future recovery the following O&M costs:

(i) $0.6 million for telematic tracking devices to understand residential charging behaviors of 500 customers;

(ii) $13.8 million for data acquisition costs for all deployed EV chargers for six years;

(iii) $8 million for marketing, education, and outreach to support the EV program; and

(iv) $16.6 million for O&M costs for all administrative services needed to support the EV program, including IT-related O&M.

III. COST RECOVERY

Q. Did the CEF-EV Order establish a method for the Company to account for and recover the costs of the CEF-EV Program?

A. Yes. The CEF-EV Order permitted the Company to establish two regulatory assets that allow it to defer for recovery in this rate case the capital and O&M costs of the CEF-EV program. Under the capital cost deferral, the Company is permitted to defer the capital costs of the CEF-EV program until those costs are rolled into rates in a future base rate case. The CEF-EV Order provided that subject to a prudence review of all CEF-EV costs, the Company's next base rate case would include a request for recovery of all prudently incurred costs associated with the CEF-EV program. Accordingly, in this case, the Company is proposing to recover the CEF-EV regulatory asset on CEF-EV related plant in-service that is or will be placed in service within six months of the end of the test year, as described in the testimony of Michael McFadden and set forth in Schedule MPM-17 R-1. Similarly, the Company is proposing recovery of the CEF-capital and

O&M regulatory assets, over the same period as set forth in Mr. McFadden's schedule MPM-49 R-1.

Q. How did the Company estimate investment levels and costs of the CEF-EV program?

A. The Company estimates these investment and cost levels based on a forecast that models participation levels and growth rates from program inception and uses investment averages per site and per charger for the average number of chargers per site. The costs are based on project costs and participation levels to date with indexes such as inflation and cost of living increases factored into the forecast.

Q. How will the Company recover future CEF-EV program costs?

A. CEF-EV investment that is not likely to be in service by six months following the end of the test year (November 30, 2024), will be deferred and placed in a regulatory asset. Consistent with the CEF-EV Order, this case will remain open so that CEF-EV investments placed in service after November 30, 2024 may be reviewed and placed into rates through annual rate adjustment filings after the Board issues an order at the conclusion of this proceeding. The Company's proposal for the methodology and schedule of the annual rate adjustment filings is set forth in the testimony of Mr. Swetz.

IV. PROGRESS IN IMPLEMENTING CEF-EV PROGRAMS

Q. Please describe implementation of the CEF-EV program.

A. Following the issuance of the CEF-EV Order, PSE&G undertook and completed program development, including development of the IT architecture and coordination with billing processes and systems necessary to administer the program, including EV-specific options such as time-of-use rebates. PSE&G then launched the CEF-EV Program in a series of steps from June through

September 2021, that included opening program enrollment applications, issuing demand charge rebates, and marketing and customer education activities.

Q. Following launch, please describe the enrollment levels in the various programs and the investment levels to date.

A. The program has been very successful to date and has exceeded expected enrollment levels for the overall program despite initial delays due in part to supply chain issues. As documented in the most recent semi-annual CEF-EV Program report that is included in Schedule KR-2 R-1, through December 2023, enrollments included 8,584 residential customers (8,775 Chargers), 130 Mixed Use Commercial customers (312 Chargers), and 51 DCFC customers in the CEF-EV Program (295 Chargers). These amounts will be updated in a future Company update.

Q. Has the Company implemented the CEF-EV Program in a reasonable and prudent manner consistent with the CEF-EV Order?

A. Yes. In implementing its CEF-EV program, PSE&G has used first-come, first-served implementation (*i.e.*, not based on geographical area or other preference) to encourage early participation and to eliminate the risk of bias or favoritism. Also, the Company's program application process ensures, consistent with the CEF-EV Order, that all customers or EV stations receiving an incentive must be networked, meaning that the charging station is capable of sending and receiving communications via a wi-fi or cellular network. Moreover, the Company has worked collaboratively with the signatory parties to the Stipulation adopted by the Board in the CEF-EV Order to refine and obtain charging data that has permitted the Company to prepare the residential and non-residential cost-of-service studies that are being presented by Company witness Mr. Swetz in support of corresponding proposed rate changes proposed in this proceeding.

Q. Please describe the Company's approach to customer education, outreach, and marketing activities for the CEF-EV program.

A. PSE&G engaged the services of a marketing consultant to help develop and manage the marketing, education, and outreach of the CEF-EV Program. The vendor collaborates with the Company to develop annual marketing plans that build upon the success of each previous year to market the program and educate customers most effectively. The overall marketing campaign included developing marketing materials in both digital and print, bill inserts, executing paid media ads, speaking at public conferences and EV-related webinars/seminars, and participating in multiple events such as National Drive Electric Week, Earth Day celebrations, and auto shows. Moreover, PSE&G actively participates in several EV organizations and has participated as speakers or panelists at multiple industry conferences and events.

Q. Is the Company proposing to use any public funding to offset the costs of the CEF-EV Program?

A. In accordance with the CEF-EV Order, PSE&G is committed to helping customers obtain all federal, state or local funding that can be used to offset the cost of the CEF-EV program. PSE&G's CEF-EV program web site's "FAQs" section advises potential participants that PSE&G incentives can be combined with other publicly funded EV incentive programs and includes links to other available State and Federal Programs.[5]

As part of the effort to maximize customers' cross-program participation the Company meets monthly with BPU Staff and the New Jersey Department of Environmental Protection ("NJDEP") to discuss implementation of the EV incentive programs managed by the Office of Clean Energy, NJDEP and the New Jersey Economic Development Authority "(NJEDA") that are available to customers alongside the utility-run programs. These meetings have resulted in the

[5] https://nj.myaccount.pseg.com/myservicepublic/electricvehicles

development of cross-promotional materials that have been posted on applicable State websites. Furthermore, PSE&G presented (virtually) to NJZIP stakeholders at a webinar scheduled by Rutgers University.[6] To the extent that any applicant for PSE&G's CEF-EV program receives public funding that, coupled with the incentives provided under the Company's program, results in a project being funded 90 percent or more, the Company will reduce its incentive funding and rebates to bring the total rebates and incentives under 90 percent of funding costs, though this scenario has rarely occurred.[7]

Q. Are there are any other steps that PSE&G takes to ensure that the costs of CEF-EV programs are reasonable?

A. Yes. PSE&G uses outside vendors to administer certain aspects of the program such as: data acquisition; marketing, education, and outreach; administrative program support; and application processing. When retaining outside vendors, PSE&G used a competitive bid process as part of the Company's procurement process to ensure the costs of procured services are reasonable. Moreover, all CEF-EV Program expenditures are subjected to an internal pre-approval review process that examines the cost prudency and appropriateness of the costs as part of the CEF-EV Program. As part of that process, the Company benchmarks against costs of similar services in other utility-led EV programs.

Q. In addition to the CEF-EV Order, are there other BPU requirements for utility EV incentive programs with which the CEF-EV program complies?

A. Yes. In April, 2023 the BPU issued an order directing the state's electric distribution companies including PSE&G to modify their respective EV programs to comply with the

[6] NJZIP is NJEDA's pilot EV incentive program that provides vouchers for medium-heavy duty EVs. *See* https://www.njeda.gov/njzip/ .

[7] The Company has reviewed 23 applications to date that have indicated receipt of public funding, and has had to reduce PSE&G's incentive on the basis of additional public funding only once. An additional 49 applications are pending review at this time.

requirements of the New Jersey Appliance Standards Law of 2022 (Appliance Act).[8] In compliance with this order, PSE&G added eligibility requirements for CEF-EV Program participants that EV chargers must be Energy Star certified.

Additionally, PSE&G requires program participants to provide charging data that PSE&G reports to the BPU in accordance with the November 2022 and November 2023 orders in the dockets establishing procedures for New Jersey electric distribution companies' basic generation service (BGS) auction requirements.[9]

Q. Does this conclude your direct testimony?

A. Yes. It does.

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[8] *In the Matter of the Petition of Public Service Electric and Gas Company for Approval of Its Clean Energy Future Electric Vehicle and Energy Storage ("CEF-EVES") Program on a Regulated Basis*, BPU Docket No. EO18101111 (Order dated April 12, 2023). The Appliance Act is codified at N.J.S.A. 52:27D-141.18 – 141.24.

[9] *In the Matter of the Provision of Basic Generation Service (BGS) for the Period Beginning June 1, 2023* (Decision and Order, November 9, 2022) (requiring EDCs to collect and report charging data from both residential EV and DCFC charging stations including total energy consumed, capacity and transmission tags, measured demands, connected load, and the resulting load factor); *In the Matter of the Provision of Basic Generation Service (BGS) for the Period Beginning June 1, 2024*, (Decision and Order, November 17, 2023) (requiring EDCs to continue to report on the charging data specified in the prior year's order).

Katherine E. Smith
Associate Counsel – Regulatory

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PSEG Services Corporation

September 1, 2021

In the Matter of the Petition of
Public Service Electric and Gas Company
for Approval of a CEF - EV Program and an
Associated Cost Recovery Mechanism

BPU Docket No. EO18101111

VIA ELECTRONIC MAIL ONLY
Stacy Peterson
Deputy Executive Director
New Jersey Board of Public Utilities
44 South Clinton Ave.
P.O. Box 350
Trenton, NJ 08625

Brian Lipman
Acting Director
New Jersey Division of Rate Counsel
140 East Front Street, 4th Floor
P.O. Box 003
Trenton, NJ 08625

RE: CEF – EV PROGRAM BPU SEMI-ANNUAL REPORT – SEPTEMBER 2021

Dear Ms. Peterson and Mr. Lipman:

Pursuant to the Board's January 27, 2021 Order in the above referenced matter, enclosed is the Public Service Electric and Gas semi-annual activity report for the Clean Energy Future – Electric Vehicle Program. This report covers the period from January 1, 2021 through June 30, 2021.

Copies of the CEF-EV Semi-Annual Report – September 2021 will be served upon all entities legally required to be noticed. Service will occur via e-mail, only, pursuant to the Board's March 19, 2020 Order in Docket No. EO20020254.[1] In addition, the report will be posted at www.pseg.com/ev.

[1] *In the Matter of the New Jersey Board of Public Utilities' Response to the Covid-19 Pandemic For a Temporary Waiver of Requirements for Certain Non-Essential Obligations*, Docket No. EO20030254, p 3 (March 19, 2020 Order).

Stacy Peterson, Deputy Executive Director September 1, 2021
Brian Lipman, Acting Director

Please advise if you have any questions or comments.

Respectfully submitted,

Katherine E. Smith

Attachments

<u>EMAIL ONLY</u>

C Cathleen Lewis
Abe Silverman
Paul Lupo
Aida Camacho

Clean Energy Future – Electric Vehicle (EV) Program

Semi-Annual Report to the Board of Public Utilities

H1-2021 – January through June 2021

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Section 1: Estimated Quantity of Work

PSE&G will provide semi-annual reports on the CEF-EV deployment ("CEF-EV Report") with the following information:

- Estimated quantity of work
- Quantity completed to date or, if the project cannot be quantified with numbers, the major tasks completed, e.g. Residential, Mixed Use Commercial L2, and DCFC Public Charging Make Ready to Charger Stub units completed and number of service upgrades

Quantity of Work

See Table 1 for a summary of the period-to-date, program-to-date, and forecasted capital costs and O&M expenses for the CEF-EV Program.

Major Tasks Completed: Following Board approval on January 27, 2021, PSE&G initiated program development, including Infrastructure Technology (IT) architecture.

Quantity Completed to Date

See Table 2 for the capital costs per subprogram, indicating the work completed to date.

Quantity Completed: As of June 30, 2021, PSE&G has given no rebates for infrastructure development. PSE&G has invested in IT systems to support the deployment of the CEF-EV program and the development of associated customer platforms.

Section 2: DCFC Distribution Demand Charge Rebate

The semi-annual reports will include the following information

- The usage of the rebate funding
- The balance remaining of the $5 million rebate funding;

Program Usage

The application and agreement form for the DCFC Distribution Charge Rebate for pre-existing sites was launched on June 15, 2021. PSE&G received 8 applications for the DCFC Distribution Demand Charge Rebate on June 30, 2021 that are under review.

Funding Balance

See Table 2 for the balance remaining of the $5 million rebate funding. No DCFC Distribution Demand Charge Rebates were issued this reporting period.

Section 3: Semi-Annual and Program To-Date Forecast and Actual Costs

The semi-annual reports will include the following information:

- The forecasted and actual capital costs
- The forecasted and actual O&M expenses

The project expenditures shall be broken out between labor, material and other costs.

Program Forecast

See Table 1 for the period-to-date, program-to-date, and forecasted capital costs and O&M expenses for the CEF-EV Program.

Capital Costs

See Table 2 for the actual capital costs by cost category and Table 3 for the capital costs broken out between labor, material and other.

O&M Expenses

See Table 4 for the actual expenses by cost category and Table 5 for the expenses broken out between labor, material and other.

Section 4: Financial Tables

Table 1: Summary of Program Investment & Expenses

Summary of Program Investment & Expenses

Utility Name: PSE&G
Program Name: Clean Energy Future - Electric Vehicles
BPU Docket No. EO18101111

Period	*Investment (a)*	*Expenses (b)*	*Total (c=a+b)*
H1 2021	**$89,635**	**$723,093**	**$812,727**
January	$0	$0	**$0**
February	$0	$0	**$0**
March	$0	$337,327	**$337,327**
April	$0	$65,997	**$65,997**
May	$20,494	$180,627	**$201,120**
June	$69,141	$139,142	**$208,282**
Period-to-Date	**$89,635**	**$723,093**	**$812,727**
Program-to-Date	**$89,635**	**$723,093**	**$812,727**
To-Go Forecast	**$166,110,365**	**$38,243,474**	**$38,153,840**
Total Program Forecast	**$166,200,000**	**$38,966,567**	**$38,966,567**
Program Caps	$166,200,000	$38,966,567	$38,966,567

Table 2: Investment by Cost Category

Program Investment by Cost Category

Utility Name: PSE&G
Program Name: Clean Energy Future - Electric Vehicles
BPU Docket No. EO18101111
Reporting Period: January 1, 2021 thru June 30, 2021

Program/Budget Line	*Make Ready: Pole-to-Meter (a)*	*Make Ready: Behind-the-Meter (b)*	*Demand Charge Rebate (c)*	*IT Systems (d)*	*Total Investment for Reporting Period (e=a+b+c+d)*
RESIDENTIAL					
Residential Subtotal	$0	$0	$0	$0	$0
MIXED USE / COMMERICAL L2					
Mixed Use Commerical Subtotal	$0	$0	$0	$0	$0
DCFC PUBLIC CHARGING					
DCFC Subtotal	$0	$0	$0	$0	$0
IT SYSTEMS					
IT Systems Subtotal	$0	$0	$0	$89,635	$89,635
TOTAL INVESTMENT BY CATEGORY	$0	$0	$0	$89,635	$89,635
PROGRAM CAPS BY CATEGORY	$43,750,000	$111,250,000	$5,000,000	$6,200,000	$166,200,000
REMAINING FUNDING BY CATEGORY	$43,750,000	$111,250,000	$5,000,000	$6,110,365	$166,110,365

Table 3: Investment by Labor, Material & Other Costs

Program Investment LM&O

Utility Name: PSE&G
Program Name: Clean Energy Future - Electric Vehicles
BPU Docket No. EO18101111
Reporting Period: January 1, 2021 thru June 30, 2021

2021	*Labor (a)*	*Materials (b)*	*Other (c)*	*Total Expenses (d=a+b+c)*
January	$0	$0	$0	$0
February	$0	$0	$0	$0
March	$0	$0	$0	$0
April	$0	$0	$0	$0
May	$18,164	$0	$2,330	$20,494
June	$56,374	$0	$12,767	$69,141
Period Total	**$74,538**	**$0**	**$15,097**	**$89,635**

CEF – EV Program
H1-2021 - January through June 2021

Table 4: Expenses by Cost Category

Program Expenses by Cost Category

Utility Name: PSE&G
Program Name: Clean Energy Future - Electric Vehicles
BPU Docket No. EO18101111
Reporting Period: January 1, 2021 thru June 30, 2021

Program/Budget Line	*Administration & Program Development (a)*	*Marketing, Education & Outreach (b)*	*Data Acquisition (c)*	*Residential Vehicle Device Technical Trial (d)*	*Total Expenses for Reporting Period (e=a+b+c+d)*
RESIDENTIAL					
Residential Subtotal	$299,186	$1,067	$21,018	$0	$321,271
MIXED USE / COMMERICAL L2					
Mixed Use Commerical Subtotal	$107,228	$903	$0	$0	$108,131
DCFC PUBLIC CHARGING					
DCFC Subtotal	$131,554	$1,067	$0	$0	$132,621
IT SYTEMS					
IT Systems Subtotal	$128,598	$0	$32,471	$0	$161,069
TOTAL EXPENSES BY CATEGORY	$666,567	$3,037	$53,489	$0	$723,093
PROGRAM CAPS BY CATEGORY	$16,620,000	$8,000,000	$13,776,567	$570,000	$38,966,567

Table 5: Expenses by Labor, Material & Other Costs

Program Expenses LM&O

Utility Name: PSE&G
Program Name: Clean Energy Future - Electric Vehicles
BPU Docket No. EO18101111
Reporting Period: January 1, 2021 thru June 30, 2021

2021	Labor (a)	Materials (b)	Other (c)	Total Expenses (d=a+b+c)
January	$0	$0	$0	$0
February	$0	$0	$0	$0
March	$77,327	$0	$260,000	$337,327
April	$59,247	$0	$6,750	$65,997
May	$58,909	$0	$121,718	$180,627
June	$77,958	$0	$61,184	$139,142
Period Total	**$273,441**	**$0**	**$449,651**	**$723,093**

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PSEG
Services Corporation

March 2, 2022

In the Matter of the Petition of
Public Service Electric and Gas Company
for Approval of a CEF - EV Program and an
Associated Cost Recovery Mechanism

BPU Docket No. EO18101111

VIA ELECTRONIC MAIL ONLY
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RE: CEF – EV PROGRAM BPU SEMI-ANNUAL REPORT – MARCH 2022

Dear Mr. Lupo and Mr. Lipman:

Pursuant to the Board's January 27, 2021 Order in the above referenced matter, enclosed is the Public Service Electric and Gas semi-annual activity report for the Clean Energy Future – Electric Vehicle Program. This report covers the period from July 31, 2021 through December 31, 2021.

Copies of the CEF-EV Semi-Annual Report – September 2021 will be served upon all entities legally required to be noticed. Service will occur via e-mail, only, pursuant to the Board's March 19, 2020 Order in Docket No. EO20020254.[1] In addition, the report will be posted at www.pseg.com/ev.

[1] *In the Matter of the New Jersey Board of Public Utilities' Response to the Covid-19 Pandemic For a Temporary Waiver of Requirements for Certain Non-Essential Obligations*, Docket No. EO20030254, p 3 (March 19, 2020 Order).

Please advise if you have any questions or comments.

Respectfully submitted,

Katherine E. Smith

Attachments

C EMAIL ONLY
Cathleen Lewis
Abe Silverman

Clean Energy Future – Electric Vehicle (EV) Program

Semi-Annual Report to the Board of Public Utilities

H2-2021 – July through December 2021

Table of Contents

Section 1: Estimated Quantity of Make-Ready Work

PSE&G will provide semi-annual reports on the CEF-EV deployment ("CEF-EV Report") with the following information:

- Estimated quantity of work
- Quantity completed to date or, if the project cannot be quantified with numbers, the major tasks completed, e.g. Residential, Mixed Use Commercial L2, and DCFC Public Charging Make Ready to Charger Stub units completed and number of service upgrades:

Quantity of Work

See Table 1 for a summary of the period-to-date, program-to-date, and forecasted capital costs and O&M expenses for the Clean Energy Future – Electric Vehicle Program ("CEF-EV Program").

Major Tasks Completed: Following Board approval on January 27, 2021, PSE&G initiated program development, including Infrastructure Technology (IT) architecture. PSE&G launched the CEF-EV Program in a series of steps from June through September, 2021 as discussed in detail in each subprogram below.

Quantity Completed to Date

See Table 2 for the capital costs per subprogram, indicating the work completed to date.

