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June 30, 2023

VIA ELECTRONIC MAIL
sherri.golden@bpu.nj.gov
board.secretary@bpu. nj.gov

Sherri L. Golden, RMC
Secretary of the Board
Board of Public Utilities
44 South Clinton Avenue, 1st Floor
P.O. Box 350
Trenton, New Jersey 08625-0350

RE: In the Matter of the Provision of Basic Generation Service ("BGS") for the Period Beginning June 1, 2024
BPU Docket No. ER23030124

Dear Secretary Golden:

In accordance with the Preliminary 2024 BGS Schedule set forth in the New Jersey Board of Public Utilities' (the "Board" or "BPU") April 12, 2023 Decision and Order in the above-referenced matter, enclosed please find Atlantic City Electric Company's ("ACE") Company-Specific Addendum proposal (the "Proposal") for the Energy Year beginning June 1, 2024. The Proposal includes ACE's request to implement a Direct Current Fast Charging Two Year Pilot Program (the "Pilot Program"). If approved, implementation of the Pilot Program will begin on June 1, 2024.[1]

Pursuant to the terms of the Preliminary 2024 BGS Schedule, a generic Proposal for the Basic Generation Service to Be Procured Effective June 1, 2024 (the "BGS Proposal") has been contemporaneously filed by Public Service Electric and Gas Company on behalf of all New Jersey electric distribution companies ("EDCs"), including ACE. The BGS Proposal describes the BGS auction process, including the pre-qualification of bidders, setting of starting prices, BGS pricing and rate design methodology, and the respective roles of the EDCs and the Board. The BGS Proposal also includes the proposed Supplier Master Agreements.

The BGS Proposal and ACE's Company-Specific Addendum can also be accessed on the BGS Auction website at http://bgs-auction.com/bgs.auction.regproc.asp.

[1] *See* the Board's November 9, 2022 Decision and Order issued in connection with BPU Docket No. ER22030127.

Pursuant to the Order issued by the Board in connection with *In the Matter of the New Jersey Board of Public Utilities' Response to the COVID-19 Pandemic for a Temporary Waiver of Requirements for Certain Non-Essential Obligations,* BPU Docket No. EO20030254, Order dated March 19, 2020, this document is being electronically filed with the Secretary of the Board, the Division of Law, the New Jersey Division of Rate Counsel, and the Service List. No paper copies will follow.

Thank you for your cooperation and courtesies. Feel free to contact the undersigned with any questions.

Respectfully submitted,

Philip J. Passanante
An Attorney at Law of the
State of New Jersey

Enclosure

cc: Service List

IN THE MATTER OF THE PROVISION OF BASIC GENERATION SERVICE FOR THE PERIOD BEGINNING JUNE 1, 2024	STATE OF NEW JERSEY BOARD OF PUBLIC UTILITIES BPU DOCKET NO. ER23030124

ATLANTIC CITY ELECTRIC COMPANY

BASIC GENERATION SERVICE
COMMENCING JUNE 1, 2024

COMPANY-SPECIFIC ADDENDUM
FILING

Proposal Dated June 30, 2023

ATLANTIC CITY ELECTRIC COMPANY'S
COMPANY-SPECIFIC ADDENDUM

The following contains the company-specific material (referred to herein as the "Addendum") of Atlantic City Electric Company ("ACE" or the "Company") for the joint compliance filing made with the New Jersey Board of Public Utilities (the "Board" or "BPU") on this date by the Electric Distribution Companies (the "EDCs") in this docket. Capitalized terms used herein shall have the meanings defined in the joint filing.

As described in the generic section of this filing, two (2) different methods will be utilized for the pricing of Basic Generation Service ("BGS") to customers – residential and small commercial energy pricing and variable hourly energy pricing. The residential and small commercial energy pricing formerly referred to as "Basic Generation Service–Fixed Price" or "BGS-FP" is now termed "Basic Generation Service–Residential Small Commercial Pricing" or "BGS-RSCP" and the hourly energy pricing service is termed "Basic Generation Service – Commercial and Industrial Energy Pricing" or "BGS- CIEP." BGS-RSCP is to be available to all residential and small commercial customers, specifically those customers taking service on Rate Schedules RS, MGS (Secondary, Secondary Electric Vehicle Charging, and Primary), AGS (Secondary and Primary), DDC, SPL, and CSL. These rate classes comprise the vast majority of ACE's customers and approximately 86% of the usage on the ACE electric system. As described in detail later in this filing, BGS-RSCP commercial or industrial customers can opt in to BGS-CIEP.

BGS-CIEP will continue to be the only default supply option available to customers taking service under ACE's Rate Schedule TGS (Transmission General Service). Pursuant to the Board's Decision on June 18, 2012, in BPU Docket No. ER12020150, changing the BGS-CIEP required customer capacity peak load share ("PLS") to 500 kW or greater effective June 1, 2013, will be the only default supply option available to customers on Rate Schedules MGS Secondary, MGS Secondary Electric Vehicle Charging, MGS Primary, AGS Secondary or AGS Primary with an annual PLS for generation capacity equal to or greater than 500 kW as of November 1 of the year prior to the BGS auction. There are an estimated 244 eligible CIEP customers representing approximately 14% of the usage on the ACE electric system, whose only default supply option is BGS-CIEP. As described in detail later in this filing, BGS-CIEP will also be available to any commercial or industrial customer on a voluntary basis, regardless of such customer's regular Rate Schedule.

A. CONTINGENCY PLANS

While not every contingency can be anticipated, ACE can differentiate four (4) areas of concern as follows:

a) there are an insufficient number of bids to provide for a fully subscribed Auction Volume either for the BGS-RSCP auction or the BGS-CIEP auction;

b) a default by one of the winning bidders prior to June 2024;

c) a default during the June 1, 2024 - May 31, 2025 supply period, under the BGS-CIEP contracts entered into for 12 months; and/or

d) a default during the June 1, 2024 - May 31, 2027 supply period, under the BGS-RSCP contracts entered into for 36 months.

1. Insufficient Number of Bids in Auction

To ensure that the auction process achieves the best price for customers, the degree of competition in the auction must be sufficient. To ensure a sufficient degree of competition, the volume of BGS-RSCP and BGS-CIEP Load purchased at each auction will be finally decided after the first round of bids are received. Provided that there are sufficient bids at the starting prices, the auctions will be held for 100% of BGS-RSCP and BGS-CIEP Loads.

It is possible that the number of initial bids will not result in a competitive auction for 100% of the BGS-RSCP or BGS-CIEP Load. This determination will be made by the Auction Manager in consultation with the EDCs and the Board Advisor.

In the event that the Auction Volume is reduced to less than 100% of BGS-RSCP or BGS-CIEP Load, ACE, at its option, will implement a Contingency Plan for the remaining tranches. Under the Plan, ACE will purchase necessary services (including, but not limited to, network transmission, capacity, energy and ancillary services, and any required Renewable Portfolio Standards ("RPS") Renewable Energy Certificate) for the remaining tranches through PJM-administered markets until May 31, 2025. Any unsubscribed tranches for the period after May 31, 2025, may be included in a subsequent auction or treated pursuant to the provisions of part 4 of the Contingency Plan described below. This Contingency Plan will alert bidders that, in order to secure BGS-RSCP and BGS-CIEP prices from New Jersey BGS customers for their supply, it will be necessary to bid in to the auctions.

Since the Contingency Plan calls for the purchase of BGS supply in PJM-administered markets, it is considered a prominent feature of the auction proposal because it provides bidders a strong incentive to participate in the auction process. If bidders were to believe that a less than fully subscribed auction would lead to a negotiation or a secondary market in which ACE, on behalf of its customers, would seek to acquire BGS supplies, the incentive to participate in the auctions and the incentive to offer the best deal in the auctions would be subsequently diminished.

2. <u>Defaults Prior to June 1, 2024</u>

If a winning bidder defaults prior to the beginning of the BGS service, then, at ACE's option, the open tranches may first be offered to the other winning bidders or will be filled as provided in part 3, below. Additional costs incurred by ACE in implementing the Contingency

Plan will be assessed against the defaulting suppliers' credit security.

3. Defaults During the June 1, 2024 - May 31, 2025 Supply Period

If a default occurs during the June 1, 2024 - May 31, 2025 period, for those contracts entered into for 12 months, at ACE's option, the tranches supplied by the defaulting supplier may be offered to the other winning bidders, may be bid out or may be procured from PJM-administered markets. Additional costs incurred by ACE in implementing this part of the Contingency Plan will be assessed against the defaulting suppliers' credit security.

If circumstances are such that it is not practical to find another such supplier, ACE proposes to utilize a process similar to the "flexible portfolio approach" for BGS wholesale supply, as previously described in ACE's filing in BPU Docket No. EM00080604, as noted in the Board's November 29, 2000 Order in that docket. This approach relies on a combination of competitive sources for BGS power, including Requests for Proposal(s), broker markets, capacity costs based on the PJM Reliability Pricing Model ("RPM"), and the PJM spot energy market.

4. Defaults During the June 1, 2024 - May 31, 2027 Supply Period

If a default occurs during the June 1, 2024 - May 31, 2027 period, for those contracts entered into for 36 months, at ACE's option, the tranches supplied by the defaulting supplier may be offered to the other winning bidders, may be bid out or may be procured from PJM-administered markets. Among the options for bidding out the tranches, ACE may include such tranches in the next BGS procurement. Additional costs incurred by ACE in implementing this part of the Contingency Plan will be assessed against the defaulting suppliers' credit security.

If circumstances are such that it is not practical to find another such supplier, ACE proposes to utilize a process similar to the "flexible portfolio approach" for BGS wholesale supply, as previously described in the Company's filing in BPU Docket No. EM00080604, as noted in the Board's November 29, 2000 Order in that docket. This approach relies on a combination of competitive sources for BGS power, including requests for proposal, broker markets, capacity costs based on the PJM RPM, and the PJM spot energy market.

B. ACCOUNTING AND COST RECOVERY

The accounting and cost recovery that ACE will use for its BGS service is summarized in this Section. These provisions are intended to be applicable to ACE only. Each EDC will provide these individual BGS cost recovery methodologies.

ACE's BGS accounting will account for BGS-RSCP revenues and BGS-CIEP revenues individually as follows:

1. BGS-RSCP and BGS-CIEP revenues will be tracked using established accounting procedures and recorded separately as BGS-RSCP revenue and BGS-CIEP revenue; and
2. as previously established for ACE, uncollectible revenues are recovered through a component of ACE's Societal Benefits Charge.

ACE will account for BGS-RSCP and BGS-CIEP costs individually as the sum of the following:

1. all payments made for the provision of BGS-RSCP and BGS CIEP service, including CIEP Standby Fee payments; and
2. any administrative costs associated with the provision of BGS-RSCP and BGS-CIEP service:
    a. Administrative costs are defined as commonly-incurred or directly-incurred. *Commonly-incurred costs* are costs shared among all of the New Jersey EDCs. *Directly-incurred costs* are costs specifically incurred by each EDC, individually.

Commonly-incurred costs include, but are not limited to, the following:

- preparing and conducting the annual auction, which include all pre-auction development work, developing and printing materials, developing and maintaining the BGS auction website, conducting information sessions for prospective bidders, as well as other consulting services provided by the Auction Manager;
- oversight of the auction process on behalf of the BPU, as performed by the Board's consultant;
- rent and maintenance of office space in New Jersey for the Auction Manager;
- outside counsel legal costs associated with the prosecution and/or defense of BGS patent claims; and
- facility costs associated with viewing the annual auction in real time, which include, but are not limited to, costs for physical space and equipment/media connections.

