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PSEG
Services Corporation

VIA BPU E-FILING SYSTEM & OVERNIGHT MAIL

May 31, 2019

In the Matter of Public Service Electric and Gas Company's 2019/2020
Annual BGSS Commodity Charge Filing for its Residential Gas Customers
Under its Periodic Pricing Mechanism and for Changes in its Balancing Charge

Docket No. GR_____________

Aida Camacho-Welch, Secretary
New Jersey Board of Public Utilities
44 South Clinton Avenue, 3rd Floor, Suite 314
Post Office Box 350
Trenton, New Jersey 08625-0350

Dear Secretary Camacho-Welch:

Enclosed for filing please find an original and two copies of Public Service Electric and Gas Company's ("Public Service") Motion, Testimony of David F. Caffery, Testimony of Stephen Swetz, and supporting attachments in the above-referenced matter, which have been uploaded to the Board of Public Utilities' E-Filing system. In this filing, Public Service is requesting a decrease in annual BGSS gas revenues of approximately $12 million (excluding losses and New Jersey Sales and Use Tax or "SUT") to be implemented for service rendered on and after October 1, 2019, or earlier should the Board deem it appropriate. The Company is also requesting two changes in its Balancing Charge; first, a change in the balancing period from the current five billing months of November to March to the eight billing months of October to May; and secondly, a change in the Balancing Charge rate. The combined impact of the proposed changes on a typical residential heating customer using 172 therms per month during the winter months and 1,040 therms on an annual basis is an annual decrease of approximately 0.66%.

This filing and the proposed BGSS rate is in accordance with the Board's January 6, 2003 Order Approving BGSS Price Structure, Docket No. GX01050304. Moreover, this filing includes the Minimum Filing Requirements as approved by the Board.

Respectfully submitted,

Matthew M. Weissman

C Attached Service List (electronic)

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1. Motion, Supporting Testimony & Tariff Modifications

Motion – dated May 31, 2019

Testimony of David F. Caffery – Attachment A-1

Testimony of Stephen Swetz – Attachment A-2

Tariff Sheets – Attachment B

STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

IN THE MATTER OF PUBLIC SERVICE	)	
ELECTRIC AND GAS COMPANY'S	)	MOTION
2019/2020 ANNUAL BGSS COMMODITY	)	
CHARGE FILING FOR ITS RESIDENTIAL	)	
GAS CUSTOMERS UNDER ITS PERIODIC	)	DOCKET NO. GR____________
PRICING MECHANISM AND FOR CHANGES	)	
IN ITS BALANCING CHARGE	)	

Public Service Electric and Gas Company ("PSE&G" or "Company"), a public utility of the State of New Jersey, with its principal offices for the transaction of business at 80 Park Plaza Newark, New Jersey 07101, hereby moves before the New Jersey Board of Public Utilities ("Board") as follows:

PSE&G, as a combination electric and gas utility, is engaged in the purchase, transmission, distribution and sale of natural gas for residential, commercial and industrial customers in New Jersey, in addition to its electric operations.

GENERIC PROCEEDING ON BGSS PRICE STRUCTURE

1) On January 6, 2003, as the result of a generic proceeding, the Board issued its Order Approving the BGSS Price Structure in Docket No. GX01050304 ("BGSS Pricing Structure Order"), in which the Board approved procedures providing for annual Basic Gas Supply Service ("BGSS") Commodity Charge filings by the Company and all the other New Jersey gas distribution companies by June 1, 2003 and each year thereafter, and for two potential 5% self-implementing rate increases on December 1st and the following February 1st. These two limited self-implementing rate adjustments would be permitted each year upon notice to the Board and the New Jersey Division of Rate Counsel ("Rate Counsel") on

November 1st and January 1st of the estimated change to take effect on December 1st and February 1st, respectively.

MINIMUM FILING REQUIREMENTS

2) In addition the Board, in its January 16, 2003 Order Adopting Provisional Rates in Docket No. GR02090702, reserved an issue to itself by directing that the parties to that proceeding meet to develop mutually agreed upon minimum filing requirements for future annual BGSS Commodity Charge petitions in time for the next petition.

3) The parties to that proceeding agreed on a list of 17 annual BGSS Minimum Filing Requirements that are applicable to the Company's June 1st annual BGSS filing. The parties included those Minimum Filing Requirements in a settlement that was approved by the Board on June 20, 2003. Also, as part of the BGSS settlement in Docket No. GR15060647 approved by the Board on February 24, 2016, Item 18 has been added to address the Company's Gas Supply Plan. Lastly, as part of the BGSS settlement in Docket No. GR17060589 approved by the Board on April 25, 2018, the parties to that proceeding agreed to modifications to Item Nos. 13 and 18.

2018/2019 ANNUAL BGSS COMMODITY CHARGE FILING

4) On June 1, 2018, the Company made its 2018/2019 Annual BGSS Commodity Charge filing for its Periodic Pricing Mechanism applicable to its residential gas customers pursuant to the BGSS Pricing Structure Order. The filing was also made in accordance with the above-referenced Minimum Filing Requirements.

5) In the 2018/2019 BGSS filing the Company requested a decrease in the then current BGSS Commodity Charge rate of $0.368938 cents per therm (including losses and Sales and Use

Tax or "SUT") to $0.349579 cents per therm (including losses and SUT) effective October 1, 2018 to remain in effect through September 30, 2019. This request was supported by the direct testimony of David F. Caffery, in which he addressed all of the Minimum Filing Requirements and provided the basis for the decrease in the BGSS rate.

6) The Company also requested an increase in its Balancing Charge, which recovers the cost of providing storage and peaking services, from the then current charge of $0.090052 per therm (including losses and SUT) to $0.102825 per therm (including losses and SUT). This charge was also supported by the direct testimony of Mr. Caffery, and is applicable only for the period November through March.

7) The Company requested a decrease in its Storage Inventory Carrying Charge which is recovered through the balancing and commodity charges. The requested charge was $0.004352 per therm (excluding losses and SUT) for the balancing portion and $0.006323 per therm (excluding losses and SUT) for the commodity portion using the applicable billing determinants for each.

8) The 2018/2019 filing by the Company also included the Company's estimated decrease in BGSS revenue of approximately $24.8 million (excluding losses and SUT) required for the period of October 1, 2018 through September 30, 2019.

9) Residential annual bills comparing the current and proposed BGSS charge and the Balancing Charge, pursuant to the 2018/2019 filing were included in the form of public notice attached as Attachment C to that motion.

10) Notice setting forth the Company's June 1, 2018 request for the BGSS Commodity Charge decrease and Balancing Charge increase, including the date, time, and place of the public

hearings, was placed in newspapers having a circulation within PSE&G's gas service territory, and was served on the county executives and clerks of all municipalities within its gas service territory.

11) Public hearings were scheduled and conducted in New Brunswick, Hackensack, and Mt. Holly on August 21, 27, and 29, 2018, respectively. Six members of the public spoke and expressed general concerns regarding utility bills and service shutoffs for lack of payment. No member of the public commented specifically on the BGSS filing.

12) Subsequent to the June 1, 2018 filing, the Company made a compliance filing on August 31, 2018 in response to the Board's Order in the Company's petition for Approval of Electric and Gas Base Rate Adjustments Pursuant to the Energy Strong Program ("Energy Strong Matter") in BPU Docket Nos. ER18040358 and GR18040359. As a result of the settlement of the Energy Strong Matter, the Company's BGSS-RSG Commodity Charge was decreased from $0.368938 per therm (including losses and SUT) to $0.368937 per therm (including losses and SUT) effective September 1, 2018.

13) PSE&G, Board Staff, and Rate Counsel agreed, on a provisional basis, to implement the BGSS-RSG Commodity Charge and Balancing Charge as of October 1, 2018, or as soon as possible upon the issuance of a Board Order approving the Stipulation for a Provisional BGSS Rates ("Provisional Stipulation"). The Provisional Stipulation was approved at the Board agenda meeting on September 17, 2018. The BGSS Commodity Charge was provisionally decreased from $0.368937 per therm (including losses and SUT) to $0.349579 per therm (including losses and SUT) for service rendered on and after October 1, 2018. The BGSS Balancing Charge was provisionally increased from $0.090052 per therm

(including losses and SUT) to $0.102825 per therm (including losses and SUT) for service rendered on and after October 1, 2018.

14) Subsequent to the Board's approval of the Provisional Stipulation, PSE&G made compliance filings in response to the Board's Orders in the Company's petitions in two matters. First, on October 30, 2018, PSE&G made a compliance filing *In the Matter of the Petition of Public Service Electric and Gas Company for Approval of an Increase in Electric and Gas Rates and for Changes in the Tariffs for Electric and Gas Service, B.P.U.N.J. No. 16 Electric and B.P.U.N.J. No. 16 Gas, and for changes in Depreciation Rates, pursuant to N.J.S.A. 48:2-18 N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1, and for Other Appropriate Relief* in BPU Docket Nos. ER18010029 and GR18010030. In this matter, the BGSS-RSG Commodity Charge was decreased from the provisionally approved rate of $0.349579 per therm (including losses and SUT) to $0.349129 per therm (including losses and SUT) effective November 1, 2018.

15) Second, on December 28, 2018, PSE&G made a compliance filing *In the Matter of the Petition of Public Service Electric and Gas Company for approval of Gas Base Rate Adjustments Pursuant to its Gas System Modernization Program ("GSMP")* under BPU Docket No. GR18070831. As a result of the settlement of this GSMP matter, PSE&G's BGSS-RSG Commodity Charge was further decreased from $0.349129 per therm (including losses and SUT) to $0.349059 per therm (including losses and SUT) effective January 1, 2019.

16) PSE&G, Board Staff, and Rate Counsel subsequently completed their review of the Company's 2018/19 BGSS filing, and agreed that the Company's: (a) BGSS Commodity Service, tariff rate

BGSS-RSG of $0.349059 per therm (including losses and SUT) would be deemed final; and (b) Balancing Charge of $0.102825 per therm (including losses and SUT) would also be deemed final. The Board approved this stipulation for final rates on March 29, 2019.

<u>2019/2020 ANNUAL BGSS COMMODITY CHARGE FILING</u>

17) The Company is making this 2019/2020 Annual BGSS Commodity Charge filing for its Periodic Pricing Mechanism applicable to its residential gas customers pursuant to the BGSS Pricing Structure Order. This filing is also made in accordance with the above-referenced Minimum Filing Requirements.

18) In this Motion the Company is requesting a decrease in the current BGSS rate of $0.349059 cents per therm (including losses and SUT) to $0.340221 cents per therm (including losses and SUT) effective October 1, 2019 and to remain in effect through September 30, 2020. This request is supported by the direct testimony of David F. Caffery attached hereto as Attachment A-1, in which he addresses the Minimum Filing Requirements and demonstrates the need for the change in the BGSS rate.

19) The Company is also requesting two changes in its Balancing Charge, which recovers the cost of providing storage and peaking services. First, the Company requests a change in the balancing period from the current five billing months of November to March to the eight billing months of October to May. Second, the Company requests a change in the Balancing Charge from $0.102825 per balancing use therm (including losses and SUT) based on the current five month balancing period to $0.098620 per balancing use therm (including losses and SUT) based on the eight month balancing period. For illustrative purposes, the Company has also calculated an updated five-month Balancing Charge of

$0.113187 per balancing use therm (including losses and SUT) to demonstrate the required change in rate from the current $0.102825 due to changes in costs. The modification of the balancing period is supported by Mr. Swetz (Attachment A-2) and the change in the balancing charge is supported by Mr. Caffery (Attachment A-1).

20) The Company is also requesting a change in its Storage Inventory Carrying Charge, which is shown on page 2 of Attachment D-1 and is recovered through the Balancing and Commodity Charges. The requested charge is $0.003871 per balancing use therm (excluding losses and SUT) for the balancing portion (inclusive of the proposed eight-month balancing period) and $0.006486 per therm (excluding losses and SUT) for the commodity portion using the applicable send out for each.

21) Price levels in the natural gas market have decreased marginally from the levels in effect last year at this time. As illustrated on Item 8 herein, the NYMEX price for June 2019 is 7.8% lower this year as compared to last year, and the average monthly price for the entire forecasted period is 2.9% lower this year as compared to last year. The May 9, 2019 forward NYMEX strip used by the Company in this filing shows that prices are expected to rise modestly from current levels through the first quarter of 2020, followed by a reduction for the balance of the BGSS period. One of the primary drivers for this decrease in prices compared to last year's levels is the record natural gas production witnessed over the past six months. In fact, an all-time high production level of 87 Bcf/d was achieved just recently, accounting for much of the reason why prices have remained moderate despite national storage levels 20% below the five-year average. These lower anticipated commodity price levels based on the NYMEX strip has helped to offset the increase in pipeline rates put in

place by both Transco and Texas Eastern, allowing the Company to propose the decrease in rates to the RSG customers.

22) The Company estimates that a decrease in BGSS revenue of approximately $12 million (excluding losses and SUT) would be required for the period of October 1, 2019 and September 30, 2020.

23) Residential annual bills comparing the current and proposed BGSS charge and Balancing Charge (inclusive of the proposed change to an eight-month balancing period) are included in the form of public notice attached hereto as Attachment C. The impact of the requested BGSS-RSG Charge and Balancing Charge changes for a typical residential gas heating customer using 172 therms per month during the winter months and 1,040 therms on an annual basis is a decrease in the winter monthly bill of approximately 1.48%, and on an annual basis the impact is a decrease of approximately 0.66%. Moreover, pursuant to paragraph 10 of the BGSS Pricing Structure Order, the attached public notice also states that such proposed rates may be subject to self-implementing rate increases of up to 5% on December 1, 2019 and February 1, 2020. The impact of such potential self-implementing increases on an average residential bill (1,200 therms annually) would be an increase of approximately $8.45 for a winter month on December 1, 2019 and an additional approximate increase of $8.44 per winter month on February 1, 2020.

24) For illustrative purposes, the Company has calculated an updated five month Balancing Charge rate of $0.113187 per balancing use therm (including losses and SUT). The impact of the requested BGSS-RSG Charge and Balancing Charge changes for a typical residential gas heating customer using 172 therms per month during the winter months and 1,040

therms on an annual basis is a decrease in the winter monthly bill of approximately 0.02%, and on an annual basis the impact is a decrease of approximately 0.29%. The impact of the potential self-implementing increases described in the previous paragraph on an average residential bill (1,200 therms annually) would be an increase of approximately $8.48 for a winter month on December 1, 2019, and an additional approximate increase of $8.48 per winter month on February 1, 2020. The illustrative bill impacts are also included in the form of public notice attached hereto as Attachment C.

25) The proposed tariff sheets (redlined and non-redlined) to implement the above request are attached hereto as Attachment B.

26) A notice setting forth the request for the BGSS-RSG Commodity Charge and Balancing Charge changes and public hearing dates will be placed in newspapers having a circulation within the Company's gas service territory, and notice of this filing will be served on the County Executives and Clerks of all municipalities within the Company's gas territory upon the receipt, scheduling, and publication of hearing dates. A copy of the form of notice is attached hereto as Attachment C.

CONCLUSION

WHEREFORE, Public Service hereby requests that the Board issue a written Order by October 1, 2019 approving:

(1) a decrease in the Company's BGSS-RSG Commodity Charge from the current charge of $0.349059 per therm (including losses and SUT) to a charge of $0.340221 per therm (including losses and SUT);

(2) the modification of the balancing period from the current five billing months of November to March to the eight billing months of October to May;

(3) a change in the Balancing Charge from $0.102825 per therm (including losses and SUT) to $0.098620 per balancing use therm (including losses and SUT) effective with the billing month of October 2019;

(4) the extension of the pricing mechanism approved in the BGSS Pricing Structure Order as requested herein;

(5) the modifications to the Tariff for Gas Service, B.P.U.N.J. No. 16 Gas, pursuant to N.J.S.A, 48:2-21 and 48:2-21.1, that are set forth in Attachment B to this Motion.

Respectfully submitted,

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Original signed by
BY: Matthew M. Weissman, *Esq.*
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General State Regulatory Counsel
PSEG Services Corporation
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DATED: May 31, 2019
Newark, New Jersey

STATE OF NEW JERSEY)
ss:
COUNTY OF ESSEX)

DAVID F. CAFFERY of full age, being duly sworn according to law, on his oath deposes and says:

1. I am David F. Caffery for PSEG Energy Resources and Trade LLC who is filing this testimony on behalf of Public Service Electric and Gas Company.

2. I have read the annexed Motion and the matters contained therein, and they are true to the best of my knowledge and belief.

Original signed by David F. Caffery

DAVID F. CAFFERY

Sworn to and subscribed to
before me this 31st day of
May, 2019

Original signed by
Deborah S. Marks

DEBORAH S. MARKS
Notary Public
State of New Jersey
My Commission Expires June 3, 2023
ID# 2374254

STATE OF NEW JERSEY)
ss:
COUNTY OF ESSEX)

STEPHEN SWETZ of full age, being duly sworn according to law, on his oath deposes and says:

1. I am Stephen Swetz for PSEG Services Corporation who is filing this testimony on behalf of Public Service Electric and Gas Company.

2. I have read the annexed Motion and the matters contained therein, and they are true to the best of my knowledge and belief.

Original signed by Stephen Swetz

STEPHEN SWETZ

Sworn to and subscribed to
before me this 31st day of
May, 2019

Original signed by
Deborah S. Marks

DEBORAH S. MARKS
Notary Public
State of New Jersey
My Commission Expires June 3, 2023
ID# 2374254

ATTACHMENT A-1

TESTIMONY
OF
DAVID F. CAFFERY
VICE PRESIDENT – GAS SUPPLY

OVERVIEW

My qualifications are attached as Schedule DFC-1. This testimony supports Public Service Electric and Gas Company's ("PSE&G" or "Company") Motion for a decrease in its Basic Gas Supply Service (BGSS) default Commodity Charge applicable to residential (RSG) customers. The requested decrease for BGSS-RSG Commodity Service is from the current charge of $0.349059 per therm (including losses and New Jersey Sales and Use Tax or "SUT" to a charge of $0.340221 per therm (including losses and SUT). The Company is also requesting two changes in its Balancing Charge, which recovers the cost of providing storage and peaking services. First, a change in the balancing period from the current five billing months of November to March to the eight billing months of October to May. Secondly, the Company requests a change in the Balancing Charge from $0.102825 per balancing use therm (including losses and SUT) based on a five-month balancing period to $0.098620 per balancing use therm (including losses and SUT) based on the proposed eight-month balancing period. The change in the balancing period is supported by Mr. Swetz (Attachment A-2) and the change in the rate is supported by the schedules provided with my testimony.

These charges are requested to be effective on October 1, 2019, or earlier should the Board deem it appropriate, and would remain in effect until the earlier of September 30, 2020 or the effective date of the Company's next periodic BGSS Commodity Charge filing, subject to the potential self-implementing increases discussed in the

Company's Motion. The revenue impact of the BGSS reduction is approximately $12 million (excluding SUT). Also provided in Attachment D-1 are schedules that support the proposed changes (on an eight-month basis) to the Balancing Charge and Storage Inventory Carrying Charge. In addition, Attachment D-2 is the same calculation, but based on the current five-month period of November to March for illustrative purposes. The combined annual bill impact of the proposed changes is a decrease of approximately 0.66% on a typical residential gas heating customer using 172 therms per month during the winter months and 1,040 therms annually.

The RSG customer class is expected to be over recovered by $3.0 million by September 30, 2019. This period began with an under recovery of $3.9 million (there was no interest rollover).

The filing herein complies with the provisions of the annual BGSS Minimum Filing Requirements (comprised of 17 items) in Docket No. GR02090702, approved by the Board on June 20, 2003 (Minimum Filing Requirements Settlement). Since Item 1 is the Company's Motion, Testimony and Tariff Sheets, Items 2 through 17 are discussed below.

As part of the settlement of the 2015-2016 BGSS proceeding the Parties agreed to the following: Beginning with the 2016-2017 BGSS period, the Company agrees to prepare a Gas Supply Plan with details concerning the Company's objectives, approach, and plans for supplying gas to its residential customers. The Gas Supply Plan (Item 18) will include the following elements:

- *Gas Procurement Objectives*
- *Current and Forecasted Gas Service Requirements*
- *Projected Sources of Capacity*
- *Affiliate Relationships/Asset Management*

- *Hedging Plan and Strategy*
- *Capacity Releases/Off-System Sales*

More recently, as part of the settlement of the 2016-2017 BGSS proceeding, the parties agreed to the following: PSE&G agrees that as part of providing the forgoing, in its 2017-2018 and subsequent BGSS filings, it will provide specific information regarding changes to the Company's pipeline transportation and storage capacity portfolio that are planned or under construction that could impact the costs to be included in the annual BGSS filings. If information to be provided pursuant to the forgoing requires confidential treatment, PSE&G will withhold such information until an agreement of non-disclosure is in place. In addition, as part of the settlement of the 2017-2018 BGSS proceeding, the parties agreed that: MFR Item No. 18 (Gas Supply Plan) shall include a listing of all existing pipeline and storage capacity contracts for which the Company has given notice to extend or terminate during the previous 12 months, and all contracts that were extended under evergreen provisions during the same period.

2. <u>Computation of Proposed BGSS Rates</u>

This summary schedule shows the forecasted BGSS cost components and applicable credits that comprise the basis for the proposed BGSS rate to become effective October 1, 2019. Additional details on the cost components and applicable credits are provided in several of the other items, as specified in the Minimum Filing Requirements Settlement. This schedule computes the BGSS Commodity Charge to residential gas customers based on all the forecasted gas cost components and applicable credits using forecasted sendout. Also included is an adjustment for the prior period over recovery, which is the result of a comparison of actual revenue recovered to actual cost (including applicable credits). Interest for the period is positive, therefore $132 thousand has been included.

Price levels in the natural gas market have decreased marginally from the levels in effect last year at this time. As illustrated on Item 8 herein, the NYMEX price for June 2019 is 7.8% lower this year as compared to last year, and the average monthly price for the entire forecasted period is 2.9% lower this year as compared to last year. The May 9, 2019 forward NYMEX strip used by the Company in this filing shows that prices are expected to rise modestly from current levels through the first quarter of 2020, followed by a reduction for the balance of the BGSS period. One of the primary drivers for this decrease in prices compared to last year's levels is the record natural gas production witnessed over the past six months. In fact, an all-time high production level of 87 Bcf/d was achieved just recently, accounting for much of the reason why prices have remained moderate despite national storage levels 20% below the five-year average. These lower anticipated commodity price levels based on the NYMEX strip, combined with the projected Transco refund during the BGSS period, have helped to offset the increase in pipeline rates put in place by both Transco and Texas Eastern, allowing the Company to propose the decrease in rates to the RSG customers.

3. <u>Public Notice with Proposed Impact on Bills</u>

Included as Attachment C is a copy of the Company's Public Notice with details concerning the impact of the proposed BGSS-RSG rate and the proposed change to the balancing period and balancing charge on typical residential gas bills at various winter therm utilization levels. The Notice includes a table showing the impacts at various levels and also a reference to the possibility of self-implementing BGSS Commodity increases of 5% on December 1, 2019 and February 1, 2020, respectively, with the impact of those possible increases.

4. Actual and Forecasted Refund Amounts

The first schedule of Item 4 shows actual supplier refunds, totaling approximately $489 thousand, that were credited to BGSS-RSG recovery costs from May 2018 through the date of this filing. The second schedule shows that the Company has included a projected refund of $20 million associated with an anticipated settlement of the Transco rate case. This amount would represent a refund of the costs paid by the Company above the settlement rates for the locked-in refund period. The Company anticipates that both the Transco and Texas Eastern rate cases will result in a settlement agreement among the pipeline, FERC Staff, and the parties to the cases sometime during the BGSS period. This would result in the pipelines putting the lower settled rates into effect and then refunding the amounts that customers paid in excess of those settled rates during the locked in period. For Transco, as noted above, the Company has included this refund during the BGSS period. For Texas Eastern, the Company does not believe that it will receive a refund during the BGSS period and therefore a projected refund is not included. These assumptions are due to both the Texas Eastern case having been filed three months after the Transco case, and the Company's belief that the Texas Eastern case will be more contentious and therefore more difficult to resolve through a settlement. These two schedules are intended to show the actual and forecasted refunds that are received by the Company as the result of various FERC proceedings and returned to the residential customers through the BGSS Commodity Charge.

5. Cost of Gas Sendout by Component

This schedule includes monthly data showing the derivation of all cost components used to calculate the BGSS residential sendout for the projected period. The individual components are utilized to derive inventory values, which form the basis of the over/under collection for the period. All of the fixed and variable charges are allocated proportionately to the residential and commercial and industrial ("C&I") customer groups monthly based on the estimated firm sendout, and are trued up when the actual firm sendout is available. Each class of customers also shares equitably in any applicable credits or contributions that serve to lower gas costs, with the exception that contributions from CSG service provided to PSEG Power's New Jersey generation facilities are credited 100% to the Company's residential gas customers. The gas costs are similarly allocated to the respective customer classes following the direct allocation of any volumes hedged exclusively for the residential category.

6. <u>BGSS Contribution and Credit Offsets</u>

This schedule provides monthly data showing the derivation of all BGSS cost offsets, including interruptible margins, off-system sales and capacity release transactions, pipeline refunds, and other credits. Included are the credits for each of the interruptible services, showing the actual credits, and the estimated credits as calculated pursuant to the Board-approved rate schedule, where applicable. These total contribution amounts serve as a credit against the total gas costs for the residential customer and are used to set the initial BGSS rate. The actual contributions are calculated monthly and, along with the actual gas costs incurred, are compared to the revenues collected and are reflected in the over/under recovery amounts for the customers as noted in Item 7 below.