Quantity Completed: As of December 31, 2021, PSE&G has invested a total of $4.2M in CEF-EV Program investment. This includes investment for the following three subprograms: (i) Residential Smart Charging Program, (ii) Level-2 Mixed Use Charging Program, and (iii) a Direct Current Fast Charging ("DCFC") Program, which also includes investment in Distribution Demand Charge Rebates. The CEF-EV Program further includes cross-program investments for IT system upgrades to support the deployment of the CEF-EV program and the development of associated customer platforms.

Section 2: DCFC Distribution Demand Charge Rebate

The semi-annual reports will include the following information:

- The usage of the rebate funding
- The balance remaining of the $5 million rebate funding

Program Usage

The application and agreement form for the DCFC Distribution Charge Rebate for pre-existing sites was launched on June 15, 2021. Through December 31, 2021, PSE&G has enrolled 32 customers to the DCFC Distribution Demand Charge Rebate.

Funding Balance

See Table 2 for the usage and balance remaining of the $5 million rebate funding. As of December 31, 2021, PSE&G distributed $292,680 in demand charge rebates for this reporting period. There is $4.7M remaining in the funding.

Section 3: Semi-Annual and Program To-Date Forecast and Actual Costs

The semi-annual reports will include the following information:

- The forecasted and actual capital costs
- The forecasted and actual O&M expenses

The project expenditures shall be broken out between labor, material, and other costs.

Program Forecast

See Table 1 for the period-to-date, program-to-date, and forecasted capital costs and O&M expenses for the CEF-EV Program.

Capital Costs

See Table 2 for the actual capital costs by cost category and Table 3 for the capital costs broken out between labor, material and other ("LM&O").

Program enrollment for make-ready funding was implemented in phases. The DCFC subprogram was launched on July 23, 2021. The Level 2 Mixed-Use Commercial subprogram was launched on July 30, 2021. The Residential make-ready subprogram was launched on September 15, 2021. As of December 31, 2021, the CEF Program has enrolled 218 residential customers, 5 Mixed Use Commercial customers, and 32 DCFC customers in the CEF-EV Program.

O&M Expenses

See Table 4 for the actual expenses by cost category and Table 5 for the expenses broken out between labor, material and other.

Section 4: Financial Tables

Table 1: CEF-EV Program Summary

Period	*Investment (a)*	*Expenses (b)*	*Total (c=a+b)*
July	$534,212	$93,260	**$627,472**
August	$828,890	$143,407	**$972,298**
September	$216,220	$173,913	**$390,133**
October	$542,813	$73,084	**$615,896**
November	$490,443	$67,845	**$558,288**
December	$1,526,801	$50,449	**$1,577,249**
Reporting Period	**$4,139,378**	**$601,958**	**$4,741,336**
Program-to-Date	**$4,229,013**	**$1,325,051**	**$5,554,064**
To-Go Forecast	**$161,970,987**	**$37,641,516**	**$199,612,503**
Total Program Forecast	**$166,200,000**	**$38,966,567**	**$205,166,567**
Program Caps	$166,200,000	$38,966,567	$205,166,567

CEF – EV Program
H2-2021 – July through December 2021

Table 2: Investment by Cost Category

Program/Budget Line	Make Ready: Pole to Meter (a)	Make Ready: Behind the Meter (b)	Demand Charge Rebate (c)	IT Systems (d)	Total (e=a+b+c+d)
RESIDENTIAL					
Residential Subtotal	$0	$159,016	$0	$0	$159,016
MIXED USE / COMMERICAL L2					
Mixed-Use Subtotal	$0	$37,500	$0	$0	$37,500
DCFC PUBLIC CHARGING					
DCFC Subtotal	$0	$0	$292,680	$0	$292,680
IT SYSTEMS					
IT Systems Subtotal	$0	$0	$0	$3,650,182	$3,650,182

Reporting Period	**$0**	**$196,516**	**$292,680**	**$3,650,182**	**$4,139,378**
Program-to-Date	$0	$196,516	$292,680	$3,739,817	$4,229,013
Remaining Funding by Category	$43,750,000	$111,053,484	$4,707,320	$2,460,183	$161,970,987
Total Program Forecast	$43,750,000	$111,250,000	$5,000,000	$6,200,000	$166,200,000
Program Caps by Category	$43,750,000	$111,250,000	$5,000,000	$6,200,000	$166,200,000

Table 3: Investment by Labor, Materials & Other ("LM&O") Costs

Period	***Labor (a)***	***Materials (b)***	***Other (c)***	***Total (d=a+b+c)***
July	$76,965	$0	$457,247	$534,212
August	$80,379	$0	$748,511	$828,890
September	$94,513	$0	$121,706	$216,220
October	$58,789	$0	$484,023	$542,813
November	$40,847	$0	$449,596	$490,443
December	$109,565	$0	$1,417,235	$1,526,801
Reporting Period	**$461,059**	**$0**	**$3,678,319**	**$4,139,378**

CEF – EV Program
H2-2021 – July through December 2021

Table 4: Program Expenses by Cost Category

Program/Budget Line	*Administration & Program Development (a)*	*Marketing, Education, and Outreach (b)*	*Data Acquisition (c)*	*Residential Vehicle Device Technical Trial (d)*	*Total (e=a+b+c+d)*
RESIDENTIAL					
Residential Subtotal	$237,875	$58,545	$46,487		**$342,907**
MIXED USE / COMMERICAL L2					
Mixed-Use Subtotal	$116,739	$21,598	$0		**$138,337**
DCFC PUBLIC CHARGING					
DCFC Subtotal	$105,697	$21,522	$0		**$127,219**
IT SYSTEMS					
IT Systems Subtotal	-$15,975	$0	$9,471		**-$6,504**
Reporting Period	**$444,336**	**$101,664**	**$55,958**	**$0**	**$601,958**
Program-to-Date	$1,110,903	$104,701	$109,447	$0	$1,325,051
Remaining Funding by Category	$15,509,097	$7,895,299	$13,667,120	$570,000	$37,641,516
Total Program Forecast	$16,620,000	$8,000,000	$13,776,567	$570,000	$38,966,567
Program Caps by Category	$16,620,000	$8,000,000	$13,776,567	$570,000	$38,966,567

Table 5: Expenses by Labor, Material & Other ("LM&O") Costs

2021	*Labor (a)*	*Materials (b)*	*Other (c)*	*Total Expenses (d=a+b+c)*
July	$102,181	$64	-$8,985	$93,260
August	$112,236	$21,956	$9,215	$143,407
September	$109,692	$0	$64,221	$173,913
October	$97,684	$0	-$24,600	$73,084
November	$31,840	$0	$36,005	$67,845
December	$57,390	$935	-$7,876	$50,449
Reporting Period	**$511,023**	**$22,955**	**$67,980**	**$601,958**

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PSEG
Services Corporation

September 1, 2022

In the Matter of the Petition of
Public Service Electric and Gas Company
for Approval of a CEF - EV Program and an
Associated Cost Recovery Mechanism

BPU Docket No. EO18101111

VIA ELECTRONIC MAIL ONLY

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RE: CEF – EV PROGRAM BPU SEMI-ANNUAL REPORT – SEPTEMBER 2022

Dear Mr. Lupo and Mr. Lipman:

Pursuant to the Board's January 27, 2021 Order in the above referenced matter, enclosed is the Public Service Electric and Gas semi-annual activity report for the Clean Energy Future – Electric Vehicle Program. This report covers the period from January through June, 2022.

Copies of the CEF-EV Semi-Annual Report will be served upon all entities legally required to be noticed. Service will occur via e-mail, only, pursuant to the Board's March 19, 2020 Order in Docket No. EO20020254.[1] In addition, the report will be posted at www.pseg.com/ev.

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[1] *In the Matter of the New Jersey Board of Public Utilities' Response to the Covid-19 Pandemic For a Temporary Waiver of Requirements for Certain Non-Essential Obligations*, Docket No. EO20030254, p 3 (March 19, 2020 Order).

Please advise if you have any questions or comments.

Respectfully submitted,

Katherine E. Smith

Attachments

EMAIL ONLY
C Cathleen Lewis
Abe Silverman

Clean Energy Future – Electric Vehicle (EV) Program

Semi-Annual Report to the Board of Public Utilities

H1-2022 – January through June 2022

Table of Contents

Section 1: Estimated Quantity of Make-Ready Work

PSE&G will provide semi-annual reports on the CEF-EV deployment ("CEF-EV Report") with the following information:

- Estimated quantity of work
- Quantity completed to date or, if the project cannot be quantified with numbers, the major tasks completed, e.g. Residential, Mixed Use Commercial L2, and DCFC Public Charging Make Ready to Charger Stub units completed and number of service upgrades:

Quantity of Work

See Table 1 for a summary of the period-to-date, program-to-date, and forecasted capital costs and O&M expenses for the Clean Energy Future – Electric Vehicle Program ("CEF-EV Program").

Major Tasks Completed: Following Board approval on January 27, 2021, PSE&G initiated program development, including Infrastructure Technology (IT) architecture. PSE&G launched the CEF-EV Program in a series of steps from June through September 2021 as discussed in detail in each subprogram below.

Quantity Completed to Date

See Table 2 for the capital costs per subprogram, indicating the work completed to date.

Quantity Completed: As of June 30, 2020, PSE&G has invested a total of $7.3M in CEF-EV Program investment. This includes investment for the following three subprograms: (i) Residential Smart Charging Program, (ii) Level-2 Mixed Use Charging Program, and (iii) a Direct Current Fast Charging ("DCFC") Program, which also includes investment in Distribution Demand Charge Rebates. The CEF-EV Program further includes cross-program investments for IT system upgrades to support the deployment of the CEF-EV program and the development of associated customer platforms.

Section 3: DCFC Distribution Demand Charge Rebate

The semi-annual reports will include the following information:

- The usage of the rebate funding
- The balance remaining of the $5 million rebate funding

Program Usage

The application and agreement form for the DCFC Distribution Charge Rebate for pre-existing sites was launched on June 15, 2021. Program to date, PSE&G has enrolled 33 customers to the DCFC Distribution Demand Charge Rebate, comprising of 242 chargers.

Funding Balance

See Table 2 for the usage and balance remaining of the $5 million rebate funding. As of June 30, 2022, PSE&G distributed $482,768 in demand charge rebates for this reporting period. There is $4.5M remaining in the funding.

Section 2: Semi-Annual and Program To-Date Forecast and Actual Costs

The semi-annual reports will include the following information:

- The forecasted and actual capital costs
- The forecasted and actual O&M expenses

The project expenditures shall be broken out between labor, material, and other costs.

Program Forecast

See Table 1 for the period-to-date, program-to-date, and forecasted capital costs and O&M expenses for the CEF-EV Program.

Capital Costs

See Table 2 for the actual capital costs by cost category and Table 3 for the capital costs broken out between labor, material and other ("LM&O").

Program enrollment for make-ready funding was implemented in phases. The DCFC subprogram was launched on July 23, 2021. The Level 2 Mixed-Use Commercial subprogram was launched on July 30, 2021. The Residential make-ready subprogram was launched on September 15, 2021. As of June 30, 2021, the CEF Program has enrolled 670 residential customers (678 Chargers), 11 Mixed Use Commercial customers (17 Chargers), and 33 DCFC customers in the CEF-EV Program (242 Chargers).

O&M Expenses

See Table 4 for the actual expenses by cost category and Table 5 for the expenses broken out between labor, material and other.

Section 4: Financial Tables

Table 1: CEF-EV Program Summary

Summary of Program Investment & Expenses

Period	*Investment*	*Expenses*	*Total*
H1 2022	**$3,108,316**	**$964,393**	**$4,072,709**
January	$716,318	$90,893	**$807,211**
February	$601,843	$153,420	**$755,263**
March	$609,068	$181,442	**$790,510**
April	$319,678	$188,446	**$508,124**
May	$567,202	$92,147	**$659,349**
June	$303,744	$258,045	**$561,789**
Period-to-Date	**$3,117,853**	**$964,393**	**$4,082,246**
Program-to-Date	**$7,238,549**	**$2,289,444**	**$9,527,993**
To-Go Forecast	**$158,961,451**	**$36,677,123**	**$195,638,574**
Total Program Forecast	**$166,200,000**	**$38,966,567**	**$205,166,567**
Program Caps	$166,200,000	$38,966,567	$205,166,567

Table 2: Investment by Cost Category

Reported Program Investment by Cost Category

Program/Budget Line	*Make Ready: Pole to Meter*	*Make Ready: Behind the Meter*	*Demand Charge Rebate*	*IT Systems*	*Total Investment for Reporting Period*
RESIDENTIAL					
Residential Subtotal	$0	$684,491	$0	$0	$684,491
MIXED USE / COMMERICAL L2					
Mixed-Use Subtotal	$0	$84,980	$0	$0	$84,980
DCFC PUBLIC CHARGING					
DCFC Subtotal	$0	$49,950	$190,088	$0	$240,038
IT SYSTEMS					
IT Systems Subtotal	$0	$0	$0	$2,108,344	$2,108,344

Reporting Period	**$0**	**$819,421**	**$190,088**	**$2,108,344**	**$3,117,853**
Program to Date	$0	$1,015,937	$482,768	$5,848,161	$7,346,866
Remaining Funding by Category	$43,750,000	$110,234,063	$4,517,232	$351,839	$158,853,134
Total Program Forecast	$43,750,000	$111,250,000	$5,000,000	$6,200,000	$166,200,000
Program Caps by Category	$43,750,000	$111,250,000	$5,000,000	$6,200,000	$166,200,000

Table 3: Investment by Labor, Materials & Other ("LM&O") Costs

2022	*Labor*	*Materials*	*Other (Incentives, O/S, AFUDC)**	*Total Investment*
January	$42,931	$0	$673,387	**$716,318**
February	$32,290	$0	$569,553	**$601,843**
March	$11,930	$0	$597,137	**$609,068**
April	$13,837	$0	$305,841	**$319,678**
May	$5,278	$0	$561,924	**$567,202**
June	$5,996	$0	$297,748	**$294,207**
Reporting Period	**$112,262**	**$0**	**$3,005,590**	**$3,117,852**

*O/S = Outside Services, AFUDC = Allowed Funds Used During Construction

Table 4: Program Expenses by Cost Category

Reported Program Investment by Cost Category

Program/Budget Line	*Administration & Program Development*	*Marketing, Education, and Outreach*	*Data Acquisition*	*Residential Vehicle Device Technical Trial*	*Total Expenses for Reporting Period*
RESIDENTIAL					
Residential Subtotal	$347,596	$64,420	$20,753	$0	**$432,769**
Mixed-Use Subtotal	$124,520	$35,960	$17,524	$0	**$178,004**
DCFC Subtotal	$118,261	$34,578	$13,516	$0	**$166,355**
IT Systems Subtotal	$0	$0	$187,264	$0	**$187,264**
Reporting Period	**$590,377**	**$134,958**	**$239,058**	**$0**	**$964,393**
Program to Date	$1,701,280	$239,659	$348,504	$0	$2,289,443
Remaining Funding by Category	$14,918,720	$7,760,341	$13,428,063	$570,000	$36,677,127
Total Program Forecast	$16,620,000	$8,000,000	$13,776,567	$570,000	$38,966,567
Program Caps by Category	$16,620,000	$8,000,000	$13,776,567	$570,000	$38,966,567

Table 5: Expenses by Labor, Material & Other ("LM&O") Costs

Period	*Labor*	*Materials*	*Other*	*Total Expenses*
January	$90,893	$0	$0	$90,893
February	$153,420	$0	$0	$153,420
March	$181,443	$0	$0	$181,443
April	$184,903	$0	$3,543	$188,446
May	$91,022	$0	$1,125	$92,147
June	$252,631	$0	$5,413	$258,044
Period Total	**$954,312**	**$0**	**$10,081**	**$964,393**

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PSEG Services Corporation

March 1, 2023

In the Matter of the Petition of
Public Service Electric and Gas Company
for Approval of a CEF - EV Program and an
Associated Cost Recovery Mechanism
BPU Docket No. EO18101111

VIA ELECTRONIC MAIL ONLY
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140 East Front Street, 4th Floor
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Trenton, NJ 08625

RE: CEF – EV PROGRAM BPU SEMI-ANNUAL REPORT – MARCH 2023

Dear Messrs. Kammer, Cummings and Lipman:

Pursuant to the Board's January 27, 2021 Order in the above referenced matter, enclosed is the Public Service Electric and Gas semi-annual activity report for the Clean Energy Future – Electric Vehicle Program. This report covers the period from July through December, 2022.

Copies of the CEF-EV Semi-Annual Report will be served upon all entities legally required to be noticed. Service will occur via e-mail, only, pursuant to the Board's March 19, 2020 Order in Docket No. EO20020254.[1] In addition, the report will be posted at www.pseg.com/ev.

[1] *In the Matter of the New Jersey Board of Public Utilities' Response to the Covid-19 Pandemic For a Temporary Waiver of Requirements for Certain Non-Essential Obligations*, Docket No. EO20030254, p 3 (March 19, 2020 Order).

Please advise if you have any questions or comments.

Respectfully submitted,

Katherine E. Smith

Attachment

<u>EMAIL ONLY</u>
C Cathleen Lewis
Abe Silverman
Dean Taklif

Clean Energy Future – Electric Vehicle (EV) Program

Semi-Annual Report to the Board of Public Utilities

H2-2022 – July through December 2022

Table of Contents

Section 1: Estimated Quantity of Make-Ready Work

PSE&G will provide semi-annual reports on the CEF-EV deployment (“CEF-EV Report”) with the following information:

- Estimated quantity of work
- Quantity completed to date or, if the project cannot be quantified with numbers, the major tasks completed, e.g. Residential, Mixed Use Commercial L2, and DCFC Public Charging Make Ready to Charger Stub units completed and number of service upgrades:

Quantity of Work

See Table 1 for a summary of the period-to-date, program-to-date, and forecasted capital costs and O&M expenses for the Clean Energy Future – Electric Vehicle Program (“CEF-EV Program”).

Major Tasks Completed: Following Board approval on January 27, 2021, PSE&G initiated program development, including Infrastructure Technology (IT) architecture. PSE&G launched the CEF-EV Program in a series of steps from June through September 2021 as discussed in detail in each subprogram below.

Quantity Completed to Date

See Table 2 for the capital costs per subprogram, indicating the work completed to date.

Quantity Completed: Program to date, PSE&G has invested a total of $13M in CEF-EV Program investment. This includes investment for the following three subprograms: (i) Residential Smart Charging Program, (ii) Level-2 Mixed Use Charging Program, and (iii) a Direct Current Fast Charging (“DCFC”) Program, which also includes investment in Distribution Demand Charge Rebates. The CEF-EV Program further includes cross-program investments for IT system upgrades to support the deployment of the CEF-EV program and the development of associated customer platforms.

Section 2: DCFC Distribution Demand Charge Rebate

The semi-annual reports will include the following information:

- The usage of the rebate funding
- The balance remaining of the $5 million rebate funding

Program Usage

The application and agreement form for the DCFC Distribution Charge Rebate for pre-existing sites was launched on June 15, 2021 with credits issued retroactive to program approval on January 27, 2021. Program to date, PSE&G has enrolled 35 customers to the DCFC Distribution Demand Charge Rebate, comprising of 252 chargers.

Funding Balance

See Table 2 for the usage and balance remaining of the $5 million rebate funding. Program to date, PSE&G distributed $628,777 in demand charge rebates, of which $210,532 was distributed this reporting period. There is $4.4M remaining in the funding. Year 3 of the credit will begin on January 27, 2023, with the distribution demand charge rebate adjusted from 75% to 50%.

Section 3: Semi-Annual and Program To-Date Forecast and Actual Costs

The semi-annual reports will include the following information:

- The forecasted and actual capital costs
- The forecasted and actual O&M expenses

The project expenditures shall be broken out between labor, material, and other costs.

Program Forecast

See Table 1 for the period-to-date, program-to-date, and forecasted capital costs and O&M expenses for the CEF-EV Program.

Capital Costs

See Table 2 for the actual capital costs by cost category and Table 3 for the capital costs broken out between labor, material and other ("LM&O").