Directly-incurred costs for ACE include, but are not limited to, the following:

- labor costs and expenses associated with employees who are considered incremental to the BGS process;
- system and software costs related to tracking BGS costs and invoicing;
- power procurement residual costs; and
- other administrative fees incurred in connection with the BGS process, including, but not limited to, fees/licenses, costs associated with public hearings, postage, and information technology support and programming changes necessitated by BPU directives.

The commonly-incurred cost estimates for each BGS Auction cycle are paid for by the winning bidders of the auction at the start of each Energy Year through the Tranche Fee. The difference between the estimated commonly-incurred costs and the actual commonly-incurred costs and all the directly-incurred costs are paid through the BGS Reconciliation Charges.

As noted, one element of commonly-incurred costs has been the costs associated with the rent and maintenance of office space in New Jersey for the Auction Manager to conduct the annual BGS Auction. As noted in the Joint EDC comments, in the November 2021 Board Order, BPU authorized Public

Service Electric and Gas Company ("PSE&G") to sublet the BGS office in Newark, New Jersey. PSE&G (on behalf of the EDCs) subsequently did sublet the office, and the revenues related to the same serve to offset other commonly-incurred EDC costs; and

3. any cost for procurement of capacity, energy, ancillary service, transmission, RPS compliance, and other expenses related to the Contingency Plan, and any payments to the winners of a subsequent bid process to cover defaults made under the Contingency Plan, less any payments recovered from defaulting bidders. In the event that implementation of the Contingency Plan is required for BGS CIEP load, CIEP Standby Fee payments will be tracked separately.

BGS-RSCP and BGS-CIEP rates will be subject to deferred accounting since there will be differences between the BGS costs (as defined above) and BGS-related revenues. Adjustment type charges (also subject to deferred accounting) are necessary in order to balance out the difference between the amount paid to the BGS-RSCP and BGS-CIEP supplier(s) for BGS-RSCP and BGS-CIEP supply, and the revenue from customers for BGS-RSCP and BGS-CIEP services. These reconciliation charges ("RC"), including interest, will be calculated periodically for BGS-RSCP and BGS-CIEP on a cent per kWh basis, and the respective rates will be applied to all BGS-RSCP and BGS-CIEP kWh. These charges will be combined with the fixed, seasonally-differentiated BGS-RSCP and hourly BGS-CIEP charges for billing, although they will be published in ACE's Rider BGS as separate BGS-RSCPRC and BGS-CIEPRC rates that will be revised periodically.

A BGS deferral/credit will be determined individually for the BGS-RSCP and BGS-CIEP rates as the difference between recorded BGS-RSCP or BGS-CIEP revenue and the total BGS-

RSCP or BGS-CIEP cost. The individual BGS deferrals will be accounted for in the following manner:

1. If individual BGS costs, as defined above, are higher than individual BGS recorded revenue, the difference will be charged on a monthly basis to the cost deferral to be reconciled and recovered from customers, with interest, on a periodic, basis through the BGS-RSCPRC and/or the BGS-CIEPRC.
2. If individual BGS costs, as defined above, are lower than individual BGS recorded revenue, the difference will be credited monthly, to the cost deferral to be reconciled and returned to customers, with interest, on a periodic basis, through the BGS-RSCPRC and/or BGS-CIEPRC.

An additional deferred balance will be maintained individually for the BGS-RSCPRC and BGS-CIEPRC rates to ensure full recovery of all of the costs associated with the provision of BGS service.

In the event the Contingency Plan is required to be implemented to serve BGS-CIEP load, the difference between CIEP Standby Fee revenues and CIEP Standby Fee payments made to winning BGS-CIEP auction bidders will be maintained in a separate deferred balance account. Interest on this account will be accrued monthly, using the same methodology and interest rate as used for the BGS-RSCP and BGS-CIEP deferred balances. Any debit/credit balance in this account at the end of the BGS period of June 1, 2024 through May 31, 2025 will be applied as a $/kWh adjustment to the CIEP Standby Fee for the next BGS-CIEP annual period. In this manner, the mechanism to reconcile any CIEP Standby Fee deferred balance is applied, to the greatest extent practicable, to all BGS-CIEP eligible customers who paid the CIEP Standby Fee, and not only to those taking BGS-CIEP service.

With the exception of any adjustment to the CIEP Standby Fee which may be required, ACE will follow the following schedule for the periodic reconciliation of its BGS-RSCP and BGS-CIEP rates:

1. For BGS-RSCPRC and BGS-CIEPRC rates effective June 1, the actual data for the months of August through March will be used. Projected data for April and May will be used for the amount of BGS-RSCPRC and BGS-CIEPRC to be recovered/returned in those months.
2. For BGS-RSCPRC and BGS-CIEPRC rates effective October 1, the actual data for the months of April through July will be used. Projected data for August and September will be used for the amount of BGS-RSCPRC and BGS-CIEPRC to be recovered/returned in those months.

ACE will file BGS-RSCPRC and BGS-CIEPRC rates with the Board at least 30 days in advance of the date upon which they are requested to be effective. The BGS Reconciliation Rate is capped at two cents per kWh. The filed rates will become effective 30 days after filing, absent a determination of manifest error by the Board.

C. DESCRIPTION OF BGS TARIFF SHEETS

This Section describes the proposed tariff sheets needed to implement ACE's BGS proposal. The proposed tariff sheets for Tariff Rider Basic Generation Service ("Rider BGS") are included as **Attachment 1**. Rider BGS provides the rates, terms, and conditions for customers being served under the BGS-RSCP or BGS-CIEP pricing mechanisms.

1. BGS-RSCP

BGS-RSCP is to be available to all customers served on Rate Schedules RS, DDC, SPL, and CSL. BGS-RSCP is also available to customers with a PLS of less than 500 kW who are served under Rate Schedules MGS Secondary, MGS Secondary Electric Vehicle Charging, MGS Primary, AGS Secondary, and AGS Primary. On any meter reading date, and with prior requisite notice, a customer taking supply service under BGS-RSCP may switch to third-party supply service, and a customer taking third-party supply service may switch to BGS-RSCP supply service.

As indicated on the proposed tariff sheets, BGS-RSCP is made up of two components: BGS Supply Charges and the BGS Reconciliation Charge. Additionally, each BGS customer is subject to transmission charges as discussed below.

a. BGS Supply Charges

The values of the BGS Supply charges applicable to Rate Schedules RS, MGS Secondary, MGS Secondary Electric Vehicle Charging, MGS Primary, AGS Secondary, AGS Primary, DDC, SPL, and CSL include the costs related to energy, generation capacity, RPS, ancillary services, and administration. This is a continuation of the current approved methodology for recovering all electric supply service costs in the kilowatt- hour charges for these Rate Schedules.

Typically, the generation capacity costs used in the development of the BGS-RSCP rates are the relevant current wholesale market prices for capacity based on the average, 2024/2025, 2025/2026, and 2026/2027 Base Residual Auctions ("BRA") results under the RPM applicable to load served in the ACE zone. This process has been impacted in recent years by delays in conducting the BRAs – resulting in the need for contract supplements with Capacity Proxy prices for delivery years with delayed BRAs. PJM has issued a schedule of upcoming BRAs, and the recently conducted BRA produced a preliminary price paid for capacity of $54.50 per MW-day for the 2024/2025 Delivery Year for the ACE Zone. Due to the postponement of the BRAs, contracts from the 2022 and 2023 BGS auctions contained supplements with Capacity Proxy Prices. With the prior postponements of the BRAs for the 2024/2025 and 2025/2026 Delivery

Years, a Capacity Proxy Price of $87.98 per MW-Day was used in place of the 2024/2025 BRA value in the 2022 contracts, while a Capacity Proxy Price of $66.38 was used in place of the 2024/2025 BRA and a Capacity Proxy Price of $44.63 per MW-Day was used in place of the 2025/2026 BRA in the 2023 contracts.

Given the continued delay in the schedule of BRAs for the 2025/2026 Delivery Year and 2026/2027 Delivery Year, a Capacity Proxy Price of $47.46. per MW-Day and a Capacity Proxy Price of $49.05. per MW-Day have been used in place of the prices paid for capacity for 2025/2026 and 2026/2027 Delivery Years, respectively.

For Energy Year ("EY") 2026, if Supplement A to the BGS-RSCP Supplier Master Agreement is approved by the BPU and if the BRA for the 2025/2026 Delivery has not occurred at least five (5) business days prior to the BGS-RSCP Auction, payments to BGS-RSCP suppliers will be adjusted for the difference between the "Zonal Capacity Price," which is the price paid by BGS-RSCP Suppliers for Capacity in the Company's PJM zone, as may be determined under the RPM or its successor or otherwise, and the Capacity Proxy Price for the 2025/2026 Delivery Year.

For EY 2027, if Supplement B to the BGS-RSCP Supplier Master Agreement is approved by the BPU and if the BRA for the 2026/2027 Delivery has not occurred at least five (5) business days prior to the BGS-RSCP Auction, payments to BGS-RSCP suppliers will be adjusted for the capacity price difference between the Zonal Capacity Price, which is the price paid by BGS-RSCP Suppliers for Capacity in the Company's PJM zone, as may be determined under the RPM or its successor or otherwise, and the Capacity Proxy Price for the 2026/2027 Delivery Year.

ACE will file new tariff sheets for EY 2026 and EY 2027, reflecting the impact of this price adjustment in a manner similar to **Attachment 4**, page 1 – Development of Capacity Proxy Price True Up - $/MWh. The rate design spreadsheets include the formulas that will be used to reflect the impact of payments made pursuant to the Supplements. However, the spreadsheets do not provide a value for the EY 2026 and EY 2027 true-ups as the actual values are not known at this time. **Attachment 4**, pages 2 and 3 provide illustrative examples of how the Capacity Proxy Price True Up will be calculated for EY 2026 and EY 2027 respectively and prospectively.

The Supplements to the SMAs signed by BGS-RSCP Suppliers in February 2022 and February 2023 are still in effect for approximately two-thirds of the load for Energy Year 2025 (the year beginning June 1, 2024). Payments to BGS-RSCP suppliers that executed the Supplements to the SMAs approved by the BPU on November 17, 2021 and November 9, 2022 will be adjusted for the price difference between the price paid by BGS-RSCP Suppliers for Capacity in the Company's PJM Zone and the Capacity Proxy Price for the 2024/2025 Delivery Year. Upon the conclusion of the Third Incremental RPM Auction, or the RPM's successor or otherwise, the price paid by BGS-RSCP Suppliers for Capacity in the Company's PJM Zone will be known. At that time, ACE will file new tariff sheets reflecting the impact of the Supplements. The rate design spreadsheets include the formulas that will be used to reflect the impact of payments made pursuant to the Supplements executed by BGS-RSCP Suppliers in February 2022 and February 2023. The value of the recently conducted BRA that was made available in early 2023 is used as an approximation for the price paid by BGS-RSCP Suppliers for Capacity in the Company's PJM Zone for the 2024/2025 Delivery Year ($54.50 per MW-Day).

The specific values that will be utilized for the BGS Supply Charges will be calculated as the tranche-weighted average of the winning BGS-RSCP bid prices for the ACE zone, adjusted for the seasonal payment factors for ACE's Atlantic Electric zone, adjusted by the appropriate factor (multiplier and constant, if applicable) as shown on Table No. 14 of the Development of Post Transition Period BGS Cost and Bid Factor Tables, included in **Attachment 2**.