7. <u>Over/Under Recovery Comparisons</u>

The schedules under this Item provide the derivation of the monthly over or under recoveries plus cumulative balances for the reconciliation and projected period. For the reconciliation period, one schedule also shows the calculation of the monthly actual or estimated accrued interest. The net interest calculated during the October 2018 to September 2019 period is positive and therefore has been included in the calculation of the new BGSS charge on Item 2. There are two schedules that include data shown for the projected period: One of these schedules shows the projected over/(under) recovery based on the current BGSS rate. The second is based on the filed BGSS rate that is necessary to achieve a zero balance at September 2020. Also included are supporting workpapers for the reconciliation period.

8. <u>Wholesale Gas Pricing Assumptions</u>

This schedule details the monthly gas prices for the end of the reconciliation period through September 2019 and the projected period through September 2020, along with a comparison of these prices with the prices included in the current BGSS rate (from last year's BGSS filing) which indicates a decrease of approximately 2.9%. These estimates reflect the future NYMEX prices on May 9, 2019, when this analysis was done.

9. <u>GCUA Recoveries and Balances</u>

This schedule is no longer necessary since the Gas Cost Underrecovery Adjustment (GCUA) recovery has been completed.

10. <u>Historical Service Interruptions</u>

This schedule provides the details of all service interruptions during the past 12 months. Included are all of the interruptible transportation and sales services, as well as the date and duration of the interruption and the number of customers affected.

11. <u>Gas Price Hedging Activities</u>

Included in this Item are the Company's last four quarterly hedging reports as filed with the Board. The reports provide gas purchase volume requirements and price-hedged volumes broken down into the Non-Discretionary Method and the Dollar Budget

Method. As agreed to in the settlement of the 2009/2010 BGSS proceeding, the Company has revised the Quarterly Hedging Report beginning with the June 30, 2010 report. The revised report provides more detail, including data on targets and a comparison of the two hedging methods.

The Company continues to utilize hedging as a means to stabilize the price of gas to the residential customer. The consistent goal of the program is to assure a reasonable level of price stability, not necessarily achieving the lowest possible price. The Company, to date, has locked in prices for approximately 98% of its planned volume for the 2019 summer period, approximately 69% of its planned volume for the 2019-2020 winter period, and approximately 41% of its planned volume for the 2020 summer period. Hedging for the 2020-2021 winter period has just begun in May 2019. The goal of the Company's hedging activities is to achieve a stable price through a disciplined hedging strategy that will, in the long run, result in a competitive price for the customer.

12. <u>Storage Gas Volumes, Prices and Utilization</u>

These schedules provide the Company's monthly data for LNG, LPG, and pipeline storage volumes. For the LNG and LPG, the schedules show volumes and dollars for balances at the various locations where the product is stored. The attached schedule for storage activity shows the ending balances for each storage service the Company has under contract. The Company does not value storage services individually, but treats them collectively as a total inventory.

13. <u>Affiliate Gas Supply Transactions</u>

As agreed to in the settlement of the 2017/18 BGSS proceeding Item 13 now outlines all the principal terms of the Gas Requirements Contract between PSE&G and PSEG

ER&T which provides BGSS services for all of PSE&G's gas customers. There have been no changes to any of the terms and provisions of the Gas Requirements Contract since last year's BGSS filing.

14. <u>Supply and Demand Data</u>

Included in this schedule is the Company's Supply/Demand data that shows the Company's firm requirements and gas supplies by component on an annual, heating season, and non-heating season basis.

15. <u>Actual Peak Day Supply and Demand</u>

Included in this schedule is the data for the five highest demand days for each of the last three years, showing the date, the temperature, firm and interruptible volumes, and the sources of supply used to meet the associated volume requirement.

16. <u>Capacity Contract Changes</u>

Included in this schedule are the most recent peak day forecast and the supplies to be utilized to meet these requirements. Also included are the details for the current winter season concerning any changes to interstate pipeline contracts (entitlements, storage capacities, daily deliverability, or transportation) and the forecast for the next four winter seasons. Also, as agreed to in the settlement of the 2009/2010 BGSS proceeding, the Company has included extensive details on the forecast and forecasting process.

17. <u>FERC Pipeline Activities</u>

The attached schedule includes details on pending FERC dockets that would affect the cost of services received from the Company's interstate pipelines. The Company has also provided details concerning its participation in such dockets and included a listing of any filings or testimony made by or on behalf of the Company. The Company's two major pipeline suppliers, Transco and Texas Eastern, have both filed rate cases at the FERC resulting in increased rates to the various transportation and storage services that the Company obtains from these pipelines. PSE&G's assumptions regarding these rate cases are set forth in the discussion of Item 4, above.

18. Gas Supply Plan

As discussed earlier herein, Item 18 consists of an overview of the Company's Gas Supply Plan, which provides additional information regarding the Company's procurement activities, supply planning, forecasted requirements, hedging activities, and capacity release and off-system sales.

OTHER CHARGES

Attachment D-1 includes the supporting information for a change in the Balancing Charge based on the new proposed eight-month period of October to May, which is comprised of three components: Annual Allocated Costs for storage and peaking supplies (page 1), Storage Inventory Carrying Charge (page 2), and Revenue Requirement on Production Plants (page 3). In addition, Attachment D-2 is the same calculation, but based on the current five-month period of November to March for illustrative purposes.

The Balancing Charge is applicable to rate schedules RSG, GSG, LVG, and CSG where applicable and recovers the cost of providing storage and peaking services. The requested change is from the current Balancing Charge of $0.102825 cents per balancing therm (including losses and SUT) to an eight-month Balancing Charge of $0.098620 cents per balancing therm (including losses and SUT). Attachment D-1 provides the detail and support for this change, which is summarized on the bottom of page 1. The requested Balancing Charge is applicable for the proposed period of October through May. For illustrative purposes, Attachment D-2 provides that same calculation but for a five-month balancing period.

The base Balancing Charge includes the annual allocated cost for transportation, storage and peaking supplies used by the Company to meet the requirements of its customers. The requested charge is $0.084350 cents per balancing therm (excluding losses and SUT), which is a decrease from the previous charge of $0.087480 cents per balancing therm (excluding losses and SUT). The decrease is the result of the proposed eight-month period. For illustrative purposes, Attachment D-2 provides that same information but for a five-month balancing period.

The Storage Inventory Carrying Charge is shown on page 2 and is recovered in the balancing and commodity charges. The requested charge is $0.003871 cents per balancing therm (excluding losses and SUT) for the balancing portion and $0.006486 cents per therm (excluding losses and SUT) for the commodity portion (included in Item 2) using the applicable billing determinants for each. The current charges are $0.004352 cents per balancing therm for Balancing (using a five-month balancing period) and $0.006323 cents per therm for Commodity (excluding losses and SUT). For illustrative purposes, Attachment D-2 provides the requested rate based on a five-month balancing period.

The revenue requirement on Production Plant is shown on page 3 and the requested charge is $0.002421 cents per therm (excluding losses and SUT), which is a decrease from the previous charge of $0.002675 cents per therm (excluding losses and SUT). The decrease is the result of the proposed eight-month period. For illustrative purposes, Attachment D-2 provides the requested rate based on a five-month balancing period. The increased total revenue requirement for Production Plant is due to an increase in O&M costs associated with the Company's peak shaving facilities. At the Company's Burlington LNG facility, the Company will be repairing a vaporizer to continue to provide reliable peak day service. At all four of the Company's LPA facilities -- Camden, Central, Harrison and Linden -- the Company will be making modifications to the truck unloading facilities. Finally, at Central and Harrison the Company will be painting as part of regular O&M for those facilities.

Also included in Attachment D is a decrease in the A&G charge. This change is included in Item 2. The current rate is $0.03698 per dth and the updated rate is $0.03566 per dth. This rate recovers the administrative cost associated with PSEG Energy Resources & Trade's provision of gas supply services to PSE&G.

CONCLUSION

The Company's filing should be approved as reasonable and fully supported. The Company will respond to any reasonable requests for additional data. The Company seeks a Board Order by October 1, 2019, or earlier should the Board deem it appropriate, decreasing the Company's BGSS-RSG Commodity Charge from the current charge of $0.349059 per therm (including losses and SUT) to a charge of $0.340221 per therm (including losses and SUT) and approve the modification of the Balancing period from the current five billing months of November to March to the eight billing months of October to May, in addition to a decrease in the Balancing Charge from $0.102825 per therm (including losses and SUT) to $0.098620 per therm (including losses and SUT) effective with the billing month of October 2019.

SCHEDULE DFC-1

PROFESSIONAL QUALIFICATIONS
OF
DAVID F. CAFFERY
VICE PRESIDENT – GAS SUPPLY

My name is David F. Caffery and my business address is 80 Park Plaza, Newark, New Jersey 07102-0570. I am the Vice President – Gas Supply for PSEG Energy Resources and Trade LLC (PSEG-ERT).

In May 1977, I graduated from Lafayette College with a Bachelor of Science degree in Civil Engineering. In 1982, I received a Master of Business Administration degree in Finance from Fairleigh Dickinson University. I began my employment with Public Service Electric and Gas Company in July 1977 as an Associate Engineer in the Fuel Supply Department. During the period from 1977 through 1998 I received a series of promotions to the level of Manager - Gas Supply in April 1998. In June 2002, as a result of the transfer of the gas supply contracts, I became an employee of PSEG-ERT. I was promoted to Director – Portfolio Management & Regulatory in March 2007. I assumed my present position in March 2017. In my present position I am responsible for all aspects of the BGSS and Fuels activities conducted by PSEG-ERT.

I am a member of the American Gas Association, having served as past Chairman of its Federal Regulatory Committee during 2016. I have provided testimony before the Federal Energy Regulatory Commission and the New Jersey Board of Public Utilities.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
DIRECT TESTIMONY
OF
STEPHEN SWETZ
SR. DIRECTOR – CORPORATE RATES AND REVENUE REQUIREMENTS

Q. Please state your name and title.

A. My name is Stephen Swetz and I am the Sr. Director - Corporate Rates and Revenues Requirements for PSEG Services Corporation. My credentials are set forth in the attached Schedule SS-BGSS-1.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to support Public Service Electric & Gas Company's ("PSE&G" or "the Company") annual Basic Gas Supply Service ("BGSS") filing. Specifically, the Company seeks approval to modify the timeframe in which its balancing costs are collected from firm customers through the balancing charge. Currently, balancing costs are collected over a five-month period in the billing months of November through March. The Company is proposing to collect these same total costs over an eight-month period (October to May).

Q. Is the Company seeking this approval for the winter of 2019/20?

A. Yes. The Company is seeking approval for this modification to be effective for the billing month of October 2019. Mr. Caffery, in his testimony, provides the schedules supporting the cost and calculations for the proposed balancing charge; see Attachment D-1 for the proposed eight-month period calculation. Note that the

Company has also included an Attachment D-2 to provide an updated five-month period calculation for illustrative purposes.

Q. How is the balancing charge presently derived?

A. As can be seen in Attachment D-2 of Mr. Caffery's testimony, the Balancing Charge is presently derived by dividing the applicable balancing costs (shown on pages 1-3 of Attachment D-2) by forecasted November to March billing determinants (*i.e.*, forecasted balancing Dth).

Q. How would the balancing charge be derived using the proposed methodology, and how does that compare with the present methodology?

A. As can be seen in Attachment D-1 of Mr. Caffery's testimony, the proposed balancing charge would be derived by dividing the applicable balancing costs (shown on pages 1-3 of Attachment D-1) by forecasted October to May billing determinants (*i.e.*, forecasted balancing Dth), resulting in a balancing charge to customers of $0.098620 per balancing therm (including losses and Sales and Use Tax or "SUT") - as compared to $0.113187 per balancing therm (including losses and SUT) using the current five-month balancing period methodology, as shown on Attachment D-2. For reference, the $0.113187 per balancing therm five-month rate would replace the existing $0.102825 per balancing therm five-month rate (including losses and SUT).

Q What is prompting the Company's request at this time?

A. The Company has observed that the current methodology of applying the Balancing Charge for the billing months of November to March is prone to under-recovery of costs from customers, which is captured in the BGSS-RSG deferral as part of the

BGSS-RSG annual true-up filing and included in the next year's BGSS-RSG rate. The Company seeks to improve the rate design by better aligning the periods when balancing revenues are collected and the balancing costs are incurred, rather than in the following year via the BGSS-RSG deferral. Therefore, the timing mismatch can be corrected with the proposed change.

Q Why is the current methodology prone to under-recovery?

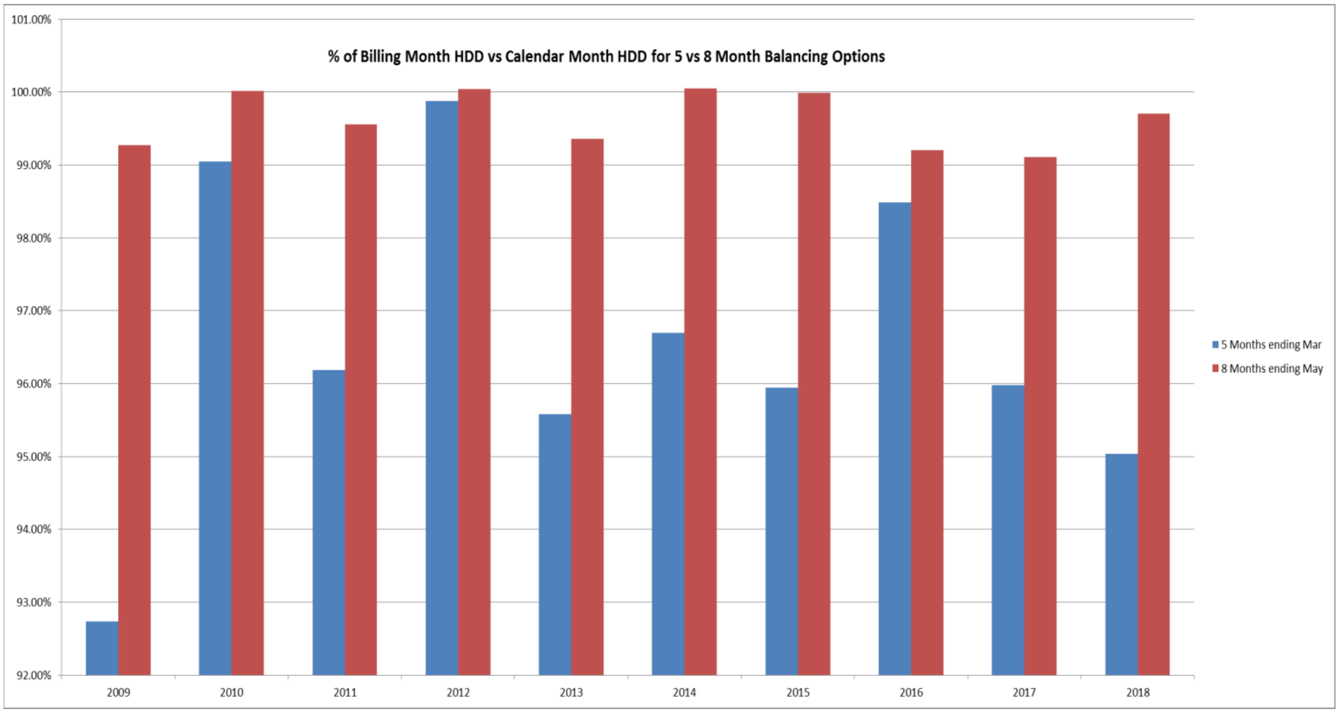
A. As BGSS-RSG (and balancing) is largely a weather sensitive rate and service (as evidenced by the volume of BGSS-RSG load in the winter versus the summer), this under-recovery issue is evident when considering weather information (*i.e.*, heating degree days ("HDDs")), and when considering differences in how the Company incurs balancing costs, on one hand, and how it bills customers for balancing (*i.e.*, recovers balancing revenues) on the other. The Company presently incurs balancing costs on a calendar month basis (*i.e.*, November 1st through March 31st), that is, costs are incurred for the periods November 1 through November 30, December 1 through December 31, and so on. However, the Company bills customers on a route-cycle basis, meaning that the billing period can transcend two calendar months, with weather that is not aligned with the (single) calendar month usage associated with balancing cost. As an example, billed usage (and balancing revenue) for customers' November bills will contain some usage from October and part of November, as compared to balancing costs which are derived solely in the November calendar month. As the full calendar month of November would normally have colder weather than a period that combines part of October and only part of November, the calendar month period of November would be expected to have greater usage and balancing therms than the period that transcends both months. For this reason, balancing revenues are not perfectly aligned with costs, as HDDs are not aligned between calendar and route-cycle methodologies. This misalignment of HDDs is far greater for the November through March five-month period as compared to the eight-month period of October through May. As an example, when considering the 2017-2018 balancing period, the chart below contains HDD information by month for “Route Cycle Billed” (which are the actual HDDs associated with the “from-to” dates associated with each month’s 21 different billing routes for the respective billing month) and the respective calendar month period (*i.e.*, the 1st of the month through the last calendar day of each month). Note that for this timeframe, the HDDs associated with the route-cycle period are only 95% of the calendar period for the five-month November to March time period, as compared to 99.7% for the eight-month period. Therefore, there is a likely under-collection of balancing revenue using the five-month period. However, if an eight-month balancing rate design were utilized, the HDDs that impact route-cycle billing are almost perfectly aligned with the HDDs that impact balancing cost, which would reasonably be expected to result in less of an under-recovery as compared to the current five-month design.

Month	HDD Route Cycle Billed	HDD Calendar	Difference (Route Cycle less Calendar)	Diff (%)	% HDD Route Cycle vs Calendar
10/1/2017	49.74	109.67	(59.93)	-54.6%	45.4%
11/1/2017	330.59	552.43	(221.85)	-40.2%	59.8%
12/1/2017	768.14	934.33	(166.20)	-17.8%	82.2%
1/1/2018	1,140.28	1,040.00	100.28	9.6%	109.6%
2/1/2018	809.05	663.83	145.22	21.9%	121.9%
3/1/2018	724.71	779.31	(54.60)	-7.0%	93.0%
4/1/2018	606.78	481.21	125.57	26.1%	126.1%
5/1/2018	184.62	66.83	117.78	176.2%	276.2%
5 Month (Nov 17 - Mar 18)	3,772.75	3,969.91	(197.15)	-5.0%	95.0%
8 Month (Oct 17 - May 18)	4,613.89	4,627.61	(13.73)	-0.3%	99.7%

Though the actual costs of balancing are included in the weighted average cost of gas for BGSS-RSG service, if we assume the total cost of balancing for BGSS-RSG customers (in the weighted average cost of gas) is the same as the Board-approved balancing rate in effect for the 2017-2018 balancing period noted above, the current five-month balancing methodology would have resulted in an approximately $8M under-collection of costs. As noted above, it is reasonable to expect that this level of under-collection would be greatly reduced if the eight month balancing charge was in effect during this same period.

With regard to the difference in HDDs noted above, this difference can largely be attributed to the magnitude of HDDs at the beginning and end of each respective period. As an example, for the five-month methodology, the November balancing cost is associated with the November Calendar HDD's of 552.43 HDD, whereas the November balancing revenue is associated with the Route Cycle Billing HDDs of 330.59 HDD (as roughly half of November route cycle billing contains October usage). Note that this difference in HDDs (~222 HDDs) is far greater than the ~60 HDD difference for October (the month that an eight-month balancing period would commence). Similarly, for the end of the balancing period, note that the differential for March (end of five-month balancing period) is ~55 HDD (Calendar greater than Route Cycle), whereas the differential for May (end of eight-month balancing period) is actually reversed (route cycle HDD is ~118 HDD greater than Calendar month). So the percentage difference in HDDs for this five-month period was -5.0%, while for the corresponding eight-month period the difference was -0.3%.

Though the figures above are for the 2017/2018 period, the same HDD trend has been present in past years. Below is a chart that contains the same calculated percentage difference for five-month versus eight-month periods for the past ten years. Note that for all ten years, the differences between the Route Cycle HDDs and Calendar HDDs associated with the eight-month methodology are less than 1% versus an average of 3.5% for the five-month methodology



Q Will the proposed eight-month balancing charge methodology lessen the chance of under-recovery of balancing revenue?

A. Yes. The proposed methodology would bill the Balancing Charge in the billing months of October through May. This will result in a much better alignment between route-cycle billed HDDs and calendar HDDs. This improved alignment of HDDs will translate into an improved matching of balancing revenues and balancing cost, resulting in a smaller true-up going into the next period's BGSS-RSG rate calculation.

Q What will the impact be on customers if the balancing period is not changed?

A. The balancing charge unit rate would be increased from $0.102825 to $0.113187 per balancing therm (including losses and SUT) under the current five-month period (Attachment D-2), versus the proposed change to $0.098620 per balancing therm including losses and SUT based on an eight-month balancing period (Attachment D-1). If the balancing period is not changed, the charge will be calculated using the same total balancing costs, though collected over the current shorter time period. As noted above, under-recoveries in the current methodology (five-month period) are included in the BGSS-RSG deferral in the annual rate filing true-up process, so customers ultimately pay for them. The proposed eight-month methodology aims to better capture the balancing revenues in the period they are incurred, thus reducing the potential carry-over to the BGSS-RSG deferral. Additionally, as the balancing charge (unit rate) utilizing the proposed methodology will be less (as compared to a five-month methodology), customers may benefit from a "smoothing" effect that will reduce their total bills in the peak winter months, lessening the bill impact associated with low winter temperatures.

Q. Does this conclude your direct testimony at this time?

A. Yes.

CREDENTIALS
OF
STEPHEN SWETZ
SR. DIRECTOR-CORPORATE RATES AND REVENUE REQUIREMENTS

My name is Stephen Swetz and I am employed by PSEG Services Corporation. I am the Sr. Director - Corporate Rates and Revenue Requirements where my main responsibility is to contribute to the development and implementation of electric and gas rates for Public Service Electric and Gas Company (PSE&G, the Company).

WORK EXPERIENCE

I have over 30 years of experience in Rates, Financial Analysis and Operations for three Fortune 500 companies. Since 1991, I have worked in various positions within PSEG. I have spent most of my career contributing to the development and implementation of PSE&G electric and gas rates, revenue requirements, pricing and corporate planning with over 20 years of direct experience in Northeastern retail and wholesale electric and gas markets.

As Sr. Director of the Corporate Rates and Revenue Requirements department, I have submitted pre-filed direct cost recovery testimony as well as oral testimony to the New Jersey Board of Public Utilities and the New Jersey Office of Administrative Law for base rate cases, as well as a number of clauses including infrastructure investments, renewable energy, and energy efficiency programs. A list of my prior testimonies can be found on pages 3 and 4 of this document. I have also contributed to other filings including unbundling electric rates and Off-Tariff Rate Agreements. I have had a leadership role in various economic analyses, asset valuations, rate design, pricing efforts and cost of service studies.

I am an active member of the American Gas Association's Rate and Strategic Issues Committee, the Edison Electric Institute's Rates and Regulatory Affairs Committee and the New Jersey Utility Association (NJUA) Finance and Regulatory Committee.

EDUCATIONAL BACKGROUND

I hold a B.S. in Mechanical Engineering from Worcester Polytechnic Institute and an MBA from Fairleigh Dickinson University.