Program enrollment for make-ready funding was implemented in phases. The DCFC subprogram was launched on July 23, 2021. The Level 2 Mixed-Use Commercial subprogram was launched on July 30, 2021. The Residential make-ready subprogram was launched on September 15, 2021.

Program to date, the CEF Program has enrolled 1,974 residential customers (1,995 Chargers), 33 Mixed Use Commercial customers (63 Chargers), and 35 DCFC customers in the CEF-EV Program (252 Chargers).

O&M Expenses

See Table 4 for the actual expenses by cost category and Table 5 for the expenses broken out between labor, material and other.

Section 4: Financial Tables

Table 1: CEF-EV Program Summary

Summary of Program Investment & Expenses

Period	*Investment*	*Expenses*	*Total*
H2 2022	**$5,695,131**	**$1,710,798**	**$7,405,929**
July	$1,105,954	$743,625	**$1,849,579**
August	$397,345	$211,971	**$609,316**
September	$1,022,141	$207,177	**$1,229,318**
October	$1,008,309	$187,788	**$1,196,097**
November	$819,372	$160,819	**$980,191**
December	$1,338,213	$199,418	**$1,537,631**
Period-to-Date	**$5,695,131**	**$1,710,798**	**$7,405,929**
Program-to-Date	**$12,988,098**	**$4,000,242**	**$16,988,340**
To-Go Forecast	**$153,211,902**	**$34,966,325**	**$188,178,227**
Total Program Forecast	**$166,200,000**	**$38,966,567**	**$205,166,567**
Program Caps	$166,200,000	$38,966,567	$205,166,567

CEF – Electric Vehicle (EV) Program
H2-2022 – July through December 2022

Table 2: Investment by Cost Category

Reported Program Investment by Cost Category

Program/Budget Line	*Make Ready: Pole to Meter*	*Make Ready: Behind the Meter*	*Demand Charge Rebate*	*IT Systems*	*Total Investment for Reporting Period*
RESIDENTIAL					
Residential Subtotal	$1,929,859	$1,660,600	$0	$0	$3,590,459
MIXED USE / COMMERICAL L2					
Mixed-Use Subtotal	$61,386	$366,843	$0	$0	$428,229
DCFC PUBLIC CHARGING					
DCFC Subtotal	$888,648	$200,000	$210,532	$0	$1,299,180
IT SYSTEMS					
IT Systems Subtotal	$0	$0	$0	$377,264	$377,264

Reporting Period	**$2,879,893**	**$2,227,442**	**$210,532**	**$377,264**	**$5,695,131**
Program to Date	$2,879,893	$3,305,000	$628,777	$6,174,428	$12,988,098
Remaining Funding by Category	$40,870,107	$107,945,000	$4,371,223	$25,572	$153,211,902
Total Program Forecast	$43,750,000	$111,250,000	$5,000,000	$6,200,000	$166,200,000
Program Caps by Category	$43,750,000	$111,250,000	$5,000,000	$6,200,000	$166,200,000

CEF – Electric Vehicle (EV) Program
H2-2022 – July through December 2022

Table 3: Investment by Labor, Materials & Other ("LM&O") Costs

2022	*Labor*	*Materials*	*Other* *(Incentives, O/S)**	*Total Investment*
July	$4,192	$0	$1,105,954	**$1,110,146**
August	$2,034	$0	$395,311	**$397,345**
September	$1,224	$0	$1,022,141	**$1,023,365**
October	$122	$0	$1,008,187	**$1,008,309**
November	$46	$0	$819,372	**$819,418**
December	$0	$0	$1,342,010	**$1,342,010**
Reporting Period	**$7,617**	**$0**	**$5,687,514**	**$5,695,131**

*O/S = Outside Services,

Table 4: Program Expenses by Cost Category

Reported Program Investment by Cost Category

Program/Budget Line	Administration & Program Development	Marketing, Education, and Outreach	Data Acquisition	Residential Vehicle Device Technical Trial	Total Expenses for Reporting Period
RESIDENTIAL					
Residential Subtotal	$395,572	$178,088	$18,074	$0	**$591,733**
Mixed-Use Subtotal	$166,956	$48,414	$17,159	$0	**$232,529**
DCFC Subtotal	$148,432	$46,208	$11,987	$0	**$206,627**
IT Systems Subtotal	$0	$0	$679,808	$0	**$679,808**
Reporting Period	**$710,961**	**$272,709**	**$727,028**	**$0**	**$1,710,798**
Program to Date	$2,412,241	$512,368	$1,075,532	$0	$4,000,241
Remaining Funding by Category	$13,787,759	$7,487,632	$12,701,035	$570,000	$34,966,326
Total Program Forecast	$16,620,000	$8,000,000	$13,776,567	$570,000	$38,966,567
Program Caps by Category	$16,620,000	$8,000,000	$13,776,567	$570,000	$38,966,567

CEF – Electric Vehicle (EV) Program
H2-2022 – July through December 2022

Table 5: Expenses by Labor, Material & Other ("LM&O") Costs

Period	*Labor*	*Materials*	*Other*	*Total Expenses*
July	$234,911	$0	$508,713	$743,625
August	$211,308	$0	$663	$211,971
September	$205,764	$0	$1,413	$207,177
October	$187,302	$0	$486	$187,788
November	$159,684	$0	$1,134	$160,819
December	$195,731	$0	$3,688	$199,418
Period Total	**$1,194,700**	**$0**	**$516,098**	**$1,710,798**

Katherine E. Smith
Managing Counsel – State Regulatory

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Email: Katherine.Smith@pseg.com

PSEG Services Corporation

August 31, 2023

In the Matter of the Petition of Public Service Electric and Gas Company for Approval of a CEF - EV Program and Associated Cost Recovery Mechanism
BPU Docket No. EO18101111

and

In the Matter of the Provision of Basic Generation Service (BGS) For the Period Beginning June 1, 2023
BPU Docket No. ER22030127

VIA ELECTRONIC MAIL ONLY
Malike Cummings, CMgr, FCMI
Deputy Director Energy and Water
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Brian Lipman
Director
New Jersey Division of Rate Counsel
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P.O. Box 003
Trenton, NJ 08625

RE: CEF – EV PROGRAM BPU SEMI-ANNUAL REPORT – SEPTEMBER 2023
***and* PROVISION OF BASIC GENERATION SERVICE (BGS) – JUNE 2023**

Dear Mr. Cummings and Mr. Lipman:

Pursuant to the Board's January 27, 2021 Order and November 09, 2022 Order in the above referenced matters, enclosed is the semi-annual activity report for the Clean Energy Future – Electric Vehicle (CEF-EV) Program, including the residential EV and DCFC Charging data. This report covers the period from January through June, 2023.

Copies of the CEF-EV Semi-Annual Report will be served upon all entities legally required to be noticed. Service will occur via e-mail, only, pursuant to the Board’s March 19, 2020 Order in Docket No. EO20020254.[1] In addition, the report will be posted at www.pseg.com/ev.

Please advise if you have any questions or comments.

Respectfully submitted,

Attachments

EMAIL ONLY
cc: Cathleen Lewis
Stacy Peterson

---

[1] *In the Matter of the New Jersey Board of Public Utilities’ Response to the Covid-19 Pandemic For a Temporary Waiver of Requirements for Certain Non-Essential Obligations*, Docket No. EO20030254, p 3 (March 19, 2020 Order).

Clean Energy Future – Electric Vehicle (EV) Program

Semi-Annual Report to the Board of Public Utilities

HY1-2023 – January through June 2023

Table of Contents

Section 1: Estimated Quantity of Make-Ready Work

PSE&G will provide semi-annual reports on the CEF-EV deployment ("CEF-EV Report") with the following information:

- Estimated quantity of work
- Quantity completed to date or, if the project cannot be quantified with numbers, the major tasks completed, e.g. Residential, Mixed Use Commercial, and DCFC Public Charging Make Ready to Charger Stub units completed and number of service upgrades:

Quantity of Work

See Table 1 for a summary of the period-to-date, program-to-date, and forecasted capital costs and O&M expenses for the Clean Energy Future – Electric Vehicle Program ("CEF-EV Program").

Major Tasks Completed: Following Board approval on January 27, 2021, PSE&G initiated program development, including Infrastructure Technology ("IT") architecture. PSE&G launched the CEF-EV Program in a series of steps from June through September 2021. Since that time PSE&G has continued to enroll eligible customers as discussed in detail in each subprogram below.

Quantity Completed to Date

See Table 2 for the capital costs per subprogram, indicating the work completed to date.

Quantity Completed: Since program inception, PSE&G has invested a total of $21M in CEF-EV Program investment. This includes investment for the following three subprograms: (i) Residential Smart Charging Program, (ii) Level-2 Mixed Use Charging Program, and (iii) a Direct Current Fast Charging ("DCFC") Program, which also includes investment in Distribution Demand Charge Rebates. The CEF-EV Program further includes cross-program investments for IT system upgrades to support the deployment of the CEF-EV program and the development of associated customer platforms.

Section 2: DCFC Distribution Demand Charge Rebate

The semi-annual reports will include the following information:

- The usage of the rebate funding
- The balance remaining of the $5 million rebate funding

Program Usage

The application and agreement form for the DCFC Distribution Charge Rebate for pre-existing sites was launched on June 15, 2021. Program to date, PSE&G has enrolled 41 customers to the DCFC Distribution Demand Charge Rebate, comprising of 267 chargers.

Funding Balance

See Table 2 for the usage and balance remaining of the $5 million rebate funding. Since program inception, PSE&G distributed $780,571 in demand charge rebates. There is $4.2M remaining in the funding.

Section 3: Semi-Annual and Program To-Date Forecast and Actual Costs

The semi-annual reports will include the following information:

- The forecasted and actual capital costs
- The forecasted and actual O&M expenses

The project expenditures shall be broken out between labor, material, and other costs.

Program Forecast

See Table 1 for the period-to-date, program-to-date, and forecasted capital costs and O&M expenses for the CEF-EV Program.

Capital Costs

See Table 2 for the actual capital costs by cost category and Table 3 for the capital costs broken out between labor, material and other ("LM&O").

Program enrollment for make-ready funding was implemented in phases. The DCFC subprogram was launched on July 23, 2021. The Level 2 Mixed-Use Commercial subprogram was launched on July 30, 2021. The Residential make-ready subprogram was launched on September 15, 2021. Since program inception, the CEF Program has enrolled 5,405 residential customers (5,640 Chargers), 72 Mixed Use Commercial customers (143 Chargers), and 41 DCFC customers in the CEF-EV Program (267 Chargers).

O&M Expenses

See Table 4 for the actual expenses by cost category and Table 5 for the expenses broken out between labor, material and other.

Section 4: EV Charging Data Summary

The CEF-EV Program semi-annual report will include a submittal of the following data:

- Residential EV Charging Data
- Direct Current Fast Charging (“DCFC”) Data

The submittal will provide the total energy consumed, capacity and transmission tags, measured demands, connected load, and the resulting load factor.

Residential EV Charging Data

The Residential EV charging data is summarized in Table 6.

DCFC Data Definitions

The DCFC EV charging data is summarized in Table 7.

Section 5: Tables

Table 1: CEF-EV Program Financial Summary

Period	*Investment*	*Expenses*	*Total*
HY1 2023	**$7,992,376**	**$2,515,249**	**$10,507,625**
January	$874,051	$1,020,473	**$1,894,524**
February	$1,274,173	$30,279	**$1,304,452**
March	$932,227	$468,444	**$1,400,671**
April	$1,553,476	$335,997	**$1,889,473**
May	$1,680,830	$308,856	**$1,989,686**
June	$1,677,619	$351,201	**$2,028,820**
Period-to-Date	**$7,992,376**	**$2,515,249**	**$10,507,625**
Program-to-Date	**$20,980,474**	**$6,515,491**	**$27,495,965**
To-Go Forecast	**$145,219,526**	**$32,451,076**	**$177,670,602**
Total Program Forecast	**$166,200,000**	**$38,966,567**	**$205,166,567**
Program Caps	$166,200,000	$38,966,567	$205,166,567

CEF – Electric Vehicle (EV) Program
HY1-2023 – January through June 2023

Table 2: Investment by Cost Category

Program/Budget Line	*Make Ready: Pole to Meter*	*Make Ready: Behind the Meter*	*Demand Charge Rebate*	*IT Systems*	*Total Investment for Reporting Period*
RESIDENTIAL					
Residential Subtotal	$2,273,203	$4,471,157	$0	$0	$6,744,360
MIXED USE / COMMERICAL L2					
Mixed-Use Subtotal	$71,230	$604,597	$0	$0	$675,827
DCFC PUBLIC CHARGING					
DCFC Subtotal	$71,586	$324,870	$151,795	$0	$548,251
IT SYSTEMS					
IT Systems Subtotal	$0	$0	$0	$23,938	$23,938
Reporting Period	**$2,416,018**	**$5,400,625**	**$151,795**	**$23,938**	**$7,992,376**
Program to Date	$5,295,912	$8,705,761	$780,571	$6,198,366	$20,980,610
Remaining Funding by Category	$38,454,088	$102,544,239	$4,219,429	$1,634	$145,219,390
Total Program Forecast	$43,750,000	$111,250,000	$5,000,000	$6,200,000	$166,200,000
Program Caps by Category	$43,750,000	$111,250,000	$5,000,000	$6,200,000	$166,200,000

Table 3: Investment by Labor, Materials & Other ("LM&O") Costs

2023	*Labor*	*Materials*	*Other**	*Total Investment*
January	$3,928	$0	$870,123	**$874,051**
February	$9,990	$0	$1,264,183	**$1,274,173**
March	$8,914	$0	$923,313	**$932,227**
April	$-9	$0	$1,553,485	**$1,553,476**
May	$0	$0	$1,680,830	**$1,680,830**
June	$0	$0	$1,677,619	**$1,677,619**
Reporting Period	**$22,823**	**$0**	**$7,969,553**	**$7,992,376**

*Other = Incentives and Outside Services ("O/S")

Table 4: Program Expenses by Cost Category

Program/Budget Line	*Administration & Program Development*	*Marketing, Education, and Outreach*	*Data Acquisition*	*Residential Vehicle Device Technical Trial*	*Total Expenses for Reporting Period*
RESIDENTIAL					
Residential Subtotal	$478,144	$276,712	$1,113,363	$0	**$1,868,219**
Mixed-Use Subtotal	$167,101	$50,130	$11,992	$0	**$229,222**
DCFC Subtotal	$158,567	$74,650	$7,221	$0	**$240,438**
IT Systems Subtotal	$0	$0	$177,370	$0	**$177,370**
Reporting Period	**$803,811**	**$401,492**	**$1,309,946**	**$0**	**$2,515,249**
Program to Date	$3,102,475	$913,860	$2,498,101	$0	$6,514,436
Remaining Funding by Category	$13,517,525	$7,086,140	$11,278,466	$570,000	$32,452,131
Total Program Forecast	$16,620,000	$8,000,000	$13,776,567	$570,000	$38,966,567
Program Caps by Category	$16,620,000	$8,000,000	$13,776,567	$570,000	$38,966,567

Table 5: Expenses by Labor, Material & Other ("LM&O") Costs

Period	Labor	Materials	Other*	Total Expenses
January	$1,019,774	$0	$699	$1,020,473
February	$29,554	$0	$724	$30,279
March	$468,102	$0	$342	$468,444
April	$329,837	$0	$6,160	$335,997
May	$307,971	$0	$885	$308,856
June	$348,047	$0	$3,154	$351,201
Period Total	**$2,503,285**	**$0**	**$11,964**	**$2,515,249**

*Other = Incentives and Outside Services ("O/S")

Table 6: Residential EV Charging Data Summary

Period	*Off-Peak kWh's*	*On-Peak kWh's*	*Grand Total kWh's*
January	337,366	75,312	412,678
February	304,691	58,513	363,204
March	468,153	74,391	542,544
April	434,899	67,780	502,679
May	536,972	79,060	616,032
June	761,527	118,402	879,929
Period Total	**2,843,608**	**473,458**	**3,317,066**

kWh's=Kilowatt-Hours

Table 7: DCFC EV Charging Data Summary

Using the 12-month period of July 2022 through June 2023					
Data	***Units***	***Total***	***Minimum***	***Average***	***Maximum***
Total Energy Consumed	kWh	30,463,996	8,621	952,000	2,685,425
Connected Load	kW	28,390	100	887	2,250
Load Factor	%		0%	18%	45%
Average Summer Demand	kW		48	423	1,128
Average Annual Demand	kW		48	414	1,112
PJM Capacity Obligation 1	kW	*January 1 – May 31*	0	125	428
PJM Capacity Obligation 2	kW	*June 1 – September 30*	3	214	722
PJM Capacity Obligation 3	kW	*October 1 – December 31*	0	125	429
PSEG Trans Obligation	kW		3	192	529

KW=Kilowatt; kWh=Kilowatt-Hour

Katherine E. Smith
Associate Counsel – Regulatory

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PSEG Services Corporation

March 1, 2024

In the Matter of the Petition of
Public Service Electric and Gas Company
for Approval of a CEF - EV Program and an
Associated Cost Recovery Mechanism
BPU Docket No. EO18101111

VIA ELECTRONIC MAIL ONLY
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RE: CEF – EV PROGRAM BPU SEMI-ANNUAL REPORTS

Dear Ms. Peterson and Mr. Lipman:

Pursuant to the Board's January 27, 2021 Order in the above referenced matter, enclosed is the Public Service Electric and Gas March 2024 semi-annual activity report for the Clean Energy Future – Electric Vehicle Program. The March 2024 report covers the period from July through December, 2023.

Also enclosed are revised versions of three previously-submitted reports that the Company recently discovered contain errors. The revised reports and corrections are as follows:

Revised Report	Revised Section	Revised Information
September 1, 2021	Table 1	Total Costs in Reporting Period, Program-to-Date, To-Go Forecast, and Total Program Forecast
September 1, 2022	Table 3	Total Investment in June 2022
March 1, 2023	Table 1	Investment for H2 2022
	Table 4	Administration & Program Development Remaining Funding by Category

Copies of the enclosed CEF-EV Semi-Annual Reports will be served upon all entities legally required to be noticed. Service will occur via e-mail, only, pursuant to the Board's March 19, 2020 Order in Docket No. EO20020254.[1] In addition, the report will be posted at www.pseg.com/ev.

Please advise if you have any questions or comments.

Respectfully submitted,

Katherine E. Smith

Attachments

EMAIL ONLY
C Cathleen Lewis
Michael Beck
Dean Taklif

[1] *In the Matter of the New Jersey Board of Public Utilities' Response to the Covid-19 Pandemic For a Temporary Waiver of Requirements for Certain Non-Essential Obligations*, Docket No. EO20030254, p 3 (March 19, 2020 Order).

Clean Energy Future – Electric Vehicle (EV) Program

Semi-Annual Report to the Board of Public Utilities

H2-2023 – July through December 2023

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Section 1: Estimated Quantity of Make-Ready Work

PSE&G will provide semi-annual reports on the CEF-EV deployment ("CEF-EV Report") with the following information:

- Estimated quantity of work
- Quantity completed to date or, if the project cannot be quantified with numbers, the major tasks completed, e.g., Residential, Mixed Use Commercial L2, and DCFC Public Charging Make Ready to Charger Stub units completed and number of service upgrades:

Quantity of Work

See Table 1 for a summary of the period-to-date, program-to-date, and forecasted capital costs and O&M expenses for the Clean Energy Future – Electric Vehicle Program ("CEF-EV Program").

Major Tasks Completed: Following Board approval on January 27, 2021, PSE&G initiated program development, including Infrastructure Technology (IT) architecture. PSE&G launched the CEF-EV Program in a series of steps from June through September 2021. Since that time PSE&G has continued to enroll eligible customers as discussed in detail in each subprogram below.

Quantity Completed to Date

See Table 2 for the capital costs per subprogram, indicating the work completed to date.

Quantity Completed: Since program inception, PSE&G has invested a total of $31M in CEF-EV Program investment. This includes investment for the following three subprograms: (i) Residential Smart Charging Program, (ii) Level-2 Mixed Use Charging Program, and (iii) a Direct Current Fast Charging ("DCFC") Program, which also includes investment in Distribution Demand Charge Rebates. The CEF-EV Program further includes cross-program investments for IT system upgrades to support the deployment of the CEF-EV program and the development of associated customer platforms.