It is the intent of ACE that the factors in the tables will be applied to the tranche-weighted average of the winning BGS-RSCP bid prices adjusted for the seasonal payment factors. For the period beginning June 1, 2024, the pricing will be based on the 36-month auction price, the 36-month price from the auction held in February 2023 and the 36-month price from the auction held in February 2022. The tables will be updated annually prior to future BGS auctions and will be utilized to develop customer charges for a related annual period in a similar manner as described above. The updates will reflect then current factors such as updated futures prices, factors based on 12-month data, and any changes in the customer groups and loads eligible for the BGS-RSCP class.

b. <u>BGS Reconciliation Charge</u>

This is the implementation of the BGS Reconciliation Charge for BGS-RSCP as explained in the Accounting and Cost Recovery section of this Addendum.

c. <u>Transmission Charges</u>

Transmission service will continue to be billed under the rates, terms, and conditions of the customer's applicable Rate Schedule as set forth in the ACE Tariff for Electric Service. The transmission charges applicable to ACE's BGS-RSCP customers are based on the annual transmission rate for network service for the ACE zone, as stated in PJM's Open Access Transmission Tariff ("OATT"). As part of a settlement approved by the Federal Energy Regulatory Commission ("FERC") on August 9, 2004, certain transmission owners in PJM, including ACE, agreed to re-examine their existing rates, and to propose a method (such as a formula rate) to harmonize new and existing transmission investments by January 31, 2005, with such new rate(s) (if any) to go into effect June 1, 2005. The objective of the formula rate filing is to establish a just and reasonable method for determining the transmission revenue requirements for the affected transmission pricing zones which would reflect both existing and new investment on a current basis. The formula rate tracks increases and decreases in costs such that no under- and no over-recovery of actual costs will occur. The formula rate protocols include provisions for an annual update to the rate based on current levels of costs and reconciliation of prior period costs and revenues. Pursuant to the protocols established in the settlement, the Company will file updates to the formula rate at FERC on or about May 15 of each year to be effective on June 1st of that same year. The Company will make corresponding filings with the Board each year seeking approval of the formula rates on a retail level.

In addition to the formula rate protocols described above, the transmission charge may change from time to time as FERC approves other changes in the PJM OATT and related charges. The transmission cost component of the BGS-RSCP charges to customers will change from time to time as FERC approves changes in the Network Integration Transmission Service rates for the ACE zone in the PJM OATT or FERC approves other network transmission-related charges in the PJM OATT.

ACE will provide the basis for any transmission cost adjustment, and will file supporting documentation from the OATT, as well as any rate translation spreadsheets used.

With the objective of incentivizing the installation and operation of electric vehicle ("EV") chargers within the State of New Jersey, and in support of furthering New Jersey clean energy and climate goals, the Company is proposing, as a two-year pilot program, to offer transmission and supply charge for Monthly General Service Secondary Electric Vehicle Charging (MGS-SEVC) customers billed on a kWh basis. The kWh charge will replace the existing demand (kW) based customer charge used for the billing of both transmission and capacity costs (Capacity cost demand charge is only applicable to customers over 500MW). This proposal was reached in an effort to balance the expressed desire for EV charging companies to reduce total kWh cost volatility, minimize subsidization, promote cost causation, and ensure administrative efficiency. The capacity cost rate change will be addressed in this docket (*see* BGS Capacity Charges in the BGS-CIEP section for more details), while the transmission cost rate change will be addressed in ACE's transmission rate filing, which will occur on or before July 1, 2024.

2. BGS-CIEP

BGS-CIEP will be the only default supply option available to customers served on Rate Schedule TGS (Transmission General Service), and to customers served on Rate Schedules MGS Secondary, MGS Secondary Electric Vehicle Charging, MGS Primary, AGS Secondary, and AGS Primary with a PLS of 500 kW and higher as of November 1 of the year prior to the BGS auctions. Additionally, BGS-CIEP is available on a voluntary basis to any commercial or industrial customer taking service under the MGS or AGS Rate Schedules. To be eligible for BGS-CIEP, the customer will need to notify ACE of its choice no later than the second working day of a given year and must commit to having BGS-CIEP as its default supply service option for a 12-month period commencing June 1st of that year. All commercial and industrial customers taking service under the MGS or AGS Rate Schedules will be notified of their option to switch to BGS-CIEP through the Company's website and tariffs. Customers who elected BGS-CIEP in a prior procurement period and who are eligible to receive BGS-RSCP service may return to BGS-RSCP if they notify ACE of their intent to return to BGS-RSCP default service no later than the second working day of January. Such election will be effective on June 1st of that year.

The charges for BGS-CIEP are comprised of three segments: BGS Energy Charges, BGS Capacity Charges, and the BGS Reconciliation Charges. Transmission service will continue to be billed under the rates, terms, and conditions of the customer's applicable Rate Schedule as set forth in the ACE Tariff for Electric Service. The transmission charges applicable to ACE's BGS-CIEP customers are based on the annual transmission rate for network service for the ACE zone, as stated in PJM's OATT. As part of a settlement approved by FERC on August 9, 2004, certain transmission owners in PJM, including ACE, agreed to re-examine their existing rates and to propose a method (such as a formula rate) to harmonize new and existing transmission investments by January 31, 2005, with such new rate (if any) to go into effect June 1, 2005. The objective of the formula rate filing is to establish a just and reasonable method for determining the transmission revenue requirements for the affected transmission pricing zones which would reflect both existing and new investment on a current basis. The formula rate tracks increases and decreases in costs such that no under- and no over-recovery of actual costs will occur. The formula rate protocols include provisions for an annual update to the rate based on current levels of costs, and reconciliation of prior period costs and revenues. Pursuant to the protocols established in the settlement, the Company will file updates to the formula rate at FERC on or about May 15 of each year, to be effective on June 1 of that year. The Company will make corresponding filings with the Board each year seeking approval of the formula rates on a retail level.

In addition to the formula rate protocols described above, the transmission charge may change from time to time as FERC approves other changes in the PJM OATT and related charges. The transmission cost component of the BGS-CIEP charges to customers will change from time to time as FERC approves changes in the Network Integration Transmission Service rates for the ACE zone in the PJM OATT or FERC approves other network transmission-related charges in the PJM OATT.

ACE will provide the basis for any transmission cost adjustment, and will file supporting documentation from the OATT, as well as any rate translation spreadsheets used.

With the objective of incentivizing the installation and operation of EV chargers within the State of New Jersey, and in support of furthering New Jersey clean energy and climate goals, the Company is proposing, as a two-year pilot program, to offer transmission and supply charge for Monthly General Service Secondary Electric Vehicle Charging (MGS-SEVC) customers billed on a kWh basis. The kWh charge will replace the existing demand (kW)-based customer charge used for the billing of both transmission and capacity costs (Capacity cost demand charge is only applicable to customers over 500MW). This proposal was reached in an effort to balance the expressed desire for EV charging companies to reduce total kWh cost volatility, minimize subsidization, promote cost causation, and ensure administrative efficiency. The capacity cost rate change will be addressed in this docket (*see* BGS Capacity Charges in the BGS-CIEP section for more details), while the transmission cost rate change will be addressed in ACE's transmission rate filing which will occur on or before July 1, 2024.

a. <u>BGS Energy Charge</u>

One of the primary components of this charge will be the actual real time PJM load-weighted average Residual Metered Load Aggregate Locational Marginal Price ("LMP"), of energy for ACE's Atlantic Electric Transmission Zone. An estimate of the Ancillary Service cost for the ACE zone expressed on a dollar per MWh basis and administrative costs will be added to this charge. This sum will then be adjusted for losses for service according to the Rate Schedule for which this service is applicable.

b. <u>BGS Capacity Charges</u>

These charges will recover the costs associated with generation capacity. Effective with the supply period beginning June 1, 2009, the BGS Capacity Charge is based on the results of the BGS-CIEP auction process. This charge, Sales and Use Tax ("SUT"), and the Board Revenue

Assessment will be applied to the customer's share of the PJM zonal capacity obligation.

i. Direct Current Fast Charging ("DCFC") Two Year Pilot Program

In the BPU's 2023 BGS Order dated November 9, 2022, released in connection with BPU Docket No. ER22030127, the Board directed Staff to work with interested parties to come to a consensus in an effort to find a BGS rate design solution for EV chargers before the filing of the proposal for the 2024 BGS Auction (*i.e.*, the proposal due July 1, 2023). The Board also ordered the EDCs, in their next BGS filing(s), to make a proposal regarding rate design for DCFC stations.

As specified in the November 9, 2022 order, EV charging companies (specifically, Electrify America) proposed a rate design to recover generation and transmission capacity charges with the following characteristics: 1) a revenue-neutral volumetric rate; and 2) availability, on an opt-in basis, for DCFC loads with a requirement for a multiyear commitment and portfolio enrollment. This request for a full volumetric generation and transmission capacity charge would replace existing rates that are currently billed based on demand or capacity. It was communicated that eliminating these primarily fixed demand and capacity charges would allow station operators to better predict operating costs. Costs would be entirely paid to the EDC based on the amount of kWh used by the charging company customers and correspondingly recovered from that customer on the same kWh basis through the charging fee. This position was re-affirmed based on additional discussions held subsequent to the November order.

Enrollment

In order to start implementation of the pilot program by June 1, 2024, the Company will need sign-up commitments from the charging companies that want to participate by January 1, 2024.

Monthly Billing and Accounting

With the objective of incentivizing the installation and operation of EV chargers within the State of New Jersey, and in support of furthering New Jersey's clean energy and climate goals, the Company is proposing, as a two-year pilot program, to offer transmission and supply charges for Monthly General Service Secondary Electric Vehicle Charging (MGS-SEVC) customers billed on a kWh basis. The kWh charge will replace the existing demand (kW)-based customer charge used for the billing of both transmission and capacity costs (Capacity cost demand charge is only applicable to customers over 500MW). This proposal was reached in an effort to balance the expressed desire for EV charging companies to reduce total kWh cost volatility, minimize subsidization, promote cost causation, and ensure administrative efficiency. The capacity cost rate change will be addressed in this docket, while the transmission cost rate change will be addressed in ACE's transmission rate filing which will occur on or before July 1, 2024. Additional transmission discussion for BGS-RSCP is discussed in the "Transmission Charges" subsection beginning on page 13 and for BGS-CIEP in the "BGS-CIEP" section beginning on page 15 of this document.

Converting these demand charges to a kWh based charge aligns the amount charging companies would pay ACE for use of electricity with that in which they bill customers, as charging occurs. This alignment will facilitate their ability to better predict and manage site profitability and operating costs, thus reducing kWh cost volatility.

While the revenue collected from charging companies from their customers will now align with the amount they pay for that usage to ACE, this will create a misalignment between that which ACE pays for BGS customers demand/capacity based supply costs and how it is recovered from the charging customer. ACE does acknowledge this as a known disconnect, however, the

Company is proposing to maintain a rate computation basis tied to total costs expected for this specific customer group of EV charging companies over their expected total kWh usage, thus avoiding cross-subsidization outside of this customer segment. The Company believes this will result in a methodology that achieves the desired goal of ensuring cost causation while minimizing subsidization.

In order to further mitigate the potential for subsidization, the Company is proposing that EDC customers who qualify for this rate commit to remain so for a period of a least two years and also enrollment of all charging company site locations. In addition, any Net Energy Metering customers would be excluded from participating in this program.

Finally, in an effort to increase availability of this rate to a larger customer base, the Company's tariff will be expanded to include charging locations separately metered under the Company's advanced metering infrastructure ("AMI"). Previously, this tariff was restricted to charging companies that were able to share charging data with ACE through specified charger networking capabilities. The ability to share such data often restricted certain companies from being able to participate in this rate. With the implementation of the ACE AMI network (known as the Smart Energy Network or SEN) currently being deployed, Company meters will be able to directly communicate hourly usage data.