LIST OF PRIOR TESTIMONIES

Company	Utility	Docket	Testimony	Date	Case / Topic
Public Service Electric & Gas Company	E	TBD	written	Apr-19	Non-Utility Generation Charge (NGC) / Cost Recovery
Public Service Electric & Gas Company	E/G	EO18101113 - GO18101112	written	Dec-18	Clean Energy Future - Energy Efficiency Program Approval
Public Service Electric & Gas Company	E/G	GR18121258	written	Nov-18	Remediation Adjustment Charge-RAC 26
Public Service Electric & Gas Company	G	GR18070831	written	Jul-18	Gas System Modernization Program (GSMP) - Third Roll-In
Public Service Electric & Gas Company	E/G	ER18070688 - GR18070689	written	Jun-18	Green Programs Recovery Charge (GPRC)-Including CA, DR, EEE, EEE Ext, S4All, S4AEXT, S4AEXT II, SLII, SLIII / Cost Recovery
Public Service Electric & Gas Company	E	ER18060681	written	Jun-18	Solar Pilot Recovery Charge (SPRC-Solar Loan I) / Cost Recovery
Public Service Electric & Gas Company	G	GR18060675	written	Jun-18	Weather Normalization Charge / Cost Recovery
Public Service Electric & Gas Company	E/G	EO18060629 - GO18060630	written	Jun-18	Energy Strong II / Revenue Requirements & Rate Design
Public Service Electric & Gas Company	G	GR18060605	written	Jun-18	Margin Adjustment Charge (MAC) / Cost Recovery
Public Service Electric & Gas Company	E/G	ER18040358 - GR18040359	written	Mar-18	Energy Strong / Revenue Requirements & Rate Design - Eighth Roll-in
Public Service Electric & Gas Company	E/G	ER18030231	written	Mar-18	Tax Cuts and Job Acts of 2017
Public Service Electric & Gas Company	E/G	GR18020093	written	Feb-18	Remediation Adjustment Charge-RAC 25
Public Service Electric & Gas Company	E/G	ER18010029 and GR18010030	written	Jan-18	Base Rate Proceeding / Cost of Service & Rate Design
Public Service Electric & Gas Company	E	ER17101027	written	Sep-17	Energy Strong / Revenue Requirements & Rate Design - Seventh Roll-in
Public Service Electric & Gas Company	G	GR17070776	written	Jul-17	Gas System Modernization Program II (GSMP II)
Public Service Electric & Gas Company	G	GR17070775	written	Jul-17	Gas System Modernization Program (GSMP) - Second Roll-In
Public Service Electric & Gas Company	G	GR17060720	written	Jul-17	Weather Normalization Charge / Cost Recovery
Public Service Electric & Gas Company	E/G	ER17070724 - GR17070725	written	Jul-17	Green Programs Recovery Charge (GPRC)-Including CA, DR, EEE, EEE Ext, S4All, S4AEXT, S4AEXT II, SLII, SLIII / Cost Recovery
Public Service Electric & Gas Company	E	ER17070723	written	Jul-17	Solar Pilot Recovery Charge (SPRC-Solar Loan I) / Cost Recovery
Public Service Electric & Gas Company	G	GR17060593	written	Jun-17	Margin Adjustment Charge (MAC) / Cost Recovery
Public Service Electric & Gas Company	E/G	ER17030324 - GR17030325	written	Mar-17	Energy Strong / Revenue Requirements & Rate Design - Sixth Roll-in
Public Service Electric & Gas Company	E/G	EO14080897	written	Mar-17	Energy Efficiency 2017 Program
Public Service Electric & Gas Company	E	ER17020136	written	Feb-17	Societal Benefits Charge (SBC) / Cost Recovery
Public Service Electric & Gas Company	E/G	GR16111064	written	Nov-16	Remediation Adjustment Charge-RAC 24
Public Service Electric & Gas Company	E	ER16090918	written	Sep-16	Energy Strong / Revenue Requirements & Rate Design - Fifth Roll-in
Public Service Electric & Gas Company	E	EO16080788	written	Aug-16	Construction of Mason St Substation
Public Service Electric & Gas Company	E	ER16080785	written	Aug-16	Non-Utility Generation Charge (NGC) / Cost Recovery
Public Service Electric & Gas Company	G	GR16070711	written	Jul-16	Gas System Modernization Program (GSMP) - First Roll-In
Public Service Electric & Gas Company	G	GR16070617	written	Jul-16	Weather Normalization Charge / Cost Recovery
Public Service Electric & Gas Company	E/G	ER16070613 - GR16070614	written	Jul-16	Green Programs Recovery Charge (GPRC)-Including CA, DR, EEE, EEE Ext, S4All, S4AEXT, SLII, SLIII / Cost Recovery
Public Service Electric & Gas Company	E	ER16070616	written	Jul-16	Solar Pilot Recovery Charge (SPRC-Solar Loan I) / Cost Recovery
Public Service Electric & Gas Company	G	GR16060484	written	Jun-16	Margin Adjustment Charge (MAC) / Cost Recovery
Public Service Electric & Gas Company	E	EO16050412	written	May-16	Solar 4 All Extension II (S4Allext II) / Revenue Requirements & Rate Design
Public Service Electric & Gas Company	E/G	ER16030272 - GR16030273	written	Mar-16	Energy Strong / Revenue Requirements & Rate Design - Fourth Roll-in
Public Service Electric & Gas Company	E/G	GR15111294	written	Nov-15	Remediation Adjustment Charge-RAC 23
Public Service Electric & Gas Company	E	ER15101180	written	Sep-15	Energy Strong / Revenue Requirements & Rate Design - Third Roll-in
Public Service Electric & Gas Company	E/G	ER15070757-GR15070758	written	Jul-15	Green Programs Recovery Charge (GPRC)-Including CA, DR, EEE, EEE Ext, S4All, S4AEXT, SLII, SLIII / Cost Recovery
Public Service Electric & Gas Company	E	ER15060754	written	Jul-15	Solar Pilot Recovery Charge (SPRC-Solar Loan I) / Cost Recovery
Public Service Electric & Gas Company	G	GR15060748	written	Jul-15	Weather Normalization Charge / Cost Recovery
Public Service Electric & Gas Company	G	GR15060646	written	Jun-15	Margin Adjustment Charge (MAC) / Cost Recovery
Public Service Electric & Gas Company	E/G	ER15050558	written	May-15	Societal Benefits Charge (SBC) / Cost Recovery
Public Service Electric & Gas Company	E	ER15050558	written	May-15	Non-Utility Generation Charge (NGC) / Cost Recovery
Public Service Electric & Gas Company	E/G	ER15030389-GR15030390	written	Mar-15	Energy Strong / Revenue Requirements & Rate Design - Second Roll-in
Public Service Electric & Gas Company	G	GR15030272	written	Feb-15	Gas System Modernization Program (GSMP)
Public Service Electric & Gas Company	E/G	GR14121411	written	Dec-14	Remediation Adjustment Charge-RAC 22
Public Service Electric & Gas Company	E/G	ER14091074	written	Sep-14	Energy Strong / Revenue Requirements & Rate Design - First Roll-in
Public Service Electric & Gas Company	E/G	EO14080897	written	Aug-14	EEE Ext II
Public Service Electric & Gas Company	G	ER14070656	written	Jul-14	Weather Normalization Charge / Cost Recovery
Public Service Electric & Gas Company	E/G	ER14070651-GR14070652	written	Jul-14	Green Programs Recovery Charge (GPRC)-Including CA, DR, EEE, EEE Ext, S4All, S4AEXT, SLII, SLIII / Cost Recovery
Public Service Electric & Gas Company	E	ER14070650	written	Jul-14	Solar Pilot Recovery Charge (SPRC-Solar Loan I) / Cost Recovery
Public Service Electric & Gas Company	G	GR14050511	written	May-14	Margin Adjustment Charge (MAC) / Cost Recovery
Public Service Electric & Gas Company	E/G	GR14040375	written	Apr-14	Remediation Adjustment Charge-RAC 21
Public Service Electric & Gas Company	E/G	ER13070603-GR13070604	written	Jun-13	Green Programs Recovery Charge (GPRC)-Including DR, EEE, EEE Ext, CA, S4All, SLII / Cost Recovery
Public Service Electric & Gas Company	E	ER13070605	written	Jul-13	Solar Pilot Recovery Charge (SPRC-Solar Loan I) / Cost Recovery
Public Service Electric & Gas Company	G	GR13070615	written	Jun-13	Weather Normalization Charge / Cost Recovery
Public Service Electric & Gas Company	G	GR13060445	written	May-13	Margin Adjustment Charge (MAC) / Cost Recovery
Public Service Electric & Gas Company	E/G	EO13020155-GO13020156	written/oral	Mar-13	Energy Strong / Revenue Requirements & Rate Design - Program Approval
Public Service Electric & Gas Company	G	GO12030188	written/oral	Mar-13	Appliance Service / Tariff Support
Public Service Electric & Gas Company	E	ER12070599	written	Jul-12	Solar Pilot Recovery Charge (SPRC-Solar Loan I) / Cost Recovery
Public Service Electric & Gas Company	E/G	ER12070606-GR12070605	written	Jul-12	RGGI Recovery Charges (RRC)-Including DR, EEE, EEE Ext, CA, S4All, SLII / Cost Recovery
Public Service Electric & Gas Company	E	EO12080721	written/oral	Jul-12	Solar Loan III (SLIII) / Revenue Requirements & Rate Design - Program Approval

LIST OF PRIOR TESTIMONIES

Company	Utility	Docket	Testimony	Date	Case / Topic
Public Service Electric & Gas Company	E	EO12080721	written/oral	Jul-12	Solar 4 All Extension(S4Allext) / Revenue Requirements & Rate Design - Program Approval
Public Service Electric & Gas Company	G	GR12060489	written	Jun-12	Margin Adjustment Charge (MAC) / Cost Recovery
Public Service Electric & Gas Company	G	GR12060583	written	Jun-12	Weather Normalization Charge / Cost Recovery
Public Service Electric & Gas Company	E/G	ER12030207	written	Mar-12	Societal Benefits Charge (SBC) / Cost Recovery
Public Service Electric & Gas Company	E	ER12030207	written	Mar-12	Non-Utility Generation Charge (NGC) / Cost Recovery
Public Service Electric & Gas Company	G	GR11060338	written	Jun-11	Margin Adjustment Charge (MAC) / Revenue Requirements & Rate Design - Program Approval
Public Service Electric & Gas Company	G	GR11060395	written	Jun-11	Weather Normalization Charge / Revenue Requirements & Rate Design - Program Approval
Public Service Electric & Gas Company	E	EO11010030	written	Jan-11	Economic Energy Efficiency Extension (EEEext) / Revenue Requirements & Rate Design - Program Approval
Public Service Electric & Gas Company	E/G	ER10100737	written	Oct-10	RGGI Recovery Charges (RRC)-Including DR, EEE, CA, S4All, SLII / Cost Recovery
Public Service Electric & Gas Company	E/G	ER10080550	written	Aug-10	Societal Benefits Charge (SBC) / Cost Recovery
Public Service Electric & Gas Company	E	ER10080550	written	Aug-10	Non-Utility Generation Charge (NGC) / Cost Recovery
Public Service Electric & Gas Company	E/G	GR09050422	written/oral	Mar-10	Base Rate Proceeding / Cost of Service & Rate Design
Public Service Electric & Gas Company	E	ER10030220	written	Mar-10	Solar Pilot Recovery Charge (SPRC-Solar Loan I) / Cost Recovery
Public Service Electric & Gas Company	E	EO09030249	written	Mar-09	Solar Loan II(SLII) / Revenue Requirements & Rate Design - Program Approval
Public Service Electric & Gas Company	E/G	EO09010056	written	Feb-09	Economic Energy Efficiency(EEE) / Revenue Requirements & Rate Design - Program Approval
Public Service Electric & Gas Company	E	EO09020125	written	Feb-09	Solar 4 All (S4All) / Revenue Requirements & Rate Design - Program Approval
Public Service Electric & Gas Company	E	EO08080544	written	Aug-08	Demand Response (DR) / Revenue Requirements & Rate Design - Program Approval
Public Service Electric & Gas Company	E/G	ER10100737	written	Jun-08	Carbon Abatement (CA) / Revenue Requirements & Rate Design - Program Approval

2. Computation of Proposed BGSS Rate

Effective October 1, 2019

Item 2

COMPUTATION OF
BGSS COMMODITY CHARGE FOR RSG
OCTOBER 2019 - SEPTEMBER 2020

($-000)

	$000	$/DTh
FIXED COSTS:		
FT DEMAND COST	$ 169,361	$1.1533
STORAGE DEMAND/CAPACITY COSTS	88,481	$0.6025
STORAGE INJ & W/D COSTS	5,280	$0.0360
PEAKING COSTS	9,039	$0.0616
	272,161	**$1.8534**
CONTRIBUTIONS	(31,954)	($0.2176)
PIPELINE REFUNDS	(20,000)	($0.1362)
OFF-SYSTEM SALES MARGIN	(34,664)	($0.2361)
ELECTRIC CONTIBUTION - CSG	(20,100)	($0.1369)
NET TOTAL FIXED COST	**$ 165,443**	**$1.12660**
FIRM RSG SENDOUT (MDTh) 10/19 - 9/20	**146,848**	
TOTAL NON-GULF COAST COST ($/DTh)		**$1.12660**
Removal of Balancing Cost (incl. above)		(0.62262)
Inventory Carrying Charge Allocation		0.06486
Gas Supply A&G		0.03566
Total Adjustments		**($0.52210)**
ADJUSTED NON-GULF COAST COST ($/DTh)		**$0.60450**
(OVER)/UNDER RECOVERY @ 9/30/19 - INCL. INTEREST	**($3,129)**	**($0.02130)**
GULF COAST COST OF GAS ($/DTh)		
FT COMMODITY AND FUEL		0.00000
COST OF GAS		**2.54380**
TOTAL GULF COAST COST		**$2.54380**

SUMMARY OF CHARGE COMPONENTS

	(cents/therm)	(dollars/therm)
	BGSS-RSG	**BGSS-RSG**
Estimated Non-Gulf Coast Cost of Gas	6.0450	$ 0.060450
Estimated Gulf Coast Cost of Gas	25.4380	$ 0.254380
Adjustment to Gulf Coast Cost of Gas	-	$ -
Prior Period (Over)/Under Recovery	(0.2130)	$ (0.002130)
Adjusted Cost of Gas	31.2700	$ 0.312700
COMMODITY CHARGE (after application of losses 2.0%)	**31.9082**	**$ 0.319082**
COMMODITY CHARGE (including SUT)	**34.0221**	**$ 0.340221**

3. <u>Public Notice with Proposed Impact on Bills</u>

Notice (including Typical Bills) – Attachment C

NOTICE TO PUBLIC SERVICE ELECTRIC AND GAS COMPANY GAS CUSTOMERS

IN THE MATTER OF PUBLIC SERVICE ELECTRIC AND GAS COMPANY'S 2019/2020 ANNUAL BGSS COMMODITY CHARGE FILING FOR ITS RESIDENTIAL GAS CUSTOMERS UNDER ITS PERIODIC PRICING MECHANISM AND FOR CHANGES IN ITS BALANCING CHARGE

Notice of Filing and Notice of Public Hearings

Docket No. XXXXXXXXXX

TAKE NOTICE that, on May 31, 2019, Public Service Electric and Gas Company ("Public Service", "the Company") filed a Motion and supporting testimony with the New Jersey Board of Public Utilities ("Board", "BPU") requesting that the Board permit Public Service to decrease its Basic Gas Supply Service (BGSS-RSG) Commodity Charge to Residential Service (RSG) customers and for changes to its Balancing Charge to customers receiving service under RSG, General Service (GSG), Large Volume Service (LVG) and Contract Service (CSG) where applicable effective October 1, 2019, or earlier should the Board deem it appropriate. Approval of the Company's request would result in a decrease in annual BGSS-RSG revenues of approximately $12 million (excluding losses and New Jersey Sales and Use Tax or "SUT"). The requested decrease in the BGSS-RSG Commodity Charge is from $0.349059 per therm (including losses and SUT) to $0.340221 per therm (including losses and SUT).

Additionally, the Company is requesting two changes in its Balancing Charge. First, the Company is seeking a change in the balancing period form the current five billing months of November through March to the eight billing months of October to May. Second, the Company seeks a change in the Balancing Charge from $0.102825 per therm (including losses and SUT), based on the current five month balancing period to $0.098620 per therm (including losses and SUT) based on the eight month balancing period.

For illustrative purposes, the Company has also calculated an updated five month Balancing Charge of $0.113187 per balancing use therm (including losses and SUT) to demonstrate the required change in rate from the current $0.102825 rate due to changes in costs.

Based on rates effective May 1, 2019, the combined effect of the requested decrease in the annual BGSS Commodity Charge and change in the Balancing Charge (inclusive of the proposed change to an eight month balancing period) on typical residential gas bills, if approved by the Board, is shown in Table #1. For illustrative purposes, the combined effect of the requested change with an updated five month Balancing Charge is shown in Table #2.

Under the Company's proposal, a residential heating customer using 100 therms per month during the winter months and 610 therms on an annual basis would see a decrease in their annual bill from $566.34 to $563.06, or $3.28 or approximately 0.58%. Moreover, under the Company's proposal, a typical residential heating customer using 172 therms per month during the winter months and 1,040 therms on an annual basis would see a decrease in their annual bill from $893.03 to $887.14, or $5.89 or approximately 0.66%.

In addition, the Board, in its Order in Docket No. GX01050304 dated January 6, 2003, granted Public Service approval to increase its Commodity Charge rates to be effective December 1st of this year and/or February 1st of next year on a self-implementing basis, with each such increase being subject to a maximum rate increase of 5% of the average rate based on a typical 100 therms per month average (1,200 therms annual usage) residential customer's total bill. Such rate increases shall be preconditioned upon written notice by Public Service to the BPU Staff and to the Division of Rate Counsel no later than November 1st of this year and/or January 1st of next year of its intention to apply a December 1st or a February 1st self-implementing rate increase, respectively, and the approximate amount of the increases based upon then current market data. These increases, if implemented, would be in accordance with the Board approved methodology.

Should it become necessary to apply the December 1st self-implementing 5% increase, the bill impact would be an increase as illustrated in Table #3. Further, if a February 1st self-implementing 5% increase becomes necessary, then there would be an additional increase as also shown in Table #3. For illustrative purposes, the combined effect of the requested change with an updated five month Balancing Charge is shown in Table #4.

The above requests will not result in any profit to the Company. Any final rate adjustments with resulting changes in bill impacts found by the Board to be just and reasonable as the result of the Company's filing may be modified and/or allocated by the Board in accordance with the provisions of N.J.S.A 48:2-21 and for other good and legally sufficient reasons to any class or classes of customers of the Company. Therefore, the described charges may increase or decrease based upon the Board's decision.

Copies of the Company's filing are available for review at the Company's Customer Service Centers (addresses located here: https://nj.pseg.com/customerservicelocations), online at the PSEG website at http://www.pseg.com/pseandgfilings, and at the Board of Public Utilities at 44 South Clinton Avenue, 2nd Floor, Trenton, New Jersey 08625-0350. Any member of the public who wants to inspect the petition at the Board may contact the Board's Division of Case Management at (609) 292-0806 to schedule an appointment.

The following dates, times and locations for public hearings have been scheduled on the Company's filing so that members of the public may present their views. Information provided at the public hearings will become part of the record of this case and will be considered by the Board in making its decision.

Date 1, 2019
Time 1
Location 1
Room 1
Address 1
Overflow Address 1
City 1, N.J. Zip Code 1

Date 2, 2019
Time 2
Location 2
Room 2
Address 2
Overflow Address 2
City 2, N.J. Zip Code 2

Date 3, 2019
Time 3
Location 3
Room 3
Address 3
Overflow Address 3
City 3, N.J. Zip Code 3

In order to encourage full participation in this opportunity for public comment, please submit any requests for needed accommodations, including interpreters, listening devices or mobility assistance, 48 hours prior to the above hearings.

Customers may also file written comments with the Secretary of the Board of Public Utilities at 44 South Clinton Avenue, 3rd Floor, Suite 314, P.O. Box 350, Trenton, New Jersey, 08625-0350 ATTN: Secretary Aida Camacho-Welch whether or not they attend the public hearings.

Table # 1
Residential Gas Service – With Proposed Change to an Eight Month Balancing Period

If Your Annual Therm Use Is:	And Your Monthly Winter Therm Use Is:	Then Your Present Monthly Winter Bill (1) Would Be:	And Your Proposed Monthly Winter Bill (2) Would Be:	Your Monthly Winter Bill Change Would Be:	And Your Monthly Percent Change Would Be:
170	25	$27.93	$27.64	($0.29)	(1.04)%
340	50	47.21	46.62	(0.59)	(1.25)
610	100	87.05	85.82	(1.23)	(1.41)
1,040	172	143.56	141.44	(2.12)	(1.48)
1,200	201	166.39	163.91	(2.48)	(1.49)
1,210	200	165.48	163.01	(2.47)	(1.49)
1,816	300	243.92	240.23	(3.69)	(1.51)

(1) Based upon Delivery Rates and Basic Gas Supply Service (BGSS-RSG) in effect May 1, 2019, and assumes that the customer receives commodity service from Public Service.
(2) Same as (1) except includes the proposed change in BGSS-RSG and Balancing Charge.

Table # 2
Residential Gas Service – With Five Month Balancing Period

If Your Annual Therm Use Is:	And Your Monthly Winter Therm Use Is:	Then Your Present Monthly Winter Bill (1) Would Be:	And Your Proposed Monthly Winter Bill (2) Would Be:	Your Monthly Winter Bill Change Would Be:	And Your Monthly Percent Change Would Be:
170	25	$27.93	$27.90	($0.03)	(0.11)%
340	50	47.21	47.14	(0.07)	(0.15)
610	100	87.05	87.02	(0.03)	(0.03)
1,040	172	143.56	143.53	(0.03)	(0.02)
1,200	201	166.39	166.36	(0.03)	(0.02)
1,210	200	165.48	165.43	(0.05)	(0.03)
1,816	300	243.92	243.85	(0.07)	(0.03)

(1) Based upon Delivery Rates and Basic Gas Supply Service (BGSS-RSG) in effect May 1, 2019, and assumes that the customer receives commodity service from Public Service.
(2) Same as (1) except includes the proposed change in BGSS-RSG and Balancing Charge.

Table # 3
Residential Gas Service – With Proposed Change to an Eight Month Balancing Period

If Your Annual Therm Use Is:	And Your Monthly Winter Therm Use Is:	Self-Implementing 5% Increases	
		December 1, 2019 Monthly Winter Change Would Be:	February 1, 2020 Monthly Winter Change Would Be:
170	25	$1.05	$1.05
340	50	2.10	2.10
610	100	4.20	4.20
1,040	172	7.22	7.23
1,200	201	8.45	8.44
1,210	200	8.41	8.40
1,816	300	12.60	12.60

Table # 4
Residential Gas Service – With Five Month Balancing Period

If Your Annual Therm Use Is:	And Your Monthly Winter Therm Use Is:	Self-Implementing 5% Increases	
		December 1, 2019 Monthly Winter Change Would Be:	February 1, 2020 Monthly Winter Change Would Be:
170	25	$1.05	$1.05
340	50	2.11	2.11
610	100	4.22	4.22
1,040	172	7.25	7.26
1,200	201	8.48	8.48
1,210	200	8.44	8.44
1,816	300	12.65	12.66

Matthew M. Weissman
General State Regulatory Counsel

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

4. Actual and Forecasted Refund Amounts

Item 4

NATURAL GAS PIPELINE REFUNDS RECEIVED

(000)

MONTH	SUPPLIER	AMOUNT	TOTAL
July 2018	Texas Eastern	$ 274	
	Dominion	88	
	Algonquin	2	$ 364
August 2018	Transcontinental	28	28
October 2018	Transcontinental	49	
	Texas Eastern	39	88
November 2018	Tennessee	9	9
Total			$ 489

Item 4

PENDING FERC CASES WHICH CONTAIN SOME POSSIBILITY OF REFUNDS TO PSE&G IN EXCESS OF $1 MILLION

(000)

DOCKET	SUPPLIER	STATUS
RP18-1126	Transco	Settlement negotiations are underway that are anticipated to resolve this general Section 4 rate case, and thereby provide refunds from the motion rates now being paid subject to refund. We have estimated the RSG portion to be $20 million.

5. Cost of Gas Sendout by Component

ACTUAL COST OF BGSS-RSG GAS SENDOUT BY COMPONENT

	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	Total
Beginning Inventory Price $000	$191,426	$213,584	$213,487	$201,506	$146,690	$97,860	$63,196	
Fixed Pipeline Charge $000	$16,154	$18,110	$18,288	$17,758	$16,514	$19,593	$19,355	
Gas Purchases and Hedges $000	$36,147	$57,150	$61,185	$49,417	$31,698	$33,098	$32,435	
Receipt Value $000	$52,301	$75,260	$79,472	$67,175	$48,212	$52,691	$51,789	$426,901
Total Inventory Value $000	$243,727	$288,844	$292,959	$268,681	$194,902	$150,551	$114,985	
Total $/dth	$3.87	$4.01	$4.13	$4.11	$4.12	$4.25	$4.04	
Beginning Inventory Volume MDth	49,254	55,323	53,210	48,760	35,659	23,641	14,780	
Receipt Volume MDth	13,764	16,625	17,650	16,588	11,688	11,818	13,678	101,811
Total Inventory Volume MDth	63,018	71,947	70,860	65,348	47,347	35,459	28,458	
RSG Sendout MDth	7,944	18,830	22,171	29,617	23,321	20,411	8,664	130,958
Total RSG Sendout Cost $000	$30,723	$75,595	$91,662	$121,771	$96,002	$86,662	$35,008	$537,423
Ending Inventory Rebalance								
Volume	249	92	71	(73)	(385)	(268)	(265)	
Amount	$580	$237	$210	($221)	($1,040)	($693)	($695)	

FORECASTED COST OF BGSS-RSG GAS SENDOUT BY COMPONENT

	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Total Oct - Sept
Beginning Inventory Cost $000	$79,283	$103,072	$134,445	$166,329	$192,099	$220,659	$239,023	$242,972	$214,307	$152,057	$104,659	$77,930	$75,361	$99,579	$130,719	$161,495	$186,861	
Receipt Value $000	$48,522	$44,740	$46,319	$38,822	$43,369	$48,323	$72,770	$67,820	$61,539	$63,003	$60,188	$46,161	$48,469	$45,242	$45,379	$38,361	$41,552	$638,807
Total Inventory Value $000	$127,805	$147,811	$180,764	$205,150	$235,468	$268,981	$311,793	$310,792	$275,846	$215,060	$164,848	$124,090	$123,829	$144,820	$176,098	$199,856	$228,414	
Total $/dth	$3.98	$4.18	$4.30	$4.45	$4.52	$4.52	$4.40	$4.37	$4.39	$4.40	$4.39	$4.44	$4.37	$4.36	$4.33	$4.36	$4.36	
Beginning Inventory Volume MDth	19,529	25,926	32,188	38,658	43,176	48,799	52,840	55,168	49,084	34,621	23,776	17,745	16,954	22,809	29,960	37,334	42,891	
Receipt Volume MDth	12,618	9,463	9,825	7,451	8,898	10,663	17,955	16,014	13,722	14,235	13,761	10,172	11,410	10,383	10,750	8,539	9,558	147,162
Total Inventory Volume MDth	32,147	35,388	42,013	46,110	52,074	59,463	70,795	71,182	62,806	48,856	37,536	27,917	28,364	33,192	40,710	45,873	52,449	
RSG Sendout MDth	6,221	3,200	3,355	2,933	3,275	6,623	15,626	22,099	28,185	25,080	19,792	10,963	5,555	3,232	3,376	2,983	3,336	146,848
Total RSG Sendout Cost $000	$24,733	$13,366	$14,435	$13,051	$14,809	$29,958	$68,821	$96,485	$123,789	$110,401	$86,918	$48,730	$24,251	$14,101	$14,603	$12,995	$14,528	$645,580

6. BGSS Contribution and Credit Offsets

Actual BGSS Contribution and Credit Offsets

($000)

			Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	Total
(1)	**BGSS-I Contribution**		$34	$35	$42	($408)	($118)	$814	$176	$575
(2)	**Cogeneration Contribution**		($962)	$1,896	$1,352	$629	($472)	$2,479	$349	$5,271
(3)	**TSG-F Contribution**		($1)	$454	$279	$234	$382	$342	($84)	$1,605
(4)	**"Contribution"**	Sum of (1) through (4)	($930)	$2,385	$1,673	$455	($208)	$3,634	$441	$7,451
(5)	**Off-System Contribution**		$1,354	$1,697	$5,981	$6,680	$2,696	$1,608	$553	$20,569
(6)	**Electric Contribution**		$2,036	$1,357	$821	$1,164	$1,153	$1,030	$839	$8,402
(7)	**FT-S Balancing Credit**		($18)	$3,637	$4,447	$4,863	$4,018	$2,481	$319	$19,747
(8)	**Pipeline Refunds**		$88	$9	$0	$0	$0	$0	$0	$97