Section 2: DCFC Distribution Demand Charge Rebate

The semi-annual reports will include the following information:

- The usage of the rebate funding
- The balance remaining of the $5 million rebate funding.

Program Usage

The application and agreement form for the DCFC Distribution Charge Rebate for pre-existing sites was launched on June 15, 2021. Program to date, PSE&G has enrolled 51 customers with a total of 295 chargers to the DCFC Distribution Demand Charge Rebate.

Funding Balance

See Table 2 for the usage and balance remaining of the $5 million rebate funding. Since program inception, PSE&G distributed $965,441 in demand charge rebates. There is $4M remaining in the funding.

Section 3: Semi-Annual and Program To-Date Forecast and Actual Costs

The semi-annual reports will include the following information:

- The forecasted and actual capital costs
- The forecasted and actual O&M expenses

The project expenditures shall be broken out between labor, material, and other costs.

Program Forecast

See Table 1 for the period-to-date, program-to-date, and forecasted capital costs and O&M expenses for the CEF-EV Program.

Capital Costs

See Table 2 for the actual capital costs by cost category and Table 3 for the capital costs broken out between labor, material and other ("LM&O").

Program enrollment for make-ready funding was implemented in phases. The DCFC subprogram was launched on July 23, 2021. The Level 2 Mixed-Use Commercial subprogram was launched on July 30, 2021. The Residential make-ready subprogram was launched on September 15, 2021. Since program inception, the CEF Program has enrolled 8,584 residential customers (8,775 Chargers), 130 Mixed Use Commercial customers (312 Chargers), and 51 DCFC customers in the CEF-EV Program (295 Chargers).

O&M Expenses

See Table 4 for the actual expenses by cost category and Table 5 for the expenses broken out between labor, material and other.

Section 4: EV Charging Data Summary

The CEF-EV Program semi-annual report will include a submittal of the following data:

- Residential EV Charging Data
- Direct Current Fast Charging (DCFC) Data

The submittal will provide the total energy consumed, capacity and transmission tags, measured demands, connected load, and the resulting load factor.

Residential EV Charging Data

The Residential EV charging data is summarized in Table 6.

DCFC Data Definitions

The DCFC EV charging data is summarized in Table 7.

Section 5: Tables

Table 1: CEF-EV Program Financial Summary

Period	*Investment*	*Expenses*	*Total*
July	$1,354,501	$288,573	**$1,643,074**
August	$1,944,639	$318,581	**$2,263,220**
September	$1,953,419	$359,880	**$2,313,299**
October	$1,959,943	$420,772	**$2,380,715**
November	$1,955,843	$277,724	**$2,233,567**
December	$1,251,908	$554,764	**$1,806,672**
Period-to-Date	**$10,420,253**	**$2,220,294**	**$12,640,547**
Program-to-Date	**$31,400,727**	**$8,735,785**	**$40,136,512**
To-Go Forecast	**$134,799,273**	**$30,230,782**	**$165,030,055**
Total Program Forecast	**$166,200,000**	**$38,966,567**	**$205,166,567**
Program Caps	$166,200,000	$38,966,567	$205,166,567

CEF – Electric Vehicle (EV) Program
H2-2023 – July through December 2023

Table 2: Investment by Cost Category

Program/Budget Line	Make Ready: Pole to Meter	Make Ready: Behind the Meter	Demand Charge Rebate	IT Systems	Total Investment for Reporting Period
RESIDENTIAL					
Residential Subtotal	$3,855,829	$3,989,916	$0	$0	$7,845,745
MIXED USE / COMMERICAL L2					
Mixed-Use Subtotal	$82,925	$1,287,482	$0	$0	$1,370,408
DCFC PUBLIC CHARGING					
DCFC Subtotal	$310,480	$709,864	$184,870	$0	$1,205,215
IT SYSTEMS					
IT Systems Subtotal	$0	$0	$0	-$1,115	-$1,115

Reporting Period	**$4,249,235**	**$5,987,262**	**$184,870**	**-$1,115**	**$10,420,253**
Program to Date	$9,545,147	$14,693,023	$965,441	$6,197,251	$31,400,862
Remaining Funding by Category	$34,204,853	$96,556,977	$4,034,559	$2,749	$134,799,138
Total Program Forecast	$43,750,000	$111,250,000	$5,000,000	$6,200,000	$166,200,000
Program Caps by Category	$43,750,000	$111,250,000	$5,000,000	$6,200,000	$166,200,000

Table 3: Investment by Labor, Materials & Other ("LM&O") Costs

2023	*Labor*	*Materials*	*Other*	*Total Investment*
July	$0	$0	$1,354,501	**$1,354,501**
August	$0	$0	$1,944,639	**$1,944,639**
September	$0	$0	$1,953,419	**$1,953,419**
October	$0	$0	$1,959,943	**$1,959,943**
November	$0	$0	$1,955,843	**$1,955,843**
December	$0	$0	$1,251,908	**$1,251,908**
Reporting Period	**$0**	**$0**	**$10,420,253**	**$10,420,253**

*O/S = Outside Services

CEF – Electric Vehicle (EV) Program
H2-2023 – July through December 2023

Table 4: Program Expenses by Cost Category

Program/Budget Line	*Administration & Program Development*	*Marketing, Education, and Outreach*	*Data Acquisition*	*Residential Vehicle Device Technical Trial*	*Total Expenses for Reporting Period*
RESIDENTIAL					
Residential Subtotal	$508,375	$477,273	$39,724	$549,912	**$1,575,284**
Mixed-Use Subtotal	$145,656	$42,376	$11,456	$0	**$199,488**
DCFC Subtotal	$140,245	$42,807	$6,015	$0	**$189,066**
IT Systems Subtotal	$0	$0	$256,456	$0	**$256,456**
Reporting Period	**$794,275**	**$562,456**	**$313,651**	**$549,912**	**$2,220,294**
Program to Date	$4,918,389	$1,476,316	$1,790,114	$549,912	$8,734,730
Remaining Funding by Category	$11,701,611	$6,523,684	$11,986,453	$20,088	$30,231,837
Total Program Forecast	$16,620,000	$8,000,000	$13,776,567	$570,000	$38,966,567
Program Caps by Category	$16,620,000	$8,000,000	$13,776,567	$570,000	$38,966,567

Table 5: Expenses by Labor, Material & Other ("LM&O") Costs

Period	*Labor*	*Materials*	*Other*	*Total Expenses*
July	$288,284	$0	$289	$288,573
August	$316,563	$0	$2,018	$318,581
September	$355,598	$0	$4,282	$359,880
October	$414,997	$0	$5,775	$420,772
November	$273,934	$0	$3,790	$277,724
December	$494,488	$0	$60,276	$554,764
Period Total	**$2,143,864**	**$0**	**$76,430**	**$2,220,294**

Table 6: Residential EV Charging Data Summary

Period	*Off-Peak kWh's*	*On-Peak kWh's*	*Grand Total kWh's*
July	667,436	103,174	770,610
August	659,116	100,659	759,775
September	729,704	98,879	828,583
October	1,037,710	127,513	1,165,223
November	1,201,261	156,342	1,357,603
December	1,242,334	192,401	1,434,735
Period Total	**5,537,561**	**778,968**	**6,316,529**

kWh's=Kilowatt-Hours

Table 7: DCFC EV Charging Data Summary

Using the 12-month period of January 2023 through December 2023					
Data	***Units***	***Total***	***Minimum***	***Average***	***Maximum***
Total Energy Consumed	kWh	34,901,536	31,046	1,090,673	2,764,361
Connected Load	kW	28,934	100	933	2,250
Load Factor			2%	12%	20%
Average Summer Demand	kW		149	853	2,051
Average Annual Demand	kW		177	821	1,900
PJM Capacity Obligation 1	kW	January 1 – May 31	0	128	428
PJM Capacity Obligation 2	kW	June 1 – September 30	0	216	722
PJM Capacity Obligation 3	kW	October 1 – December 31	0	216	721
PSEG Trans Obligation	kW		0	195	529

KW=Kilowatt; kWh=Kilowatt-Hour

CEF-EV Semi Annual Report September 2021 – REVISED

Clean Energy Future – Electric Vehicle (EV) Program

Semi-Annual Report to the Board of Public Utilities

H1-2021 – January through June 2021

Revised March 1, 2024

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Section 1: Estimated Quantity of Work

PSE&G will provide semi-annual reports on the CEF-EV deployment ("CEF-EV Report") with the following information:

- Estimated quantity of work
- Quantity completed to date or, if the project cannot be quantified with numbers, the major tasks completed, e.g. Residential, Mixed Use Commercial L2, and DCFC Public Charging Make Ready to Charger Stub units completed and number of service upgrades

Quantity of Work

See Table 1 for a summary of the period-to-date, program-to-date, and forecasted capital costs and O&M expenses for the CEF-EV Program.

<u>Major Tasks Completed</u>: Following Board approval on January 27, 2021, PSE&G initiated program development, including Infrastructure Technology (IT) architecture.

Quantity Completed to Date

See Table 2 for the capital costs per subprogram, indicating the work completed to date.

<u>Quantity Completed</u>: As of June 30, 2021, PSE&G has given no rebates for infrastructure development. PSE&G has invested in IT systems to support the deployment of the CEF-EV program and the development of associated customer platforms.

Section 2: DCFC Distribution Demand Charge Rebate

The semi-annual reports will include the following information

- The usage of the rebate funding
- The balance remaining of the $5 million rebate funding;

Program Usage

The application and agreement form for the DCFC Distribution Charge Rebate for pre-existing sites was launched on June 15, 2021. PSE&G received 8 applications for the DCFC Distribution Demand Charge Rebate on June 30, 2021 that are under review.

Funding Balance

See Table 2 for the balance remaining of the $5 million rebate funding. No DCFC Distribution Demand Charge Rebates were issued this reporting period.

Section 3: Semi-Annual and Program To-Date Forecast and Actual Costs

The semi-annual reports will include the following information:

- The forecasted and actual capital costs
- The forecasted and actual O&M expenses

The project expenditures shall be broken out between labor, material and other costs.

Program Forecast

See Table 1 for the period-to-date, program-to-date, and forecasted capital costs and O&M expenses for the CEF-EV Program.

Capital Costs

See Table 2 for the actual capital costs by cost category and Table 3 for the capital costs broken out between labor, material and other.

O&M Expenses

See Table 4 for the actual expenses by cost category and Table 5 for the expenses broken out between labor, material and other.

Section 4: Financial Tables

Table 1: Summary of Program Investment & Expenses

Summary of Program Investment & Expenses

Utility Name: PSE&G
Program Name: Clean Energy Future - Electric Vehicles
BPU Docket No. EO18101111

Period	*Investment (a)*	*Expenses (b)*	*Total (c=a+b)*
H1 2021	**$89,635**	**$723,093**	**$812,728**
January	$0	$0	**$0**
February	$0	$0	**$0**
March	$0	$337,327	**$337,327**
April	$0	$65,997	**$65,997**
May	$20,494	$180,627	**$201,120**
June	$69,141	$139,142	**$208,282**
Period-to-Date	**$89,635**	**$723,093**	**$812,728**
Program-to-Date	**$89,635**	**$723,093**	**$812,728**
To-Go Forecast	**$166,110,365**	**$38,243,474**	**$204,353,839**
Total Program Forecast	**$166,200,000**	**$38,966,567**	**$205,166,567**
Program Caps	$166,200,000	$38,966,567	$205,166,567

PSEG

Table 2: Investment by Cost Category

Program Investment by Cost Category

Utility Name: PSE&G
Program Name: Clean Energy Future - Electric Vehicles
BPU Docket No. EO18101111
Reporting Period: January 1, 2021 thru June 30, 2021

Program/Budget Line	*Make Ready: Pole-to-Meter (a)*	*Make Ready: Behind-the-Meter (b)*	*Demand Charge Rebate (c)*	*IT Systems (d)*	*Total Investment for Reporting Period (e=a+b+c+d)*
RESIDENTIAL					
Residential Subtotal	$0	$0	$0	$0	$0
MIXED USE / COMMERICAL L2					
Mixed Use Commerical Subtotal	$0	$0	$0	$0	$0
DCFC PUBLIC CHARGING					
DCFC Subtotal	$0	$0	$0	$0	$0
IT SYSTEMS					
IT Systems Subtotal	$0	$0	$0	$89,635	$89,635
TOTAL INVESTMENT BY CATEGORY	$0	$0	$0	$89,635	$89,635
PROGRAM CAPS BY CATEGORY	$43,750,000	$111,250,000	$5,000,000	$6,200,000	$166,200,000
REMAINING FUNDING BY CATEGORY	$43,750,000	$111,250,000	$5,000,000	$6,110,365	$166,110,365

Table 3: Investment by Labor, Material & Other Costs

Program Investment LM&O

Utility Name: PSE&G

Program Name: Clean Energy Future - Electric Vehicles
BPU Docket No. EO18101111
Reporting Period: January 1, 2021 thru June 30, 2021

2021	Labor (a)	Materials (b)	Other (c)	Total Expenses (d=a+b+c)
January	$0	$0	$0	$0
February	$0	$0	$0	$0
March	$0	$0	$0	$0
April	$0	$0	$0	$0
May	$18,164	$0	$2,330	$20,494
June	$56,374	$0	$12,767	$69,141
Period Total	**$74,538**	**$0**	**$15,097**	**$89,635**

Table 4: Expenses by Cost Category

Program Expenses by Cost Category

Utility Name: PSE&G

Program Name: Clean Energy Future - Electric Vehicles
BPU Docket No. EO18101111
Reporting Period: January 1, 2021 thru June 30, 2021

Program/Budget Line	Administration & Program Development (a)	Marketing, Education & Outreach (b)	Data Acquisition (c)	Residential Vehicle Device Technical Trial (d)	Total Expenses for Reporting Period (e=a+b+c+d)
RESIDENTIAL					
Residential Subtotal	$299,186	$1,067	$21,018	$0	$321,271
MIXED USE / COMMERICAL L2					
Mixed Use Commerical Subtotal	$107,228	$903	$0	$0	$108,131
DCFC PUBLIC CHARGING					
DCFC Subtotal	$131,554	$1,067	$0	$0	$132,621
IT SYTEMS					
IT Systems Subtotal	$128,598	$0	$32,471	$0	$161,069
TOTAL EXPENSES BY CATEGORY	$666,567	$3,037	$53,489	$0	$723,092
PROGRAM CAPS BY CATEGORY	$16,620,000	$8,000,000	$13,776,567	$570,000	$38,966,567

Table 5: Expenses by Labor, Material & Other Costs

Program Expenses LM&O

Utility Name: PSE&G

Program Name: Clean Energy Future - Electric Vehicles
BPU Docket No. EO18101111
Reporting Period: January 1, 2021 thru June 30, 2021

2021	Labor (a)	Materials (b)	Other (c)	Total Expenses (d=a+b+c)
January	$0	$0	$0	$0
February	$0	$0	$0	$0
March	$77,327	$0	$260,000	$337,327
April	$59,247	$0	$6,750	$65,997
May	$58,909	$0	$121,718	$180,627
June	$77,958	$0	$61,184	$139,142
Period Total	**$273,441**	**$0**	**$449,651**	**$723,093**

CEF-EV Semi Annual Report September 2022 – REVISED

Clean Energy Future – Electric Vehicle (EV) Program

Semi-Annual Report to the Board of Public Utilities

H1-2022 – January through June 2022

Revised March 1, 2024

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Section 1: Estimated Quantity of Make-Ready Work

PSE&G will provide semi-annual reports on the CEF-EV deployment ("CEF-EV Report") with the following information:

- Estimated quantity of work
- Quantity completed to date or, if the project cannot be quantified with numbers, the major tasks completed, e.g. Residential, Mixed Use Commercial L2, and DCFC Public Charging Make Ready to Charger Stub units completed and number of service upgrades:

Quantity of Work

See Table 1 for a summary of the period-to-date, program-to-date, and forecasted capital costs and O&M expenses for the Clean Energy Future – Electric Vehicle Program ("CEF-EV Program").

Major Tasks Completed: Following Board approval on January 27, 2021, PSE&G initiated program development, including Infrastructure Technology (IT) architecture. PSE&G launched the CEF-EV Program in a series of steps from June through September 2021 as discussed in detail in each subprogram below.

Quantity Completed to Date

See Table 2 for the capital costs per subprogram, indicating the work completed to date.

Quantity Completed: As of June 30, 2020, PSE&G has invested a total of $7.3M in CEF-EV Program investment. This includes investment for the following three subprograms: (i) Residential Smart Charging Program, (ii) Level-2 Mixed Use Charging Program, and (iii) a Direct Current Fast Charging ("DCFC") Program, which also includes investment in Distribution Demand Charge Rebates. The CEF-EV Program further includes cross-program investments for IT system upgrades to support the deployment of the CEF-EV program and the development of associated customer platforms.

Section 3: DCFC Distribution Demand Charge Rebate

The semi-annual reports will include the following information:

- The usage of the rebate funding
- The balance remaining of the $5 million rebate funding

Program Usage

The application and agreement form for the DCFC Distribution Charge Rebate for pre-existing sites was launched on June 15, 2021. Program to date, PSE&G has enrolled 33 customers to the DCFC Distribution Demand Charge Rebate, comprising of 242 chargers.

Funding Balance

See Table 2 for the usage and balance remaining of the $5 million rebate funding. As of June 30, 2022, PSE&G distributed $482,768 in demand charge rebates for this reporting period. There is $4.5M remaining in the funding.

Section 2: Semi-Annual and Program To-Date Forecast and Actual Costs

The semi-annual reports will include the following information:

- The forecasted and actual capital costs
- The forecasted and actual O&M expenses

The project expenditures shall be broken out between labor, material, and other costs.

Program Forecast

See Table 1 for the period-to-date, program-to-date, and forecasted capital costs and O&M expenses for the CEF-EV Program.

Capital Costs

See Table 2 for the actual capital costs by cost category and Table 3 for the capital costs broken out between labor, material and other ("LM&O").

Program enrollment for make-ready funding was implemented in phases. The DCFC subprogram was launched on July 23, 2021. The Level 2 Mixed-Use Commercial subprogram was launched on July 30, 2021. The Residential make-ready subprogram was launched on September 15, 2021. As of June 30, 2021, the CEF Program has enrolled 670 residential customers (678 Chargers), 11 Mixed Use Commercial customers (17 Chargers), and 33 DCFC customers in the CEF-EV Program (242 Chargers).

O&M Expenses

See Table 4 for the actual expenses by cost category and Table 5 for the expenses broken out between labor, material and other.