Implementation and Contingency Costs

ACE respectfully requests that all costs associated with this proposal (including, but not limited to, the rate reconciliation, customer education and outreach, and the implementation costs of upgrading systems) flow through the Company's periodic BGS reconciliation charge filings. During the two-year pilot program, these costs would be reconciled and charged to only the charging companies that have opted into the program. Should no one opt into this program, the

Company would still request cost recovery of any costs incurred through an appropriate cost recovery mechanism to be determined.

c. BGS Reconciliation Charge

This is the BGS Reconciliation Charge for the BGS-CIEP service as explained in the Accounting and Cost Recovery section of this Addendum.

d. CIEP Standby Fee

For the period June 1, 2024 through May 31, 2025, the EDCs will pay each BGS-CIEP supplier a CIEP Standby Charge equal to $0.000150 per kWh times their pro-rata share of the total energy usage measured at the meters of all of ACE's BGS-CIEP eligible customers. The CIEP Standby Fee is a delivery charge that is applicable to all customers having BGS-CIEP as their default supply service. This includes all customers served on Rate Schedules TGS, all customers served on Rate Schedules MGS Secondary, MGS Secondary Electric Vehicle Charging, MGS Primary, AGS Secondary, and AGS Primary with a peak load share of 500 kW or greater, and all customers on Rate Schedules MGS Secondary, MGS Secondary Electric Vehicle Charging, MGS Primary, AGS Secondary, and AGS Primary with a peak load share of less than 500 kW that have elected the BGS-CIEP default supply option. Any under- or over-recovery of the CIEP Standby Fee will continue to be subject to deferred accounting.

D. BGS RATE DESIGN METHODOLOGY

1. ACE BGS-RSCP Pricing Spreadsheet

The resulting charge for each BGS-RSCP rate element (*i.e.,* Rate RS summer charge, winter charge, etc.) for the non-hourly BGS-RSCP supply service will be based on factors applied to the tranche-weighted average of the BGS-RSCP winning bid prices adjusted for the seasonal payment factors. The rate class specific factors have been developed based on the ratios of the estimated underlying market costs of each rate element (for each rate class) to the overall BGS-

RSCP cost. The tables included in **Attachment 2** and described below present all of the input data, intermediate calculations, and the final results in the calculation of these factors.

Table No. 1 (% Usage During PJM On-Peak Period) contains the percentage of on-peak load, by month, for each applicable Rate Schedule. The on-peak period as used in this table (referred to as PJM periods) is defined as the 16-hour period from 7 A.M. to 11 P.M., Monday through Friday. All remaining weekday hours and all hours on weekends and holidays recognized by the National Electric Reliability Council (also known as NERC) are considered the off-peak period. This is consistent with the time periods used in the forwards market for trading of bulk power. The values in this table for each month are based on the most recent available settlement data for current ACE customers.

Table No. 2 (% Usage During ACE On-Peak Billing Period) contains the percentage of on- peak load, by month, for each applicable Rate Schedule based on the definitions of time periods as contained in ACE's delivery Rate Schedules. These percentages are based on usage history for the RS TOU BGS customers for the most recent period.

Table No. 3 (Class Usage @ Customer) contains the billing month sales forecasted for the period of June 2024 through May 2025, with migration adjustments. The values in Table No. 3 will be updated in January 2024 to better reflect forecasts for the June 1st delivery year.

Table No. 4 (Forward Prices – Energy Only @ Bulk System) contains the forward prices for energy, by time period and month, for the BGS analysis period. These values are the energy on- peak forwards as of June 1, 2023, for the PJM West trading hub for the period of June 2024 to May 2025, as utilized in BGS market-to-market calculations, and the historical ratio of actual off-peak to on-peak PJM LMPs for the prior summer and winter periods. An adjustment of the forward prices contained in Table No. 4 must be made to correct for the pricing differential between the PJM West trading hub and the ACE zone where the BGS supply will be utilized.

Table No. 5 (Zone-Hub Basis Differential) contains an estimate of the average zone-hub basis differential factors, by month and time period, which, when multiplied by the prices at the PJM West trading hub, will result in costs for power delivered into the ACE zone.

Table No. 6 (Losses) contains the factors utilized for average system losses by Rate Schedule and voltage level. Loss factors are developed by including losses at the 500kV transmission level as well as losses at lower transmission and distribution voltage levels currently approved for use by the Board.

Table No. 7 (Summary of Average BGS Energy Unit Costs @ Customer – PJM Time Periods) is the calculation of the energy costs by rate, time period and season. These values are the seasonal and time period average costs per Megawatt hour ("MWh") as measured at the customer billing meter (from Table No. 3), based on the forwards prices (from Table No. 4), corrected for zone-hub basis differential (from Table No. 5), losses (from Table No. 6), and monthly time period weights (from Table No. 1). These average costs do not include the costs associated with Ancillary Services, RPS compliance or Generation Obligation costs, which will be considered in subsequent calculations.

Table No. 8 (Summary of Average BGS Energy Costs @ Customer – PJM Time Periods) indicates the total value, in thousands of dollars, of the average BGS energy costs. These are the results of the multiplication of the unit costs from Table No. 7, the monthly time period weights from Table No. 1, and the total sales to customers from Table No. 3. Since the end result of these calculations are to be utilized in the development of retail BGS rates, the rates utilizing time of day pricing must be developed based upon the time periods as defined for billing.

Table No. 9 (Summary of Average BGS Energy Unit Costs @ Customer – ACE Time Periods) shows the result of the corrections for the RS TOU BGS rate. These values are calculated based on the assumption that the MWhs included in the PJM on-peak time period and not included in the ACE on-peak time periods are at the average of the on- and off-peak PJM prices.

Table No. 10 (Generation Obligations and Costs and Other Adjustments) includes the values necessary for the inclusion of the costs of the Generation Capacity obligations. The top portion of Table No. 10 shows the total generation obligations with a migration adjustment, by applicable Rate Schedule, that are currently being utilized in the year 2023. Table No. 10 will be updated in January 2024, similar to Table No. 3. The middle portion of this table shows the number of summer and winter days and months that are used in this analysis. The bottom portion of this table shows the seasonally differentiated average market price of generation capacity, using the relevant RPM auction result for Delivery Year 2024/2025, the Capacity Proxy Price for Delivery Year 2025/2026, and the Capacity Proxy Price for Delivery Year 2026/2027. The Capacity Proxy Price will be replaced with the Zonal Capacity Prices, which are the prices paid by BGS-RSCP Suppliers for Capacity for the 2025/2026 and the 2026/2027 Delivery Years when available as may be determined through the RPM or its successor or otherwise.

Table No. 11 (Ancillary Services and RPS) contains an estimate of the effects of the costs of ancillary services and RPS. The values of $2.00 per MWh and $17.22 per MWh are used, respectively. Since the actual costs are a complex combination of many factors, an estimate of the overall annual average value, expressed on a dollar per MWh basis, is used as a reasonable and practical alternative.

Table No. 12 (Summary of Obligation Costs Expressed as $/MWh @ Customer) shows the result of the allocation of the generation costs, on a per MWh basis, to all Rate Schedules. For RS TOU BGS, the per MWh Generation Capacity Obligation Costs are based on the on-peak usage only.

Table No. 13 (Summary of BGS Unit Costs @ Customer) is the result of the inclusion of the generation capacity, Ancillary Services, and RPS costs to the energy only costs shown in Table No. 9. This table shows the total estimated costs for BGS, based on the assumptions utilized in the above tables, and the average per unit cost, as measured at the customer meters or the bulk system meters.

Table No. 14 (Ratio of BGS Unit Costs @ Customer to Average Cost @ transmission nodes) indicates the ratio of the individual rate element costs from Table No. 13 to the overall cost as measured at the transmission nodes, plus constants, where applicable.

Table No. 15 (Summary of Total BGS Costs by Season) shows the calculation of the total BGS Costs, utilizing the total customer usage from Table No. 3 and the BGS unit costs from Table No. 13. The lower left portion of the table indicates the relative percentage of total costs by season for all Rate Schedules, while the center shows the calculation of the overall average seasonal unit costs on a dollar per MWh basis. The ratio of these overall average seasonal costs to the overall total cost, shown in the lower right-hand portion of Table No. 15, are the seasonal payment ratios upon which payments to the winning bidders are based. The final section summarizes some of the most important assumptions utilized in the above calculations.

Table No. 16 (Retail Rates Charged to BGS-RSCP Customers), shows the calculation of retail rates to be charged to the BGS-RSCP customers for their BGS services. This table utilizes the information computed in Table No. 14 (Ratio of BGS Unit Costs) and applies the applicable ratios for each rate class to the BGS average price which, in turn, is based on the weighted average winning bids . The upper left portion of this table provides the BGS average price.

Table No. 17 (Retail Rates Charged to BGS-RSCP Customers Including Revenue Assessment and SUT), shows the BGS-RSCP customer rates inclusive of the BPU and Division of Rate Counsel revenue assessments, as well as SUT. This table utilizes the information provided in Table No. 16 and applies the applicable revenue assessment factor and SUT rate to derive the tax effected BGS-RSCP customer's rates.

The second spreadsheet used in the calculation of the final BGS-RSCP rates is included as **Attachment 3** and is titled "Calculation of June 2024 to May 2025 BGS-RSCP Rates." The tables in this spreadsheet calculate the weighted average winning bid price and convert it into the final BGS-RSCP rates that are charged to customers. An explanation of each of the six tables, labeled as Tables A through F, is as follows:

Table A (Auction Results) contains the results of the 2022/2023 BGS auction, the results of the 2023/2024 BGS auction, and the results of the current auction. The Capacity Proxy Price True Up cost in $ per MWh will be used to reflect the impact of payments made pursuant to the Supplements executed by BGS Suppliers in February 2022 and February 2023. Upon conclusion of the Third Incremental RPM Auction through the RPM or its successor or otherwise, the price paid by BGS-RSCP Suppliers for Capacity in the Company's PJM Zone will be known. The Capacity Proxy Price True-Up will then be determined by the price difference between the price paid by BGS-RSCP Suppliers for Capacity in the Company's PJM Zone and the Capacity Proxy Price for the 2024/2025 Delivery Year. The value of the recently concluded BRA made available in early 2023 is used as an approximation of the price paid by BGS-RSCP Suppliers for Capacity in the Company's PJM Zone for 2024/2025. From these values, the weighted average annual bid price (shown on line 13) is calculated. All of the formulas used in this table are shown in the right-hand column of this table, under the heading “Notes”.

Table B (Ratio of BGS Unit Costs @ Customer to Average Cost @ transmission nodes) is a repeat of the values shown in Table No. 14 from **Attachment 2**, the bid factors calculated based on current market conditions.

Table C (Preliminary Resulting BGS Rates) contains the preliminary customer BGS-RSCP rates as the product of the weighted average bid price (from Table A) and the Bid Factors from Table B.

Table D (Revenue Recovery Calculations) contains a comparison of the total anticipated rate revenue billed to customers based on the preliminary BGS-RSCP rates developed in Table C and the anticipated total season payments to BGS suppliers, based on the data in Table A. The calculation of the kWh Rate Adjustment Factors are also provided in this table, which are equal to the seasonal dollar differences between the anticipated billed revenue and supplier payments, divided by the total anticipated seasonal billed BGS-RSCP energy-related charges.

Table E (Final Resulting BGS Rates) contains the final adjusted BGS-RSCP rates, which are equal to the preliminary BGS–RSCP rates shown in Table C, times the seasonal kWh Rate Adjustment Factors that were developed in Table D.

Table F (Spreadsheet Error Checking) contains a comparison of the total anticipated rate revenue billed to customers based on the final BGS-RSCP rates developed in Table E, and the anticipated total season payments to BGS suppliers, based on the data in Table A.