Forecasted BGSS Contribution and Credit Offsets

		May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Total Oct - Sept
(1)	**BGSS-RSG Sendout, Mdth**	5,440	3,200	3,355	2,933	3,275	6,623	15,626	22,099	28,185	25,080	19,792	10,963	5,555	3,232	3,376	2,983	3,336	146,848
(2)	**BGSS-F Sendout, Mdth**	1,709	1,181	1,133	1,232	1,238	2,438	4,110	7,529	9,895	8,471	6,928	3,692	1,746	1,171	1,125	1,241	1,245	49,590
(3)	**Total Firm Sendout, Mdth**	7,149	4,381	4,488	4,166	4,513	9,060	19,737	29,627	38,080	33,551	26,719	14,655	7,301	4,403	4,500	4,224	4,581	196,438
(4)	**Annual % BGSS-RSG of Firm Sendout**	74.8%	74.8%	74.8%	74.8%	74.8%	74.8%	74.8%	74.8%	74.8%	74.8%	74.8%	74.8%	74.8%	74.8%	74.8%	74.8%	74.8%	74.8%
(5)	**BGSS-I Contribution**	($71.6)	$37.3	($82.8)	$36.2	($53.6)	$34.5	$33.5	$41.6	($411.8)	($117.9)	$821.3	$175.6	($71.6)	$37.1	($82.5)	$36.1	($53.4)	$442.5
(6)	**Cogeneration Contribution, $000**	$445.8	$429.4	$514.1	$243.3	($0.8)	($810.4)	$1,309.9	$962.1	$348.2	($617.0)	$2,231.9	($20.8)	$445.9	$427.3	$512.4	$242.6	($0.8)	$5,031.3
(7)	**TSG-F Contribution**	($168.1)	($12.4)	$217.3	$25.4	($66.3)	($1.5)	$428.4	$280.1	$177.7	$382.0	$345.0	($84.0)	($168.1)	($12.4)	$216.6	$25.4	($66.1)	$1,523.2
(8)	**CSG**	$314.9	$314.9	$314.9	$314.9	$314.9	$314.9	$314.9	$314.9	$314.9	$314.9	$314.9	$314.9	$314.9	$314.9	$314.9	$314.9	$314.9	$3,778.9
(9)	**"Contribution"**	$521.0	$769.2	$963.6	$619.8	$194.2	($462.4)	$2,086.7	$1,598.7	$429.0	($38.1)	$3,713.2	$385.8	$521.0	$767.0	$961.4	$619.0	$194.6	$10,775.9
(10)	**Off-System Contribution, $000**	$921.1	$921.1	$921.1	$921.1	$921.1	$921.1	$6,471.9	$6,471.9	$4,399.8	$4,399.8	$6,471.9	$921.3	$921.3	$921.3	$921.3	$921.3	$921.3	$34,664.1
(11)	**Electric Contribution, $000**	$1,180.1	$1,538.8	$2,802.5	$2,755.8	$2,255.7	$2,385.1	$1,609.8	$1,416.5	$984.2	$823.9	$968.1	$1,379.9	$1,180.1	$1,538.8	$2,802.5	$2,755.8	$2,255.7	$20,100.5
(12)	**Pipeline Refund, $000**	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$20,000.0	$0.0	$0.0	$20,000.0
(13)	**FT-S Balancing Use, Mdth**	0.0	0.0	0.0	0.0	0.0	1,441.3	3,194.7	5,488.4	7,435.1	6,981.7	5,460.7	3,252.0	332.1	0.0	0.0	0.0	0.0	
(14)	**Balancing Charge, $/dth**	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.8435	$0.8435	$0.8435	$0.8435	$0.8435	$0.8435	$0.8435	$0.8435	$0.0000	$0.0000	$0.0000	$0.0000	
(15)	**FT-S Balancing Credit, $000**	$0.0	$0.0	$0.0	$0.0	$0.0	$908.8	$2,014.5	$3,460.8	$4,688.3	$4,402.4	$3,443.3	$2,050.6	$209.4	$0.0	$0.0	$0.0	$0.0	$21,178.0
(16)	**BGSS-RSG Balancing Use, Mdth**	0	0	0	0	0	3,380	12,488	18,855	24,942	22,046	16,548	7,824	2,312	0	0	0	0	
(17)	**Balancing Charge, $/dth**	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.8435	$0.8435	$0.8435	$0.8435	$0.8435	$0.8435	$0.8435	$0.8435	$0.0000	$0.0000	$0.0000	$0.0000	
(18)	**BGSS-RSG Balancing Rev., $000**	$0.0	$0.0	$0.0	$0.0	$0.0	$2,850.6	$10,533.4	$15,904.4	$21,038.2	$18,595.9	$13,958.5	$6,599.8	$1,949.8	$0.0	$0.0	$0.0	$0.0	$91,430.7

BGSS-RSG MARGIN FROM GAS TRANSPORTATION FOR ELECTRIC GENERATION

	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	Total
BGSS Asset Charge ($000)	$1,529	$1,053	$904	$1,120	$867	$761	$758	$6,993
CSG Transportation Revenues ($000)	$507	$303	($83)	$44	$286	$269	$82	$1,408
Total BGSS-RSG Margin ($000)	$2,036	$1,356	$821	$1,164	$1,153	$1,030	$839	$8,401

7. Over/Under Recovery Comparisons

Summary of Monthly Over/(Under) Recoveries

Calculation of Interest on Over/(Under) Balance

Over/(Under) Balance (before & after change)

Supporting Workpapers – Actual Results

Item 7

MONTHLY RECOVERIES COMPARED TO EXCESS COST
OCTOBER 2018 - SEPTEMBER 2019

(000)

		TOTAL RECOVERY	LESS: TOTAL EXPENSE	MONTHLY OVER/(UNDER) RECOVERY
Balance September 30, 2018				**($3,899)**
Interest Adjustment				**0**
October 1, 2018 Adjusted Balance				**($3,899)**
October 2018		$ 21,275	$ 27,734	(6,459)
November		79,405	76,394	3,011
December		98,399	93,359	5,040
January 2019		119,594	113,368	6,226
February		103,211	97,352	5,859
March		87,224	87,303	(79)
April		30,528	34,046	(3,518)
May	**(Est.)**	19,335	22,111	(2,776)
June	**(Est.)**	9,946	10,137	(191)
July	**(Est.)**	10,428	9,748	680
August	**(Est.)**	9,117	8,754	363
September	**(Est.)**	10,179	11,438	(1,259)
Total				**$2,997**

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INTEREST
COMPUTED AT 8.21% ROR FOR OCTOBER 2018
COMPUTED AT 6.99% ROR FOR NOVEMBER 2018 - SEPTEMBER 2019

(000)

		OVER/(UNDER) RECOVERIES			
		Monthly	Cumulative	Average Balance	INTEREST
Balance September 30, 2018			**($3,899)**		
Interest Adjustment			**0**		
October 1, 2018 Adjusted Balance			**($3,899)**		
October 2018		$ (6,459)	(10,358)	$ (7,129)	$ (49)
November		3,011	(7,347)	$ (8,853)	(52)
December		5,040	(2,307)	(4,827)	(28)
January 2019		6,226	3,919	806	5
February		5,859	9,778	6,849	40
March		(79)	9,699	9,739	57
April		(3,518)	6,181	7,940	46
May	**(Est.)**	(2,776)	3,405	4,793	28
June	**(Est.)**	(191)	3,214	3,310	19
July	**(Est.)**	680	3,894	3,554	21
August	**(Est.)**	363	4,256	4,075	24
September	**(Est.)**	(1,259)	2,997	3,627	21
Total					**$ 132**

BGSS-RSG 2019-2020
NYMEX====>>> May 9, 2019

NO CHANGE IN RATES

	BGSS-RSG MDTh	COST	REFUNDS	CONTRIB	OFF-SYS Margin	Electric Contribution	FT Balancing Credit	ADJ COST	RSG Bal. Revenue	BGSS RECOVERY	EXCESS COST	OVER/(UNDER) RECOVERY Month	Cumulative	RSG Rate $/dth
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)=(2).+.(7)	(9)	(10)=(1)*(14)+(9)	(11)=(10)-(8)	(12)=-(11)	(13)	(14)
Apr-19 Act													**$6,181**	$3.1080
May-19 Est.	6,221	$24,733	$0	($521)	($921)	($1,180)	$0	$22,111	$0	$19,335	$2,776	($2,776)	$3,405	$3.1080
Jun-19 Est.	3,200	$13,366	$0	($769)	($921)	($1,539)	$0	$10,137	$0	$9,946	$191	($191)	$3,214	$3.1080
Jul-19 Est.	3,355	$14,435	$0	($964)	($921)	($2,803)	$0	$9,748	$0	$10,428	($680)	$680	$3,894	$3.1080
Aug-19 Est.	2,933	$13,051	$0	($620)	($921)	($2,756)	$0	$8,754	$0	$9,117	($363)	$363	$4,256	$3.1080
Sep-19 Est.	**3,275**	**$14,809**	**$0**	**($194)**	**($921)**	**($2,256)**	**$0**	**$11,438**	**$0**	**$10,179**	**$1,259**	**($1,259)**	**$2,997**	$3.1080
Oct-19 Est.	6,623	$29,958	$0	$462	($921)	($2,385)	($909)	$26,206	$2,851	$23,434	$2,771	($2,771)	$225	$3.1080
Nov-19 Est.	15,626	$68,821	$0	($2,087)	($6,472)	($1,610)	($2,014)	$56,638	$10,533	$59,100	($2,462)	$2,462	$2,687	$3.1080
Dec-19 Est.	22,099	$96,485	$0	($1,599)	($6,472)	($1,417)	($3,461)	$83,537	$15,904	$84,587	($1,050)	$1,050	$3,737	$3.1080
Jan-20 Est.	28,185	$123,789	$0	($429)	($4,400)	($984)	($4,688)	$113,288	$21,038	$108,637	$4,651	($4,651)	($915)	$3.1080
Feb-20 Est.	25,080	$110,401	$0	$38	($4,400)	($824)	($4,402)	$100,813	$18,596	$96,545	$4,268	($4,268)	($5,183)	$3.1080
Mar-20 Est.	19,792	$86,918	$0	($3,713)	($6,472)	($968)	($3,443)	$72,322	$13,958	$75,471	($3,149)	$3,149	($2,034)	$3.1080
Apr-20 Est.	10,963	$48,730	$0	($386)	($921)	($1,380)	($2,051)	$43,992	$6,600	$40,672	$3,320	($3,320)	($5,353)	$3.1080
May-20 Est.	5,555	$24,251	$0	($521)	($921)	($1,180)	($209)	$21,419	$1,950	$19,214	$2,205	($2,205)	($7,558)	$3.1080
Jun-20 Est.	3,232	$14,101	$0	($767)	($921)	($1,539)	$0	$10,874	$0	$10,045	$829	($829)	($8,387)	$3.1080
Jul-20 Est.	3,376	$14,603	($20,000)	($961)	($921)	($2,803)	$0	($10,082)	$0	$10,492	($20,575)	$20,575	$12,187	$3.1080
Aug-20 Est.	2,983	$12,995	$0	($619)	($921)	($2,756)	$0	$8,699	$0	$9,270	($572)	$572	$12,759	$3.1080
Sep-20 Est.	**3,336**	**$14,528**	**$0**	**($195)**	**($921)**	**($2,256)**	**$0**	$11,156	**$0**	$10,368	$788	($788)	$11,971	$3.1080
Oct-19 to Sept-20	**146,848**	**$645,580**	**($20,000)**	**($10,776)**	**($34,664)**	**($20,101)**	**($21,178)**	**$538,861**	**$91,431**	**$547,835**	**($8,974)**			

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BGSS-RSG 2019-2020 NYMEX====>>> May 9, 2019												ZERO BALANCE		
	BGSS-RSG				OFF-SYS	Electric	FT Balancing		RSG Bal.	BGSS	EXCESS	OVER/(UNDER) RECOVERY		RSG Rate
	MDTh	COST	REFUNDS	CONTRIB	Margin	Contribution	Credit	ADJ COST	Revenue	RECOVERY	COST	Month	Cumulative	$/dth
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)=(2).+.(7)	(9)	(10)=(1)*(14)+(9)	(11)=(10)-(8)	(12)=-(11)	(13)	(14)
Apr-19 Act.													**$6,181**	$3.1080
May-19 Est.	6,221	$24,733	$0	($521)	($921)	($1,180)	$0	$22,111	$0	$19,335	$2,776	($2,776)	$3,405	$3.1080
Jun-19 Est.	3,200	$13,366	$0	($769)	($921)	($1,539)	$0	$10,137	$0	$9,946	$191	($191)	$3,214	$3.1080
Jul-19 Est.	3,355	$14,435	$0	($964)	($921)	($2,803)	$0	$9,748	$0	$10,428	($680)	$680	$3,894	$3.1080
Aug-19 Est.	2,933	$13,051	$0	($620)	($921)	($2,756)	$0	$8,754	$0	$9,117	($363)	$363	$4,256	$3.1080
Sep-19 Est.	**3,275**	**$14,809**	**$0**	**($194)**	**($921)**	**($2,256)**	**$0**	**$11,438**	**$0**	**$10,179**	**$1,259**	**($1,259)**	**$2,997**	$3.1080
Oct-19 Est.	6,623	$29,958	$0	$462	($921)	($2,385)	($909)	$26,206	$2,851	$22,894	$3,311	($3,311)	($314)	$3.0265
Nov-19 Est.	15,626	$68,821	$0	($2,087)	($6,472)	($1,610)	($2,014)	$56,638	$10,533	$57,826	($1,188)	$1,188	$873	$3.0265
Dec-19 Est.	22,099	$96,485	$0	($1,599)	($6,472)	($1,417)	($3,461)	$83,537	$15,904	$82,785	$752	($752)	$122	$3.0265
Jan-20 Est.	28,185	$123,789	$0	($429)	($4,400)	($984)	($4,688)	$113,288	$21,038	$106,339	$6,949	($6,949)	($6,827)	$3.0265
Feb-20 Est.	25,080	$110,401	$0	$38	($4,400)	($824)	($4,402)	$100,813	$18,596	$94,501	$6,312	($6,312)	($13,140)	$3.0265
Mar-20 Est.	19,792	$86,918	$0	($3,713)	($6,472)	($968)	($3,443)	$72,322	$13,958	$73,857	($1,536)	$1,536	($11,604)	$3.0265
Apr-20 Est.	10,963	$48,730	$0	($386)	($921)	($1,380)	($2,051)	$43,992	$6,600	$39,779	$4,213	($4,213)	($15,817)	$3.0265
May-20 Est.	5,555	$24,251	$0	($521)	($921)	($1,180)	($209)	$21,419	$1,950	$18,761	$2,658	($2,658)	($18,475)	$3.0265
Jun-20 Est.	3,232	$14,101	$0	($767)	($921)	($1,539)	$0	$10,874	$0	$9,781	$1,093	($1,093)	($19,568)	$3.0265
Jul-20 Est.	3,376	$14,603	($20,000)	($961)	($921)	($2,803)	$0	($10,082)	$0	$10,217	($20,299)	$20,299	$732	$3.0265
Aug-20 Est.	2,983	$12,995	$0	($619)	($921)	($2,756)	$0	$8,699	$0	$9,027	($329)	$329	$1,060	$3.0265
Sep-20 Est.	**3,336**	**$14,528**	**$0**	**($195)**	**($921)**	**($2,256)**	**$0**	**$11,156**	**$0**	**$10,096**	**$1,060**	**($1,060)**	**$0**	$3.0265
Oct-19 to Sept-20	**146,848**	**$645,580**	**($20,000)**	**($10,776)**	**($34,664)**	**($20,101)**	**($21,178)**	**$538,861**	**$91,431**	**$535,864**	**$2,997**			

Item 7

BGSS FOR PERIOD Oct. 18 to Sept. 19							
	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19
Beginning Balance	$ (3,899,348)	$ (10,358,579)	$ (7,347,662)	$ (2,307,436)	$ 3,918,446	$ 9,778,056	$ 9,698,882
FUEL REVENUES							
Fuel Revenues	22,204,433	77,020,025	96,725,736	119,139,261	103,418,767	83,589,618	30,087,349
Interruptible Contribution	(929,718)	2,385,332	1,673,217	455,159	(208,191)	3,634,331	440,949
Total Fuel Revenues	21,274,715	79,405,357	98,398,953	119,594,420	103,210,576	87,223,949	30,528,298
FUEL EXPENSE							
Gas Purchases	27,821,921	76,403,608	93,358,727	113,368,538	97,350,965	87,303,123	34,046,225
Refunds	(87,975)	(9,168)	0	0	0	0	0
Total Fuel Expense	27,733,946	76,394,440	93,358,727	113,368,538	97,350,965	87,303,123	34,046,225
OVER / (UNDER) RECOVERY	(6,459,231)	3,010,917	5,040,225	6,225,882	5,859,610	(79,174)	(3,517,927)
Cumulative Recovery	$ (10,358,579)	$ (7,347,662)	$ (2,307,436)	$ 3,918,446	$ 9,778,056	$ 9,698,882	$ 6,180,955

BGSS
Calculation of Fuel Revenues
FOR PERIOD Oct. 18 to Sept. 19

	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19
RSG Fuel Revenues	$21,945,805	$56,686,864	$71,441,198	$89,076,711	$77,188,170	$67,408,952	$29,096,129
RSGM Fuel Revenues	$417,826	$1,131,827	$1,622,134	$1,874,453	$1,631,737	$1,425,772	$675,324
Subtotal	$22,363,631	$57,818,690	$73,063,332	$90,951,164	$78,819,908	$68,834,724	$29,771,453
FT Balancing Revenues	-159,198	11,589,516	22,501,053	25,260,609	27,929,305	23,125,106	315,896
FT Balancing Revenues (Unbilled Calc)	0	7,611,819	8,773,170	11,700,659	8,370,212	0	0
FT Balancing Revenues (Prior Unbilled Calc)	0	0	-7,611,819	-8,773,170	-11,700,659	-8,370,212	0
Total BGSSR Fuel Recovery	$22,204,433	$77,020,025	$96,725,736	$119,139,261	$103,418,767	$83,589,618	$30,087,349

Bill Credits

	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19
Billed Revenues	$ 157,241	$ 132,928	$ 117,100	$ 114,743	$ 52,324	$ 68,762	$ 122,150
Current Unbilled Usage	0	85,843,424	86,718,704	114,887,773	81,988,349	60,668,341	28,116,000
Prior Unbilled Usage	0	0	85,843,424	86,718,704	114,887,773	81,988,349	60,668,341
Net Unbilled Usage	0	85,843,424	875,280	28,169,069	-32,899,424	-21,320,008	-32,552,341
Rate (.28 less 7% taxes)	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000
Subtotal Unbilled Revenues	$0	$0	$0	$0	$0	$0	$0
Total Bill Credits	$157,241	$132,928	$117,100	$114,743	$52,324	$68,762	$122,150

Input Page

	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19
Interruptible Contributions:							
ISG (BGSS-I):							
ISG (BGSS-I) Sales Therms	572,601	994,384	1,120,378	1,010,726	1,206,759	2,604,901	436,979
ISG BGSS-I) Gross Revenues	$226,742	360,803.40	422,629.77	319,756.75	569,887.27	1,150,288.55	$377,250
ISG (BGSS-I) Cost	$164,162	$305,427	$325,542	$496,144	$494,753	$294,209	$168,136
PSEG Power's share of Contribution	$28,830	$19,901	$55,539	$231,300	$193,076	$42,277	$33,410
ISG Interuptible Contribution to BGSSR	$33,751	$35,476	$41,548	($407,687)	($117,942)	$813,802	$175,704
CIG:							
CIG SBC Rate adjustment (line 84)							
CIG Sales Therms	-41,532	6,515,273	4,303,302	3,394,883	559,242	7,571,166	1,757,612
CIG Gross Revenues	$19,877	2,922,405	2,621,389	1,708,611	63,412	3,588,421	$713,771
CIG SBC/GPRC Revenues	-$2,026	$330,572	$218,341	$172,250	$28,375	$384,146	$89,178
CIG Cost	$747,930	$1,334,041	$1,342,727	$957,985	$597,397	$1,007,711	$595,845
CIG TAC revenues	$0	-$145,458	-$25,043	-$12,201	-$466	-$84,578	-$19,274
PSEG Power's share of Contribution	$66,400	$15,958	$125,432	$128,328	$55,177	$69,602	$68,792
CIG Interuptible Contribution to BGSSR	-$792,428	$1,387,293	$959,932	$462,251	-$617,071	$2,211,541	-$20,769
TSG-F:							
TSG-F SBC Rate adjustment (line 84)							
TSG-F Sales Therms	1,123,977	1,513,416	2,140,902	2,841,547	2,797,264	2,891,707	1,559,004
TSG-F Gross Revenues	$128,941	423,494	383,925	504,489	565,810	545,211	$15,055
TSG-F SBC/GPRC Revenues	$54,832	$76,788	$108,625	$144,174	$141,928	$146,719	$79,101
TSG-F TAC Revenues	$0	-$193,570	-$90,165	$7,427	-$59,032	-$50,253	-$32,062
TSG-F MAC Revenues	-$7,124	-$9,592	-$13,569	-$18,010	-$17,729	-$18,328	-$9,881
TSG-F PSEG Power's share of Contribution	$82,652	$96,103	$99,601	$137,041	$118,673	$125,183	$61,909
TSG-F Interuptible Contribution to BGSSR	-$1,419	$453,766	$279,433	$233,856	$381,971	$341,889	-$84,012
CSG NON-Power:							
CSG Non-Power Therms	(9,512,027)	22,106,445	10,387,656	1,923,250	3,440,845	1,757,280	7,494,822
CSG Non-Power Revenues	55,697	441,812	461,212	275,757	256,133	213,758	330,367
CSG Non Power SBC Revenues	196,784	265,557	315,762	172,058	168,053	4,434	4,434
CSG TAC Revenues Power and NON-Power	-	(391,071)	(243,278)	(88,073)	(80,955)	(66,850)	(66,055)
CSG Non-Power ER&T's share of Contribution	28,536	58,530	(3,576)	25,032	24,184	9,075	21,962
CSG Non-Power Contribution to BGSSR	(169,623)	508,797	392,303	166,740	144,851	267,099	370,025
Total Interruptible Contributions	(929,718)	2,385,332	1,673,217	455,159	(208,191)	3,634,331	440,949
SBC & GPRC rate-CIG & TSG-F (CHECK tariff pages for rate changes)	0.048784	0.050738	0.050738	0.050738	0.050738	0.050738	0.050738
TEFA rate-TSG-F (Reduced 25% 2012 & 25% 2013, zero out 2014)	0.00	-	-	-	-	-	-
Cogen Contract RAC rate (separate schedule beginning 12/02)	n/a	n/a	n/a	n/a	n/a	n/a	n/a
MAC rate-TSG-F (Per MAC CALC Worksheet)	-0.006338	(0.006338)	(0.006338)	(0.006338)	(0.006338)	(0.006338)	(0.006338)
Current Month Estimate - Gas Purchases (1) See below row 96	$28,471,524	$76,685,159	$93,929,498	$118,301,577	$97,176,182	$88,023,519	$34,459,026
Prior Month Actual - Gas Purchases (1) See below row 105	$6,954,298	$28,180,804	$76,114,388	$88,996,459	$118,476,360	$96,455,786	$87,610,718