Section 4: Financial Tables

Table 1: CEF-EV Program Summary

Summary of Program Investment & Expenses

Period	*Investment*	*Expenses*	*Total*
H1 2022	**$3,117,853**	**$964,393**	**$4,082,246**
January	$716,318	$90,893	**$807,211**
February	$601,843	$153,420	**$755,263**
March	$609,068	$181,442	**$790,510**
April	$319,678	$188,446	**$508,124**
May	$567,202	$92,147	**$659,349**
June	$303,744	$258,045	**$561,789**
Period-to-Date	**$3,117,853**	**$964,393**	**$4,082,246**
Program-to-Date	**$7,238,549**	**$2,289,444**	**$9,527,993**
To-Go Forecast	**$158,961,451**	**$36,677,123**	**$195,638,574**
Total Program Forecast	**$166,200,000**	**$38,966,567**	**$205,166,567**
Program Caps	$166,200,000	$38,966,567	$205,166,567

Table 2: Investment by Cost Category

Reported Program Investment by Cost Category

Program/Budget Line	*Make Ready: Pole to Meter*	*Make Ready: Behind the Meter*	*Demand Charge Rebate*	*IT Systems*	*Total Investment for Reporting Period*
RESIDENTIAL					
Residential Subtotal	$0	$684,491	$0	$0	$684,491
MIXED USE / COMMERICAL L2					
Mixed-Use Subtotal	$0	$84,980	$0	$0	$84,980
DCFC PUBLIC CHARGING					
DCFC Subtotal	$0	$49,950	$190,088	$0	$240,038
IT SYSTEMS					
IT Systems Subtotal	$0	$0	$0	$2,108,344	$2,108,344

Reporting Period	**$0**	**$819,421**	**$190,088**	**$2,108,344**	**$3,117,853**
Program to Date	$0	$1,015,937	$482,768	$5,848,161	$7,346,866
Remaining Funding by Category	$43,750,000	$110,234,063	$4,517,232	$351,839	$158,853,134
Total Program Forecast	$43,750,000	$111,250,000	$5,000,000	$6,200,000	$166,200,000
Program Caps by Category	$43,750,000	$111,250,000	$5,000,000	$6,200,000	$166,200,000

CEF – Electric Vehicle (EV) Program
H1-2022 – January through June 2022

Table 3: Investment by Labor, Materials & Other ("LM&O") Costs

2022	*Labor*	*Materials*	*Other (Incentives, O/S, AFUDC)**	*Total Investment*
January	$42,931	$0	$673,387	**$716,318**
February	$32,290	$0	$569,553	**$601,843**
March	$11,930	$0	$597,137	**$609,068**
April	$13,837	$0	$305,841	**$319,678**
May	$5,278	$0	$561,924	**$567,202**
June	$5,996	$0	$297,748	**$294,207**
Reporting Period	**$112,262**	**$0**	**$3,005,590**	**$3,117,852**

*O/S = Outside Services, AFUDC = Allowed Funds Used During Construction

Table 4: Program Expenses by Cost Category

Reported Program Investment by Cost Category

Program/Budget Line	*Administration & Program Development*	*Marketing, Education, and Outreach*	*Data Acquisition*	*Residential Vehicle Device Technical Trial*	*Total Expenses for Reporting Period*
RESIDENTIAL					
Residential Subtotal	$347,596	$64,420	$20,753	$0	**$432,769**
Mixed-Use Subtotal	$124,520	$35,960	$17,524	$0	**$178,004**
DCFC Subtotal	$118,261	$34,578	$13,516	$0	**$166,355**
IT Systems Subtotal	$0	$0	$187,264	$0	**$187,264**
Reporting Period	**$590,377**	**$134,958**	**$239,057**	**$0**	**$964,392**
Program to Date	$1,701,280	$239,659	$348,504	$0	$2,289,443
Remaining Funding by Category	$14,918,720	$7,760,341	$13,428,063	$570,000	$36,677,127
Total Program Forecast	$16,620,000	$8,000,000	$13,776,567	$570,000	$38,966,567
Program Caps by Category	$16,620,000	$8,000,000	$13,776,567	$570,000	$38,966,567

CEF – Electric Vehicle (EV) Program
H1-2022 – January through June 2022

Table 5: Expenses by Labor, Material & Other ("LM&O") Costs

Period	*Labor*	*Materials*	*Other*	*Total Expenses*
January	$90,893	$0	$0	$90,893
February	$153,420	$0	$0	$153,420
March	$181,443	$0	$0	$181,443
April	$184,903	$0	$3,543	$188,446
May	$91,022	$0	$1,125	$92,147
June	$252,631	$0	$5,413	$258,044
Period Total	**$954,312**	**$0**	**$10,081**	**$964,393**

CEF-EV Semi Annual Report March 2023 – REVISED

Clean Energy Future – Electric Vehicle (EV) Program

Semi-Annual Report to the Board of Public Utilities

H2-2022 – July through December 2022

Revised March 1, 2024

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Section 1: Estimated Quantity of Make-Ready Work

PSE&G will provide semi-annual reports on the CEF-EV deployment ("CEF-EV Report") with the following information:

- Estimated quantity of work
- Quantity completed to date or, if the project cannot be quantified with numbers, the major tasks completed, e.g. Residential, Mixed Use Commercial L2, and DCFC Public Charging Make Ready to Charger Stub units completed and number of service upgrades:

Quantity of Work

See Table 1 for a summary of the period-to-date, program-to-date, and forecasted capital costs and O&M expenses for the Clean Energy Future – Electric Vehicle Program ("CEF-EV Program").

Major Tasks Completed: Following Board approval on January 27, 2021, PSE&G initiated program development, including Infrastructure Technology (IT) architecture. PSE&G launched the CEF-EV Program in a series of steps from June through September 2021 as discussed in detail in each subprogram below.

Quantity Completed to Date

See Table 2 for the capital costs per subprogram, indicating the work completed to date.

Quantity Completed: As of June 30, 2020, PSE&G has invested a total of $13M in CEF-EV Program investment. This includes investment for the following three subprograms: (i) Residential Smart Charging Program, (ii) Level-2 Mixed Use Charging Program, and (iii) a Direct Current Fast Charging ("DCFC") Program, which also includes investment in Distribution Demand Charge Rebates. The CEF-EV Program further includes cross-program investments for IT system upgrades to support the deployment of the CEF-EV program and the development of associated customer platforms.

Section 2: DCFC Distribution Demand Charge Rebate

The semi-annual reports will include the following information:

- The usage of the rebate funding
- The balance remaining of the $5 million rebate funding

Program Usage

The application and agreement form for the DCFC Distribution Charge Rebate for pre-existing sites was launched on June 15, 2021. Program to date, PSE&G has enrolled 35 customers to the DCFC Distribution Demand Charge Rebate, comprising of 252 chargers.

Funding Balance

See Table 2 for the usage and balance remaining of the $5 million rebate funding. As of June 30, 2021, PSE&G distributed $628,777 in demand charge rebates for this reporting period. There is $4.4M remaining in the funding.

Section 3: Semi-Annual and Program To-Date Forecast and Actual Costs

The semi-annual reports will include the following information:

- The forecasted and actual capital costs
- The forecasted and actual O&M expenses

The project expenditures shall be broken out between labor, material, and other costs.

Program Forecast

See Table 1 for the period-to-date, program-to-date, and forecasted capital costs and O&M expenses for the CEF-EV Program.

Capital Costs

See Table 2 for the actual capital costs by cost category and Table 3 for the capital costs broken out between labor, material and other ("LM&O").

Program enrollment for make-ready funding was implemented in phases. The DCFC subprogram was launched on July 23, 2021. The Level 2 Mixed-Use Commercial subprogram was launched on July 30, 2021. The Residential make-ready subprogram was launched on September 15, 2021. As of June 30, 2021, the CEF Program has enrolled 1,974 residential customers (1,995 Chargers), 33 Mixed Use Commercial customers (63 Chargers), and 35 DCFC customers in the CEF-EV Program (252 Chargers).

O&M Expenses

See Table 4 for the actual expenses by cost category and Table 5 for the expenses broken out between labor, material and other.

Section 4: Financial Tables

Table 1: CEF-EV Program Summary

Summary of Program Investment & Expenses

Period	*Investment*	*Expenses*	*Total*
H2 2022	**$5,691,334**	**$1,710,798**	**$7,402,132**
July	$1,105,954	$743,625	**$1,849,579**
August	$397,345	$211,971	**$609,316**
September	$1,022,141	$207,177	**$1,229,318**
October	$1,008,309	$187,788	**$1,196,097**
November	$819,372	$160,819	**$980,191**
December	$1,338,213	$199,418	**$1,537,631**
Period-to-Date	**$5,691,334**	**$1,710,798**	**$7,402,132**
Program-to-Date	**$12,988,098**	**$4,000,242**	**$16,988,340**
To-Go Forecast	**$153,211,902**	**$34,966,325**	**$188,178,227**
Total Program Forecast	**$166,200,000**	**$38,966,567**	**$205,166,567**
Program Caps	$166,200,000	$38,966,567	$205,166,567

CEF – Electric Vehicle (EV) Program
H2-2022 – July through December 2022

Table 2: Investment by Cost Category

Reported Program Investment by Cost Category

Program/Budget Line	*Make Ready: Pole to Meter*	*Make Ready: Behind the Meter*	*Demand Charge Rebate*	*IT Systems*	*Total Investment for Reporting Period*
RESIDENTIAL					
Residential Subtotal	$1,929,859	$1,660,600	$0	$0	$3,590,459
MIXED USE / COMMERICAL L2					
Mixed-Use Subtotal	$61,386	$366,843	$0	$0	$428,229
DCFC PUBLIC CHARGING					
DCFC Subtotal	$888,648	$200,000	$210,532	$0	$1,299,180
IT SYSTEMS					
IT Systems Subtotal	$0	$0	$0	$377,264	$377,264

Reporting Period	**$2,879,893**	**$2,227,443**	**$210,532**	**$377,264**	**$5,695,131**
Program to Date	$2,879,893	$3,305,000	$628,777	$6,174,428	$12,988,098
Remaining Funding by Category	$40,870,107	$107,945,000	$4,371,223	$25,572	$153,211,902
Total Program Forecast	$43,750,000	$111,250,000	$5,000,000	$6,200,000	$166,200,000
Program Caps by Category	$43,750,000	$111,250,000	$5,000,000	$6,200,000	$166,200,000

CEF – Electric Vehicle (EV) Program
H2-2022 – July through December 2022

PSEG

Table 3: Investment by Labor, Materials & Other ("LM&O") Costs

2022	*Labor*	*Materials*	*Other (Incentives, O/S)**	*Total Investment*
July	$4,192	$0	$1,105,954	**$1,110,146**
August	$2,034	$0	$395,311	**$397,345**
September	$1,224	$0	$1,022,141	**$1,023,365**
October	$122	$0	$1,008,187	**$1,008,309**
November	$46	$0	$819,372	**$819,418**
December	$0	$0	$1,342,010	**$1,342,010**
Reporting Period	**$7,618**	**$0**	**$5,692,975**	**$5,700,593**

*O/S = Outside Services,

Table 4: Program Expenses by Cost Category

Reported Program Investment by Cost Category

Program/Budget Line	*Administration & Program Development*	*Marketing, Education, and Outreach*	*Data Acquisition*	*Residential Vehicle Device Technical Trial*	*Total Expenses for Reporting Period*
RESIDENTIAL					
Residential Subtotal	$395,572	$178,088	$18,074	$0	**$591,734**
Mixed-Use Subtotal	$166,956	$48,414	$17,159	$0	**$232,529**
DCFC Subtotal	$148,432	$46,208	$11,987	$0	**$206,627**
IT Systems Subtotal	$0	$0	$679,808	$0	**$679,808**
Reporting Period	**$710,960**	**$272,710**	**$727,028**	**$0**	**$1,710,798**
Program to Date	$2,412,241	$512,368	$1,075,532	$0	$4,000,141
Remaining Funding by Category	$13,787,759	$7,487,632	$12,701,035	$570,000	$34,966,326
Total Program Forecast	$16,620,000	$8,000,000	$13,776,567	$570,000	$38,966,567
Program Caps by Category	$16,620,000	$8,000,000	$13,776,567	$570,000	$38,966,567

CEF – Electric Vehicle (EV) Program
H2-2022 – July through December 2022

Table 5: Expenses by Labor, Material & Other ("LM&O") Costs

Period	*Labor*	*Materials*	*Other*	*Total Expenses*
July	$234,911	$0	$508,713	$743,625
August	$211,308	$0	$663	$211,971
September	$205,764	$0	$1,413	$207,177
October	$187,302	$0	$486	$187,788
November	$159,684	$0	$1,134	$160,819
December	$195,731	$0	$3,688	$199,418
Period Total	**$1,194,700**	**$0**	**$516,098**	**$1,710,797**

STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

In the Matter of the Petition of
Public Service Electric and Gas Company
for Approval of an Increase in Electric and Gas
Rates and for Changes in the Tariffs for
Electric and Gas Service, B.P.U.N.J.
No. 17 Electric and B.P.U.N.J. No. 17
Gas, and for Changes in Depreciation Rates,
Pursuant to N.J.S.A. 48:2-18,
N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1, and
for Other Appropriate Relief

BPU Docket Nos. ER23120924 and GR23120925

DIRECT TESTIMONY

OF

DAVID JOHNSON
9+3 UPDATE

VICE PRESIDENT – CUSTOMER CARE AND CHIEF
CUSTOMER OFFICER, PSE&G

April 15, 2024
P-12 R1

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
DIRECT TESTIMONY
OF
DAVID JOHNSON
VICE PRESIDENT – CUSTOMER CARE AND
CHIEF CUSTOMER OFFICER PSE&G

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is David Johnson. My business address is 80 Park Plaza, Newark, New Jersey, 07102.

Q. In what capacity are you employed?

A. I am currently employed by Public Service Electric and Gas Company ("PSE&G" or "Company") as Vice President Customer Care and Chief Customer Officer (COO). I have over 25 years of experience in customer service for energy providers. For example, I previously served as CCO for Duquesne Light Company in Pittsburgh, PA, Vice President for Customer Service at Entergy Louisiana and Senior Vice President of Customer Service at DTE Energy. In my current role, I am responsible for the successful deployment of the CEF-EC program and operationalizing the AMI capabilities that result from this program. Implementation of the CEF-EC program and AMI functionalities involve many of the areas that I oversee including billing, meter reading, collections, customer experience and the contact center.

Q. What is the purpose of your direct testimony?

A. As part of PSE&G's 2023 base rate filing with the New Jersey Board of Public Utilities ("BPU" or "Board"), the purpose of my testimony is to provide information that will support a finding by the Board that the investments and expenditures made by PSE&G for its Clean Energy Future – Energy Cloud ("CEF-EC") program are prudent and reasonable. The CEF-EC costs that the Company proposes to recover in this proceeding are the investments placed in service by November 30, 2024, six months after the end of the test year, as well as the regulatory asset balances of the CEF-EC Infrastructure Deferral, Stranded Cost Deferral and Operation and Maintenance ("O&M") regulatory assets that have been established in accordance with the Board's January 7, 2021 Order in BPU Docket No. EO18101115 that authorized the CEF-EC program and establishment of the CEF-EC regulatory assets.[1] The accounting and cost recovery for the program and the treatment of depreciation are described in the testimony of Company witness Mr. Michael McFadden.

Q. Do you sponsor any schedules as part of your direct testimony?

A. Yes. I sponsor the following schedules that were prepared or compiled under my direction and supervision.

(1) Schedule DJ-1 sets forth my credentials;

(2) Schedule DJ-2 R-1 provides the CEF-EC semi-annual reports that have been submitted to BPU Staff to date. Revision R-1 of Schedule DJ-2 adds the most recent semi-annual report (dated February 26, 2024), and adds the cover letter that accompanied each semi-annual report.

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[1] *I/M/O The Petition of Public Service Electric and Gas Company for Approval of Its Clean Energy Future – Energy Cloud ("CEF-EC") Program on a Regulated Basis*, BPU Docket No. EO18101115, "Decision and Order Approving Stipulation" (January 7, 2021) ("CEF-EC Order").

II. <u>THE COMPANY'S CEF-EC PROGRAM AND CURRENT STATUS</u>

Q. Please describe the Company's CEF-EC Program that was approved by the Board in its CEF-EC Order.

A. By Order dated February 19, 2020, the Board found that AMI is a means to achieve the objectives of the 2019 Energy Master Plan ("EMP").[2] Accordingly, the Board directed PSE&G and other utilities to file petitions for AMI implementation. In the CEF-EC Order, the Board authorized the Company to install approximately 2.2 million Advanced Meter Infrastructure ("AMI") meters at an estimated investment cost of up to $707 million for the advanced meters, network infrastructure and associated information technology required to implement Release 1 of the CEF-EC program. The Company planned to install AMI meters over the period 2021 to 2024 in accordance with the following schedule:

2021	80,000 meters
2022	300,000 meters
2023	900,000 meters
2024	900,000 meters

Under the CEF-EC Order the Company had the right to accelerate this deployment schedule to effectuate the efficient deployment of AMI meters. The Company began installing AMI meters during 2021 and 2022 according to this plan and, beginning in 2023, conducted an accelerated geographic strategic deployment in which the Company divided its service territory into three separate regions and employed a strategy to identify and group meters for replacement on a daily basis. The Company utilized its existing manual meter reading assignments to develop a deployment strategy to support the efficient deployment of AMI meters and consolidation of meter reading assignments.

[2] *In re the Petition of Rockland Electric Company for Approval of an Advanced Metering Program, and for Other Relief*, BPU Docket No. ER16060524 (February 19, 2020).

Q. What is the current status of PSE&G's AMI installation project?

A. The project is currently ahead of its installation schedule and under the program budget.

Q. What is the status of the AMI network installation and functionality?

A. The Company completed installation of its Landis + Gyr Network ("Network") in June 2022, and 100 percent of the Network was communicating by September of 2022.

Q. How many AMI meters have been installed so far?

A. As of February 29, 2024, 1,494,038 residential and 195,319 commercial AMI meters have been installed, for a total of 1,689,357. Installations are expected to continue ahead of pace.

Q. Is the Company projecting to complete full AMI deployment within six months beyond the end of the rate case test year (by November 30, 2024)?

A. At this time, yes, PSE&G projects full deployment will be accomplished by November 30, 2024, and possibly could be accomplished earlier.[3] Certain factors that are difficult to predict may impact the timing, such as new supply chain issues, or other issues impacting PSE&G's ability to obtain AMI meter inventory or impacting the labor force. Based on current conditions, the Company expects to finish ahead of schedule.

Q. What are program costs compared to the program forecast as of February 29, 2024?

A. Total actual costs as of February 29, 2024, were approximately $442 million (approximately $404 million for capital and $38 million for O&M). PSE&G forecasts total costs of the Program upon completion in November 2024 to be $625 million (approximately $570 million for capital and $55 million for O&M) well below the approved amount of up to $779 million ($707 for capital and $72 for O&M).

[3] With the exception of customers who elect to opt out of an AMI meter.

Q. How has PSE&G managed implementation of the CEF-EC program to deliver the program to date significantly under the forecast budget?

A. PSE&G has achieved numerous meter deployment efficiencies by implementing the following strategies.

Successful customer communications ahead of meter changes has resulted in an approximate 84% success rate of changing the meter on the first visit. While some areas remain at 90% but as the Company addresses harder to access areas the percentage will be impacted. Making only a single visit to a customer location has reduced the need for appointments and unscheduled visits, which, by nature, are less productive and more costly.

Additionally, PSE&G has worked closely with the meter installation vendor to optimize meter change routes. The meter change schedule was organized by "sectors," which are geographic areas. Each sector was carefully designed to reduce travel time both within each sector and to the various warehouses and laydown yards.

PSE&G's internal workforce has also taken advantage of "opportunistic" meter changes on customers' premises. In other words, as PSE&G has been visiting customer homes to address meter-related issues, such as non-registering meters or high bill complaints, PSE&G has taken the opportunity to replace the existing meter with an AMI meter at that visit. This eliminates the need for a separate, future visit just to change that customer's meter.

III. BENEFITS OF CEF-EC PROGRAM INVESTMENTS

Q. Recognizing that the Company has not concluded the implementation of its CEF-EC program, have the benefits of the program identified previously by PSE&G begun to be realized?

A. Yes. PSE&G's CEF-EC program strategy prioritized delivering the benefits of AMI meters to customers as soon as possible following AMI meter installation. The program currently is delivering substantial benefits to customers. Some benefits have been, or are expected to be, achieved ahead of the forecast schedule for delivery.

Q. Please generally explain AMI customer benefits and the expected timing of achieving these benefits.

A. As a result of PSE&G's CEF-EC program deployment design, some customer benefits are already active, such as billing on actual usage transmitted by the AMI meters, and remote capabilities such as move in/move out and disconnect/reconnect.

Additionally, as set forth in the CEF-EC Order, other benefits are achievable over longer periods. In the October 11, 2018 filing to implement the CEF-EC program, the Company proposed a program that would implement 22 out of a total of 70 potential AMI functionalities or "Use Cases" that focused on customer engagement, network operations and planning, and new utility products and services.[4] PSE&G committed in the stipulation of settlement approved by the CEF-EC Order to use "best efforts" to provide the AMI capabilities of the 22 Use Cases within the approved program budget, and the parties recognized that, "these capabilities may not be available until after the full deployment if the AMI meters is complete."[5]

Notwithstanding, PSE&G's CEF-EC program to date has already accomplished deployment of multiple Use Cases that benefit all customers by improving the efficiency of operations and reducing truck dispatches that would previously have been required to perform move in/move out and reconnects.

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[4] Those 22 use cases were referred to as "Release 1." *See* CEF-EC Order at Stipulation ¶ 3. The remaining 48 Use Cases were generally described in PSE&G's AMI cost-benefit analysis that accompanied its 2018 filing, and could be proposed as part of future program proposal filings but are not included in the budget or implementation of the currently approved CEF-EC Program.