E. CONCLUSION

In connection with the approval of this filing, the Company respectfully requests that the Board determine as follows:

1. it is necessary and in the public interest for the electric public utilities to secure service for the BGS-RSCP and BGS-CIEP customers, as approved herein, for the period June 1, 2024 to May 31, 2027;
2. the Company's proposed accounting for BGS is approved for purposes of accounting and BGS cost recovery;
3. the proposed BGS Contingency Plan is approved, and there will exist a presumption of prudence with respect to the BGS Auction Plan method and the costs incurred for BGS service under the Auction Plan and the related Contingency Plan;
4. the Company's proposed DCFC Two-Year Pilot Program is approved and authorized to commence implementation on or by June 1, 2024; and
5. the Company's Rate Design Methodology and Tariff Sheets are approved.

Attachment 1

ATLANTIC CITY ELECTRIC COMPANY
BPU NJ No. 11 Electric Service - Section IV **Revised Sheet Replaces** **Revised Sheet No. 60**

RIDER (BGS)
Basic Generation Service (BGS)

Basic Generation Service (BGS) will be arranged for any customer taking service under Electric Rate Schedules RS, MGS Secondary, MGS-SEVC, MGS Primary, AGS Secondary, AGS Primary, TGS, DDC, SPL, and CSL who has not notified the Company of an Alternative Electric Supplier choice. BGS is also available to customers whose arrangements with Alternative Electric Suppliers have terminated for any reason, including nonpayment.

BGS is offered under two different terms of service; Basic Generation Service-Residential Small Commercial Pricing (BGS-RSCP) and Basic Generation Service -Commercial and Industrial Energy Pricing (BGS-CIEP). BGS-RSCP is offered to customers on Rate Schedules RS, DDC, SPL and CSL. BGS-RSCP is also offered to customers on Rate Schedules MGS Secondary, MGS-SEVC, MGS Primary, AGS Secondary, AGS Primary with an annual peak load share ("PLS") for generation capacity of less than 500 kW as of November 1 or each year. Additionally, BGS customers on Rate Schedule RS have the option of taking BGS-RSCP on a time of use basis.

BGS customers on Rate Schedule TGS and BGS customers on Rate Schedules MGS Secondary, MGS-SEVC, MGS Primary, AGS Secondary or AGS Primary with a PLS for generation capacity equal to or greater than 500 kW as of November 1 of each year are required to take service under BGS-CIEP.

Customers on Rate Schedules MGS Secondary, MGS-SEVC, MGS Primary, AGS Secondary or AGS Primary with a PLS of less than 500 kW, have the option of taking either BGS-RSCP or BGS-CIEP service. Customers who elect BGS-CIEP must notify the Company of their selection no later than the second working day of January of the year they wish to begin BGS-CIEP service. Such election will be effective on June 1 of that year and remain as the customer's default supply for the following twelve months. Customers electing BGS-CIEP as their default supply in a prior procurement period and who are otherwise eligible to return to BGS-RSCP may return to BGS RSCP by notifying the Company no later than the second working day of January of the year that they wish to return to BGS-RSCP service. Such election shall be effective on June 1 of that year.

BGS-RSCP Supply Charges ($/kWh):	SUMMER	WINTER
Rate Schedule	June Through September	October Through May
RS		$ x.xxxxxx
<=750 kwhs summer	$ x.xxxxxx	
> 750 kwh summer	$ x.xxxxxx	
RS TOU BGS Option		
On Peak (See Note 1)	$ x.xxxxxx	$ x.xxxxxx
Off Peak (See Note 1)	$ x.xxxxxx	$ x.xxxxxx
MGS-Secondary and MGS-SEVC	$ x.xxxxxx	$ x.xxxxxx
MGS-Primary	$ x.xxxxxx	$ x.xxxxxx
AGS-Secondary	$ x.xxxxxx	$ x.xxxxxx
AGS-Primary	$ x.xxxxxx	$ x.xxxxxx
DDC	$ x.xxxxxx	$ x.xxxxxx
SPL/CSL	$ x.xxxxxx	$ x.xxxxxx

Note 1: On Peak hours are considered to be 8:00 AM to 8:00 PM, Monday through Friday.

The above Basic Generation Service Energy Charges reflect costs for Energy, Generation Capacity, Ancillary Services and administrative charges pursuant to N.J.S.A. 48:2-60 plus New Jersey Sales and Use Tax as set forth in Rider SUT.

Date of Issue: **Effective Date:**

Issued by:

RIDER (BGS) continued
Basic Generation Service (BGS)

BGS Reconciliation Charge ($/kWh):
The above charge shall recover the difference between the monthly amount paid to Basic Generation Service (BGS) suppliers and the total revenue from customers for BGS for the preceding months for the applicable BGS supply. These charges include New Jersey Sales and Use Tax as set forth in Rider SUT and are changed on June 1 and October 1 of each year.

Rate Schedule	Charge ($ per kWh)
RS	$ (0.004888)
MGS Secondary, MGS-SEVC, AGS Secondary, SPL/CSL, DDC	$ (0.004888)
MGS Primary, AGS Primary	$ (0.004760)

BGS-CIEP

Energy Charges
BGS Energy Charges for Rate Schedule TGS, AGS and MGS customers with a Peak Load Share (PLS) of 500 kW or more, and AGS and MGS customers with a PLS of less than 500 kW who have elected BGS-CIEP are hourly and are provided at the real time PJM Load Weighted Average Residual Metered Load Aggregate Locational Marginal Prices for the Atlantic Electric Transmission Zone, adjusted for losses, plus administrative charges pursuant to N.J.S.A. 48:2-60 and New Jersey Sales and Use Tax as set forth in Rider SUT.

Generation Capacity Obligation Charge

	Summer	Winter
Charge per kilowatt of Generation Obligation ($ per kW per day)	$x.xxxxxx	$x.xxxxxx

This charge is equal to the winning bid price from the BGS-CIEP default service auction plus administrative charges pursuant to N.J.S.A. 48:2-60 and New Jersey Sales and Use Tax as set forth in Rider SUT. The above charge shall be applied to each customer's annual peak load share ("PLS") for generation capacity, adjusted for the applicable PJM-determined Zonal Scaling Factor and the applicable PJM-determined capacity reserve margin factor, on a daily basis for each day in each customer's respective billing cycle.

CIEP DCFC EV Chargers (MGS-SEVC Class) Generation Capacity Charge

Generation Capacity Charge per kilowatt hour ($/kWh) $x.xxxxxx

This charge is only available to the MGS-SEVC Rate Schedule on an opt-in basis. Customers opting into this rate must have a Peak Load Share (PLS) of 500 kW or more, consistent with BGS-CIEP. The above charge shall be applied to MGS-SEVC customers who have opted into the volumetric option to pay for generation capacity costs plus administrative charges pursuant to N.J.S.A. 48:2-60, plus New Jersey Sales and Use Tax as set forth in Rider SUT. Customers who have elected for this rate must remain for a period of at least two years and also must enroll all of their charging company site locations. Customers on a rate schedule other than MGS-SEVC are not eligible for this option. MGS-SEVC customers on Rider BGS-RSCP are not eligible for this option. NEM customers are not eligible for this option.

Ancillary Service Charge

	Charge ($ per kWh)
Service taken at Secondary Voltage	$ x.xxxxxx
Service taken at Primary Voltage	$ x.xxxxxx
Service taken at Sub-Transmission Voltage	$ x.xxxxxx
Service taken at Transmission Voltage	$ x.xxxxxx

This charge represents the average annual cost of Ancillary Services in the Atlantic Electric Transmission zone adjusted for losses, plus administrative charges pursuant to N.J.S.A. 48:2-60 and New Jersey Sales and Use Tax as set forth in Rider SUT.

ATLANTIC CITY ELECTRIC COMPANY
BPU NJ No. 11 Electric Service - Section IV **Revised Sheet Replaces** **Revised Sheet No. 60b**

RIDER (BGS) continued
Basic Generation Service (BGS)

BGS Reconciliation Charge:

	Charge ($ per kWh)
Service taken at Secondary Voltage	$ (0.030443)
Service taken at Primary Voltage	$ (0.029646)
Service taken at Sub-Transmission Voltage	$ (0.029310)
Service taken at Transmission Voltage	$ (0.029023)

The above charge shall recover the difference between the monthly amount paid to Basic Generation Service (BGS) suppliers and the total revenue from customers for BGS for the preceding months for the applicable BGS supply. These charges include administrative charges pursuant to N.J.S.A. 48:2-60 and New Jersey Sales and Use Tax as set forth in Rider SUT and are changed on June 1 and October 1 of each year.

CIEP Standby Fee $ x.xxxxxx per kWh
This charge recovers the costs associated with the winning BGS-CIEP bidders maintaining the availability of the hourly priced default electric supply service plus administrative charges pursuant to N.J.S.A. 48:2-60 and New Jersey Sales and Use Tax as set forth in Rider SUT. This charge is assessed on all kWhs delivered to all CIEP- eligible customers on Rate Schedules MGS Secondary, MGS-SEVC, MGS Primary, AGS Secondary, AGS Primary or TGS.

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RIDER (BGS) continued
Basic Generation Service (BGS)

Transmission Enhancement Charge

This charge reflects Transmission Enhancement Charges ("TECs"), implemented to compensate transmission owners for the annual transmission revenue requirements for "Required Transmission Enhancements" (as defined in Schedule 12 of the PJM OATT) that are requested by PJM for reliability or economic purposes and approved by the Federal Energy Regulatory Commission (FERC). The TEC charge (in $ per kWh by Rate Schedule), including administrative charges pursuant to N.J.S.A. 48:2-60 and New Jersey Sales and Use Tax as set forth in Rider SUT, is delineated in the following table.

Rate Class

	RS	MGS Secondary And MGS-SEVC	MGS Primary	AGS Secondary	AGS Primary	TGS	SPL/ CSL	DDC
VEPCo	0.000323	0.000225	0.000154	0.000162	0.000132	0.000124	-	0.000097
TrAILCo	0.000275	0.000192	0.000131	0.000138	0.000113	0.000104	-	0.000082
PSE&G	0.002811	0.001961	0.001345	0.001415	0.001157	0.001078	-	0.000846
PATH	0.000003	0.000002	0.000001	0.000001	0.000001	0.000001	-	0.000001
PPL	0.000095	0.000066	0.000046	0.000048	0.000039	0.000036	-	0.000029
PECO	0.000216	0.000150	0.000103	0.000109	0.000088	0.000083	-	0.000065
Pepco	0.000022	0.000016	0.000011	0.000012	0.000010	0.000009	-	0.000006
MAIT	0.000031	0.000021	0.000015	0.000015	0.000013	0.000012	-	0.000010
JCP&L	0.000003	0.000002	0.000001	0.000001	0.000001	0.000001	-	0.000001
EL05-121	0.000019	0.000013	0.000009	0.000010	0.000007	0.000007	-	0.000005
Delmarva	0.000010	0.000006	0.000004	0.000004	0.000004	0.000003	-	0.000003
BG&E	0.000041	0.000028	0.000019	0.000020	0.000017	0.000015	-	0.000012
AEP-East	0.000075	0.000052	0.000035	0.000037	0.000031	0.000029	-	0.000022
Silver Run	0.000329	0.000230	0.000157	0.000165	0.000135	0.000126	-	0.000099
NIPSCO	0.000003	0.000002	0.000001	0.000001	0.000001	0.000001	-	0.000001
CW Edison	-	-	-	-	-	-	-	-
ER18-680 & Form 715	-	-	-	-	-	-	-	-
SFC	0.000004	0.000003	0.000002	0.000002	0.000002	0.000001	-	0.000001
Duquesne	0.000002	0.000001	0.000001	0.000001	0.000001	0.000001	-	0.000001
Total	0.004262	0.002970	0.002035	0.002141	0.001752	0.001631	-	0.001281

Date of Issue: **Effective Date:**

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Attachment 2

Table #1 **% usage during PJM On-Peak period**
(data rounded to nearest %)