Prior Month Estimate - Gas Purchases See below row 115	$7,691,876	$28,471,524	$76,685,159	$93,929,498	$118,301,577	$97,176,182	$88,023,519
Gas Purchases	$27,733,946	$76,394,440	$93,358,727	$113,368,538	$97,350,965	$87,303,123	$34,046,225
Gas Refunds	-$87,975	-$9,168	$0	$0	$0	$0	$0
ISG (BGSS-I) Cost Est. (2)	$163,503	$303,993	$324,754	$459,857	$434,492	$287,199	$162,642
PSEG Power's share of Contribution CMnth Est. (2)	$28,487	$16,067	$47,309	$89,374	$81,851	$39,346	$31,734
ISG (BGSS-I) Cost Pr Mnth Act. (2)	$56,761	$164,937	$304,781	$361,041	$520,118	$441,503	$292,692
PSEG Power's share of Contribution Pr Mnth Act. (2)	$15,320	$32,321	$24,297	$189,235	$200,599	$84,782	$41,022
ISG (BGSS-I) Cost PrMnth Est.	$56,102	$163,503	$303,993	$324,754	$459,857	$434,492	$287,199
PSEG Power's share of Contribution PrMnth Est.	$14,977	$28,487	$16,067	$47,309	$89,374	$81,851	$39,346
CIG Cost (3) - CMnth Est. (3)	$743,123	$1,328,903	$1,340,262	$959,214	$613,201	$906,954	$591,937
PSEG Power's share of Contribution - CMnth Est. (3)	$64,849	$7,880	$125,514	$120,491	$67,873	$58,180	$67,121
CIG Cost (3) - PrMnth Act. (3)	$652,543	$748,261	$1,331,368	$1,339,032	$943,411	$713,957	$910,862
PSEG Power's share of Contribution - PrMnth Act. (3)	$105,250	$72,927	$7,799	$133,350	$107,795	$79,294	$59,851
CIG Cost - PrMnth Est.	$647,737	$743,123	$1,328,903	$1,340,262	$959,214	$613,201	$906,954
PSEG Power's share of Contribution - PrMnth Est.	$103,698	$64,849	$7,880	$125,514	$120,491	$67,873	$58,180
TSG-F PSEG Power's share of Contribution CMth Est. (4)	$79,281	$85,424	$94,696	$131,065	$111,175	$117,713	$58,178
TSG-F PSEG Power's share of Contribution PrMth Actual (4)	$94,592	$89,960	$90,329	$100,673	$138,564	$118,645	$121,444
TSG-F PSEG Power's share of Contribution PrMth Est.	$91,221	$79,281	$85,424	$94,696	$131,065	$111,175	$117,713
CSC Non-Power Cost & PSEG Power's share of Contribution CMth Est. (6)	$59,107	$49,743	$23,415	$25,648	$25,099	$16,876	$20,154
CSC Non-Power Cost & PSEG Power's share of Contribution PMth Act. (6)	$72,562	$67,893	$22,752	$22,799	$24,734	$17,297	$18,684
CSC Non-Power Cost & PSEG Power's share of Contribution PMth Est.	$103,132	$59,107	$49,743	$23,415	$25,648	$25,099	$16,876
BGSS-RSG Prior Month Actual	$7,784,173	$29,199,250	$77,782,634	$90,846,068	$120,248,284	$97,775,323	$88,915,146
BGSS-RSG Cogen Contracts Prior Month Actual (6)	$0	$0	$0	$0	$0	$0	$0
BGSS-RSG TSG Cashouts Prior Mnth Actuals	$0	$0	$0	$0	$0	$0	$0
Subtotal	$8,302,993	$29,694,137	$77,753,043	$90,791,772	$120,540,147	$97,993,088	$89,115,064
Total BGSS-RSG Actual Bill	$8,302,993	$29,694,137	$77,753,043	$90,791,772	$120,540,147	$97,993,088	$89,115,064
Difference	$0	$0	$0	$0	$0	$0	$0
BGSS-RSG Current Month Estimate	$29,957,346	$78,636,366	$96,000,439	$120,261,766	$98,620,781	$89,613,349	$35,492,386
BGSS-RSG Cogen Contracts Prior Month Estimate (6)	$0	$0	$0	$0	$0	$0	$0
Subtotal	$29,957,346	$78,636,366	$96,000,439	$120,261,766	$98,620,781	$89,613,349	$35,492,386
Total BGSS-RSG Estimate Bill	$29,957,346	$78,636,366	$96,000,439	$120,261,766	$98,620,781	$89,613,349	$35,492,386
Difference	$0	$0	$0	$0	$0	$0	$0
Gas Purchases Details:							
Current Month Estimate							
BGSS-RSG GAS COMMODITY VOLUMES MDTh	8,034,116	19,032,120	23,426,952	29,582,629	23,525,040	20,524,399	8,670,870
BGSS-RSG GAS COMMODITY COST	$31,051,248	$76,465,158	$96,984,405	$121,330,544	$96,706,348	$87,172,893	$35,011,628
BGSS-RSG Balancing	$805,099	$3,282,728	$4,064,471	$5,176,694	$4,112,314	$3,539,817	$868,908
BGSS-RSG Off System Sales	($1,378,735)	($1,761,540)	($6,010,438)	($6,787,885)	($2,562,585)	($1,661,735)	($565,234)
Electric Reservation Charge	($1,520,228)	($1,038,339)	($906,610)	($1,115,519)	($862,125)	($678,193)	($676,350)
Other	$0	$31,516	$30,772	$28,996	$29,411	$29,065	$0

CSG Revenues		($485,861)	($294,364)	($233,103)	($331,252)	($247,181)	($298,151)	($179,926)
Credit for Pipeline Refunds		$0	$0	$0	$0	$0	$0	$0
	Total	$28,471,524	$76,685,159	$93,929,498	$118,301,577	$97,176,182	$88,023,519	$34,459,026
Prior Actual								
BGSS-RSG GAS COMMODITY VOLUMES MDTh		2,965,874	7,951,735	18,837,783	22,188,275	29,603,996	23,335,667	20,435,547
BGSS-RSG GAS COMMODITY COST		$11,550,283	$30,737,415	$75,618,844	$91,791,397	$121,669,640	$96,010,137	$86,752,870
BGSS-RSG Balancing		$325,505	$796,843	$3,242,196	$3,894,593	$5,218,362	$4,053,407	$3,517,597
BGSS-RSG Off System Sales		-$2,863,182	-$1,314,583	-$1,732,416	-$5,902,213	-$6,921,228	-$2,508,600	-$1,649,111
Electric Reservation Charge		-$1,451,513	-$1,534,815	-$1,035,919	-$911,532	-$1,120,319	-$865,143	-$759,607
CSG Revenues		-$518,820	-$494,887	$21,517	$54,297	-$370,094	-$217,765	-$199,918
Non Compliance Penalty		$0	$0	$0	$0	$0	-$16,249	-$339
Residential Share of Propane Contract Deficiency Charges		$0	$0	$165	$0	$0	$0	$0
Residential Share of Property Taxes Paid		$0	$0	$0	$51,286	$0	$0	$0
Prior Period Adjustments		($87,975)	($9,168)	$0	$18,632	$0	$0	($50,774)
Other		$0	$0	$0	$0			$0
	Total	$6,954,298	$28,180,804	$76,114,388	$88,996,459	$118,476,360	$96,455,786	$87,610,718
Prior Estimate								
BGSS-RSG GAS COMMODITY VOLUMES MDTh		3,127,243	8,034,116.00	19,032,120.00	23,426,952.00	29,582,629.00	23,525,040.00	20,524,399.00
BGSS-RSG GAS COMMODITY COST		$12,176,562	$31,051,248	$76,465,158	$96,984,405	$121,330,544	$96,706,348	$87,172,893
BGSS-RSG Balancing		$343,215	$805,099	$3,282,728	$4,064,471	$5,176,694	$4,112,314	$3,539,817
BGSS-RSG Off System Sales		($2,887,978)	($1,378,735)	($1,761,540)	($6,010,438)	($6,787,885)	($2,562,585)	($1,661,735)
Electric Reservation Charge		($1,442,584)	($1,520,228)	($1,038,339)	($906,610)	($1,115,519)	($862,125)	($678,193)
Other		$0	$0	$0	$0	$28,996	$29,411	$29,065
Prior CSG Revenues		($497,337)	($485,861)	($294,364)	($233,103)	($331,252)	($247,181)	($298,151)
Credit for Pipeline Refunds		$0	$0	$0	$0	$0	$0	$0
	Total	$7,691,876	$28,471,524	$76,653,643	$93,898,726	$118,301,577	$97,176,182	$88,103,696
Net								
BGSS-RSG GAS COMMODITY VOLUMES MDTh		7,872,747	18,949,739.00	23,232,615.00	28,343,952.00	23,546,407.00	20,335,026.00	8,582,018.00
BGSS-RSG GAS COMMODITY COST		$30,424,970	$76,151,325	$96,138,091	$116,137,536	$97,045,443	$86,476,681	$34,591,606
BGSS-RSG Balancing		$787,389	$3,274,473	$4,023,939	$5,006,815	$4,153,983	$3,480,910	$846,687
BGSS-RSG Off System Sales		($1,353,938)	($1,697,388)	($5,981,314)	($6,679,659)	($2,695,929)	($1,607,749)	($552,610)
Electric Reservation Charge		($1,529,156)	($1,052,927)	($904,190)	($1,120,442)	($866,925)	($761,388)	($757,764)
Other		$0	$31,516	($579)	$68,140	$416	($16,596)	$0
CSG Revenues		($507,343)	($303,391)	$82,779	($43,853)	($286,023)	($268,735)	($81,693)
Credit for Pipeline Refunds		($87,975)	($9,168)	$0		$0	$0	$0
	Total	$27,733,946	$76,394,440	$93,358,727	$113,368,538	$97,350,965	$87,303,123	$34,046,225
BGSS-RSG GAS COMMODITY VOLUMES MDTh		7,872,747	18,949,739	23,232,615	28,343,952	23,546,407	20,335,026	8,582,018
NET SALES VOLUMES RESIDENTIAL		6,784,165	17,633,625	22,287,990	27,768,326	24,073,241	21,019,136	9,074,053
	Diff	1,088,582	1,316,114	944,625	575,626	(526,834)	(684,110)	(492,035)

Interest Calculation

FOR PERIOD Oct. 18 to Sept. 19

	Oct-18	**Nov-18**	**Dec-18**	**Jan-19**	**Feb-19**	**Mar-19**	**Apr-19**
CUMULATIVE OVER/(UNDER) RECOVERY PRIOR MONTH	($3,899,348)	($10,358,579)	($7,347,662)	($2,307,436)	$3,918,446	$9,778,056	$9,698,882
CUMULATIVE OVER/(UNDER) RECOVERY CURRENT MONTH	($10,358,579)	($7,347,662)	($2,307,436)	$3,918,446	$9,778,056	$9,698,882	$6,180,955
AVERAGE BALANCE	($7,128,964)	($8,853,121)	($4,827,549)	$805,505	$6,848,251	$9,738,469	$7,939,919
MONTHLY INTEREST (Income)/Expense allowed rate of return of 6.99%	**($48,776)**	**($51,569)**	**($28,120)**	**$4,692**	**$39,891**	**$56,727**	**$46,250**
INTEREST ACCUMULATED, (Income)/Expense	($48,776)	($100,346)	($128,466)	($123,774)	($83,883)	($27,157)	$19,093

8. Wholesale Gas Pricing Assumptions

Item 8

A Comparison of the Forecasted Cost of Gas as represented by the NYMEX
June 2019 Filing versus June 2018 Filing

($/Mbtu)

		June '19 Filing Nymex - 5/09/19	June '18 Filing Nymex - 5/10/18	Difference	Percentage Difference
2019	**May**	$2.566	$2.821	($0.255)	-9.0%
	June	$2.595	$2.814	($0.219)	-7.8%
	July	$2.631	$2.828	($0.197)	-7.0%
	August	$2.652	$2.836	($0.184)	-6.5%
	September	$2.650	$2.822	($0.172)	-6.1%
	October	$2.681	$2.829	($0.148)	-5.2%
	November	$2.755	$2.865	($0.110)	-3.8%
	December	$2.919	$2.965	($0.046)	-1.6%
2020	**January**	$3.007	$3.047	($0.040)	-1.3%
	February	$2.963	$3.009	($0.046)	-1.5%
	March	$2.838	$2.898	($0.060)	-2.1%
	April	$2.590	$2.568	$0.022	0.9%
	May	$2.554	$2.536	$0.018	0.7%
	June	$2.586	$2.567	$0.019	0.7%
	July	$2.619	$2.600	$0.019	0.7%
	August	$2.627	$2.604	$0.023	0.9%
	September	$2.611	$2.588	$0.023	0.9%
	Average	$2.697	$2.776	($0.080)	-2.9%

9. <u>GCUA Recoveries and Balances</u>

N/A

10. Historical Service Interruptions

Item 10

<u>SERVICE INTERRUPTIONS</u>

During the current winter, service to the Company's tariff gas customers was interrupted during the following time periods:

Note: All dates below represent heating season for year 2018-2019.

<u>Rate Schedule CIG:</u>
Number of Customers: 13 (including 4 CEGs)

- 10:00 AM January 20 through 10:00 AM January 22
  (CEG was offered at $12.7750/Dth)
- 10:00 AM January 30 through 10:00 AM February 1
  (CEG was offered at $12.9125/Dth, only for the period 11:00AM January 31 through 10:00AM February 1)

<u>Rate Schedule TSG-NF (BGSS-I):</u>
Number of Customers: 26

- 10:00 AM January 20 through 10:00 AM January 22
- 10:00 AM January 30 through 10:00 AM February 1

<u>Rate Schedule TSG-NF (Third Party Suppliers):</u>
Number of Customers: 142

- 10:00 AM January 20 through 10:00 AM January 22
- 10:00 AM January 30 through 10:00 AM February 1

<u>Rate Schedule CSG-I (Third Party Suppliers):</u>
Number of Customers: 3

- 10:00 AM January 20 through 10:00 AM January 22
- 10:00 AM January 30 through 10:00 AM February 1

All of the above interruptions were done for operational reasons.

11. <u>Gas Price Hedging Activities</u>

Reports Dated:

April 10, 2019

January 8, 2019

October 3, 2018

July 17, 2018

Matthew M. Weissman
General State Regulatory Counsel

Law Department
PSEG Services Corporation
80 Park Plaza – T5, Newark, New Jersey 07102-4194
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PSEG
Services Corporation

April 10, 2019

In the Matter of Public Service Electric and Gas Company
Proposal for a Change in its Monthly Pricing Mechanism
Within its Levelized Gas Adjustment Clause for Residential
Gas Customers Pursuant to
N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1
Docket No. GR00070491

VIA ELECTRONIC MAIL

Stacy Peterson, Director
Division of Energy
Board of Public Utilities
44 South Clinton Avenue, 3rd Floor, Suite 314
P.O. Box 350
Trenton, New Jersey, 08625-0350

RE: PSE&G GAS HEDGING QUARTERLY REPORT – FIRST QUARTER 2019

Dear Director Peterson:

Enclosed please find Public Service Electric and Gas Company's ("Public Service" or the "Company") quarterly status report which is filed pursuant to the Board's March 30, 2001 Decision and Order in the above-referenced matter. This quarterly report identifies the Company's outstanding hedging positions as of March 31, 2019.

As shown on the attached schedules, approximately 98% of the planned residential volume has been completed for the 2019 summer season. Hedging for the 2019/2020 winter season is at 60% of plan and 32% of the plan has been completed for 2020 summer. All of these periods are based on a plan of approximately 70bcf with an even split between winter and summer.

The Company will continue to monitor the performance of its hedging program and the criteria it utilizes deciding when to implement hedges, and keep the Board appraised of any changes it anticipates in the program.

Very truly yours,

Matthew Weissman

Matthew M. Weissman

Attachment

C Stefanie A. Brand
Kevin Moss

PSE&G Residential Hedging Report November 2018 - October 2019 As of March 31, 2019	Bcf Target*	Bcf Hedged	% Hedged Target		% Hedged Actual	Current Price/ MMBtu
WINTER - Nov 18-Mar 19 Hedge Volume						
(230,000/ day) (151 days)						
Non-Discretionary Volume	17.500	**17.365**	94%	100%	99%	**$2.62**
Dollar Budget Method	17.500	**16.565**	$2.464M/mo.		95%	**$2.63**
Total Winter Hedge Volume	35.000	**33.930**			97%	**$2.62**
			Nymex Actual Settles			**$3.47**
SUMMER - Apr 19-Oct 19 Hedge Volume						
(160,000/ day) (214 days)						
Non-Discretionary Volume	17.500	**17.120**	94%	100%	98%	**$2.14**
Dollar Budget Method	17.500	**17.184**	$2.050M/mo.		98%	**$2.12**
Total Summer Hedge Volume	35.000	**34.304**			98%	**$2.13**
			Actual & 3/29/19 Nymex Settles			**$2.75**
Total Non-Discretionary Method	35.000	**34.485**				**$2.38**
Total Dollar Budget Method	35.000	**33.749**				**$2.37**
					Difference	**($0.01)**
					Percent	**-0.5%**

PSE&G Residential Hedging Report November 2019 - October 2020 As of March 31, 2019	Bcf Target*	Bcf Hedged	% Hedged Target		% Hedged Actual	Current Price/ MMBtu
WINTER - Nov 19-Mar 20 Hedge Volume (230,000/ day) (151 days)						
Non-Discretionary Volume	17.500	**11.400**	56%	61%	65%	**$2.51**
Dollar Budget Method	17.500	**9.470**	$2.175M/mo.		54%	**$2.51**
Total Winter Hedge Volume	35.000	**20.870**			60%	**$2.51**
			3/29/19 Nymex Settles			**$2.98**
SUMMER - Apr 20-Oct 20 Hedge Volume (160,000/ day) (214 days)						
Non-Discretionary Volume	17.500	**5.350**	28%	33%	31%	**$2.00**
Dollar Budget Method	17.500	**5.757**	$1.95M/mo.		33%	**$2.01**
Total Summer Hedge Volume	35.000	**11.107**			32%	**$2.01**
			3/29/19 Nymex Settles			**$2.61**
Total Non-Discretionary Method	35.000	**16.750**				**$2.35**
Total Dollar Budget Method	35.000	**15.227**				**$2.32**
					Difference	**($0.03)**
					Percent	**-1.3%**

Matthew M. Weissman
General State Regulatory Counsel

Law Department
PSEG Services Corporation
80 Park Plaza – T5, Newark, New Jersey 07102-4194
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January 8, 2019

In the Matter of Public Service Electric and Gas Company
Proposal for a Change in its Monthly Pricing Mechanism
Within its Levelized Gas Adjustment Clause for Residential
Gas Customers Pursuant to
N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1
Docket No. GR00070491

VIA ELECTRONIC MAIL

Stacy Peterson, Director
Division of Energy
Board of Public Utilities
44 South Clinton Avenue, 3rd Floor, Suite 314
P.O. Box 350
Trenton, New Jersey, 08625-0350

RE: PSE&G GAS HEDGING QUARTERLY REPORT – FOURTH QUARTER 2018

Dear Director Peterson:

Enclosed please find Public Service Electric and Gas Company's ("Public Service" or the "Company") quarterly status report which is filed pursuant to the Board's March 30, 2001 Decision and Order in the above-referenced matter. This quarterly report identifies the Company's outstanding hedging positions as of December 31, 2018.

As shown on the attached schedules, approximately 97% of the planned residential volume has been completed for the 2018/19 winter season. Hedging for the 2019 summer is at 81% of plan. Hedging for the 2019/2020 winter is at 44% of plan and 17% of plan has been completed for the 2020 summer. All of these periods are based on a plan of approximately 70bcf with an even split between winter and summer.

The Company will continue to monitor the performance of its hedging program and the criteria it utilizes deciding when to implement hedges, and keep the Board appraised of any changes it anticipates in the program.

Very truly yours,

Matthew Weissman

Matthew M. Weissman

Attachment

C Stefanie A. Brand
Kevin Moss

PSE&G Residential Hedging Report
November 2018 - October 2019
As of 12/31/2018

	Bcf Target*	Bcf Hedged	% Hedged Target		% Hedged Actual	Current Price/ MMBtu
WINTER - Nov 18-Mar 19 Hedge Volume						
(230,000/ day) (151 days)						
Non-Discretionary Volume	17.500	**17.365**	94%	100%	99%	**$2.62**
Dollar Budget Method	17.500	**16.565**	$2.464M/mo.		95%	**$2.63**
Total Winter Hedge Volume	35.000	**33.930**			97%	**$2.62**
			Nymex Actual & Settle 12/28/18			**$3.60**
SUMMER - Apr 19-Oct 19 Hedge Volume						
(160,000/ day) (214 days)						
Non-Discretionary Volume	17.500	**13.910**	78%	83%	79%	**$2.09**
Dollar Budget Method	17.500	**14.552**	$2.050M/mo.		83%	**$2.09**
Total Summer Hedge Volume	35.000	**28.462**			81%	**$2.09**
			Nymex Settle 12/28/18			**$2.83**
Total Non-Discretionary Method	35.000	**31.275**				**$2.38**
Total Dollar Budget Method	35.000	**31.117**				**$2.38**
					Difference	**($0.01)**
					Percent	**-0.3%**

PSE&G Residential Hedging Report November 2019 - October 2020 As of 12/31/2018	Bcf Target*	Bcf Hedged	% Hedged Target		% Hedged Actual	Current Price/ MMBtu
WINTER - Nov 19-Mar 20 Hedge Volume						
(230,000/ day) (151 days)						
Non-Discretionary Volume	17.500	**8.360**	38%	44%	48%	**$2.45**
Dollar Budget Method	17.500	**7.038**	$2.175M/mo.		40%	**$2.45**
Total Winter Hedge Volume	35.000	**15.398**			44%	**$2.45**
			Nymex Settle 12/28/18			**$3.01**
SUMMER - Apr 20-Oct 20 Hedge Volume						
(160,000/ day) (214 days)						
Non-Discretionary Volume	17.500	**3.210**	11%	17%	18%	**$1.97**
Dollar Budget Method	17.500	**2.910**	$1.95M/mo.		17%	**$1.99**
Total Summer Hedge Volume	35.000	**6.120**			17%	**$1.98**
			Nymex Settle 12/28/18			**$2.53**
Total Non-Discretionary Method	35.000	**11.570**				**$2.31**
Total Dollar Budget Method	35.000	**9.948**				**$2.32**
					Difference	**$0.00**
					Percent	**0.1%**

Matthew M. Weissman
General State Regulatory Counsel

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PSEG
Services Corporation

October 3, 2018

In the Matter of Public Service Electric and Gas Company
Proposal for a Change in its Monthly Pricing Mechanism
Within its Levelized Gas Adjustment Clause for Residential
Gas Customers Pursuant to
N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1
Docket No. GR00070491

VIA ELECTRONIC MAIL

Stacy Peterson, Director
Division of Energy
Board of Public Utilities
44 South Clinton Avenue, 3rd Floor, Suite 314
P.O. Box 350
Trenton, New Jersey, 08625-0350

RE: PSE&G GAS HEDGING QUARTERLY REPORT – THIRD QUARTER 2018

Dear Director Peterson:

Enclosed please find Public Service Electric and Gas Company's ("Public Service" or the "Company") quarterly status report which is filed pursuant to the Board's March 30, 2001 Decision and Order in the above-referenced matter. This quarterly report identifies the Company's outstanding hedging positions as of September 30, 2018.

As shown on the attached schedules, approximately 92% of the planned residential volume has been completed for the 2018/19 winter season. Hedging for the 2019 summer is at 68% of plan. Hedging for the 2019/2020 winter is at 26% of plan and we have not begun to hedge for the 2020 summer. All of these periods are based on a plan of approximately 70bcf with an even split between winter and summer.

The Company will continue to monitor the performance of its hedging program and the criteria it utilizes deciding when to implement hedges, and keep the Board appraised of any changes it anticipates in the program.

Very truly yours,

Matthew Weissman

Matthew M. Weissman

Attachment

C Stefanie A. Brand

PSE&G Residential Hedging Report November 2018 - October 2019 As of September 30, 2018	Bcf Target*	Bcf Hedged	% Hedged Target		% Hedged Actual	Current Price/ MMBtu
WINTER - Nov 18-Mar 19 Hedge Volume						
(230,000/ day) (151 days)						
Non-Discretionary Volume	17.500	**16.610**	89%	94%	95%	**$2.60**
Dollar Budget Method	17.500	**15.749**	$2.464M/mo.		90%	**$2.61**
Total Winter Hedge Volume	35.000	**32.359**			92%	**$2.60**
			9/30/2018 Nymex settle price			**$3.06**
SUMMER - Apr 19-Oct 19 Hedge Volume						
(160,000/ day) (214 days)						
Non-Discretionary Volume	17.500	**11.770**	61%	67%	67%	**$2.06**
Dollar Budget Method	17.500	**11.856**	$2.050M/mo.		68%	**$2.05**
Total Summer Hedge Volume	35.000	**23.626**			68%	**$2.06**
			9/30/2018 Nymex settle price			**$2.66**
Total Non-Discretionary Method	35.000	**28.380**				**$2.38**
Total Dollar Budget Method	35.000	**27.605**				**$2.37**
					Difference	**($0.01)**
					Percent	**-0.4%**

PSE&G Residential Hedging Report November 2018 - October 2020 As of September 30, 2018	**Bcf Target***	**Bcf Hedged**	**% Hedged Target**		**% Hedged Actual**	**Current Price/ MMBtu**
WINTER - Nov 19-Mar 20 Hedge Volume						
(230,000/ day) (151 days)						
Non-Discretionary Volume	17.500	**4.560**	22%	28%	26%	**$2.36**
Dollar Budget Method	17.500	**4.530**	$2.175M/mo.		26%	**$2.39**
Total Winter Hedge Volume	35.000	**9.090**			26%	**$2.37**
			9/30/2018 Nymex settle price			**$2.84**
SUMMER - Apr 20-Oct 20 Hedge Volume						
(160,000/ day) (214 days)						
Non-Discretionary Volume	17.500	**0.000**	0%	0%	0%	**$0.00**
Dollar Budget Method	17.500	**0.000**	$0M/mo.		0%	**$0.00**
Total Summer Hedge Volume	35.000	**0.000**			0%	**#DIV/0!**
			Current NYMEX Strip ===>			
Total Non-Discretionary Method	35.000	**4.560**				**$2.36**
Total Dollar Budget Method	35.000	**4.530**				**$2.39**
					Difference	**$0.02**
					Percent	**0.9%**

Matthew M. Weissman
General Regulatory Counsel - Rates

Law Department
PSEG Services Corporation
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PSEG
Services Corporation

July 17, 2018

In the Matter of Public Service Electric and Gas Company
Proposal for a Change in its Monthly Pricing Mechanism
Within its Levelized Gas Adjustment Clause for Residential
Gas Customers Pursuant to
N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1
Docket No. GR00070491

VIA ELECTRONIC MAIL

Stacy Peterson, Director
Division of Energy
Board of Public Utilities
44 South Clinton Avenue, 3rd Floor, Suite 314
P.O. Box 350
Trenton, New Jersey, 08625-0350

RE: PSE&G GAS HEDGING QUARTERLY REPORT – SECOND QUARTER 2018

Dear Director Peterson:

Enclosed please find Public Service Electric and Gas Company's ("Public Service" or the "Company") quarterly status report which is filed pursuant to the Board's March 30, 2001 Decision and Order in the above-referenced matter. This quarterly report identifies the Company's outstanding hedging positions as of June 30, 2018.

As shown on the attached schedules, approximately 78% of the planned residential volume has been completed for the 2018/19 winter season. Hedging for the 2019 summer is at 50% of plan. Hedging for the 2019/2020 winter is at 12% of plan and we have not begun to hedge for the 2019 summer. All of these periods are based on a plan of approximately 70bcf with an even split between winter and summer.