[5] CEF-EC Order at Stipulation ¶ 17.

Q. Beginning with the most basic AMI functions, when AMI meters are installed, when does data begin to communicate with the Company's systems, and is the AMI data being used for billing?

A. PSE&G's primary goal for the CEF-EC program is that after each meter is installed, the customer will receive an accurate bill utilizing an AMI meter read. Following installation of a meter, PSE&G verifies that the meter is communicating with the Company's systems. After three successful days communicating, the billing system utilizes the AMI read to bill the customer. The Company has achieved a sustained AMI actual read billing rate of over 99 percent. Where there have been a small number of communication issues, these are addressed expeditiously.

Q. Regarding the 22 Use Cases, please provide an overview and the status of their deployment.

A. These 22 Use Cases and deployment status are as follows:

Use Case #	Use Case Name	Deployment Status	Use Case Overview & Value
1,2,3,4	1. Enhanced Customer Engagement & Communications	**Deployed Q3, 2023** (customer access to usage data via portal) **Deployment scheduled Q2, 2024** (enable customer inquiries via portal)	A set of customer benefiting functions and analytic applications that provide visualizations and analytics across a variety of customer and iESP data combined with other data – bills, usage, prices, tips, alerts, energy efficiency, appliance profiles, new products and services, notifications, and available through mobile and web portals.
	2. Rate Analyzer & Comparator	**Deployment scheduled Q3, 2024**	
	3. Usage & Bill Alerts, Saving Tips, Interactive Bill Presentment	**Deployment scheduled Q2, 2024**	
	4. Interactive Energy Demand & Bill Management (Portal part of Meter Data Management System - MDMS project)	**Deployment scheduled Q2, 2024**	
5	Customer Segmentation & Behavioral Analysis	**Deployed Q4, 2023** (pull system) **Deployment scheduled Q2, 2024** (push system)	Provides the ability to develop highly targeted customer segmentation models based on more granular energy usage data and customer interactions to improve customer service, marketing, time of use ("TOU") rates, new products and services, and planning load forecasts. Capability depends on data integration to PSE&G systems to enable usage via "pull system" and "push system"

Use Case #	Use Case Name	Deployment Status	Use Case Overview & Value
6	Customer Power Quality	**Deployment scheduled Q3, 2024**	Capability that allows PSE&G to obtain voltage, load, and alert data directly from the meter to analyze customer power quality issues (flicker, sag, swell), without the need for further instrumentation, and can also help ensure appropriate corrective actions are taken (utility or customer side of the meter).
7	Customer Energy Efficiency Programs (Thermostats & Supporting CEF-EE Filing)	**Deployed Q4, 2023**	iESP data gives the customer the ability to make more educated energy efficiency related decisions, change energy consumption habits, and ultimately lower utility bills. This is enabled by providing customers with detailed iESP data through web or mobile portals, smart devices and in-home devices. PSE&G can also use this iESP data to design and offer energy efficiency products and services.
8	Customer Service & Call Center Performance	**Deployment scheduled Q3, 2024**	Enables the use of broader range of information (including iESP) to increase call center knowledge, improve service, improve customer satisfaction, and lower customer costs by bringing together historical and real-time information to support decision analysis and improve the customer experience.
9	Customer DER/PV/EV	**Deployed Q4, 2023**	Services and systems that will use iESP data to help assist customers with DER (solar, EV, energy storage) installations and the management of any power quality issues that occur as a result of variable DER load
10	Customer Device Safety	**Deployment scheduled Q3, 2024**	Enhances customer safety by using iESP data, such as alerts and voltage data to detect safety issues relating to customer meters and power connections such as hot sockets and fallen wires, and provide alerts to customers and PSE&G.
11	iESP Sensor, Network & Data Operations	**Deployed Q3, 2023**	Back office processes and systems that manage the initial iESP infrastructure deployment and the ongoing and updated Meter Operations business function including acquisition, warehousing, testing, installation, maintenance, data streams and quality, alarm management, and meter data management.
12	Automated Move in/Move out & Remote Disconnect/ Reconnect	**Deployed Q3, 2023**	This use case addresses the messages exchanged between Customer Operations processes and Smart Meter through the HeadEnd and Network when a customer move in or out request is issued by Customer Operations or other customer processes. PSE&G currently sends a metering service employee to move a customer in or out for a variety of reasons. With iESP, the turn on functions and on demand read functions to support these processes can be automated and performed remotely and instantaneously, thereby increasing customer satisfaction and efficiency across various customer processes. • Electric operations reduction due to MIMO and Collection activity automated. • Gas operations reduction due to remote MIMO and Collection activity automated: • Cost reduction due to 85k avoided truck roll costs for move in move outs
13	Remote Disconnect/ Reconnect	**Deployed Q3, 2023**	This use case addresses the messages exchanged between Customer Operations processes and Smart Meter through the HeadEnd and Network when a meter connect/disconnect request is issued by Customer Operations or other processes. PSE&G currently sends a metering service or collections employee to connect or disconnect the meter for a variety of reasons. With iESP, the reconnect/disconnect functions to support these processes can be automated and performed remotely and instantaneously, thereby increasing customer satisfaction and efficiency across various customer processes.

Use Case #	Use Case Name	Deployment Status	Use Case Overview & Value
			• Electric operations reduction due to remote turn-on/off of electric meters • Gas operations reduction due to remote turn-on/off of gas meters: • Cost reduction due to 171k avoided truck roll costs for move in standard turn on/turn offs • Cost reduction due to avoided truck roll costs for turn on/turn off type events • Reduction in writes offs due to energy consumed on inactive accounts. Being able to remotely detect and disconnect will reduce the occurrence. $20m written off yearly. Assuming 70% reduction due to iESP capabilities
14	Next Generation Meter-to-Cash	**Deployed Q3, 2023** (enables billing department to provide revised bills via AMI data) **Deployment scheduled Q3, 2024** (obtain missing interval reads)	With more granular and quality iESP data available, alongside numerous other internal data sources, PSE&G can optimize and re-invent their meter-to-cash processes and drive out inefficiencies, increase service, and reduce costs. The iESP data is significantly more accurate at the source and by mapping the data from the iESP to its end use, leakage can be detected more easily. The cost of these losses is spread across the customer base so any improvement ultimately reduces customer bills. • Billing cost reduction due to a decline of billing irregularities and analysis work • Collection cost reduction due to a decline of backoffice collection workload • Reduction in bad debt due to improvement in field collections. Being able to remotely detect and disconnect will reduce the occurrence. $60m written off yearly. Assuming 31% reduction due to iESP capabilities
15	Network Connectivity Analysis	**Deployment scheduled Q2, 2024**	PSE&G's electricity network is complex, covers a large area, and provides power to different customers at different voltage levels. Ensuring that the required sources and end-use loads are correctly represented in operations systems is often very difficult. The iESP end-point meters can extend the network model and enable a high level of accuracy of connections and phasing, which in turn results in better planning and operations performance, and enables many other network dependent use cases.
16	Outage Detection & Analysis	**Deployment scheduled Q2, 2024**	Uses outage data from operations systems and smart meters to identify and verify possible outage locations, as well as identify network sections and specific customers (and numbers) that are out of power. This data is provided and displayed in real-time, to allow analysis, fast response, and crew dispatch to the precise location (down to meter) with information on the potential cause of the outage in order to more quickly restore power and ensure all customers are restored.
17	Outage Response Notification (ETR)	**Deployment scheduled Q2, 2024**	Use iESP outage data to calculate and communicate reasonable, more accurate, and acceptable outage status and restoration times to customers in real time. This largely eliminates one of the most common customer complaints about utility service, *i.e.,* inaccurate estimated restoration times. Messaging solutions within scope of this use case include Interactive Voice Response (IVR), web portals, text messaging, social media, mobile applications, and press releases.

Use Case #	Use Case Name	Deployment Status	Use Case Overview & Value
18	Voltage Monitoring & Analysis	**Deployment Q3, 2024**	Using iESP data and other network data sources, voltage readings are captured, visualized, and system-wide analysis is run to determine locations where voltage violations exist both above and below nominal voltage. Utilities can utilize this information for accurate analysis of voltage issues and a base for voltage planning and optimization across the network. Further, this information can help planners identify strategic locations for deployment of Volt/VAR optimization equipment.
19	Asset Load/Phase Management, Balancing & Power Analysis (incl. Transformer Load Monitoring & Customer Load Curtailment/Limiting)	**Deployment scheduled Q3, 2024**	Using iESP data and other network data sources, load data is imported, aggregated, and visualized. Power flow analysis is run to examine and monitor loading profiles of every network asset along the feeder from the substation to the smart meter. This use case gives visibility of loading profiles and load flows of all network assets and customers with real-time or overnight iESP data updates. This information can be used by planners and operators to determine areas of overloading of assets on the system, plan responses to major events, execute asset balancing, and customer load curtailment.
20	Load Profiling & Forecasting	**Deployment scheduled Q3, 2024**	Capability that would enhance load profiles and forecasts by using iESP data in combination with network, customer billing or other data (*e.g.*, weather) to perform more detailed usage analysis. This is beneficial to customers and PSE&G planners by supporting optimized planning of load growth, which in turn leads to optimized capital spending and reliability of the network.
21	Distribution Losses	**Deployment scheduled Q3, 2024**	Distribution losses can be identified by comparing the iESP end-point meter usage data with usage data at the distribution entry point (*i.e.*, substation). Areas of high losses or network sections with particularly high losses can be identified through the analysis. Further analysis on the causes of the high losses will shed light into the different types of corrective / mitigating actions that can be taken to reduce the technical losses. Technical losses are spread across the customer base, so any improvement in this area could reduce customer bills.
22	Revenue Protection & Assurance	**Deployment scheduled Q3, 2024**	Revenue protection refers to the prevention, detection, and recovery of losses caused by interference with or theft of utility service. This use case will leverage smart meter consumption, as well as voltage and event data, to detect energy theft and meter tampering by employing multiple screening techniques, including cross-service correlations. Energy theft is spread across the customer base, so any improvement reduces customer bills.

Q. Please identify the Use Cases that have already been deployed.

A. PSE&G has already deployed or partially deployed the following 8 Use Cases:

- Use Case 1: Enhanced Customer Engagement
- Use Case 5: Customer Segmentation & Behavioral Analysis
- Use Case 7: Customer Energy Efficiency Programs
- Use Case 9: Customer DER/PV/EV

- Use Case 11: Sensor, Network & Data Operations
- Use Case 12: Automated Move in/Move out & Remote Disconnect/Reconnect
- Use Case 13: Remote Disconnect/Reconnect
- Use Case 14: Next Generation Meter to Cash

Q. Please describe the benefits currently being realized as a result of the installation and general functionality of installed AMI meters, use of the AMI meter data for billing, and the 8 Use Cases deployed to date.

A. Benefits of the CEF-EC program currently being realized through the CEF-EC program to date can be grouped as follows: meter reading/meter accuracy; benefits derived from remote capabilities; revenue integrity benefits; collections benefits; and customer access to their AMI data. I will generally describe each of these benefit types below:

<u>Meter Reading/Meter Accuracy</u>

Operational and customer benefits result from reduced labor and costs of meter reading and increased accuracy of bills due to a higher meter reading rate due to AMI. Please reference the Company's semi-annual reports in Schedule DJ-2 R-1 for meter read rates attributable to AMI.

<u>Remote Capabilities</u>

Currently remote meter reading, remote move-in/move-out, and remote disconnect/reconnect functionalities are enabled and are being used via installed AMI meters. Operational benefits from these functionalities include reduced costs through eliminating the need to dispatch trucks, and the efficiencies of completing these tasks remotely. Through February 29, 2024, there have been 28,301 reconnects following disconnection for non-payment completed remotely, avoiding a truck dispatch and greatly reducing the customers' wait time to be reconnected. Additionally, there have been

388,638 move-ins and move-outs completed remotely (meter reads, turn-ons, and turn-offs). There are also tangential environmental benefits because reducing the need to dispatch a truck reduces the overall greenhouse gas emissions from vehicles.

Collections Benefits

Field collectors now have the ability to disconnect an AMI meter remotely when they update a collection order on their hand-held device. This improves their efficiency and effectiveness. Before having remote turn-on and turn-off capability, the effective rate for a field collector visit was 28%.[6] Since the addition of this capability, the effective rate for a field collector on visits with AMI meters is greater than 90%. There have been 72,430 move-ins and move-outs remotely turned on and off, resulting in the reduction of unknown accounts and the revenue associated with these accounts (a subset of total remote move-ins/move-outs). In the future, this will result in reduced bad debt expense related to unknown revenues.

Customer Access to Their Data

Customers with AMI meters have access to PSE&G's AMI portal. The portal allows customers to view their usage, set usage threshold alerts, and access existing energy savings tips. The portal available to residential customers also has additional information about home energy assessments.

[6] A field collector visits is typically considered "effective" if it results in either a payment or a shut-off.

Q. Has the Company realized any additional benefits simply by virtue of replacing existing meters?

A. Yes. PSE&G's observations during meter replacement have resulted in PSE&G investigating 657 cases of tampering through February 29, 2024.[7] This yields a direct customer benefit, as detecting tampering reduces the costs of theft from meter tampering.

Q. Will AMI meters assist the company in detecting metering tampering and theft going forward?

A. Yes. As described in the table above, the current plan is to deploy an analytical tool by the end of the third quarter of 2024 that will enable identification of potential theft more quickly.

Q. Has the Company implemented the CEF-EC program in a manner consistent with the CEF-EC Order and with regard to customers wishing to opt-out of AMI meters?

A. Yes. The Company has complied with applicable reporting requirements and attempted to implement the program as efficiently as possible. The semi-annual reports submitted to the BPU are attached hereto as Schedule DJ-2 R1. Additionally, the Company has implemented the CEF-EC program in a manner consistent with the CEF-EC Order that fully recognized the rights of customers to opt out of the program. As of February 29, 2024, only 6,794 customers opted out of the AMI meter. This is an opt-out rate of less than one-half of one percent.

Q. Is the Company proposing in this case a change to the manual meter reading fee as was permitted by the CEF-EC Order?

A. No. The CEF-EC Order permits PSE&G to "provide testimony and actual cost information for these fees in its Next Base Rate Case, at which time these fees will be subject to review and

[7] Note that the original testimony attached to the Company's initial December 29, 2023 filing contained an error that misidentified this statistic through September 30, 2023. The number in the original testimony should have read "434 cases through September 30, 2023," not "9,134 cases through September 30, 2023."

modification."[8] However, and in order to achieve an equitable and appropriately non-discriminatory result for all customers, PSE&G is not currently collecting the manual meter-reading fees from opt-out customers. Therefore, there is not yet sufficient data to present in this matter regarding the actual costs based on all opt-outs that would support a change in the fee established in the CEF-EC Order. The CEF-EC Order states that "ongoing review and assessment of these fees will be subject to review and modification in future rate cases;" therefore, PSE&G anticipates it will present data related to actual costs of manual meter reads for the entire population of opt-outs in its next rate case.[9]

Q. How does PSE&G communicate these fees to customers that have chosen to opt out?

A. Any customer opting out was notified during the opt-out process that the $12 fee will begin to apply in 2024. PSE&G also intends to send each such customer a letter providing the opportunity to opt back in before PSE&G starts charging the fee. Any customer that opts back in will not be charged a fee.

Q. When will PSE&G begin charging customers the opt-out fees?

A. PSE&G will begin charging a customer an opt-out fee only after PSE&G sends that customer the letter described above providing that customer an opportunity to opt back in.

Q. The CEF-EC Order also established a one-time opt out fee for customers wishing to remove an AMI meter that was previously installed. Is PSE&G currently charging this fee?

A. Yes. PSE&G is currently charging this fee.

---

[8] CEF-EC Order at Stipulation ¶ 31.

[9] *Id.*

IV. ACCOUNTING AND COST RECOVERY FOR CEF-EC PROGRAM

Q. Did the CEF-EC Order establish a method for the Company to account for and recover the costs of the CEF-EC program?

A. Yes. The CEF-EC enables accelerated installation of AMI meters and retirement of legacy and non-AMI meters before they are fully depreciated. The prudence of the costs included in these regulatory assets is subject to review by the Board in this case. The Order provided that until the costs of the CEF-EC programs were rolled into base rates, AMI-related capital costs, legacy meter stranded costs, and AMI-related O&M costs would be deferred and placed in regulatory assets as separate and identifiable accounts. Specifically, the details are shown on Schedule MPM-16 R-1, the proposed amortization of the CEF-EC deferrals are shown on Schedule MPM-47 R-1, and the *pro forma* revenue requirement adjustment is shown on Schedule MPM-48 R-1.

Q. How are the projected O&M savings related to the CEF-EC Program reflected in the Company's filing?

A. In accordance with CEF-EC Order, PSE&G will include a reduction for future O&M savings after the test year. As described in Mr. McFadden's testimony, the Company is proposing a *pro-forma* adjustment to its revenue request in this proceeding to account for future O&M savings resulting from AMI that are not reflected in the test year and is shown on Schedule MPM-48 R-1.

Q. Does this conclude your direct testimony?

A. Yes. It does.

Matthew M. Weissman
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PSEG Services Corporation

September 8, 2021

In the Matter of the Petition of
Public Service Electric and Gas Company for
Approval of its Clean Energy Future-Energy Cloud (CEF-EC)
Program on a Regulated Basis
BPU Docket No. EO18101115

VIA ELECTRONIC MAIL
Stacy Peterson
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New Jersey Board of Public Utilities
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Brian Lipman
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P.O. Box 003
Trenton, NJ 08625

Re: Advanced Metering Infrastructure (AMI) Program - Semi Annual Report to the Board of Public Utilities for the Period January 1, 2021 - June 30, 2021

Dear Ms. Peterson and Mr. Lipman:

Pursuant to the Board's January 7, 2021 Order in the above referenced matter, enclosed is Public Service Electric and Gas Advanced Meter Infrastructure (AMI) Program's semi-annual report for the period January 1, 2021 through June 30, 2021.

Copies of the CEF-EC AMI Semi-Annual Report, January 1, 2021 – June 30, 2021 will be served upon all entities legally required to be noticed. Service will occur via e-mail, only, pursuant to the Board's March 19, 2020 Order in Docket No. EO20020254.[1] In addition, the report will be posted at www.pseg.com/ev.

[1] *In the Matter of the New Jersey Board of Public Utilities' Response to the Covid-19 Pandemic For a Temporary Waiver of Requirements for Certain Non-Essential Obligations*, Docket No. EO20030254, p 3 (March 19, 2020 Order).

Please advise if you have any questions or comments.