On-Peak periods defined as the 16 hr PJM Trading period, adj for NERC holidays

	RS	RS TOU - BGS	MGS - SEC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC
January	43.43%	43.25%	53.44%	46.88%	52.49%	47.13%	30.94%	45.72%
February	45.63%	45.81%	54.87%	49.57%	52.97%	48.80%	29.87%	47.41%
March	46.17%	46.26%	55.60%	49.02%	55.44%	49.92%	27.38%	48.52%
April	45.04%	45.14%	55.46%	45.10%	51.47%	46.14%	21.88%	43.95%
May	41.96%	42.44%	50.35%	45.08%	50.31%	46.09%	20.26%	44.21%
June	53.85%	53.69%	63.48%	53.18%	56.08%	49.68%	20.39%	47.23%
July	48.60%	48.83%	51.47%	49.27%	49.86%	45.27%	17.71%	42.81%
August	56.40%	56.71%	56.76%	53.60%	55.58%	51.21%	22.00%	49.00%
September	47.24%	47.51%	53.52%	48.78%	53.53%	48.61%	23.26%	46.47%
October	45.87%	45.94%	50.67%	47.46%	52.02%	47.38%	25.69%	44.53%
November	46.59%	46.29%	50.76%	49.96%	52.59%	48.96%	31.03%	46.47%
December	45.35%	45.59%	49.11%	48.98%	48.83%	47.86%	31.28%	45.70%

Table #2 **% Usage During ACECO On-Peak Billing Period**

	RS TOU - BGS
January	29.01%
February	29.94%
March	30.90%
April	30.06%
May	29.73%
June	38.97%
July	37.36%
August	43.53%
September	35.14%
October	31.88%
November	30.73%
December	32.23%

Table #3 **Class Usage @ customer**
calendar month sales forecasted for period
in MWh

	RS	RS TOU - BGS	MGS - SEC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC	Total
Jan-25	352,933	191	77,661	5,713	65,498	6,429	5,769	917	515,111
Feb-25	318,507	173	76,003	5,436	64,481	5,977	4,803	879	476,258
Mar-25	277,230	150	74,407	5,211	65,679	5,453	4,685	853	433,669
Apr-25	239,546	130	73,654	5,411	60,896	5,862	4,150	839	390,488
May-25	196,962	107	71,123	5,583	56,680	5,260	3,502	803	340,021
Jun-24	285,976	155	85,940	5,794	73,145	5,611	3,538	953	461,112
Jul-24	430,273	233	96,052	6,526	81,635	5,957	3,678	1,058	625,412
Aug-24	493,656	268	99,914	8,426	84,317	4,952	4,026	1,105	696,664
Sep-24	435,916	236	98,724	7,123	83,063	5,353	4,510	1,112	636,037
Oct-24	241,751	131	77,936	5,943	64,593	4,612	4,447	901	400,314
Nov-24	231,060	125	76,594	5,851	62,605	4,835	4,962	897	386,930
Dec-24	275,141	149	74,027	5,027	67,357	5,065	5,294	863	432,923
Total	3,778,951	2,048	982,036	72,046	829,949	65,366	53,364	11,179	5,794,940

Table #4 **Forwards Prices - Energy Only @ bulk system**
($/MWH)

	On-Peak	Off/On Pk LMP ratio	Off-Peak
Jan-25	72.30	0.820	59.28
Feb-25	68.50	0.820	56.16
Mar-25	48.30	0.820	39.60
Apr-25	44.25	0.820	36.28
May-25	45.85	0.820	37.59
Jun-24	43.85	0.639	28.01
Jul-24	61.15	0.639	39.06
Aug-24	54.70	0.639	34.94
Sep-24	43.40	0.639	27.73
Oct-24	38.95	0.820	31.93
Nov-24	42.40	0.820	34.76
Dec-24	54.50	0.820	44.68

Table #5 **Zone-Hub Basis Differential** **'Based on 3 Year Average**

	On-Peak	Off-Peak
Jan-25	81%	88%
Feb-25	81%	88%
Mar-25	81%	88%
Apr-25	81%	88%
May-25	81%	88%
Jun-24	85%	91%
Jul-24	85%	91%
Aug-24	85%	91%
Sep-24	85%	91%
Oct-24	81%	88%
Nov-24	81%	88%
Dec-24	81%	88%

Table #6

Losses	**RS**	**RS TOU - BGS**	**MGS - SEC**	**MGS - PRI**	**AGS - SEC**	**AGS - PRI**	**SPL/CSL**	**DDC**
Delivery Loss Factor	6.6720%	6.6720%	6.6720%	4.1641%	6.6720%	4.1641%	6.6720%	6.6720%
Loss Factors + EHV Losses =	7.0688%	7.0688%	7.0688%	4.5715%	7.0688%	4.5715%	7.0688%	7.0688%
Expansion Factor =	1.07606	1.07606	1.07606	1.04790	1.07606	1.04790	1.07606	1.07606
Marginal Loss Factor (w/ EHV Losses) =	1.6831%	1.6831%	1.6831%	1.6831%	1.6831%	1.6831%	1.6831%	1.6831%
Loss Factor w/o Marginal Loss =	5.4779%	5.4779%	5.4779%	2.9379%	5.4779%	2.9379%	5.4779%	5.4779%
Expansion Factor w/o Marginal Loss =	1.05795	1.05795	1.05795	1.03027	1.05795	1.03027	1.05795	1.05795

Table #7 **Summary of Average BGS Energy Unit Costs @ customer - PJM Time Periods**
based on Forwards @ PJM West - corrected for congestion & losses
in $/MWh

	RS	**RS TOU - BGS**	**MGS - SEC**	**MGS - PRI**	**AGS - SEC**	**AGS - PRI**	**SPL/CSL**	**DDC**
Summer - all hrs	$ 39.75	$ 39.78	$ 39.93	$ 38.34	$ 39.61	$ 37.81	$ 34.58	$ 38.51
On Peak	$ 46.90	$ 46.91	$ 46.04	$ 45.22	$ 46.15	$ 44.92	$ 45.49	$ 46.13
Off Peak	$ 32.16	$ 32.16	$ 32.11	$ 31.10	$ 32.02	$ 31.10	$ 31.68	$ 31.92
Winter - all hrs	$ 44.08	$ 44.09	$ 43.02	$ 41.50	$ 43.11	$ 42.38	$ 42.59	$ 42.76
On Peak	$ 46.69	$ 46.68	$ 45.43	$ 43.97	$ 45.43	$ 44.88	$ 46.83	$ 45.46
Off Peak	$ 41.95	$ 41.95	$ 40.36	$ 39.24	$ 40.60	$ 40.10	$ 40.96	$ 40.48
Annual	$ 42.20	$ 42.21	$ 41.82	$ 40.28	$ 41.75	$ 40.86	$ 40.23	$ 41.16

System Average Cost @ customer - (limited to classes shown above) = $ 42.01

Table #8 **Summary of Average BGS Energy Costs @ customer - PJM Time Periods**
based on Forwards prices corrected for congestion & losses
in $1000

		RS	**RS TOU - BGS**	**MGS - SEC**	**MGS - PRI**	**AGS - SEC**	**AGS - PRI**	**SPL/CSL**	**DDC**
Summer - all hrs		$ 65,425	$ 35	$ 15,197	$ 1,068	$ 12,760	$ 827	$ 545	$ 163
	PJM on pk	$ 39,748	$ 22	$ 9,832	$ 646	$ 7,985	$ 477	$ 150	$ 90
	PJM off pk	$ 25,677	$ 14	$ 5,366	$ 422	$ 4,774	$ 350	$ 394	$ 72
Winter - all hrs		$ 94,033	$ 51	$ 25,875	$ 1,833	$ 21,891	$ 1,843	$ 1,602	$ 297
	PJM on pk	$ 44,843	$ 24	$ 14,354	$ 927	$ 12,003	$ 932	$ 490	$ 145
	PJM off pk	$ 49,190	$ 27	$ 11,521	$ 906	$ 9,888	$ 911	$ 1,112	$ 152
Annual		$ 159,459	$ 86	$ 41,072	$ 2,902	$ 34,651	$ 2,671	$ 2,147	$ 460

System Total $ 243,447

Table #9 **Summary of Average BGS Energy Unit Costs @ customer - ACECO Time Periods**
based on Forwards prices corrected for congestion & losses - ACECO billing time periods
in $/MWh

		RS	RS TOU - BGS	MGS - SEC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC
Summer - all hrs		$ 39.75	$ 39.78	$ 39.93	$ 38.34	$ 39.61	$ 37.81	$ 34.58	$ 38.51
	ACECO On pk		$ 49.34						
	ACECO Off pk		$ 33.70						
Winter - all hrs		$ 44.08	$ 44.09	$ 43.02	$ 41.50	$ 43.11	$ 42.38	$ 42.59	$ 42.76
	ACECO On pk		$ 47.82						
	ACECO Off pk		$ 42.45						
Annual Average		$ 42.20	$ 42.21	$ 41.82	$ 40.28	$ 41.75	$ 40.86	$ 40.23	$ 41.16
System Average		$ 42.01							

Table #10 **Generation Obligations and Costs and Other Adjustments**
obligations - values effective January 2023; costs are market estimates
in MW

	RS	RS TOU - BGS	MGS - SEC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC	Total
Gen Load - MW	1,319.6	0.5	280.6	12.1	174.1	9.9	0.0	1.4	1,798.2
Gen Obl - MW	1,512.3	0.5	321.6	13.9	199.5	11.3	0.0	1.6	2,060.7

# of Months and Days used in this analysis

# of summer days =	122	# of summer months =	4
# of winter days =	243	# of winter months =	8
		total # months =	12

Generation Capacity Cost

	Base Capacity			
Summer	$50.34	$/MW/day	Summer Total	$ 12,656,025
Winter	$50.34	$/MW/day	Winter Total	$ 25,208,311
			Annual Total	$ 37,864,336

Residential Inversion Determination

---------- Rate RS ----------

	Charges	% usage		
Block 1 (0-750 kWh/m)	5.480200	62.75%	SUM 'First 750 KWh	1,145,011,676
Block 2 (>750 kWh/m)	6.345400	37.25%	SUM '> 750 KWh	679,853,053
Calculated inversion =	0.865200		WIN	2,200,358,872
				4,025,223,600

Table #11 **Ancillary Services & Renewable Power Cost (forecasted overall annual average)**

Ancillary Services	$ 2.00
Renewable Power Cost	$ 17.22
Total Ancillary Services & Renewable Power Costs	$ 19.22

Table #12 **Summary of Obligation Costs expressed as $/MWh @ customer**

Generation Obl -	RS	RS TOU - BGS	MGS - SEC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC
per annual MWh	$ 7.35	$ 13.96	$ 6.02	$ 3.55	$ 4.42	$ 3.18	$ 0.00	$ 2.56
recovery per summer MWh	$ 5.64	$ 9.41	$ 5.19	$ 3.07	$ 3.80	$ 3.18	$ 0.00	$ 2.26
recovery per winter MWh	$ 8.67	$ 18.43	$ 6.54	$ 3.85	$ 4.81	$ 3.18	$ 0.00	$ 2.74

Table #13 **Summary of BGS Unit Costs @ customer**

Includes energy, Generation capacity obligations, Ancillary Services, and Renewable Power Costs - unadjusted for billing vs. PJM time period differences.
in $/MWh

	RS	RS TOU - BGS	MGS - SEC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC
Summer - all hrs	$ 66.08	$ 69.87	$ 65.80	$ 61.55	$ 64.09	$ 61.13	$ 55.27	$ 61.45
On-Peak		$ 79.42						
Off-Peak		$ 54.38						
Block 1 (0-750 kWh/m)	$ 62.85							
Block 2 (>750 kWh/m)	$ 71.51							
Winter - all hrs	$ 73.44	$ 83.20	$ 70.25	$ 65.49	$ 68.60	$ 65.71	$ 63.28	$ 66.19
On-Peak		$ 86.93						
Off-Peak		$ 63.13						
Annual	$ 70.23	$ 67.66	$ 68.52	$ 63.97	$ 66.85	$ 64.18	$ 60.91	$ 64.40
Grand Total Cost in $1000 =	$ 401,088							
Average cost for rates shown (@ customer) =					$ 69.21			
Average costs for rates shown (@ transmission nodes) =					$ 65.46			

Table #14 **Ratio of BGS Unit Costs @ customer to Average Cost @ transmission nodes (rounded to 3 decimal places)**

Includes energy, Generation capacity obligations, Ancillary Services, and Renewable Power Costs - unadjusted for billing vs. PJM time period differences.