The Company will continue to monitor the performance of its hedging program and the criteria it utilizes deciding when to implement hedges, and keep the Board appraised of any changes it anticipates in the program.

Very truly yours,

Matthew Weissman

Matthew M. Weissman

Attachment

C Stefanie A. Brand

PSE&G Residential Hedging Report November 2018 - October 2019 As of 6/30/2018	Bcf Target*	Bcf Hedged	% Hedged Target		% Hedged Actual	Current Price/ MMBtu
WINTER - Nov 18-Mar 19 Hedge Volume (230,000/ day) (151 days)						
Non-Discretionary Volume	17.500	**14.345**	78%	83%	82%	**$2.60**
Dollar Budget Method	17.500	**12.941**	$2.464M/mo.		74%	**$2.61**
Total Winter Hedge Volume	35.000	**27.286**			78%	**$2.60**
			Current NYMEX Strip ===>			**$3.00**
SUMMER - Apr 19-Oct 19 Hedge Volume (160,000/ day) (214 days)						
Non-Discretionary Volume	17.500	**8.560**	44%	50%	49%	**$2.04**
Dollar Budget Method	17.500	**9.009**	$2.050M/mo.		51%	**$2.02**
Total Summer Hedge Volume	35.000	**17.569**			50%	**$2.03**
			Current NYMEX Strip ===>			**$2.64**
Total Non-Discretionary Method	35.000	**22.905**				**$2.39**
Total Dollar Budget Method	35.000	**21.950**				**$2.37**
					Difference	**($0.02)**
					Percent	**-1.0%**

PSE&G Residential Hedging Report November 2019 - October 2020 As of 6/30/2018	Bcf Target*	Bcf Hedged	% Hedged Target		% Hedged Actual	Current Price/ MMBtu
WINTER - Nov 19-Mar 20 Hedge Volume (230,000/ day) (151 days)						
Non-Discretionary Volume	17.500	**2.280**	11%	17%	13%	**$2.39**
Dollar Budget Method	17.500	**1.824**	$2.175M/mo.		10%	**$2.37**
Total Winter Hedge Volume	35.000	**4.104**			12%	**$2.38**
			Current NYMEX Strip ===>			**$2.86**
SUMMER - Apr 20-Oct 20 Hedge Volume (160,000/ day) (214 days)						
Non-Discretionary Volume	17.500	**0.000**	0%	0%	0%	**$0.00**
Dollar Budget Method	17.500	**0.000**	$0M/mo.		0%	**$0.00**
Total Summer Hedge Volume	35.000	**0.000**			0%	**#DIV/0!**
			Current NYMEX Strip ===>			
Total Non-Discretionary Method	35.000	**2.280**				**$2.39**
Total Dollar Budget Method	35.000	**1.824**				**$2.37**
					Difference	**($0.02)**
					Percent	**-0.8%**

12. Storage Gas Volumes, Prices and Utilization

Ending Storage Inventory by Contract

Mdth

Storage Contract	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19
DTI GSS	16,182.7	15,368.9	12,897.4	8,102.1	3,974.4	648.7	3,105.9
ARLINGTON	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TR GSS	15,483.9	14,638.5	13,946.2	10,673.1	7,438.4	3,500.9	4,522.0
TR S-2	5,815.1	5,741.0	4,998.5	3,144.1	1,466.5	675.3	874.4
TR LSS	4,945.9	4,637.9	3,876.9	2,714.6	1,783.5	1,126.3	1,740.9
TENN FS-MA	2,503.6	2,344.5	1,838.8	1,838.5	1,529.3	1,419.3	1,663.7
DTI GSS-TE	14,090.2	13,084.5	11,662.0	7,579.5	4,185.5	1,141.4	3,194.8
TE SS-1 / SS	3,735.7	3,481.0	3,186.6	2,234.5	1,315.7	494.9	879.2
TE SS1	1,452.8	1,367.8	1,235.0	887.0	527.4	189.7	358.6
TR ESS	1,163.9	1,129.8	1,186.5	703.8	568.0	619.4	1,099.4
GULF SOUTH	995.7	961.6	1,000.0	588.1	719.4	911.7	409.5
TR LNG	1,333.8	1,333.8	1,327.2	1,203.9	1,181.5	1,181.5	1,321.5
TR LNG New	15.5	15.5	15.5	15.5	15.5	15.5	15.5
Total	67,718.7	64,104.8	57,170.5	39,684.7	24,705.2	11,924.8	19,185.6
Ending Inventory Cost ($/Dth)	$3.86	$4.01	$4.13	$4.11	$4.14	$3.99	$3.82

NOTE: All volumes shown above represent total storage for all firm customers while the average inventory cost is applicable to residential only.

LPG INVENTORY VOLUMES AND COST BY LOCATION
(000)

	Camden		Central		Harrison		Linden	
Month	**Dth**	**Dollars**	**Dth**	**Dollars**	**Dth**	**Dollars**	**Dth**	**Dollars**
Jan-16	48	$548	88	$816	80	$889	56	$593
Feb-16	47	$542	88	$816	77	$852	56	$593
Mar-16	47	$542	84	$794	63	$672	48	$510
Apr-16	47	$542	84	$794	73	$748	48	$510
May-16	47	$537	84	$794	72	$739	48	$510
Jun-16	47	$537	84	$794	72	$739	48	$510
Jul-16	47	$537	84	$794	72	$739	48	$510
Aug-16	47	$537	84	$794	72	$739	77	$667
Sep-16	47	$537	87	$816	72	$739	77	$667
Oct-16	47	$537	92	$858	80	$811	78	$671
Nov-16	47	$537	92	$858	80	$811	78	$671
Dec-16	47	$537	94	$858	81	$811	62	$531
Jan-17	46	$528	91	$836	78	$781	62	$531
Feb-17	46	$528	91	$836	78	$781	62	$531
Mar-17	46	$528	85	$780	70	$694	62	$531
Apr-17	46	$528	92	$835	70	$694	55	$476
May-17	46	$528	92	$835	76	$748	49	$422
Jun-17	46	$528	92	$835	76	$748	49	$422
Jul-17	46	$528	92	$835	76	$748	49	$422
Aug-17	46	$528	92	$835	76	$748	49	$422
Sep-17	46	$528	92	$835	76	$748	60	$550
Oct-17	46	$528	92	$835	76	$748	60	$549
Nov-17	46	$528	92	$835	76	$748	60	$549
Dec-17	46	$521	91	$828	73	$725	60	$544

LPG INVENTORY VOLUMES AND COST BY LOCATION
(000)

	Camden		Central		Harrison		Linden	
Month	**Dth**	**Dollars**	**Dth**	**Dollars**	**Dth**	**Dollars**	**Dth**	**Dollars**
Jan-18	45	$510	88	$802	71	$698	60	$544
Feb-18	42	$480	65	$588	35	$342	60	$544
Mar-18	42	$480	65	$588	35	$342	60	$544
Apr-18	42	$480	65	$588	35	$342	60	$544
May-18	42	$480	65	$588	35	$342	60	$544
Jun-18	42	$480	65	$588	35	$342	60	$544
Jul-18	42	$480	65	$588	35	$342	60	$544
Aug-18	42	$480	65	$588	35	$342	60	$544
Sep-18	42	$480	65	$588	35	$342	60	$544
Oct-18	45	$512	65	$670	35	$922	60	$577
Nov-18	45	$512	65	$807	35	$922	60	$577
Dec-18	45	$512	65	$802	35	$898	60	$577
Jan-19	43	$495	80	$777	71	$849	62	$577
Feb-19	41	$474	79	$770	68	$822	61	$568
Mar-19	41	$474	79	$770	75	$896	61	$568
Apr-19 est	41	$474	79	$770	75	$896	61	$568
May-19 est	41	$474	79	$770	75	$896	61	$568
Jun-19 est	41	$474	79	$770	75	$896	61	$568
Jul-19 est	41	$474	79	$770	75	$896	61	$568
Aug-19 est	41	$474	79	$770	75	$896	61	$568
Sep-19 est	41	$474	79	$770	75	$896	61	$568
Oct-19 est	41	$474	79	$770	75	$896	61	$568
Nov-19 est	41	$474	79	$770	75	$896	61	$568
Dec-19 est	41	$474	79	$770	75	$896	61	$568

LNG INVENTORY VOLUMES AND COST
(000)

Month	Dth	Dollars	Month		Dth	Dollars
Jan-16	327	$453	Jan-18		129	$136
Feb-16	174	$241	Feb-18		122	$128
Mar-16	236	$253	Mar-18		198	$207
Apr-16	325	$378	Apr-18		190	$199
May-16	331	$396	May-18		181	$190
Jun-16	322	$393	Jun-18		174	$182
Jul-16	314	$383	Jul-18		167	$175
Aug-16	306	$373	Aug-18		161	$169
Sep-16	442	$376	Sep-18		155	$162
Oct-16	419	$386	Oct-18		144	$151
Nov-16	404	$372	Nov-18		135	$142
Dec-16	376	$346	Dec-18		154	$162
Jan-17	355	$328	Jan-19		282	$152
Feb-17	177	$163	Feb-19		262	$141
Mar-17	179	$168	Mar-19		237	$128
Apr-17	160	$150	Apr-19	est	228	$123
May-17	200	$195	May-19	est	228	$123
Jun-17	190	$187	Jun-19	est	228	$123
Jul-17	184	$180	Jul-19	est	228	$123
Aug-17	177	$174	Aug-19	est	228	$123
Sep-17	171	$167	Sep-19	est	228	$123
Oct-17	151	$148	Oct-19	est	228	$123
Nov-17	203	$213	Nov-19	est	228	$123
Dec-17	165	$174	Dec-19	est	228	$123

13. Affiliate Gas Supply Transactions

Item 13

Principal Terms of the Requirements Contract between PSE&G and PSEG Energy Resources & Trade (ER&T)

1. Effective Date: May 1, 2002, as amended March 31, 2007 and April 1, 2014
2. Supply Obligation: In daily consultation with PSE&G, ER&T is obligated to supply Basic Gas Supply Service ("BGSS") to PSE&G
   - BGSS is the retail gas supply service, by which ER&T provides all needed firm and non-firm gas to PSE&G to meet the natural gas requirements of its customers, including:
     - PSE&G's firm obligations
     - PSE&G's balancing services
     - PSE&G's non-firm supply obligations
     - PSE&G's non-tariff service agreements
   - To meet this obligation, ER&T holds all the necessary firm transportation, storage and gas purchase contracts to reliably serve PSE&G, as they may change over time
     - Gas capacity, storage, and transportation contracts were transferred from PSE&G to ER&T

        - Natural gas, LNG, and propane inventories were transferred from PSE&G to ER&T at book value as of April 30, 2002
        - BPU order authorizing the transfer was entered April 17, 2002
    - ER&T provides administrative and management services to PSE&G related to the wholesale delivery of gas, including:
        - Load scheduling
        - Load balancing
        - Mitigation of price volatility
        - When appropriate, input into decisions regarding whether to interrupt service and when to call upon peak shaving
    - PSE&G maintains peak shaving facilities, for which ER&T pays operating and maintenance costs, and also return
    - Deliveries of BGSS services are to be made to PSE&G at pipeline or peak shaving interconnections
        - ER&T is responsible for transportation of gas to the Points of Delivery, and PSE&G is responsible for transportation of gas from the Points of Delivery
    - ER&T is the sole supplier of the BGSS full requirements

3. Term: Through March 31, 2019, and year-to-year thereafter, subject to cancellation by either party with 2 years notice
    - Original term was to March 31, 2004, with option to extend

- Revised term was to March 31, 2007, and year-to-year thereafter
- Further revised term was to March 31, 2012, and year-to-year thereafter

4. Quality: The quality of gas delivered to PSE&G shall conform with the specifications of ER&T's interstate transportation providers, with the exception of refinery, landfill, and peaking gas, which shall be blended
5. Pressure: The pressure of gas delivered to PSE&G shall conform with the specifications of ER&T's interstate transportation providers
6. Default: PSE&G may recall all BGSS assets upon a default by ER&T
7. Warranty: ER&T warrants that:
    - It holds good Title to gas it sells
    - It holds sufficient entitlements to provide the full requirements services
8. Interruptible Loads: PSE&G is responsible for curtailing interruptible loads when appropriate
9. Payment: PSE&G pays ER&T monthly for these services:
    - All gas supply and capacity charges
    - Balancing
10. Non-Tariff Services: Non-tariff service to cogenerators is provided
11. Regulatory: The contract is subject to regulatory oversight, and ER&T shall supply expert witness testimony in any BPU proceeding concerning the gas component of any rate.

14. Supply and Demand Data

FIRM GAS SUPPLY AND DEMAND DATA (October 2016 - September 2017)

	Oct-16	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Total
Gas Supplies (MDTh)													
Beginning Inventory	67,103	71,216	72,093	61,442	44,701	31,826	18,750	24,172	33,601	44,025	53,695	62,237	
Natural Gas Receipt	13,415	18,706	21,010	16,046	12,544	16,742	16,112	16,911	15,266	13,595	12,636	11,137	184,119
Total Inventory Available	80,518	89,922	93,102	77,488	57,245	48,567	34,862	41,083	48,868	57,621	66,331	73,374	
Gas Demand (MDTh)													
Firm Sendout	9,302	17,829	31,660	32,788	25,419	29,817	10,690	7,481	4,842	3,926	4,093	4,342	182,190
Ending Inventory MDTh	71,216	72,093	61,442	44,701	31,826	18,750	24,172	33,601	44,025	53,695	62,237	69,032	

FIRM GAS SUPPLY AND DEMAND DATA (October 2017 - September 2018)

	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Total
Gas Supplies (MDTh)													
Beginning Inventory	69,032	76,094	71,634	61,028	49,251	39,341	24,392	22,908	31,832	39,547	48,502	57,467	
Natural Gas Receipt	13,910	16,355	24,624	28,007	15,893	14,558	16,202	14,696	12,316	12,824	12,832	12,977	195,194
Total Inventory Available	82,942	92,449	96,258	89,036	65,144	53,899	40,594	37,604	44,148	52,371	61,335	70,444	
Gas Demand (MDTh)													
Firm Sendout	6,848	20,815	35,229	39,785	25,803	29,507	17,686	5,771	4,602	3,869	3,868	4,205	197,988
Ending Inventory MDTh	76,094	71,634	61,028	49,251	39,341	24,392	22,908	31,832	39,547	48,502	57,467	66,239	

FIRM GAS SUPPLY AND DEMAND DATA (October 2018- September 2019)

	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Total
Gas Supplies (MDTh)													
Beginning Inventory	66,239	74,400	71,559	65,575	47,955	31,793	19,876	26,516	34,994	43,441	51,980	58,253	
Natural Gas Receipt	19,302	21,429	23,363	22,415	16,238	16,389	18,113	16,654	12,828	13,027	10,438	12,171	202,367
Total Inventory Available	85,540	95,829	94,922	87,990	64,194	48,182	37,989	43,170	47,822	56,468	62,419	70,424	
Gas Demand (MDTh)													
Firm Sendout	11,140	24,270	29,347	40,034	32,400	28,305	11,473	8,176	4,381	4,488	4,166	4,513	202,695
Ending Inventory MDTh	74,400	71,559	65,575	47,955	31,793	19,876	26,516	34,994	43,441	51,980	58,253	65,911	

FIRM GAS SUPPLY AND DEMAND DATA (October 2019- September 2020)

	Oct-19	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Total
Gas Supplies (MDTh)													
Beginning Inventory	65,911	71,350	74,104	65,705	45,915	31,167	22,777	21,830	29,629	39,489	49,428	57,433	
Natural Gas Receipt	14,499	22,491	21,228	18,290	18,803	18,329	13,708	15,100	14,263	14,440	12,229	13,248	196,628
Total Inventory Available	80,410	93,840	95,332	83,995	64,718	49,496	36,485	36,930	43,891	53,929	61,657	70,681	
Gas Demand (MDTh)													
Firm Sendout	9,060	19,737	29,627	38,080	33,551	26,719	14,655	7,301	4,403	4,500	4,224	4,581	196,438
Ending Inventory MDTh	71,350	74,104	65,705	45,915	31,167	22,777	21,830	29,629	39,489	49,428	57,433	66,100	

FIRM GAS SUPPLY AND DEMAND DATA (October 2020- September 2021)

	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Total
Gas Supplies (MDTh)													
Beginning Inventory	66,100	70,580	74,365	63,867	44,466	31,162	23,293	22,798	30,113	39,360	49,224	57,253	
Natural Gas Receipt	13,720	24,289	19,116	18,985	19,588	19,036	14,240	14,861	13,587	14,411	12,279	13,248	197,360
Total Inventory Available	79,820	94,869	93,481	82,852	64,054	50,198	37,534	37,659	43,700	53,771	61,504	70,501	
Gas Demand (MDTh)													
Firm Sendout	9,240	20,503	29,614	38,386	32,892	26,905	14,735	7,546	4,340	4,546	4,251	4,597	197,557
Ending Inventory MDTh	70,580	74,365	63,867	44,466	31,162	23,293	22,798	30,113	39,360	49,224	57,253	65,903	

15. Actual Peak Day Supply and Demand

Actual Peak Day Supply and Demand - Item 15

		NEWARK AVG.	LOAD (000 DTh)			SUPPLY SOURCES (000 DTh) NATURAL GAS		LPA / REFINERY /
	DATE	TEMP (F)	TOTAL	FIRM	INTERR.	HLF TRANSP.	STORAGE / LNG	LANDFILL
2018 / 2019 WINTER								
	21-Jan-19	13.0	2782	2591	191	1636	1146	0
	31-Jan-19	13.1	2761	2510	251	1686	1075	0
	30-Jan-19	12.5	2624	2406	218	1581	1043	0
	1-Feb-19	18.0	2605	2295	310	1612	993	0
	20-Jan-19	18.0	2357	2107	250	1754	603	0
2017 / 2018 WINTER								
	6-Jan-18	8.8	2604	2556	48	1656	922	26
	31-Dec-17	11.1	2596	2424	173	1791	805	0
	5-Jan-18	11.9	2527	2499	28	1734	779	14
	1-Jan-18	15.7	2505	2350	155	1851	654	0
	28-Dec-17	15.3	2502	2281	220	1987	514	0
2016 / 2017 WINTER								
	15-Mar-17	25.7	2538	1878	660	1581	940	17
	9-Jan-17	20.1	2501	2156	345	1357	1132	13
	14-Mar-17	25.4	2479	1810	669	1626	834	18
	8-Jan-17	18.5	2456	2133	323	1332	1112	12
	4-Mar-17	21.9	2383	1906	477	1206	1160	17

16. <u>Capacity Contract Changes</u>

Including Gas Sales Forecast Support

May 2019

PEAK DAY GAS REQUIREMENTS AND SUPPLY
(MDTh)

	SUPPLY		2019-20	2020-21	2021-22	2022-23	2023-2024
	Transco FT		432.4	432.4	432.4	432.4	432.4
	Transco FT (DTI)		32.2	32.2	32.2	32.2	32.2
	Transco FT (Cove Point)		20.0	20.0	20.0	20.0	20.0
	Texas Eastern FT		246.6	246.6	246.6	246.6	246.6
	Tennessee FT		36.4	36.4	36.4	36.4	36.4
	FT from Lebanon:						
	Texas Eastern		180.7	180.7	180.7	180.7	180.7
	DTI/Transco		49.6	49.6	49.6	49.6	49.6
	Columbia		12.5	12.5	12.5	12.5	12.5
	Subtotal		242.8	242.8	242.8	242.8	242.8
	Transco/Tetco FT (Leidy)		330.5	330.5	330.5	330.5	330.5
	Columbia (Hanover)		12.5	12.5	12.5	12.5	12.5
	Algonquin		15.0	15.0	15.0	15.0	15.0
	Pipeline Firm Transportation		1,368.4	1,368.4	1,368.4	1,368.4	1,368.4
	Refinery Gas		0.0	0.0	0.0	0.0	0.0
	Total Firm FT Supply		1,368.4	1,368.4	1,368.4	1,368.4	1,368.4
	Storage		895.5	895.5	895.5	895.5	895.5
	Transco Peaking		13.2	13.2	13.2	13.2	13.2
	Transco LGA		275.4	275.4	275.4	275.4	275.4
	PSEG Burlington LNG		67.0	67.0	67.0	67.0	67.0
	LPA		185.7	185.7	185.7	185.7	185.7
	Total Peaking Supply		541.3	541.3	541.3	541.3	541.3
	PSEG Firm Supply Subtotal		2,805.2	2,805.2	2,805.2	2,805.2	2,805.2
	FTS DCQ 1./		312.5	313.3	289.6	314.6	290.5
[a]	Total PSEG Gas Supply		3,117.7	3,118.5	3,094.8	3,119.8	3,095.7
	Peak Day Sendout Forecast 2./		2,972.7	2,998.5	3,015.3	3,040.9	3,058.5
[b]	Total Peak Day Capacity Requirements	3./	3,127.7	3,153.0	3,175.0	3,200.0	3,226.3
[a]-[b]	Surplus / (Deficiency)	3./	(10.0)	(34.5)	(80.2)	(80.2)	(130.6)

1./ Forecasted FT-S DCQ (January)

2./ Based on Corporate Energy Forecast, Gas -2019

3./ 3% Loss of Load Probability

Item 16

Natural Gas Sales Forecast - 2019

Public Service Electric & Gas Company

Finance Department

Electric and Gas Sales and Revenue Forecasting Group

September 2018

Contents

Introduction

The natural gas sales forecast has a key role in both the operating and financial planning processes of Public Service Electric & Gas (PSE&G).

The volumetric and maximum day sendout projections are used in the development of strategies for optimal gas procurement by PSE&G's BGSS supplier.

The sales forecast also serves as the basis for the natural gas revenue forecast that is a key parameter in PSE&G's financial planning process. This includes not only the budgeting process but also the regulatory process.

The purpose of this document is to describe the current forecast methodology, forecast assumptions, and the 2019 gas sales forecast. The first section describes the econometric sales models. A discussion of the forecast assumptions used to develop the sales forecast follows. Section III describes the maximum daily send-out projection. An appendix contains more detailed information on the billing period to calendar month conversion, and forecast tables.

I Model Specification and Estimation

Residential Model

Residential gas sales are determined by the number of residential customers and the amount of gas that each of these customers uses. As a result, the modeling of residential sales is disaggregated into two components: the projection of the number of customers and the estimate of what, on average, each of these customers will use. While the projection of the number of residential natural gas customers can be based on historical trends and expected residential construction activity in the service area, the models utilized to develop the average use forecast are more complicated and are described below.

The demand for energy is a derived demand from the demand for the services that the energy provides. In the case of gas in the residential sector, this is a demand for the three main end-uses of gas: space heating, water heating, and cooking. Standard microeconomic theory suggests that the demand for these gas-fueled end-uses is a function of the real, i.e. inflation adjusted, price of gas, and the income of the household. In addition, since space heating and, to a lesser extent, water heating is affected by the weather; weather also needs to be included in the model specification, i.e.

$$\text{THERM/CUST} = f(\text{PRICEGAS, INCOME, WEATHER}) \qquad [1]$$

where:

THERM/CUST	= Average gas sales per customer,
PRICEGAS	= Real price of gas,
INCOME	= Measure of customer income,
WEATHER	= Billing-month weather.

While information on individual appliance ownership and consumption is not available, PSE&G does segregate its Residential customer data into those customers that have gas space heating and those that do not. As a result, separate models estimating the average gas sales for space heating customers and non-space heating customers were developed.

Weather is incorporated into the models using billing-month heating degree days (HDD). To allow for the possibility of month-specific response to weather, the heating degree data was multiplied by monthly binary variables to produce month-specific HDD independent variables.

The real price of gas was defined as the annual average revenue per therm divided by the Consumers' Price Index –All Urban Consumers. However, the extreme seasonality of monthly gas consumption made the utilization of this variable directly in a linear specification impractical because it is unrealistic to expect that a change in price would have the same impact, measured in therms, in January, a high consumption month, as in July where consumption can be only one-tenth the January volume. As a result, this variable was incorporated as an interactive variable with HDD to create the effect that a change in price will affect the magnitude of the response to weather, i.e. a small response in the summer months and a much larger response during the space heating season.

Income is defined as the total real wages and salary disbursements for New Jersey from the U.S. Department of Commerce, Bureau of Economic Analysis. This is a narrower measure than personal income, omitting for example dividends, interest and rental income, and, as a result, is assumed to more accurately reflect the economic well-being of the majority of our customers. The incorporation of this variable directly into a linear specification suffers from the same drawback as that of the price. As a result, this variable was also incorporated into the specification as an interactive variable with HDD. In the models the economic variables were lagged one year to account for the delay in the impact that these variables have on consumer behavior.

As a result, the final functional form of the model that was estimated is:

$$THERM/CUST_t = f(\overline{MONTH}xHDD_t \times PRICEGAS_{a-1}, \overline{MONTH}xHDD_t \times INCOME_{a-1}, \overline{MONTH}xHDD_t) \qquad [2]$$

where:

THERM/CUST	= Average gas sales per customer,
PRICEGAS	= Real price of gas,
INCOME	= Real Wage and Salary Disbursements,
HDD	= Heating degree days,
$\overline{MONTH}$	= Vector of binary variables for each heating month,
t	= Billing-month,
a	= Year associated with billing-month, t.

The models were estimated using monthly data from the 2006-2017 period (excluding data from 2009 due to distortions resulting from the implementation of a new billing system.)The results of the OLS estimation procedure are summarized in Table 1 and Figures 1 and 2.

As Figures 1 and 2 illustrate, the high values of the coefficients of determination of both the model for gas space heating customers and the model of those customers without gas heating explain an extremely high proportion of the variation from the mean values. The estimates of the individual coefficients of the RSG model estimations are what one would expect given the characteristics of residential natural gas consumption. The key predictor of gas sales to this sector is weather with the weather having a greater impact on those customers with gas space heating than those without. Price is a factor for residential customers during the winter months but, it's impact is relatively small.