Very truly yours,

Matthew M. Weissman

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Clean Energy Futures-Energy Cloud

Advanced Metering Infrastructure (AMI) Program

Semi-Annual Report to the Board of Public Utilities

For the period January 1, 2021-June 30, 2021

PSEG

Reporting Metric Tables:

Metric Description	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Current Reporting Period 1/1/2021-6/30/2021	Project to Date
Residential Meters Installed	17	1,975	3,613	4,177	6,457	6,880	23,119	23,119
Commercial Meters Installed	2	63	169	314	861	1,151	2,560	2,560
Poles Installed	0	0	0	0	0	0	0	See Note A
Three-radio Network gateways installed	0	0	0	0	0	0	0	See Note A
Single-radio Network gateways installed	0	0	0	0	0	0	0	See Note A
Routers Installed	0	0	0	0	0	0	0	See Note A
Percentage of Network Communicating to L+G Platform	0	0	0	0	0	0	0	See Note B
Total number of opt-out customers	1	11	28	41	56	65	65	65
Number of actual reads recorded from AMI meters each month		997,135	1,239,155	1,431,373	1,815,845	2,204,059	7,687,567	See Note C
Number of meter readers employed by PSE&G each month	357	359	387	416	442	419		
Number of customers who have accessed the AMI web portal	1,083	906	1,149	1,232	1,220	1,232	6,822	6,822
Number of customers identified to have received energy saving messaging	1,817,845	2,725,974	2,550,372	1,553,621	219,038	1,524,373	10,391,223	10,391,223
Number of customers who have authorized third party supplier access to their energy usage data	N/A	N/A	N/A	N/A	N/A	N/A	N/A	See Note D
Third Party Program-to-date customer engagement efforts undertaken by the Company	N/A	N/A	N/A	N/A	N/A	N/A	N/A	See Note E
Number of AMI meters replaced due to functioning errors	0	0	0	0	0	1	1	1
Number of remote connects/disconnects performed	N/A	N/A	N/A	N/A	N/A	N/A	N/A	See Note F
Number of AMI meter tampering cases found	N/A	N/A	N/A	N/A	N/A	N/A	N/A	See Note G
Estimated CEF-EC project completion date							12/31/2024	12/31/2024

N/A – Not applicable at this stage of the AMI Program

PSEG

Average Installation Costs Costs			Current Reporting Period 1/1/2021-6/30/2021	Project to Date
Average Cost Residential Meters Installed -Total			**$ 215.91**	**$ 215.91**
Average Cost Residential Meters Installed - Labor			$ 99.88	$ 99.88
Average Cost Residential Meters Installed - Materials			$ 116.03	$ 116.03
Average Cost Commercial Meters Installed - Total			**$ 268.83**	**$ 268.83**
Average Cost Commercial Meters Installed - Labor			$ 128.03	$ 128.03
Average Cost Commercial Meters Installed - Materials			$ 140.80	$ 140.80
Captial and O&M Costs	**FORECAST**		**ACTUALS**	
	Current Reporting Period 1/1/2021-6/30/2021	**Project to Date**	**Current Reporting Period 1/1/2021-6/30/2021**	**Project to Date**
CEF-EC Capital Costs - Total	**$8.56M**	**$8.56M**	**$9.82M**	**$9.82M**
CEF-EC Capital Costs - Labor	$.57M	$.57M	$4.45M	$4.45M
CEF-EC Capital Costs - Material	$1.13M	$1.13M	$3.06M	$3.06M
CEF-EC Capital Costs - Other	$6.86M	$6.86M	$2.31M	$2.31M
CEF-EC O&M Expenses - Total	**$3.34M**	**$3.34M**	**$870K**	**$870K**
CEF-EC O&M Expenses - Labor	$0	$0	$500K	$500K
CEF-EC O&M Expenses - Material	$0	$0	$0	$0
CEF-EC O&M Expenses - Other	$3.34M	$3.34M	$370K	$370K
Stranded Costs Deferred			**N/A**	**See Note H**

N/A – Not applicable at this stage of the AMI Program

Reporting Metric Notes:

A. Network Installation

Estimated Quantity of Work: 161 new poles and three radio gateways, 47 single-radio network gateways and 2207 routers are estimated to be installed beginning in July 2021 with completion by mid-2022 to support the expansion of the existing RF Network

B. Percentage of Network Communicating to L+G Platform

Estimated Quantity of Work: 100% installation of network to be completed by mid-2022

C. Actual Reads Recorded from AMI Meters

Actual read number is inclusive of large commercial AMI meters installed prior to start of current AMI Project

D. Customers who have authorized third party supplier access to their energy usage data

The development of a Data Access Plan has been deferred pending the statewide proceeding in Docket No. EO20110716. On August 23, 2021, in that docket, the BPU issued a Straw Proposal on Advanced Metering Infrastructure (AMI) Data Transparency, Privacy & Billing, and has sought written comment from all interested parties by October 7, 2021. Per that August 23, 2021 notice, after submission of comments, Board Staff anticipates having one or more stakeholder meetings to discuss that feedback and, once all feedback is received, Staff expects to recommend that the Board approve an MFR order on data access, among other things, which will be followed by a rulemaking proceeding to codify the requirements placed on each electric public utility with an AMI deployment plan. PSE&G is participating in that Board Staff proceeding.

E. Third Party Customer Engagement Efforts

PSE&G has utilized social media outlets for third party customer engagement efforts to date. The activities and results are as follows:

1. Published 17 messages:

a) *2 paid Facebook ads,*

b) *15 organic messages on Facebook, Twitter and LinkedIn:*

  (1) 5 on Facebook,

  (2) 9 on Twitter,

    (a) 7 on PSEGDelivers,

    (b) 2 on PSEGNews.

c) 1 on LinkedIn

2. Channel followers (as of July 2021):

a) *Facebook: 116,659*

b) *PSEGDelivers (Twitter): 101,704 followers*

c) *PSEGNews (Twitter): 20,418*

d) *LinkedIn: 55,182*

3. The social media posts generated:

a) *2,355,520 impressions (how many times an AMI social message was displayed),*

b) *Reached 797,462 Facebook users*

F. Remote Connects/Disconnects Performed

Use case not yet implemented

G. AMI Metering Tampering Cases

Use case not yet implemented

H. Stranded Costs Deferred

Expected to be available for next reporting period

Katherine E. Smith
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PSEG
Services Corporation

March 1, 2022

In the Matter of the Petition of
Public Service Electric and Gas Company for
Approval of its Clean Energy Future-Energy Cloud (CEF-EC)
Program on a Regulated Basis
BPU Docket No. EO18101115

VIA ELECTRONIC MAIL
Paul Lupo
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Trenton, NJ 08625

Re: Advanced Metering Infrastructure (AMI) Program - Semi Annual Report to the Board of Public Utilities for the Period July 1, 2021 - December 31, 2021

Dear Ms. Peterson and Mr. Lipman:
Pursuant to the Board's January 7, 2021 Order in the above referenced matter, enclosed is Public Service Electric and Gas Advanced Meter Infrastructure (AMI) Program's semi-annual report for the period July 1, 2021 through December 31, 2021.

Copies of the CEF-EC AMI Semi-Annual Report, July 1, 2021 – December 31, 2021 will be served upon all entities legally required to be noticed. Service will occur via e-mail, only, pursuant to the Board's March 19, 2020 Order in Docket No. EO20020254. [1] In addition, the report will be posted at www.pseg.com/ev.

1 *In the Matter of the New Jersey Board of Public Utilities' Response to the Covid-19 Pandemic For a Temporary Waiver of Requirements for Certain Non-Essential Obligations*, Docket No. EO20030254, p 3 (March 19, 2020 Order).

Please advise if you have any questions or comments.

Very truly yours,

Katherine Smith

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Clean Energy Future-Energy Cloud

Advanced Metering Infrastructure (AMI) Program

Semi-Annual Report to the Board of Public Utilities

For the period July 1, 2021-December 31, 2021

Reporting Metric Tables:

Metric Description	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Current Reporting Period 7/1/2021-12/31/2021	Project to Date 1/7/2021 - 12/31/2021
Residential Meters Installed	7,538	8,720	8,663	12,558	6,394	6,007	49,880	72,999
Commercial Meters Installed	973	1,542	1,815	2,322	2,428	2,029	11,109	13,669
Poles Installed	0	0	0	11	14	32	57	57
Three-radio Network gateways installed	0	0	0	10	10	11	31	31
Single-radio Network gateways installed	0	0	0	0	21	3	24	24
Routers Installed	14	236	167	374	483	475	1,749	1,749
Percentage of Network Communicating to L+G Platform	0.64%	12.36%	20.61%	40.14%	66.24%	91.99%	91.99%	91.99%
Total number of opt-out customers	98	111	117	120	128	135	135	135
Number of actual reads recorded from AMI meters each month	2,697,426	3,280,196	3,721,308	4,659,650	5,203,311	6,189,795	25,751,686	See Note C
Number of meter readers and meter reader support staff employed by PSE&G each month	421	415	405	386	363	362		
Number of customers who have accessed the AMI web portal	1,844	1,539	1,789	1,627	1,149	1,378	9,326	16,148
Number of customers identified to have received energy saving messaging	149,173	19,383	1,638,684	2,277,086	2,307,772	11,581	6,403,679	16,794,902
Number of customers who have authorized third party supplier access to their energy usage data	N/A	N/A	N/A	N/A	N/A	N/A	N/A	See Note E
Third Party Program-to-date customer engagement efforts undertaken by the Company	N/A	N/A	N/A	N/A	N/A	N/A	N/A	See Note F
Number of AMI meters replaced due to functioning errors	0	0	2	1	0	0	3	4
Number of remote connects/disconnects performed	N/A	N/A	N/A	N/A	N/A	N/A	N/A	See Note G
Number of AMI meter tampering cases found	N/A	N/A	N/A	N/A	N/A	N/A	N/A	See Note H
Estimated CEF-EC project completion date							12/31/2024	12/31/2024

N/A – Not applicable at this stage of the AMI Program

Average Installation Costs			**Current Reporting Period 7/1/2021-12/31/2021**	**Project to Date 1/7/2021 - 12/31/2021**
Average Cost Residential Meters Installed –Total			**$190**	**$198**
Average Cost Residential Meters Installed – Labor			$75	$83
Average Cost Residential Meters Installed – Materials			$115	$115
Average Cost Commercial Meters Installed – Total			**$242**	**$248**
Average Cost Commercial Meters Installed – Labor			$ 88	$97
Average Cost Commercial Meters Installed – Materials			$154	$51
	FORECAST		**ACTUALS**	
Metric Description (Cost Info.)	**Current Reporting Period 7/1/2021-12/31/2021**	**Project to Date 1/7/2021 - 12/31/2021**	**Current Reporting Period 7/1/2021-12/31/2021**	**Project to Date 1/7/2021 - 12/31/2021**
CEF-EC Capital Costs - Total	**$29.40M**	**$39.22M**	**$23.38M**	**$33.20M**
CEF-EC Capital Costs - Labor	$12.50M	$16.95M	$7.28M	$11.74M
CEF-EC Capital Costs - Material	$7.99M	$11.04M	$8.01M	$11.07M
CEF-EC Capital Costs - Other	$8.92M	$11.23M	$8.08M	$10.39M
CEF-EC Deferred O&M Expenses - Total	**$0.87M**	**$10.03M**	**$3.32M**	**$4.19 M**
CEF-EC Deferred O&M Expenses - Labor	$0.50M	$2.37M	$(0.50)M	$0.00M
CEF-EC Deferred O&M Expenses - Material	N/A	N/A	$0.57M	$0.57M
CEF-EC Deferred O&M Expenses - Other	$0.37M	$7.65M	$3.24M	$3.62M
Stranded Costs Deferred	**N/A**	**N/A**	**See Note I**	**See Note I**

N/A – Not applicable at this stage of the AMI Program

Reporting Metric Notes:

A. Network Installation

Estimated Quantity of Work: 161 new poles and three radio gateways, 47 single-radio network gateways and 2207 routers are estimated to be installed beginning in July 2021 with completion by mid-2022 to support the expansion of the existing RF Network

B. Percentage of Network Communicating to L+G Platform

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C. Actual Reads Recorded from AMI Meters

Actual read number is inclusive of large commercial AMI meters installed prior to start of current AMI Project

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E. Third Party Customer Engagement Efforts

PSE&G has utilized social media outlets for third party customer engagement efforts to date. The activities and results are as follows:

1. Published 6 messages:

a) *6 organic messages on Facebook, Twitter and LinkedIn:*
   - *(1)* 1 on Facebook,
   - (2) 4 on Twitter,
     - (a) 3 on PSEGDelivers,
     - (b) 1 on PSEGNews.
   - (3) 1 on LinkedIn.

2. Channel followers (as of December 2021):

a) *Facebook: 118,251*
b) *PSEGDelivers (Twitter): 101,942*
c) *PSEGNews (Twitter): 20,673*
d) *LinkedIn: 57,213*

3. The social media posts generated:

a) *18,523 impressions (how many times an AMI social message was displayed),*
b) *Reached 7,242Facebook users*

F. Remote Connects/Disconnects Performed

Use case not yet implemented

G. AMI Metering Tampering Cases

Use case not yet implemented

H. Stranded Costs Deferred

Expected to be available in future reports.

Katherine E. Smith
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PSEG
Services Corporation

March 22, 2023

In the Matter of the Petition of
Public Service Electric and Gas Company for
Approval of its Clean Energy Future-Energy Cloud (CEF-EC)
Program on a Regulated Basis
BPU Docket No. EO18101115

VIA ELECTRONIC MAIL
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Re: Advanced Metering Infrastructure (AMI) Program - Semi Annual Report to the Board of Public Utilities for the Period January 1, 2022 – June 30, 2022 (Corrected Copy 03.01.2023)

Dear Ms. Peterson and Mr. Lipman:

Pursuant to the Board's January 7, 2021 Order in the above referenced matter, enclosed is Public Service Electric and Gas Advanced Meter Infrastructure (AMI) Program's semi-annual report for the period January 1, 2022 through June 30, 2022. This copy corrects an error on the original report previously issued September 1, 2022. The correction, which is to the figures on page 2 of the report for residential and commercial meters installed to date, is red-lined for your convenience.

Copies of the CEF-EC AMI Semi-Annual Report, January 1, 2022 – June 30, 2022 will be served upon all entities legally required to be noticed. Service will occur via e-mail, only, pursuant to the Board's March 19, 2020 Order in Docket No. EO20020254. [1] In addition, the report will be posted at www.pseg.com/ev.

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Clean Energy Future-Energy Cloud

Advanced Metering Infrastructure (AMI) Program

Semi-Annual Report to the Board of Public Utilities

For the period January 1, 2022-June 30, 2022
Corrected copy – 03.01.2023

CEF-EC-AMI Program
Semi-Annual Reporting (2022) – Period ending June 30, 2022 , Corrected copy – 03.01.2023

Reporting Metric Tables:

Metric Description	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Current Reporting Period 1/1/2022-6/30/2022	Project to Date 1/7/2021 - 6/30/2022
Residential Meters Installed	6,596	7,537	8,744	8,064	8,444	17,280	56,665	~~129,664~~ 129,738 See Note J
Commercial Meters Installed	2.367	2,474	3,910	4,188	3,969	4,027	20,935	~~45,713~~ 34,661 See Note J
Poles Installed	9	29	40	11	1	0	90	159 See Note A
Three-radio Network gateways installed	13	38	50	17	5	4	127	159 See Note A
Single-radio Network gateways installed	28	1	0	0	0	0	29	53 See Note A
Routers Installed	338	69	0	14	58	0	479	2,207 See Note A
Percentage of Network Communicating to L+G Platform	89.40%	93.90%	95.96%	97.30%	99.90%	100.00%	100.00%	100.00% See Note B
Number of opt-out customers	12	7	5	4	34	34	96	231
Number of actual reads recorded from AMI meters each month	6,445,369	6,104,754	7,669,478	8,417,578	8,958,500	9,802,700	47,398,379	See Note C
Number of meter reading staff employed by PSE&G each month	366	390	446	449	475	463	See Note D	See Note D
Number of total visits by customers to AMI portal.	1,626	1,273	1,354	1,413	1,499	2,589	9,754	25,902
Number of customers receiving energy saving messages.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	See Note E
Number of customers who have authorized third party supplier access to their energy usage data	N/A	N/A	N/A	N/A	N/A	N/A	N/A	See Note F
Third Party Program-to-date customer engagement efforts undertaken by the Company	N/A	N/A	N/A	N/A	N/A	N/A	N/A	See Note G
Number of AMI meters replaced due to functioning errors	0	0	0	6	6	6	18	21
Number of remote connects/disconnects performed	N/A	N/A	N/A	N/A	N/A	N/A	N/A	See Note H
Number of AMI meter tampering cases found	N/A	N/A	N/A	N/A	N/A	N/A	N/A	See Note I
Estimated CEF-EC project completion date							12/31/2024	12/31/2024

N/A – Not applicable at this stage of the AMI Program

CEF-EC-AMI Program
Semi-Annual Reporting (2022) – Period ending June 30, 2022 , Corrected copy – 03.01.2023

Average Installation Costs			Current Reporting Period 1/1/2022-6/30/2022	Project to Date 1/7/2021 - 06/30/2022
Average Cost Residential Meters Installed –Total			**$250**	**$220**
Average Cost Residential Meters Installed – Labor			$136	$104
Average Cost Residential Meters Installed – Materials			$114	$116
Average Cost Commercial Meters Installed – Total			**$335**	**$298**
Average Cost Commercial Meters Installed – Labor			$144	$118
Average Cost Commercial Meters Installed – Materials			$190	$180

	FORECAST		ACTUALS	
Metric Description (Cost Info.)	**Current Reporting Period 1/1/2022-6/30/2022**	**Project to Date 1/7/2021 - 06/30/2022**	**Current Reporting Period 1/1/2022-6/30/2022**	**Project to Date 1/7/2021 - 06/30/2022**
CEF-EC Capital Costs - Total	**$34.45M**	**$67.65M**	**$31.85M**	**$65.04M**
CEF-EC Capital Costs - Labor	$8.96M	$20.7M	$10.23M	$22.26M
CEF-EC Capital Costs – Material	$12.68M	$23.75M	$10.95M	$22.01M
CEF-EC Capital Costs – Other	$12.81M	$23.2M	$10.67M	$20.77M
CEF-EC Deferred O&M Expenses - Total	**$5.66M**	**$9.85M**	**$5.88M**	**$10.07 M**
CEF-EC Deferred O&M Expenses - Labor	$2.36M	$2.36M	$0.46M	$0.46M
CEF-EC Deferred O&M Expenses – Material	$0.20M	$0.77M	N / A	$0.57M
CEF-EC Deferred O&M Expenses – Other	$3.1M	$6.72M	$5.42M	$9.04M
Stranded Costs Deferred	**N / A**	**N / A**	**$28.07M**	**$28.07M**

N/A – Not applicable at this stage of the AMI Program

Reporting Metric Notes:

A. Network Installation

Estimated Quantity of Work: 159 new poles and three radio gateways, 53 single-radio network gateways and 2207 routers have been installed to support the expansion of the existing RF Network

B. Percentage of Network Communicating to L+G Platform

Estimated Quantity of Work: Network installation has completed.

C. Actual Reads Recorded from AMI Meters

Actual read number is inclusive of large commercial AMI meters installed prior to start of current AMI Project.

D. Meter Reading Staff

Meter reading staffing fluctuates for various reasons. Permanent Meter Readers continue to decline month over month via natural attrition. Additional temporary Meter Reading staff have been hired to support Collection activities and vacations.

E. Number of customers receiving energy saving messages

Reports issued on September 1, 2021 and March 1, 2022 reported data based on all PSE&G electric customers who had received energy saving messages. In this report and subsequent reports, this metric will indicate how many PSE&G electric customers with AMI meters have received messages based on the implementation of use cases 1, 2, 3, 4, 5 and 7. Use cases not yet implemented.

F. Customers who have authorized third party supplier access to their energy usage data

The development of a Data Access Plan has been deferred pending the statewide proceeding in Docket No. EO20110716. PSE&G is participating in that Board Staff proceeding.

G. Third Party Customer Engagement Efforts

PSE&G has utilized social media outlets for third party customer engagement efforts to date. The activities and results are as follows:

1. **Published 4 messages:**
   a) *4 organic messages on Facebook, Twitter and LinkedIn:*
      (1) 2 on Facebook,
      (2) 2 on Twitter,
         (a) 1 on PSEGDelivers,
         (b) 1 on PSEGNews.

2. **Channel followers (as of June 2022):**
   a) *Facebook: 118,384*
   b) *PSEGDelivers (Twitter): 102,165*
   c) *PSEGNews (Twitter): 20,860*

3. **The social media posts generated:**
   a) *16,224 impressions (how many times an AMI social message was displayed),*
   b) *Reached 14,009 Facebook users*

H. Remote Connects/Disconnects Performed

Use case not yet implemented. A. AMI Metering Tampering Cases

Use case not yet implemented.

I. AMI Metering Tampering Cases

Use case not yet implemented.

J. Correction issued for Meters Installed.

The ‘**Project to date 1/7/2021 to 6/30/2022**’ data figures for line items related to ‘residential meters installed’ and ‘commercial meters installed’ was corrected to read as 129,738 and 34,661 meters respectively.