	RS	RS TOU - BGS	MGS - SEC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC
Summer - all hrs		**1.067**	**1.005**	**0.940**	**0.979**	**0.934**	**0.844**	**0.939**
On-Peak		**1.213**						
Off-Peak		**0.831**						
All usage Multiplier	**1.009**							
Constant	**$ (3.22)**		for Block 1 (0-750 kWh/m) usage					
Constant	**$ 5.43**		for Block 2 (>750 kWh/m) usage					
Winter - all hrs	**1.122**	**1.271**	**1.073**	**1.000**	**1.048**	**1.004**	**0.967**	**1.011**
On-Peak		**1.328**						
Off-Peak		**0.964**						
Annual	**1.073**	**1.034**	**1.047**	**0.977**	**1.021**	**0.980**	**0.930**	**0.984**

Table #15 **Summary of Total BGS Costs by Season**

	RS	RS TOU - BGS	MGS - SEC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC
Total Costs by Rate - in $1000								
Summer	$ 108,752	$ 62	$ 25,044	$ 1,715	$ 20,648	$ 1,337	$ 871	$ 260
Winter	$ 156,650	$ 96	$ 42,247	$ 2,893	$ 34,834	$ 2,858	$ 2,380	$ 460
Total	$ 265,402	$ 159	$ 67,291	$ 4,609	$ 55,482	$ 4,195	$ 3,251	$ 720
% of Annual Total $ by Rate								
Summer	41%	39%	37%	37%	37%	32%	27%	36%
Winter	59%	61%	63%	63%	63%	68%	73%	64%
Total Costs - in $1000								
Summer	$ 158,689							
Winter	$ 242,419							
Total	$ 401,108							

% of Annual Total $		If total $ were split on a per MWh basis (on bulk system MWhs):				
Summer	40%	$ 62.04 per MWh @ trans nodes	Ratio to BGS Cost	>>>	Summer	**1.0000**
Winter	60%	$ 67.92 per MWh @ trans nodes	(rounded to 4 decimal places)		Winter	**1.0000**

Assumptions:

Gen Cost =	$50.34	per MW-day	summer
=	$50.34	per MW-day	winter
Ancillary Services =	$ 2.00	per MWH	
Renewable Power Cost =	$ 17.22	per MWH	

Energy Prices = Quotes for the period June 1, 2024 to May 31, 2025 - corrected for hub-zone basis differential.
Usage patterns = forecasted energy use by class, on/off % from class load profiles
Obligations = class totals as of June 2023
Losses = existing approved loss factors
PJM Time Periods = PJM trading time periods - 7 AM to 11 PM weekdays, local time, x NERC holidays
- New Year's, Memorial, 4th of July, Labor Day, Thanksgiving & Christmas

Table #16

Retail Rates Charged to BGS RSCP (Previously "FP") Customers
Includes energy, Generation Obligations, Ancillary Services, and Renewable Power Costs
in $/MWh

BGS Avg. Price >>>>>>>>>>> $ 85.050

	RS	RS TOU - BGS	MGS - SEC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC
Summer - all hrs		$ 95.791	$ 90.225	$ 84.390	$ 87.891	$ 83.851	$ 75.771	$ 84.300
On-Peak		$ 108.899						
Off-Peak		$ 74.604						
Block 1 (0-750 kWh/m)	$ 87.182							
Block 2 (>750 kWh/m)	$ 96.315							
Winter - all hrs	$ 91.961	$ 104.173	$ 87.945	$ 81.962	$ 85.896	$ 82.290	$ 79.257	$ 82.863
On-Peak		$ 108.845						
Off-Peak		$ 79.011						
Annual	$ 91.259	$ 87.942	$ 89.047	$ 83.094	$ 86.836	$ 83.349	$ 79.097	$ 83.689

Table #17

Retail Rates Charged to BGS RSCP Customers including Revenue Assessment and SUT
Includes energy, Generation Obligations, Ancillary Services, and Renewable Power Costs
in $/kWh
Revenue Assessment Factor 1.002639741
(BPU, RC Assessments)

	RS	RS TOU - BGS	MGS - SEC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC
Summer - all hrs			$ 0.096456	$ 0.090218	$ 0.093961	$ 0.089642	$ 0.081004	$ 0.090122
On-Peak		$ 0.116420						
Off-Peak		$ 0.079757						
Block 1 (0-750 kWh/m)	$ 0.093203							
Block 2 (>750 kWh/m)	$ 0.102967							
Winter - all hrs	$ 0.098312		$ 0.094019	$ 0.087622	$ 0.091828	$ 0.087973	$ 0.084731	$ 0.088586
On-Peak		$ 0.116363						
Off-Peak		$ 0.084468						
Annual	$ 0.097561	$ 0.094015	$ 0.095197	$ 0.088833	$ 0.092833	$ 0.089105	$ 0.084559	$ 0.089469

Attachment 3

Atlantic City Electric Company
Calculation of June 2024 to May 2025 BGS-RSCP Rates
based on results of February 2024 BGS RSCP Auction

Table A **Auction Results**

line #	**Payment Identifier >>**	*remaining portion of 36 month bid - 2022/23 filing*	*remaining portion of 36 month bid - 2023/24 filing*	*36 month bid - 2024/25 filing*	*Notes:*
1	Winning Bid - in $/MWh	$ 75.57	$ 92.17	$ 92.17	winning Bids
1A	Capacity Proxy Price True-Up - in $/MWh	$ (4.11)	$ (1.46)		entered after 2024 BGS Auction
1B	Total - in $/Mwh	$ 71.46	$ 90.71	$ 92.17	= line 1 + line 1A
2	# of Tranches for Bid	7	8	7	from then current Bid
3	Total # of Tranches	22	22	22	from then current Bid
	Payment Factors				
4	Summer	1.0000	1.0000	1.0000	from then current Bid Factor Spreadsheet
5	Winter	1.0000	1.0000	1.0000	from then current Bid Factor Spreadsheet
	Applicable Customer Usage @ bulk system - in MWh				
6	Summer MWh	2,558,051			from current Bid Factor Spreadsheet
7	Winter MWh	3,568,922			
	Total Payment to Suppliers - in $1000				
8	Summer	$ 58,163	$ 84,378	$ 75,019	= (1 + 1A) * (2)/(3) * (4) * (6) / 1000
9	Winter	$ 81,148	$ 117,723	$ 104,665	= (1 + 1A) * (2)/(3) * (5) * (7) / 1000
10	Total	$ 139,311	$ 202,101	$ 179,685	
	Average Payment to Suppliers - in $/MWh				
11	Summer	$ 85.05			= sum(line 8) / (6) - rounded to 2 decimal places
12	Winter	$ 85.05			= sum(line 9) / (7) - rounded to 2 decimal places
13	Total weighted average	**$ 85.05**	<<< used in calculation of Customer Rates		= sum(line 10) / [(6) + (7)] rounded to 2 decimal places
	Reconciliation of amounts - in $1000				
14	Weighted avg * Total MWh =	$ 521,099			= (13) * [(6)+(7)] / 1000
15	Total Payment to Suppliers =	$ 521,096			= sum (line 10)
16	Difference =	$ 3			= line (14) - line (15)

Atlantic City Electric Company
Calculation of June 2024 to May 2025 BGS-RSCP Rates
based on results of February 2024 BGS RSCP Auction

Table B **Ratio of BGS Unit Costs @ customer to Average Cost @ transmission nodes**

from Table #14 of the bid factor spreadsheet --- round to 3 decimal places

includes energy, G obligations, Ancillary Services, and Renewable Power Cost - adjusted to billing time periods

		RS	RS TOU - BGS	MGS - SEC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC
Summer - all hrs			**1.067**	**1.005**	**0.940**	**0.979**	**0.934**	**0.844**	**0.939**
	On-Peak		**1.213**						
	Off-Peak		**0.831**						
	All usage Multiplier	**1.009**							
	Constant	**(3.223)**		for Block 1 (0-750 kWh/m) usage					
	Constant	**5.429**		for Block 2 (>750 kWh/m) usage					
Winter - all hrs		**1.122**	**1.271**	**1.073**	**1.000**	**1.048**	**1.004**	**0.967**	**1.011**
	On-Peak		**1.328**						
	Off-Peak		**0.964**						
Annual - all hrs		**1.073**	**1.034**	**1.047**	**0.977**	**1.021**	**0.980**	**0.930**	**0.984**

Table C **Preliminary Resulting BGS Rates (in cents per kWh) -***equal to bid factors times weighted average bid price*
rounded to 4 decimal places

includes energy, G obligations, Ancillary Services, and Renewable Power Cost - adjusted to billing time periods

		RS	RS TOU - BGS	MGS - SEC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC
Summer - all hrs			***9.0748***	***8.5475***	***7.9947***	***8.3264***	***7.9437***	***7.1782***	***7.9862***
	On-Peak		***10.3166***						
	Off-Peak		***7.0677***						
for Block 1 (0-750 kWh/m) usage		***8.2592***							
for Block 2 (>750 kWh/m) usage		***9.1244***							
Winter - all hrs		***9.5426***	***10.8099***	***9.1259***	***8.5050***	***8.9132***	***8.5390***	***8.2243***	***8.5986***
	On-Peak		***11.2946***						
	Off-Peak		***8.1988***						

Atlantic City Electric Company
Calculation of June 2024 to May 2025 BGS-RSCP Rates
based on results of February 2024 BGS RSCP Auction

Table D **Revenue Recovery Calculations -** *Reconciliation of seasonal Customer Revenue and Supplier Payments, based on actual anticipated revenues and payments*

	RS	RS TOU - BGS	MGS - SEC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC
Total Rate Revenue - in $1000								
Summer	$ 141,237	$ 78	$ 32,534	$ 2,228	$ 26,824	$ 1,738	$ 1,131	$ 338
Winter	$ 203,556	$ 111	$ 54,884	$ 3,757	$ 45,260	$ 3,714	$ 3,093	$ 598
Total	$ 344,793	$ 189	$ 87,418	$ 5,985	$ 72,085	$ 5,451	$ 4,224	$ 935
Total Summer	$ 206,107							
Total Winter	$ 314,973							
Grand Total	$ 521,080							
Total Supplier Payment - in $1000								
Summer	$ 217,561							
Winter	$ 303,535							
Total	$ 521,096							
Differences - in $1000								
Summer	$ 11,454							
Winter	$ (11,438)							
Total	$ 16							

kWh Rate Adjustment Factors	rounded to 5 decimal places
1.05557	
0.96369	

% difference
5.2646%
-3.7682%
0.0030%

Note: These differences are due to rounding and seasonal differences in Bidder Payments (which are based on prior wining bids and Seasonal Payment Factors) and current Rates (based on current seasonal market differentials)

Atlantic City Electric Company
Calculation of June 2024 to May 2025 BGS-RSCP Rates
based on results of February 2024 BGS RSCP Auction