Figure 1
RSG Space Heating Model
Actual vs. Fitted Values

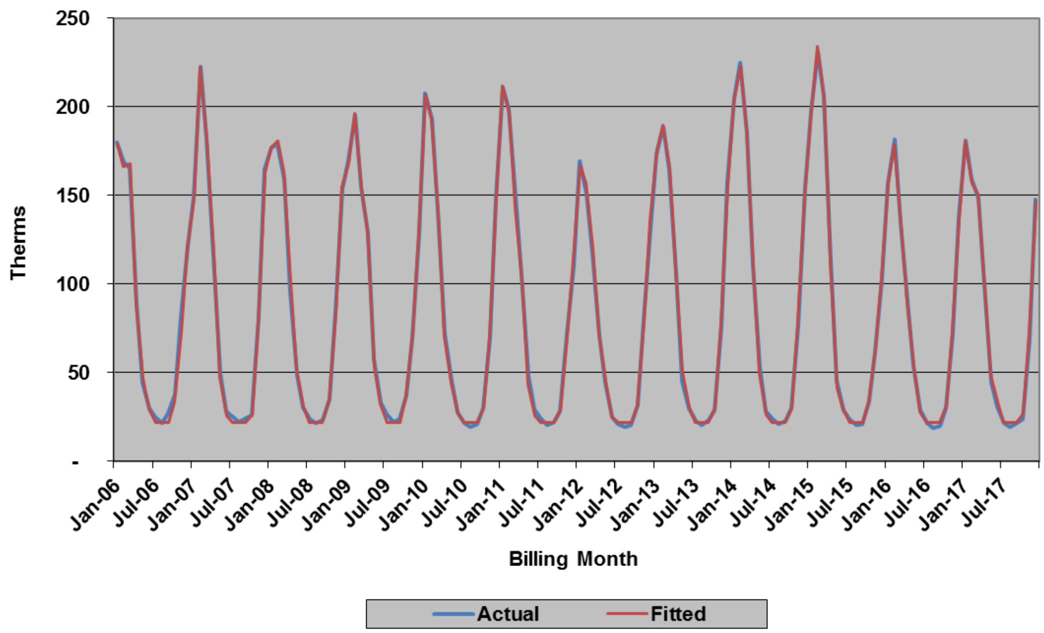
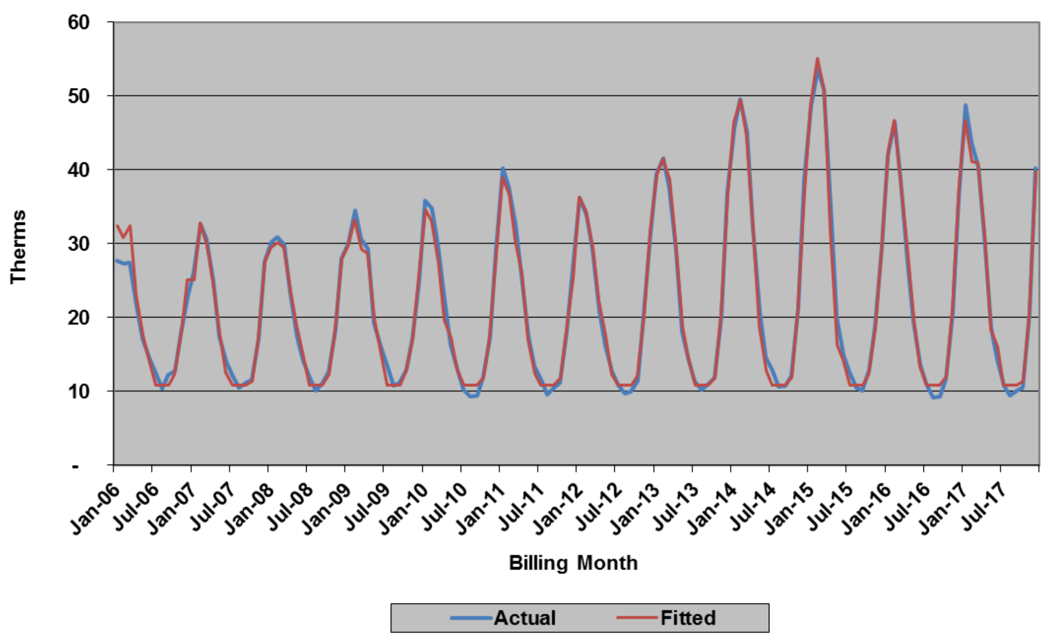


Figure 2
RSG Non-Space Heating Model
Actual vs. Fitted Values



The price elasticity estimates were estimated to be -0.0049 and -0.22 for space heating and non-space heating customers, respectively and consistent with lower gas prices and the lack of a surge in consumption in response to them. The non-space heating elasticity is the result of a similar therm impact of price but, measured over a much smaller base usage. Income was found to have an effect on gas consumption by space heating customers in the fall. This is consistent with income changes resulting affecting when space heating equipment is turned on. The economic downturn appeared to result in a delay in turning on this equipment in the fall reducing use.

Table 1

Estimated Coefficients of the Residential Models

(standard errors in parentheses)

		JAN	FEB	MAR	APR	MAY	JUNE	OCT	NOV	DEC	R2	DW	n
HEATING													
	HDD	0.19448	0.20185	0.20141	0.18424	0.13503	0.16139			0.16905	0.998	1.321	132
		(0.008)	(0.007)	(0.007)	(0.010)	(0.005)	(0.021)			(0.001)			
FEB -MAR	PRICE x HDD		-0.00378										
			(0.002)										
	WAGE x HDD							0.00133	0.00206				
								(0.000)	(0.000)				
	I-POWER	-0.00637											
		(0.001)											
NON-HEATING													
	HDD	0.05637	0.05606	0.05771	0.05781	0.03701	0.07371	0.01189	0.03976	0.05275	0.988	1.037	132
		(0.002)	(0.002)	(0.002)	(0.003)	(0.002)	(0.011)	(0.005)	(0.004)	(0.002)			
	PRICE x HDD	-0.01898	-0.01867	-0.01869	-0.01719				-0.01232	-0.01693			
		(0.001)	(0.001)	(0.001)	(0.002)				(0.003)	(0.001)			

The second key element of the residential forecast, as noted above, is the projection of the number of residential natural gas customers. This forecast is based on historical trends between customer growth and residential construction activity in the service area and is discussed in the Forecast Assumptions section.

Commercial

The demand for natural gas by the non-residential sector, as with any other factor of production, is a function of the input's price, the price of substitutes (if any) and the level of production. This implies that gas sales to the commercial sector is a function of the real price of gas and the level of "output" of the commercial sector in PSE&G's service territory, i.e. Again, since gas is primarily used for space and/or water heating, weather needs to be included in the specification resulting in the following:

THERMS = *f*(PRICEGAS, OUTPUT, HDD) [3]

where:

THERMS	= Gas Sales,
PRICEGAS	= Real price of gas,
OUTPUT	= Commercial sector output,
HDD	= Heating degree days.

The problem with this specification is that there is not a good measure of output for the local commercial sector. However, if it is assumed that the demand for local commercial output is a function of the local economic and demographic factors, i.e., how many households there are (HSH) and how much money do they have to spend (INCOME), commercial output can then be defined as:

OUTPUT = *f*(INCOME, HSH) [4]

Substituting [4] into [3] yields:

THERMS = *f*(PRICEGAS, INCOME, HSH, HDD) [5]

This model was estimated for customers in the commercial sector using monthly billing data from the 2005-2017 period (again, excluding 2009). The firm delivery customers in this class whose usage does not exceed 300 Dth are served under rate GSG. These customers are further disaggregated into those with gas space heat and those that heat with other fuels. These two groups of customers are modeled separately. The larger commercial customers are served under rate LVG. These are also modeled separately.

Historical annual household estimates for New Jersey is available from the U.S. Bureau of the Census. As with the residential models, the strong seasonality associated with commercial gas sales dictates that the economic/demographic variables can be used in the model directly but, need to be used as interactive variables with HDD. In addition, in the models the economic variables were lagged one year to account for the delay in the impact that these variables have on consumer behavior. As a result, the functional form that was estimated for each of the three groups of commercial customers is[1]:

$$\begin{aligned} THERMS_t = f(&\overline{MONTH} \times HDD_t \times PRICEGAS_{a-1}, \\ &\overline{MONTH} \times HDD_t \times INCOME_{a-1}, \\ &\overline{MONTH} \times HDD_t \times HSH_{a-1}, HDD_t) \end{aligned} \qquad [6]$$

where:

THERMS	=	Gas sales,
PRICEGAS	=	Real price of gas,
INCOME	=	Real Wage and Salary Disbursements,
HDD	=	Heating degree days,
$\overline{MONTH}$	=	Vector of binary variables for each heating month,
t	=	Billing-month,
a	=	Year associated with billing-month, t.

The results of the OLS estimation procedure, summarized in Figures 3-5, show that the commercial models also fit the historical data well.

The estimated coefficients of the three commercial models indicate that while the small commercial space heating are sensitive to price, with an estimated elasticity of -0.23 the non-space heating customers are not and the large LVG, customers are sensitive to price, with an estimated elasticity of -0.01. In addition, while the coefficients on households, the economic indicator in the models, are highly statistically significant, this does not imply large sales increases given the anticipated slow growth in the number of households.

[1] It was not necessary to incorporate month-specific HDD specification since the LVG sales are less sensitive to the weather.

Figure 3
GSG Commercial Space Heating Model
Actual vs. Fitted Values

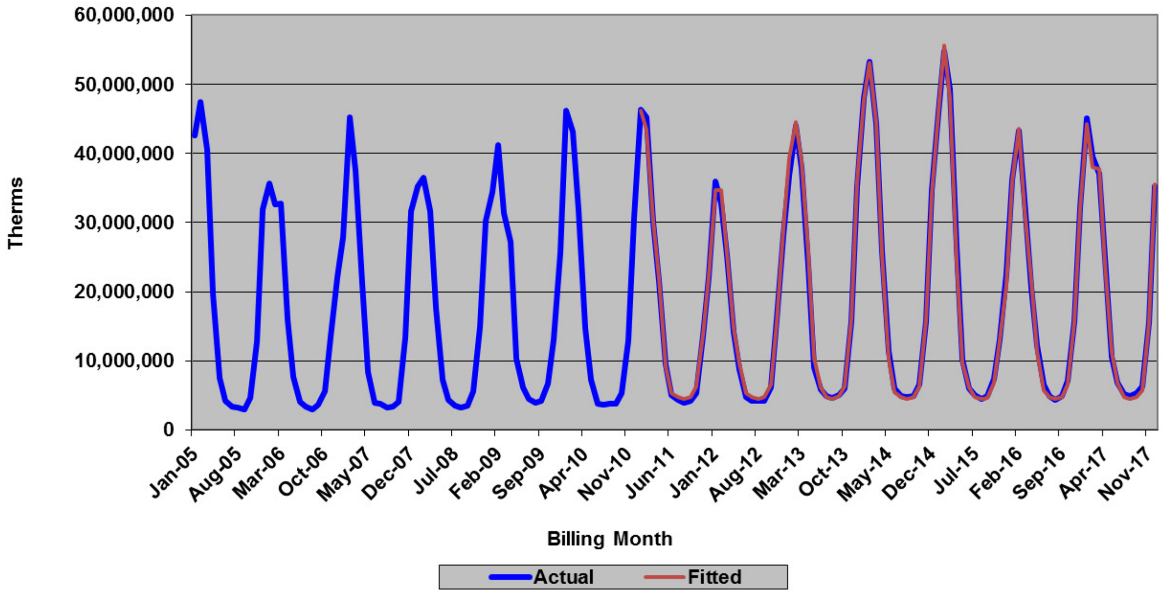


Figure 4
GSG Commercial Non-Space Heating Model
Actual vs. Fitted Values

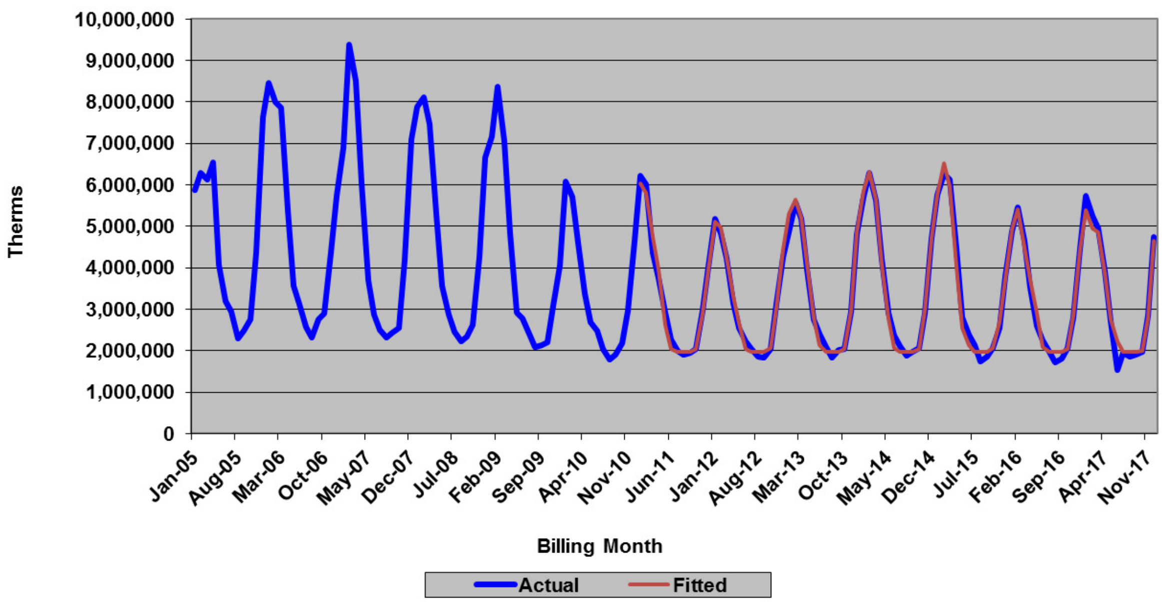


Figure 5
LVG Commercial Model
Actual vs. Fitted Values

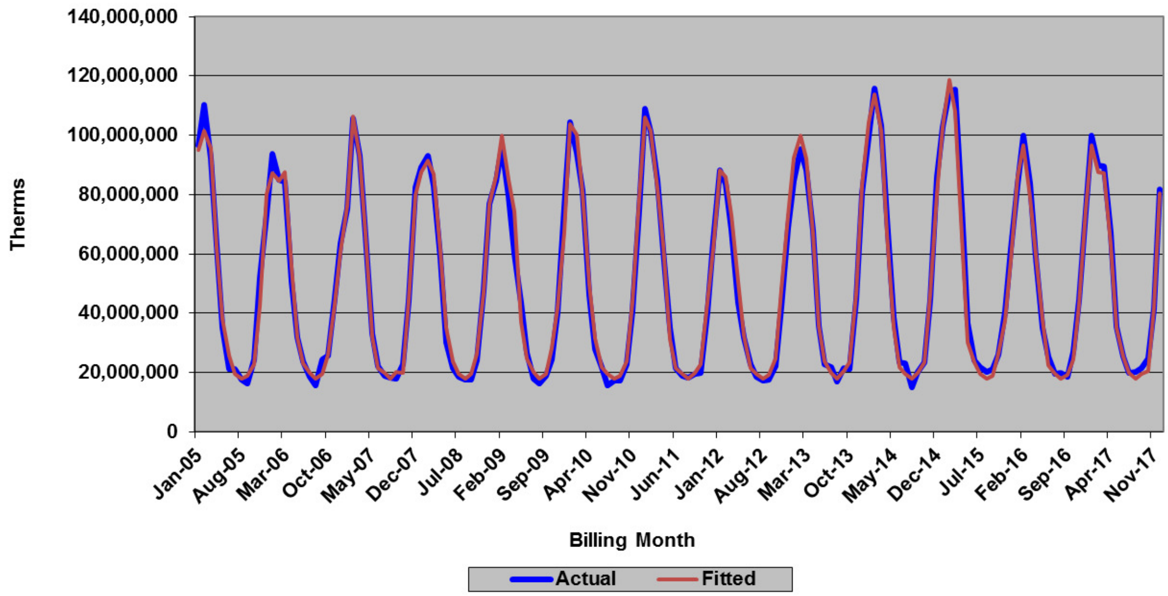


Table 2

Estimated Coefficients of the GSG Commercial Gas Sales Models
(standard errors in parentheses)

	JAN	FEB	MAR	APR	MAY	JUN	SEP	OCT	NOV	DEC	R2	DW	n
HEATING													
PRICE x HDD	-14217	-11336	-16106	-11855	-21865				-15737	-11068	0.997	1.536	84
	(3,144)	(3,066)	(3,682)	(5,519)	(20,481)				(7,460)	(3,995)			
CUST x HDD	22.09	18.86	20.30	19.33	9.23	9.56	3.59	4.75	12.32	17.44			
	(1.97)	(1.42)	(1.29)	(1.91)	(4.58)	(6.60)	(18.63)	(5.04)	(4.02)	(1.21)			
NON-HEATING													
HDD	3779	3903	3962	3984	3864	3533		836	2529	3510	0.985	1.443	84
	(86)	(84)	(103)	(168)	(406)	(1,862)		(846)	(221)	(115)			

Table 3

Estimated Coefficients of the LVG Commercial Gas Sales Models

(standard errors in parentheses)

HDD x PRICE	HDD x CUST	R2	DW	n
-3610.13	25.10	0.989	1.632	144
(1,801)	(1)			

Industrial

While gas sales to the commercial sector are correlated with commercial output because output tends to be correlated with commercial space-heated floor space, sales to the PSE&G rate GSG and rate LVG gas customers in the industrial sector are not correlated with the industrial output because gas, for the most part, is not used for process heat. It is used to heat employee workspaces and the number of employees has been declining while industrial output has been increasing. Therefore, rather than used the traditional function for the demand for a factor of production such as [3], the following specification is used:

$$THERMS = f(PRICEGAS, EMP, HDD) \qquad [7]$$

where:

EMP = Manufacturing employment.

Since gas is used primarily for space heating the economic variables need to be used as interactive variables with HDD to account for the extreme seasonality of the data. As a result, the functional forma that was estimated is:

$$THERMS_t = f(HDD_t \times PRICEGAS_{a-1}, HDD_t \times EMP_{a-1}, HDD_t) \qquad [8]$$

where:

THERMS	= Gas sales,
PRICEGAS	= Real price of gas,
HDD	= Heating degree days,
t	= Billing-month,
a	= Year associated with billing-month, t.

The results of the OLS estimation procedure, summarized in Figures 6-8, show that the industrial models for customers in the two space heating segments fit the historical data well. The data for industrial GSG non-heating customers, however, seems to indicate the presence of out of period adjustments in the billing data which the model doesn't, and can't be expected to, account for. These were addressed with binary variables.

Like the small and medium commercial models, the estimated coefficients of the three industrial models indicate that sensitivity to price is small. The small industrial customers, rate GSG did not show any statistically significant response to price while rate LVG sensitive to price, with an estimated elasticity of -0.01. Small response of the industrial sector to gas prices is attributed to the fact that gas, since it is not used for process heat, is a relatively small proportion of the total costs of production.

Figure 6

GSG Industrial Space Heating Model

Actual vs. Fitted Values

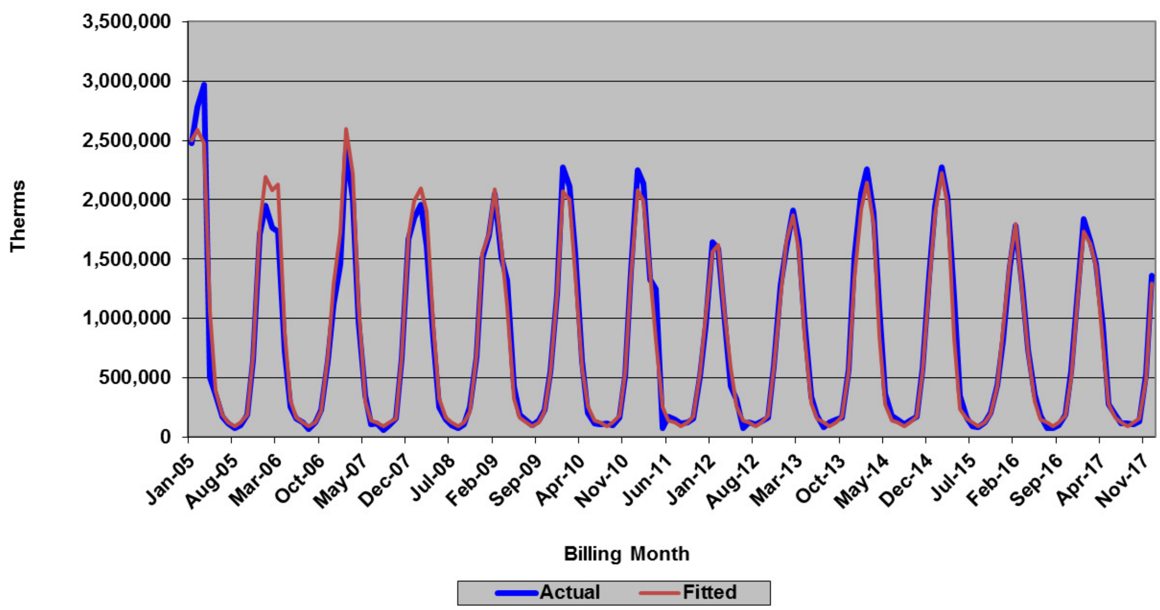


Figure 7
GSG Industrial Non-Space Heating Model
Actual vs. Fitted Values

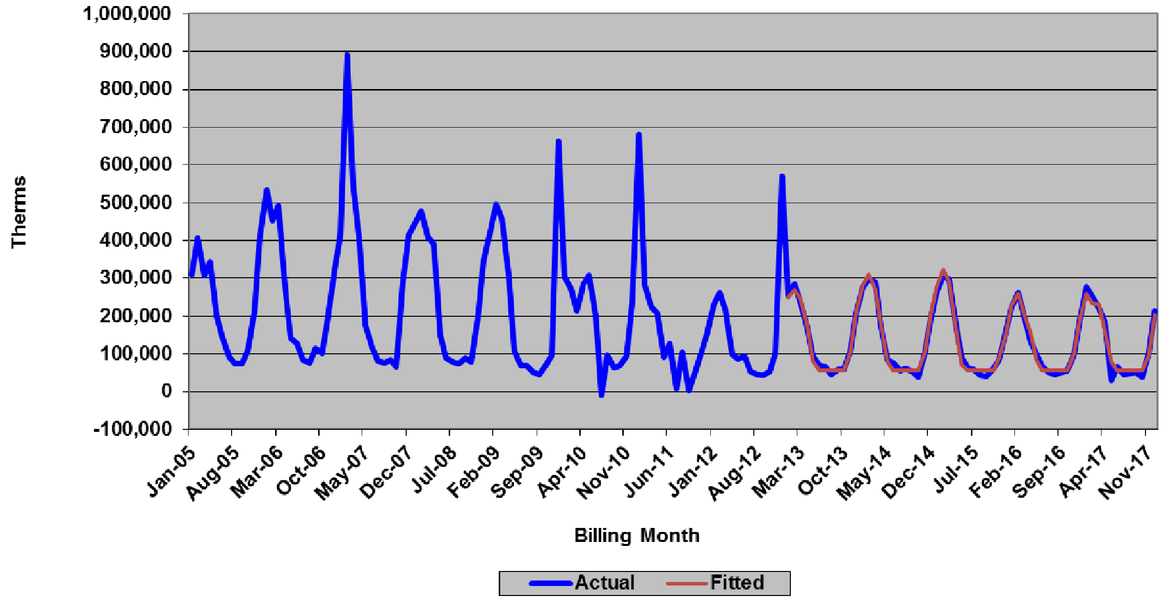


Figure 8
LVG Industrial Heating Model
Actual vs. Fitted Values

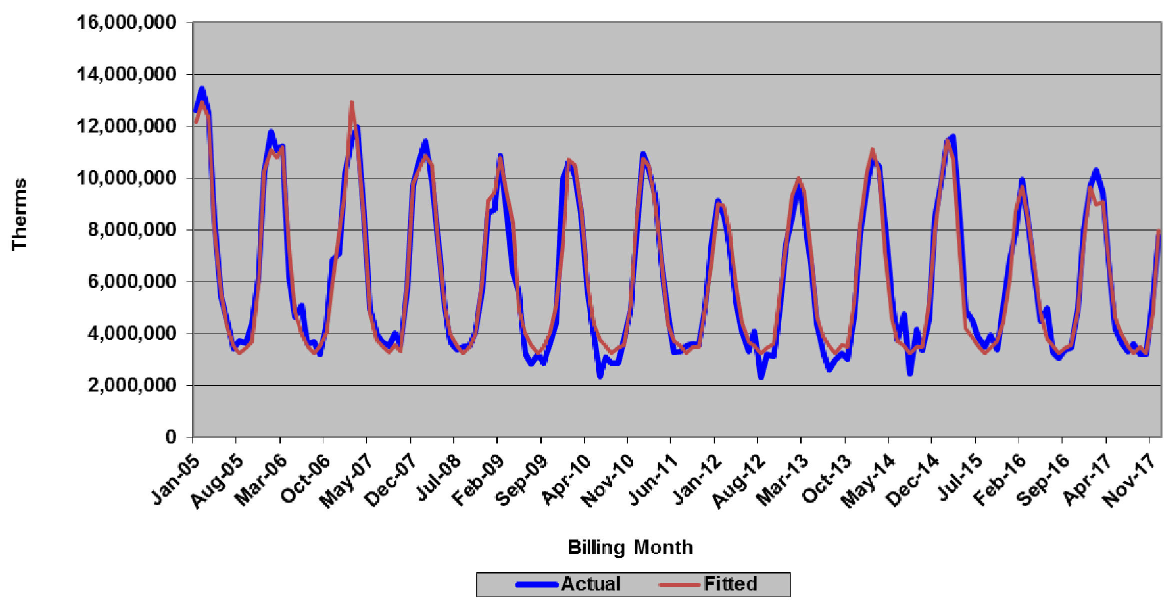


Table 4

Estimated Coefficients of the GSG Industrial Gas Sales Models
(standard errors in parentheses)

	JAN	FEB	MAR	APR	MAY	JUN	OCT	NOV	DEC	R2	DW	n
HEATING												
EMP x HDD	8.03	6.52	8.72	5.66	3.05	2.41	2.28	4.51	5.70	0.975	1.481	144
	(1.06)	(0.79)	(0.77)	(0.34)	(0.79)	(3.24)	(1.61)	(0.43)	(0.87)			
NON-HEATING												
EMP x HDD	0.92	0.96	0.99	0.94	0.49			0.52	0.79	0.980	2.258	60
	(0.03)	(0.03)	(0.03)	(0.05)	(0.13)			(0.08)	(0.04)			

Table 5

Estimated Coefficients of the LVG Industrial Gas Sales Models
(standard errors in parentheses)

HDD x PRICE	HDD x EMP	R2	DW	n
-206.86	27.98	0.968	1.732	144
(639.21)	(3.84)			

II Forecast Assumptions

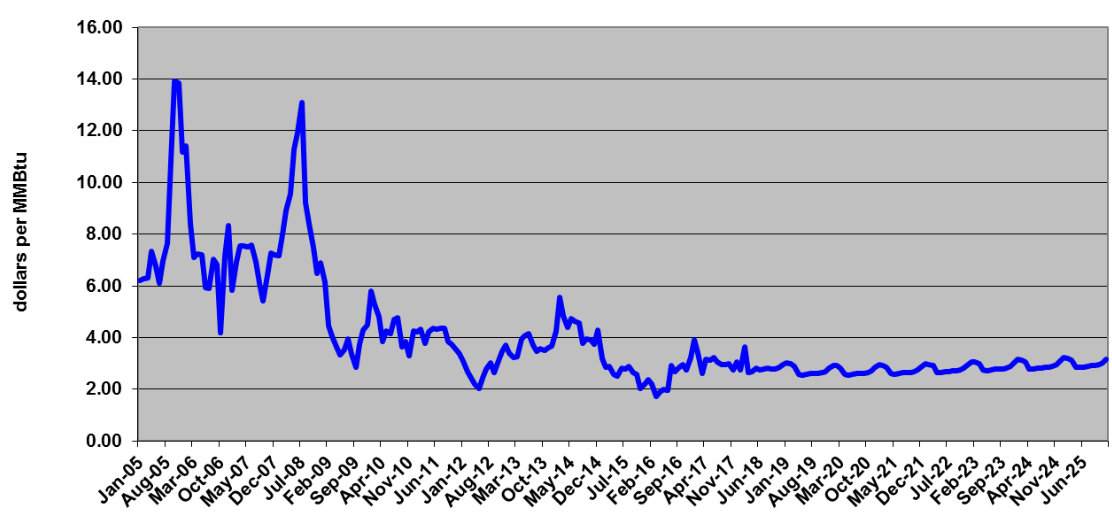
The models described above, in concert with assumptions about future prices and local economic and demographic parameters, were utilized to produce a forecast of billed natural gas delivered sales by rate for the residential, commercial, and industrial customer classes. The assumptions and the forecasts are described in more detail below.