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PSEG Services Corporation

March 1, 2023

In the Matter of the Petition of
Public Service Electric and Gas Company for
Approval of its Clean Energy Future-Energy Cloud (CEF-EC)
Program on a Regulated Basis
BPU Docket No. EO18101115

VIA ELECTRONIC MAIL
Stacy Peterson
Deputy Executive Director
New Jersey Board of Public Utilities
44 South Clinton Ave.
P.O. Box 350
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Brian Lipman
Director
New Jersey Division of Rate Counsel
140 East Front Street, 4th Floor
P.O. Box 003
Trenton, NJ 08625

Re: Advanced Metering Infrastructure (AMI) Program - Semi Annual Report to the Board of Public Utilities for the Period July 1, 2022 – December 31, 2022

Dear Ms. Peterson and Mr. Lipman:
Pursuant to the Board's January 7, 2021 Order in the above referenced matter, enclosed is Public Service Electric and Gas Advanced Meter Infrastructure (AMI) Program's semi-annual report for the period July 1, 2022 through December 31, 2022.

Copies of the CEF-EC AMI Semi-Annual Report, July 1, 2022 – December 31, 2022 will be served upon all entities legally required to be noticed. Service will occur via e-mail, only, pursuant to the Board's March 19, 2020 Order in Docket No. EO20020254. [1] In addition, the report will be posted at www.pseg.com/ev.

[1] *In the Matter of the New Jersey Board of Public Utilities' Response to the Covid-19 Pandemic For a Temporary Waiver of Requirements for Certain Non-Essential Obligations*, Docket No. EO20030254, p 3 (March 19, 2020 Order).

Please advise if you have any questions or comments.

Very truly yours,

Katherine Smith

C: Carol Artale
Alice Bator
Cindy Bianco
David Brown
Robert Brabston
Charles Gurkas
Scott Hunter
Sherri Jones
Bart Kilar
Christine Lin
Malike Cummings
Mike Kammer
Dean Taklif
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Stacy Richards
Christine Sadovy
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Tylise Hyman
Christine Juarez
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Henry Odgen
Brian Weeks

Clean Energy Future-Energy Cloud

Advanced Metering Infrastructure (AMI) Program

Semi-Annual Report to the Board of Public Utilities

For the period July 1, 2022 - December 31, 2022

Reporting Metric Tables:

Metric Description	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	Current Reporting Period 7/1/2022-12/31/2022	Project to Date 1/7/2021 - 12/31/2022
Residential Meters Installed	25,488	32,331	28,198	42,597	63,856	68,761	261,231	390,972
Commercial Meters Installed	3.870	5,765	5,839	6,779	7,248	7,381	36,882	71,563
Network Installed								See Note A
Number of opt-out customers	31	135	200	468	499	351	1,684	1,912
Number of actual reads recorded from AMI meters each month	11,352,467	13,279,195	15,337,058	18,485,408	21,330,381	27,508,752	107,293,261	See Note B
Number of meter reading staff employed by PSE&G each month	449	408	395	371	356	338	See Note C	See Note C
Number of total visits by customers to AMI portal.	2,254	1,412	2,430	2,305	1,574	1,738	11,713	38,613
Number of unique monthly Log-in's to AMI portal.	110	121	106	124	117	108	686	N/A
Number of customers receiving energy saving messages.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	See Note D
Number of customers who have authorized third party supplier access to their energy usage data	N/A	N/A	N/A	N/A	N/A	N/A	N/A	See Note E
Third Party Program-to-date customer engagement efforts undertaken by the Company	N/A	N/A	N/A	N/A	N/A	N/A	N/A	See Note F
Number of AMI meters replaced due to functioning errors	8	11	16	14	31	50	130	152
Number of remote connects/disconnects performed	N/A	N/A	N/A	N/A	N/A	N/A	N/A	See Note G
Number of AMI meter tampering cases found	N/A	N/A	N/A	N/A	N/A	N/A	N/A	See Note H
Estimated CEF-EC project completion date							12/31/2024	12/31/2024

N/A – Not applicable at this stage of the AMI Program

CEF-EC-AMI Program
Semi-Annual Reporting (2022) – Period ending December 31, 2022

Average Installation Costs (Per Unit Cost in USD)			**Current Reporting Period 7/1/2022-12/31/2022**	**Project to Date 1/7/2021 - 12/31/2022**
Average Cost Residential Meters Installed –Total			**$201**	**$219**
Average Cost Residential Meters Installed – Labor *(1)			$100	$113
Average Cost Residential Meters Installed – Materials			$101	$106
Average Cost Commercial Meters Installed – Total			**$270**	**$285**
Average Cost Commercial Meters Installed – Labor *(1)			$117	$123
Average Cost Commercial Meters Installed – Materials			$153	$162

	FORECAST		**ACTUALS**	
Metric Description (USD in Millions)	**Current Reporting Period 7/1/2022-12/31/2022**	**Project to Date 1/7/2021 - 12/31/2022**	**Current Reporting Period 7/1/2022-12/31/2022**	**Project to Date 1/7/2021 - 12/31/2022**
CEF-EC Capital Costs - Total	**$49.2M**	**$116.9M**	**$66.4M**	**$130.8M**
CEF-EC Capital Costs - Labor *(2)	$10.98M	$31.68M	$9.4M	$30.8M
CEF-EC Capital Costs – Material	$19.78M	$43.53M	$32.8M	$55.3M
CEF-EC Capital Costs – Other *(3)	$18.5M	$41.7M	$24.2M	$44.7M
CEF-EC Deferred O&M Expenses - Total	**$5.7M**	**$15.5M**	**$10.0M**	**$20.0M**
CEF-EC Deferred O&M Expenses - Labor *(2)	$2.58M	$4.94M	$3.7M	$4.1M
CEF-EC Deferred O&M Expenses – Material		$0.77M		$0.6M
CEF-EC Deferred O&M Expenses – Other *(3)	$3.1M	$9.82M	$6.3M	$15.3M
Stranded Costs Deferred			**$26.8M**	**$54.8M**

*(1) Average Installation costs - Internal and External Labor.
*(2) Labor - Internal PSE&G Labor.
*(3) Other - Includes all contractors and Outside services.

Reporting Metric Notes:

A. Network Installation

Network Complete: 159 new poles and three radio gateways, 53 single-radio network gateways and 2207 routers have been installed to support the expansion of the existing RF Network

B. Actual Reads Recorded from AMI Meters

Actual read number is inclusive of large commercial AMI meters installed prior to start of current AMI Project.

C. Meter Reading Staff

Meter reading staffing fluctuates for various reasons. Permanent Meter Readers continue to decline month over month via natural attrition. Additional temporary Meter Reading staff have been hired to support Collection activities and vacations.

D. Number of customers receiving energy saving messages

Reports issued on September 1, 2021 and March 1, 2022 reported data based on all PSE&G electric customers who had received energy saving messages. In this report and subsequent reports, this metric will indicate how many PSE&G electric customers with AMI meters have received messages based on the implementation of use cases 1, 2, 3, 4, 5 and 7. Use cases not yet implemented.

E. Customers who have authorized third party supplier access to their energy usage data

The development of a Data Access Plan has been deferred pending the statewide proceeding in Docket No. EO20110716. PSE&G is participating in that Board Staff proceeding.

F. Third Party Customer Engagement Efforts

PSE&G has utilized social media outlets for third party customer engagement efforts to date. The activities and results are as follows:

1. **Published 0 messages:**
   a) *0 organic messages on Facebook, Twitter and LinkedIn:*
      (1) 0 on Facebook,
      (2) 0 on Twitter,
         (a) 0 on PSEGDelivers,
         (b) 0 on PSEGNews.

2. **Channel followers (as of December 2022):**
   a) *Facebook: 121K*
   b) *PSEGDelivers (Twitter): 101K*
   c) *PSEGNews (Twitter): 21K*

3. **The social media posts generated:**
   a) *0 impressions (how many times an AMI social message was displayed),*
   b) *Reached 0 Facebook users*

G. Remote Connects/Disconnects Performed

Use case not yet implemented.

H. AMI Metering Tampering Cases

Use case not yet implemented.

Katherine E. Smith
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PSEG
Services Corporation

October 11, 2023

In the Matter of the Petition of
Public Service Electric and Gas Company for
Approval of its Clean Energy Future-Energy Cloud (CEF-EC)
Program on a Regulated Basis
BPU Docket No. EO18101115

VIA ELECTRONIC MAIL
Stacy Peterson
Deputy Executive Director
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44 South Clinton Ave.
P.O. Box 350
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Re: Advanced Metering Infrastructure (AMI) Program - Semi Annual Report to the Board of Public Utilities for the Period January 1, 2023 – June 30, 2023

Dear Ms. Peterson and Mr. Lipman:

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1577180 v1 1 *In the Matter of the New Jersey Board of Public Utilities' Response to the Covid-19 Pandemic For a Temporary Waiver of Requirements for Certain Non-Essential Obligations*, Docket No. EO20030254, p 3 (March 19, 2020 Order).

Please advise if you have any questions or comments.

Very truly yours,

Katherine Smith

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Clean Energy Future-Energy Cloud

Advanced Metering Infrastructure (AMI) Program

Semi-Annual Report to the Board of Public Utilities

For the period January 1, 2023 – June 30, 2023

Reporting Metric Tables:

Metric Description	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Current Reporting Period 1/1/2023 - 6/30/2023	Project to Date 1/7/2021 - 6/30/2023
Residential Meters Installed	80,150	76,707	85,227	79,610	83,894	80,954	486,542	877,514
Commercial Meters Installed	10.148	8,797	12,181	9,476	12,196	8,792	61,590	133,153
Network Installed								See Note A
Number of opt-out customers	414	371	571	622	428	239	2,645	4,557
Number of actual reads recorded from AMI meters each month	29,425,887	31,276,962	37,330,599	45,059,057	49,170,579	54,147,479	246,410,563	See Note B
Number of meter reading staff employed by PSE&G each month	332	312	295	302	331	325	See Note C	See Note C
Number of total visits by customers to AMI portal.	1,961	1,349	1,906	1,728	1,956	1,781	10,681	49,294
Number of unique monthly Log-in's to AMI portal.	131	128	142	116	134	135	786	N/A
Number of customers receiving energy saving messages.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	See Note D
Number of customers who have authorized third party supplier access to their energy usage data	N/A	N/A	N/A	N/A	N/A	N/A	N/A	See Note E
Third Party Program-to-date customer engagement efforts undertaken by the Company	N/A	N/A	N/A	N/A	N/A	N/A	N/A	See Note F
Number of AMI meters replaced due to functioning errors	32	7	3	9	7	17	75	227
Number of remote connects/disconnects performed	0	0	0	0	0	0	0	See Note G
Number of AMI meter tampering cases found	0	8	2	2	5	1	18	See Note H
Estimated CEF-EC project completion date							12/31/2024	12/31/2024

N/A – Not applicable at this stage of the AMI Program

CEF-EC-AMI Program
Semi-Annual Reporting (2023) – Period ending June 30, 2023

Average Installation Costs (Per Unit Cost in USD)			Current Reporting Period 1/1/20223-6/30/2023	Project to Date 1/7/2021 - 6/30/2023
Average Cost Residential Meters Installed –Total			**$175**	**$194**
Average Cost Residential Meters Installed – Labor *(1)			$58	$82
Average Cost Residential Meters Installed – Materials			$117	$112
Average Cost Commercial Meters Installed – Total			**$256**	**$272**
Average Cost Commercial Meters Installed – Labor *(1)			$89	$108
Average Cost Commercial Meters Installed – Materials			$167	$164

	FORECAST		ACTUALS	
Metric Description (USD in Millions)	**Current Reporting Period 1/1/2023-6/30/2023**	**Project to Date 1/7/2021 - 6/30/2023**	**Current Reporting Period 1/1/2023-6/30/2023**	**Project to Date 1/7/2021 - 6/30/2023**
CEF-EC Capital Costs - Total	**$114.1M**	**$244.9M**	**$114.7M**	**$245.5M**
CEF-EC Capital Costs - Labor *(2)	$10.0M	$40.8M	$8.8M	$39.6M
CEF-EC Capital Costs – Material	$54.9M	$110.1M	$61.3M	$116.5M
CEF-EC Capital Costs – Other *(3)	$49.2M	$93.9M	$44.6M	$89.3M
CEF-EC Deferred O&M Expenses - Total	**$12.2M**	**$32.2M**	**$8.0M**	**$28.0M**
CEF-EC Deferred O&M Expenses - Labor *(2)	$3.2M	$7.3M	$1.5M	$5.6M
CEF-EC Deferred O&M Expenses – Material		$0.6M		$0.6M
CEF-EC Deferred O&M Expenses – Other *(3)	$9.0M	$24.3M	$6.5M	$21.8M
Stranded Costs Deferred			**$27.0M**	**$81.8M**

*(1) Average Installation costs - Internal and External Labor.
*(2) Labor - Internal PSE&G Labor.
*(3) Other - Includes all contractors and Outside services.

Reporting Metric Notes:

A. Network Installation

Network Complete: 159 new poles and three radio gateways, 53 single-radio network gateways and 2207 routers have been installed to support the expansion of the existing RF Network

B. Actual Reads Recorded from AMI Meters

Actual read number is inclusive of large commercial AMI meters installed prior to start of current AMI Project.

C. Meter Reading Staff

Meter reading staffing fluctuates for various reasons. Permanent Meter Readers continue to decline month over month via natural attrition. In May 2023, additional temporary Meter Reading staff had been hired to support Collection activities and vacations.

D. Number of customers receiving energy saving messages

In this report and subsequent reports, this metric will indicate how many PSE&G electric customers with AMI meters have received messages based on the pending implementation of use cases 1, 2, 3, 4, 5 and 7~~.~~

E. Customers who have authorized third party supplier access to their energy usage data

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F. Third Party Customer Engagement Efforts

PSE&G has utilized social media outlets for third party customer engagement efforts to date. The activities and results are as follows:

1. Published 0 messages:

a) *0 organic messages on Facebook, Twitter and LinkedIn:*

- *(1)* 0 on Facebook,
- (2) 0 on Twitter,
  - (a) 0 on PSEGDelivers,
  - (b) 0 on PSEGNews.

2. Channel followers (as of June 2023):

a) *Facebook: 117K*

b) *PSEGDelivers (Twitter): 101K*

c) *PSEGNews (Twitter): 21K*

3. The social media posts generated:

a) *0 impressions (how many times an AMI social message was displayed),*

b) *Reached 0 Facebook users*

G. Remote Connects/Disconnects Performed

Use case not yet implemented.

H. AMI Metering Tampering Cases

Use case not yet implemented.

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March 19, 2024

In the Matter of the Petition of
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BPU Docket No. EO18101115

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Please advise if you have any questions or comments.

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Clean Energy Future-Energy Cloud

Advanced Metering Infrastructure (AMI) Program

Semi-Annual Report to the Board of Public Utilities

For the period July 1, 2023 – December 31, 2023

Reporting Metric Tables:

Metric Description	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Current Reporting Period 7/1/2023 - 12/31/2023	Project to Date 1/7/2021 - 12/31/2023
Residential Meters Installed	81,326	101,123	75,776	67,140	67,635	82,714	475,714	1,353,228
Commercial Meters Installed	9,381	10,476	7,425	9,613	8,695	6,365	51,955	185,108
Network Installed								See Note A
Number of opt-out customers	289	451	163	161	170	353	1,587	6,144
Number of actual reads recorded from AMI meters each month	63,345,793	71,816,470	77,526,980	76,966,882	81,166,730	92,360,644	463,183,499	See Note B
Number of meter reading staff employed by PSE&G each month	322	313	301	294	287	276	See Note C	See Note C
Number of total visits by customers to AMI portal.	17,004	32,916	29,721	28,171	25,605	27,407	160,824	210,118
Number of unique monthly Log-in's to AMI portal.	8,303	15,692	14,226	13,266	12,243	13,352	77,082	N/A
Number of customers receiving energy saving messages.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	See Note D
Number of customers who have authorized third party supplier access to their energy usage data	N/A	N/A	N/A	N/A	N/A	N/A	N/A	See Note E
Third Party Program-to-date customer engagement efforts undertaken by the Company	N/A	N/A	N/A	N/A	N/A	N/A	N/A	See Note F
Number of AMI meters replaced due to functioning errors	25	7	32	26	24	5	119	346
Number of remote connects/disconnects performed	3,467	16,266	26,477	42,438	21,994	11,918	122,560	See Note G
Number of AMI meter tampering cases found	3	8	12	22	6	5	56	See Note H
Estimated CEF-EC project completion date							12/31/2024	12/31/2024

N/A – Not applicable at this stage of the AMI Program

CEF-EC-AMI Program
Semi-Annual Reporting (2023) – Period ending December 31, 2023

Average Installation Costs (Per Unit Cost in USD)			Current Reporting Period 7/1/2023 - 12/31/2023	Project to Date 1/7/2021 - 12/31/2023
Average Cost Residential Meters Installed –Total			**$187.8**	**$191.9**
Average Cost Residential Meters Installed – Labor *(1)			$70.7	$78.2
Average Cost Residential Meters Installed – Materials			$117.1	$113.7
Average Cost Commercial Meters Installed – Total			**$243.9**	**$264.3**
Average Cost Commercial Meters Installed – Labor *(1)			$89.9	$103.0
Average Cost Commercial Meters Installed – Materials			$154.0	$161.3

	FORECAST		ACTUALS	
Metric Description (USD in Millions)	**Current Reporting Period 7/1/2023 - 12/31/2023**	**Project to Date 1/7/2021 - 12/31/2023**	**Current Reporting Period 7/1/2023 - 12/31/2023**	**Project to Date 1/7/2021 - 12/31/2023**
CEF-EC Capital Costs - Total	**$113.9M**	**$358.8M**	**$120.0M**	**$365.5M**
CEF-EC Capital Costs - Labor *(2)	$10.2M	$51.0M	$7.3M	$46.9M
CEF-EC Capital Costs – Material	$53.7M	$163.8M	$58.4M	$175.0M
CEF-EC Capital Costs – Other *(3)	$50.0M	$144.0M	$54.3M	$143.6M
CEF-EC Deferred O&M Expenses - Total	**$14.1M**	**$46.3M**	**$7.6M**	**$35.6M**
CEF-EC Deferred O&M Expenses - Labor *(2)	$3.1M	$10.4M	$1.7M	$7.3M
CEF-EC Deferred O&M Expenses – Material		$0.6M	$0.5M	$1.1M
CEF-EC Deferred O&M Expenses – Other *(3)	$11.1M	$35.4M	$5.4M	$27.2M
Stranded Costs Deferred			**$17.4M**	**$99.2M**

*(1) Average Installation costs - Internal and External Labor.
*(2) Labor - Internal PSE&G Labor.
*(3) Other - Includes all contractors and Outside services.

Reporting Metric Notes:

A. Network Installation

Network Complete: 159 new poles and three radio gateways, 53 single-radio network gateways and 2207 routers have been installed to support the expansion of the existing RF Network

B. Actual Reads Recorded from AMI Meters

Actual read number is inclusive of large commercial AMI meters installed prior to start of current AMI Project.

C. Meter Reading Staff

Meter reading staffing fluctuates for various reasons. Permanent Meter Readers continues to decline month over month via natural attrition.

D. Number of customers receiving energy saving messages

In this report and subsequent reports, this metric will indicate how many PSE&G electric customers with AMI meters have received messages based on the pending implementation of use cases 1, 2, 3, 4, 5 and 7.

E. Customers who have authorized third party supplier access to their energy usage data

The development of a Data Access Plan has been deferred pending the statewide proceeding in Docket No. EO20110716. PSE&G is participating in that Board Staff proceeding.

F. Third Party Customer Engagement Efforts

PSE&G has utilized social media outlets for third party customer engagement efforts to date. The activities and results are as follows:

1. **Published messages:**
    a) *5 organic messages on Facebook, Twitter/X and LinkedIn:*
        (1) 1 on Facebook,
        (2) 3 on Twitter/X,
            (a) 1 on PSEGDelivers,
            (b) 2 on PSEGNews.
        (3) 1 on Instagram

2. **Channel followers (as of December-end 2023):**
    a) *Facebook: 118K followers*
    b) *PSEGDelivers (Twitter/X): 99.1K followers*
    c) *PSEGNews (Twitter/X): 20.4K followers*
    d) *Instagram: 2.9K*

3. **The social media posts generated:**
    a) *4.3K impressions (how many times an AMI social message was displayed),*
    b) *Reached 2.1K Facebook and Instagram users.*

G. Remote Connects/Disconnects Performed

Use case not yet implemented.

H. AMI Metering Tampering Cases

Use case not yet implemented.