Table E **Final Resulting BGS Rates (in cents per kWh) -** *with preliminary kWh rates adjusted by the kWh Rate Adjustment Factor rounded to 4 decimal places*

includes energy, G obligations, Ancillary Services, and Renewable Power Cost - adjusted to billing time periods

		RS	RS TOU - BGS	MGS - SEC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC
Summer - all hrs			***9.5791***	***9.0225***	***8.4390***	***8.7891***	***8.3851***	***7.5771***	***8.4300***
	On-Peak		***10.8899***						
	Off-Peak		***7.4605***						
for Block 1 (0-750 kWh/m) usage		***8.7182***							
for Block 2 (>750 kWh/m) usage		***9.6314***							
Winter - all hrs		***9.1961***	***10.4174***	***8.7945***	***8.1962***	***8.5896***	***8.2289***	***7.9257***	***8.2864***
	On-Peak		***10.8845***						
	Off-Peak		***7.9011***						

Table F **Spreadsheet Error Checking** - *Checking of seasonal Customer Revenue and Supplier Payments, based on final actual anticipated revenues and payments*

	RS	RS TOU - BGS	MGS - SEC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC
Total Rate Revenue - in $1000								
Summer	$ 149,085	$ 82	$ 34,342	$ 2,352	$ 28,315	$ 1,834	$ 1,194	$ 356
Winter	$ 196,165	$ 107	$ 52,891	$ 3,621	$ 43,617	$ 3,579	$ 2,981	$ 576
Total	$ 345,250	$ 189	$ 87,233	$ 5,973	$ 71,932	$ 5,413	$ 4,175	$ 932
Total Summer	$ 217,561							
Total Winter	$ 303,536							
Grand Total	$ 521,097							
Total Supplier Payment - in $1000								
Summer	$ 217,561							
Winter	$ 303,535							
Total	$ 521,096							
Differences - in $1000								
Summer	$ (0)							
Winter	$ 1							
Total	$ 1							

Attachment 4

Development of Capacity Proxy Price True-Up - $/MWh

2024/2025 Delivery Year - Illustrative Data for ACE

		Capacity Proxy Price True-Up for Winning Suppliers from 2022 BGS-RSCP Auction 2024/25 Delivery Year	Capacity Proxy Price True-Up for Winning Suppliers from 2023 BGS-RSCP Auction 2024/25 Delivery Year	*Notes:*
1	**Zonal Capacity Price ($/MW-day)**	$54.50	$54.50	as may be determined by the RPM, or its successor, or otherwise
2	**Capacity Proxy Price ($/MW-day)**	$87.98	$66.38	per Board Orders dated 11/17/2021 and 11/09/2022
3	**Capacity Proxy Price True-Up - $/MW-day**	-$33.48	-$11.88	= line 1 - line 2
4	**BGS-RSCP Gen Obl - MW**	2,060.7	2,060.7	
5	**Days in Year**	365	365	
6	**Capacity Proxy Price True-Up Annual Cost**	-$25,182,717	-$8,935,803	= line 3 * line 4 * line 5
7	**Eligible Tranches**	7	8	from Table A
8	**Total Tranches**	22	22	from Table A
9	**% of tranches eligible for payment**	31.82%	36.36%	= line 7 / line 8
10	**Capacity Proxy Price True-Up Cost**	-$8,012,683	-$3,249,383	= line 6 * line 9
11	**Total Applicable Customer Usage @ bulk system - in MWh**	6,126,973	6,126,973	
12	**Eligible Customer Usage @ bulk system - *in MWh***	1,949,491	2,227,990	= line 9 * line 11
13	**Capacity Proxy Price True-Up - $/MWh**	**-$4.11**	**-$1.46**	**= line 10/ line 12 - rounded to 2 decimal places**

Development of Capacity Proxy Price True-Up - $/MWh

2025/2026 Delivery Year - Illustrative Data for ACE

		Capacity Proxy Price True-Up Development for Winning Suppliers from 2023 BGS-RSCP Auction 2025/26 Delivery Year	Capacity Proxy Price True-Up Development for Winning Suppliers from 2024 BGS-RSCP Auction (if needed) * 2025/26 Delivery Year	*Notes:*
1	**Zonal Capacity Price ($/MW-day)**	$50.00	$50.00	as may be determined by the RPM, or its successor, or otherwise
2	**Capacity Proxy Price ($/MW-day)**	$44.63	$47.46	per Board Order dated 11/09/2022 and XX/XX/2023
3	**Capacity Proxy Price True-Up - $/MW-day**	$5.37	$2.54	= line 1 - line 2
4	**BGS-RSCP Gen Obl - MW**	2,060.7	2,060.7	
5	**Days in Year**	365	365	
6	**Capacity Proxy Price True-Up Annual Cost**	$4,039,163	$1,910,517	= line 3 * line 4 * line 5
7	**Eligible Tranches**	8	7	from Table A
8	**Total Tranches**	22	22	from Table A
9	**% of tranches eligible for payment**	36.36%	31.82%	= line 7 / line 8
10	**Capacity Proxy Price True-Up Cost**	$1,468,787	$607,892	= line 6 * line 9
11	**Total Applicable Customer Usage @ bulk system - in MWh**	6,126,973	6,126,973	
12	**Eligible Customer Usage @ bulk system - *in MWh***	2,227,990	1,949,491	= line 9 * line 11
13	**Capacity Proxy Price True-Up - $/MWh**	**$0.66**	**$0.31**	**= line 10/ line 12 - rounded to 2 decimal places**

* **Winners in the 2024 BGS-RSCP Auction will only receive a true-up if results of 2025/2026 BRA are not known at least 5 business days prior to the 2024 BGS-RSCP Auction.**

Development of Capacity Proxy Price True-Up - $/MWh

2026/2027 Delivery Year - Illustrative Data for ACE

		Capacity Proxy Price True-Up Development for Winning Suppliers from 2024 BGS-RSCP Auction (if needed)* 2026/27 Delivery Year	*Notes:*
1	**Zonal Capacity Price ($/MW-day)**	$50.00	as may be determined by the RPM, or its successor, or otherwise
2	**Capacity Proxy Price ($/MW-day)**	$49.05	per Board Order dated XX/XX/2023
3	**Capacity Proxy Price True-Up - $/MW-day**	$0.95	= line 1 - line 2
4	**BGS-RSCP Gen Obl - MW**	2,060.7	
5	**Days in Year**	365	
6	**Capacity Proxy Price True-Up Annual Cost**	$714,563	= line 3 * line 4 * line 5
7	**Eligible Tranches**	7	from Table A
8	**Total Tranches**	22	from Table A
9	**% of tranches eligible for payment**	31.82%	= line 7 / line 8
10	**Capacity Proxy Price True-Up Cost**	$227,361	= line 6 * line 9
11	**Total Applicable Customer Usage @ bulk system - in MWh**	6,126,973	
12	**Eligible Customer Usage @ bulk system *- in MWh***	1,949,491	= line 9 * line 11
13	**Capacity Proxy Price True-Up - $/MWh**	**$0.12**	**= line 10/ line 12 - rounded to 2 decimal places**

* **Winners in the 2024 BGS-RSCP Auction will only receive a true-up if results of 2026/2027 BRA are not known at least 5 business days prior to the 2024 BGS-RSCP Auction.**

Table A With Additional Line Item

Calculation of June 2025 to May 2026 BGS-RSCP Rates

Illustrative Purposes Only for ACE

Table A **Auction Results**

line #	**Specific BGS-RSCP Auction >>**	*remaining portion of 36 month bid - 2023 auction*	*remaining portion of 36 month bid - 2024 auction*	*36 month bid - 2025 auction*	*Notes:*
1	**Winning Bid - in $/MWh**	$ 92.17	$ 92.17	$ 92.17	winning Bids
1A	**25/25 Capacity Proxy Price True-up - in $/MWh**	$ 0.66	$ 0.31		entered after 2025 BGS Auction
1B	**Total - in $/MWh**	$ 92.83	$ 92.48	$ 92.17	= line 1 + line 1A
2	**# of Tranches for Bid**	8	7	7	from then current Bid
3	**Total # of Tranches**	22	22	22	from then current Bid
	Payment Factors				
4	Summer	1.0000	1.0000	1.0000	from then current Bid Factor Spreadsheet
5	Winter	1.0000	1.0000	1.0000	from then current Bid Factor Spreadsheet
	Applicable Customer Usage @ bulk system - in MWh				
6	Summer MWh	2,558,051			from current Bid Factor Spreadsheet
7	Winter MWh	3,568,922			
	Total Payment to Suppliers - *in $1000*				
8	Summer	$ 86,350	$ 75,272	$ 75,019	= (1 + 1A) * (2)/(3) * (4) * (6) / 1000
9	Winter	$ 120,474	$ 105,017	$ 104,665	= (1 + 1A) * (2)/(3) * (5) * (7) / 1000
10	Total	$ 206,824	$ 180,289	$ 179,685	
	Average Payment to Suppliers - *in $/MWh*				
11	Summer	$ 92.51			= sum(line 8) / (6) - rounded to 2 decimal places
12	Winter	$ 92.51			= sum(line 9) / (7) - rounded to 2 decimal places
13	Total weighted average	**$ 92.51**	<<< used in calculation of Customer Rates		= sum(line 10) / [(6) + (7)] rounded to 2 decimal places

* **Winners in the 2024 BGS-RSCP Auction will only receive a true-up if results of 2025/2026 BRA are not known at least 5 business days prior to the 2024 BGS-RSCP Auction.**

Table A With Additional Line Item

Calculation of June 2026 to May 2027 BGS-RSCP Rates

Illustrative Purposes Only for ACE

Table A **Auction Results**

line #	**Specific BGS-RSCP Auction >>**	*remaining portion of 36 month bid - 2024 auction*	*remaining portion of 36 month bid - 2025 auction*	*36 month bid - 2026 auction*	*Notes:*
1	**Winning Bid - in $/MWh**	$ 92.17	$ 92.17	$ 92.17	winning Bids
1A	**26/27 Capacity Proxy Price True-up - in $/MWh**	$ 0.12			entered after 2026 BGS Auction
1B	**Total - in $/MWh**	$ 92.29	$ 92.17	$ 92.17	= line 1 + line 1A
2	**# of Tranches for Bid**	7	7	8	from then current Bid
3	**Total # of Tranches**	22	22	22	from then current Bid
	Payment Factors				
4	Summer	1.0000	1.0000	1.0000	from then current Bid Factor Spreadsheet
5	Winter	1.0000	1.0000	1.0000	from then current Bid Factor Spreadsheet
	Applicable Customer Usage @ bulk system - in MWh				
6	Summer MWh	2,558,051			from current Bid Factor Spreadsheet
7	Winter MWh	3,568,922			
	Total Payment to Suppliers *- in $1000*				
8	Summer	$ 75,117	$ 75,019	$ 85,737	= (1 + 1A) * (2)/(3) * (4) * (6) / 1000
9	Winter	$ 104,801	$ 104,665	$ 119,617	= (1 + 1A) * (2)/(3) * (5) * (7) / 1000
10	Total	$ 179,919	$ 179,685	$ 205,354	
	Average Payment to Suppliers *- in $/MWh*				
11	Summer	$ 92.21			= sum(line 8) / (6) - rounded to 2 decimal places
12	Winter	$ 92.21			= sum(line 9) / (7) - rounded to 2 decimal places
13	Total weighted average	**$ 92.21**	<<< used in calculation of Customer Rates		= sum(line 10) / [(6) + (7)] rounded to 2 decimal places

* **Winners in the 2024 BGS-RSCP Auction will only receive a true-up if results of 2026/2027 BRA are not known at least 5 business days prior to the 2024 BGS-RSCP Auction.**

In the Matter of the Provision of Basic Generation Service for the Period Beginning June 1, 2024
BPU Docket No. ER23030124
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