Natural Gas Prices

The main driver of retail natural gas prices is the wholesale cost of gas which changes monthly. While these costs are passed through to commercial and industrial customers on monthly basis, the gas cost under- or over-collection of the residential customers is addressed in October where the rate is adjusted to collect or return the imbalance over the following twelve months. For the purpose of the forecast, the wholesale natural gas price was assumed to follow the NYMEX future prices as of April 30, 2018. As figure 9 shows, the wholesale price of gas is projected to stay relatively stable during the 2016-2025 periods.

Figure 9

NYMEX Natural Gas Futures Prices, April 30, 2018
($/MMBtu)



This price projection was used in the ER&T Gas cost model which generated commodity gas costs by rate. The residential costs, along with the actual imbalance in the residential gas supply cost and the revenue collection to offset this cost was utilized in the Cognos residential model to produce a stream of residential prices assuming that every October the imbalance was trued-up over the following 12 months. These projected commodity costs, combined with delivery tariff assumptions results in projected retail prices that are summarized below.

Table 6

Historic and Projected Retail Gas Prices

(dollars per therm)

			Commercial			Industrial		
	RSG		GSG			GSG		
Year	Heating	Non-Heating	Heating	Non-Heating	LVG	Heating	Non-Heating	LVG
2006	1.39	1.58	1.41	1.30	1.23	1.43	1.33	1.22
2007	1.35	1.54	1.31	1.27	1.17	1.32	1.24	1.13
2008	1.40	1.57	1.42	1.42	1.29	1.41	1.40	1.25
2009	1.40	1.56	1.09	1.05	0.94	1.09	1.06	0.92
2010	1.24	1.43	1.10	1.07	0.97	1.11	1.06	0.92
2011	1.09	1.26	1.06	1.04	0.92	1.05	1.05	0.87
2012	1.00	1.18	0.95	0.93	0.80	0.95	0.98	0.75
2013	0.94	1.09	1.00	0.99	0.84	1.00	1.01	0.80
2014	0.80	0.94	1.06	1.04	0.91	1.10	1.08	0.90
2015	0.64	0.80	0.86	0.85	0.74	0.86	0.88	0.74
2016	0.71	0.87	0.83	0.83	0.69	0.83	0.86	0.70
2017	0.77	0.91	0.95	0.95	0.79	0.95	0.98	0.80
2018	0.73	0.81	0.89	0.88	0.73	0.89	0.91	0.68
2019	0.75	0.84	0.89	0.88	0.72	0.89	0.91	0.67
2020	0.77	0.85	0.90	0.89	0.73	0.90	0.92	0.68
2021	0.77	0.85	0.90	0.89	0.73	0.90	0.92	0.68
2022	0.76	0.85	0.91	0.90	0.74	0.92	0.93	0.69
2023	0.76	0.85	0.91	0.90	0.73	0.91	0.92	0.69
2024	0.76	0.85	0.91	0.89	0.73	0.91	0.92	0.68
2025	0.76	0.84	0.90	0.89	0.73	0.91	0.92	0.68
2026	0.76	0.84	0.90	0.89	0.73	0.91	0.92	0.68
2027	0.76	0.84	0.90	0.89	0.73	0.91	0.92	0.68
2028	0.76	0.84	0.90	0.89	0.73	0.91	0.92	0.68
2029	0.76	0.84	0.90	0.89	0.73	0.91	0.92	0.68
2030	0.76	0.84	0.90	0.89	0.73	0.91	0.92	0.68

Economic Projections

Economic and demographic forecast assumptions for the nation and New Jersey are from Moody's Economy March 2018 forecast. This forecast assumes that, nationally, the economy continues to recover at a slow but steady rate. This national forecast is expected to be reflected in New Jersey's economic outlook that is also expected to be at a slow pace. The forecast is summarized in Table 7.

Weather during the forecast period is assumed to be "normal" as defined by the average daily weather during the twenty-year period ending December 31, 2017.

Table 7

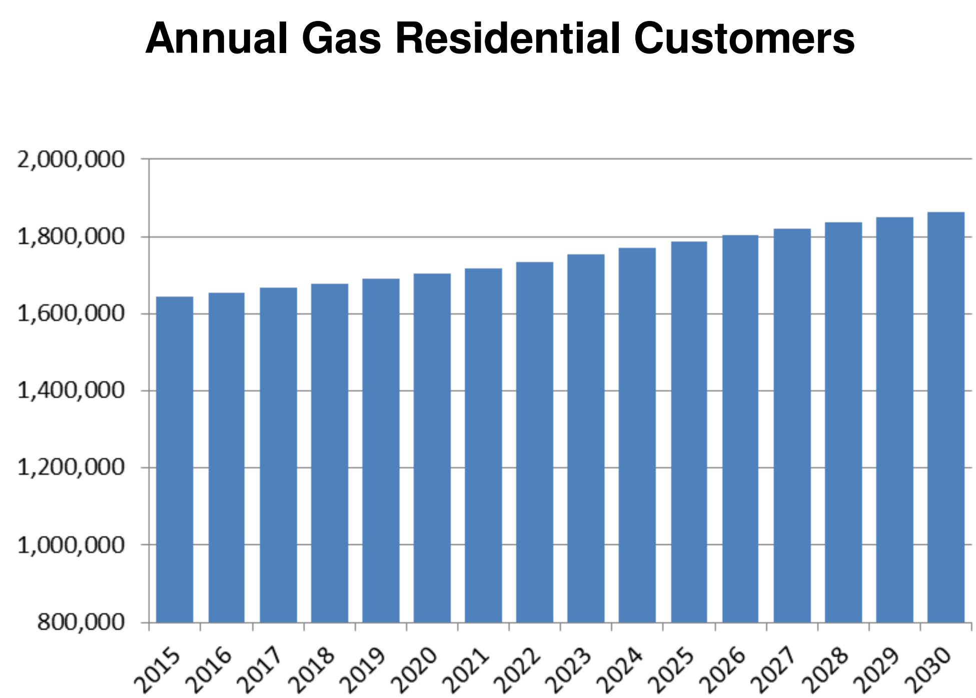
National and New Jersey Economic Forecast Assumptions

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
United States													
Gross Domestic Product, (Bil. USD, SAAR)	16,692	17,428	18,121	18,625	19,386	20,409	21,529	22,167	23,214	24,338	25,385	26,433	27,459
Industrial Production: Total, (Index 2012=100, SA)	102	105	104	103	105	108	110	111	113	115	117	118	120
Income: Personal - Total, (Bil. Ch. 2009 USD, SAAR)	13,087	13,575	14,206	14,377	14,582	14,915	15,257	15,503	15,756	16,101	16,419	16,739	17,072
Employment: Total Nonagricultural, (Mil. #, SA)	136	139	142	144	147	149	151	151	151	153	154	155	156
Household Survey: Unemployment Rate, (%, SA)	7.4	6.2	5.3	4.9	4.4	3.8	3.5	4.2	4.9	5.0	5.0	5.1	5.2
CPI: Urban Consumer - All Items, (Index 1982-84=100, SA)	233	237	237	240	245	252	258	265	271	277	283	289	296
Interest Rates: 3-Month Treasury Bills EBY, (% p.a., NSA)	0.1	0.0	0.1	0.3	0.9	1.9	3.3	3.5	3.2	2.7	2.8	3.0	3.3
Fannie Mae: FHA/VA 30-Year Mortgage Rate - Fixed, (%, NSA)	4.2	4.4	4.2	4.2	4.5	5.1	5.8	5.8	5.8	6.0	5.9	6.0	6.1
New Jersey													
Real Personal Income, (Mil. 09$, SAAR)	459,412	471,224	491,609	496,286	499,693	508,409	516,273	521,020	528,488	539,324	548,546	558,247	568,299
Employment: Total Nonagricultural, (Ths., SA)	3,936	3,968	4,012	4,073	4,129	4,184	4,219	4,221	4,224	4,258	4,282	4,304	4,324
Employment: Total Manufacturing, (Ths., SA)	239	239	239	242	245	247	244	240	235	233	229	225	222
Employment: Total Non-Manufacturing, (Ths., SA)	3,697	3,729	3,773	3,831	3,884	3,938	3,975	3,981	3,989	4,026	4,053	4,079	4,103
Labor: Unemployment Rate, (%, SA)	8.2	6.7	5.8	5.0	4.6	4.6	4.5	5.2	5.9	5.9	6.0	6.0	6.0
Population: Total, (Ths.)	8,915	8,943	8,961	8,980	9,007	9,031	9,037	9,037	9,036	9,041	9,046	9,053	9,059
Households: Total, (Ths.)	3,277	3,298	3,313	3,329	3,341	3,361	3,385	3,406	3,424	3,444	3,464	3,483	3,502
Housing Starts: Single-family, (#, SAAR)	10,744	10,299	10,718	10,748	10,762	11,654	13,739	13,655	16,137	17,285	16,936	16,919	16,711

Customer Forecasts

The number of residential customers with and without natural gas space heat is based on historical trends and expected residential construction activity in the service area. Residential non-heating customers have been steadily declining at an average annual rate of 0.8 percent and this is expected to continue. Furthermore it is assumed that these customers are converting to gas heat. The number of gas heating customers is also expected to increase as new residential construction occurs. The number of gas customers is assumed to reflect the current decline seen in new single family housing construction. As a result, as the figure below shows, the number of residential customers is expected to remain relatively stable.

Figure 10



BGSS Share

The share of delivered sales that are BGSS supplied is assumed to follow recent trends where therm shares have stabilized at their current levels across the broad range of customer classes.

III Maximum Daily Sendout Forecast

Introduction

Distribution facilities are designed to meet the estimated maximum hour demand on a day with a mean temperature of 0°F and an assumed average wind velocity of 15 m.p.h. with Newark Airport as the measuring base. Gas supplies are designed to meet the estimated maximum daily as well as maximum hourly demand. The maximum daily sendout forecast process consists of:

- Estimating the relationship between weather and firm daily sendout,
- Extrapolating that relationship to determine the current level of daily sendout at 0 degrees if no day that cold appeared in the model estimation data,
- Forecasting future maximum daily sendout levels based on the current estimated level

The remainder of this section describes each of these steps in turn.

Daily Firm Sendout Model Estimation

There are two major issues in modeling maximum firm daily sendout. First, the diversity of the customer base needs to be controlled for. Second, the model has to be designed to be extrapolated rather than interpolated. Each of these issues is discussed below.

The firm sendout number accounts for gas deliveries to a diverse set of customers ranging from residential homes to large industrial sites. Since sales to different types of customers respond to weather differently, customer mix must be controlled for in any modeling effort. In addition, the behavior of this diverse group of customers will change differently over time as prices and other economic parameters change over time. As a result, these changes also need to be accounted for. Unfortunately, the firm sendout number is not available by rate. As a result, the only way to control for changes in customer mix and changes in the behavior over time by these customers is to limit the time period of data that is used in the model estimation.

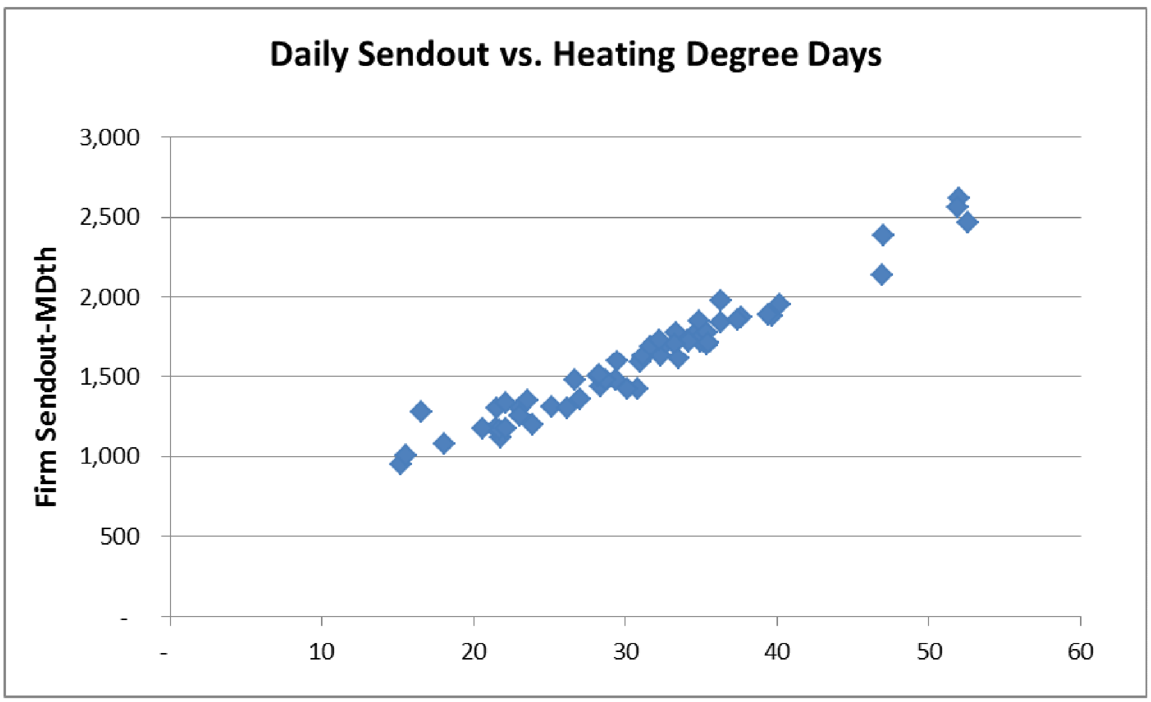
The second issue, of extrapolation, is addressed in a similar way. The relationship between sendout and weather is fairly linear. In reality, it is probably not perfectly linear. This is not an issue when estimating a model and using the results to interpolate values with the range of the estimation data. However, when extrapolating the data outside the range of the estimation data the imprecision increases. The way to minimize this imprecision is to limit the observations to the lower temperature data so as to get a linear estimation of that portion of a non-linear curve that is closest to the ultimate extrapolation value.

To address both of these forecasting issues, the data used in estimating the relationship between daily sendout and weather was limited to the January and February during the most recent year available, 2019. Customer class mix will not change significantly in this short period and it contains the two coldest months when the maximum sendout would most likely occur. Analysis of the data for these two months indicates two things.

First, the data confirms the general responsiveness of firm sendout to the weather, as Figure 11 shows. Second, the relationship appears linear

Figure 11

January & February 2019



To refine the impact of the day-type on sendout, the regression model from previous years was enhanced to allow for not only an intercept change from the day-type but, also a HDD response change.

The regression model that modeled daily sendout, SENDOUT, is specified as:

$$SENDOUT_t = f(HDD_t, WEEKDAY_t, HOLIDAY_t, SNOW_t) \qquad [9]$$

Where:

HDD	=	Heating degree days on gas day t,
WEEKDAY	=	Interactive variable that takes the value of HDD on weekdays, otherwise 0,
HOLIDAY	=	Interactive variable that takes the value of HDD on Sundays or Holidays, otherwise 0,
SNOW	=	Binary variable that takes the value of 1 when reported snowstorm accumulation in any portion of the service area is 6 inches or more, 0 otherwise.

The estimation results are shown in Table 8 and Figure 12 below.

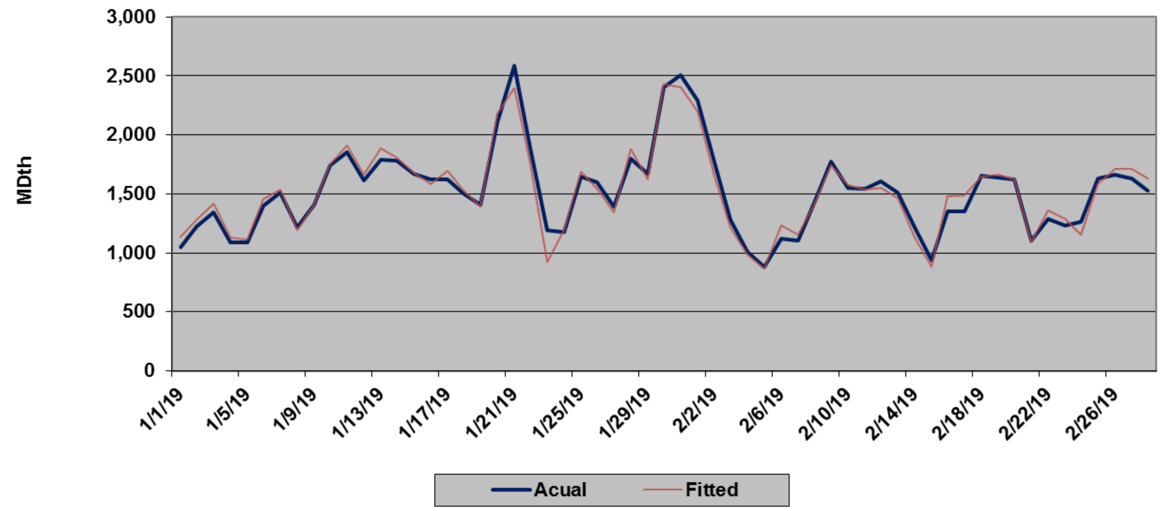
Table 8

Estimated Coefficients of the Daily Sendout Model
(standard errors in parentheses)

Intercept	HDD	HOLIDAY	WEEKDAY	R2	DW	n
228.00	40.59	1.06	1.26	0.954	1.235	59
(39.99)	(1.55)	(1.16)	(.99)			

Figure 12

Daily Sendout Model
Actual vs. Fitted Values



The estimated coefficients of the model suggest that the estimated maximum daily peak would occur on a Wednesday. The model predicts that the maximum peak daily sendout would be 2,427.1 MDth.

A. Calendar-Month Sales Calculation

Introduction

Utilities have traditionally had a disconnection in the timing of their revenues and their costs. Revenues from retail sales are a revenue stream from meter readings and the resulting bills to their customers that occur on a daily basis throughout the month. The bills issued from meter reads in the current month's meter reading schedule are all recorded as billing-month revenue. Billing-month revenue will include revenue from electricity or gas delivered during the previous month while excluding deliveries of electricity or gas delivered during the current month that occurred after the meters were read. Expenses, on the other hand, such as wages, fuel, depreciation, etc., have been recorded on a calendar-month basis. This inconsistency in the revenue and expense streams can be tolerated if there are no major changes in the revenue and/or expense streams. If major changes are occurring, such as a rapid increase in fossil fuel prices or a high seasonality in sales, a comparison of the billing-month revenue and the calendar-month expenses can give a false view of a utility's financials. To remedy this situation, the sales and revenue accrual calculation, the estimation of calendar-month sales and revenue from billed sales and revenue and the estimation of unbilled sales and revenue was developed.

Section II will discuss how, in theory, the billed sales and the unbilled estimates are used to calculate calendar-month sales using a simple example and introduce the notation that will serve as the basis of the analysis. A description of the theory's specific application to PSE&G's meter reading schedule, that can have a single billing month encompass up to four calendar-months, follows.

Section III will describe the implementation of the estimation of the calendar-month sales and revenue process at PSE&G.

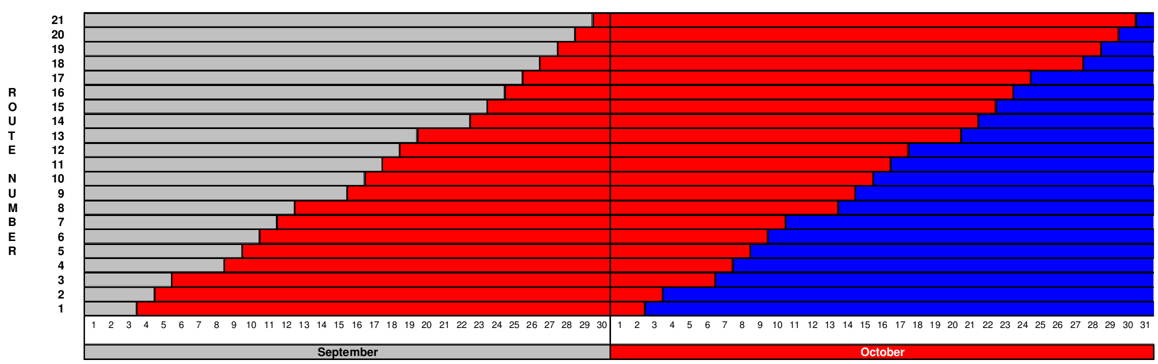
The Unbilled and Calendar-Month Estimation

A Simple Example

Utilities generally read all of their meters every month on 21 workdays. Figure 1, below shows a hypothetical October billing-month (in red) as determined by the September and October meter reading schedules. In the chart, each row represents a Route Number or a group of meters that are always read on the same day (although the day when they are all read may vary from month to month). The bottom row is red on all the days after the September read date, September 3rd until the October read date, October 2nd. If it is assumed that the customers' meters are read at noon, the October bill to these customers will reflect 28.5 days of service in September and only 1.5 days in October[2]. The second row from the bottom represents Route 2 whose customers' meters were read on September 4th and October 3rd. The October bill to these customers will reflect 27.5 days of service in September and only 2.5 days in October. This continues until the top row, Route 21, that had meter reading days of September 29th and October 30th. The October bills to these customers represent only 1.5 days of September service and 29.5 days of October service.

Figure 1

Hypothetical October 2008 Billing-Month



From the red portion of the diagram, it can be seen that the October billing-month consists of September sales that are billed in October that, to facilitate discussion, will be referred to as SEP B> OCT and October sales that are billed in October i.e., OCT B> OCT. The calendar-month sales are defined as the red and blue rectangle defined by the month of October and the 21 read-cycles. This consists of OCT B> OCT sales and the October unbilled sales, OCT B> NOV, the October sales that will be billed in November.

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[2] Or, more realistically, if the meter reads for all the Route 1 customers are evenly distributed throughout an 8:00 AM to 4:00 PM workday, the reads, on average, would represent a half day's sales on the read day.

The relationship between billed, unbilled, and calendar-month sales can be derived from these identities from the steps below.

$$\text{October Calendar} = \boxed{\text{OCT B> OCT}} + \boxed{\text{OCT B> NOV}} = \boxed{\begin{array}{l}\text{OCT B> OCT}\\ \text{OCT B> NOV}\end{array}} \qquad [1]$$

Adding and subtracting $\boxed{\text{SEP B> OCT}}$ to the r.h.s. of [1] yields:

$$\text{October Calendar} = \boxed{\begin{array}{l}\text{OCT B> OCT}\\ \text{OCT B> NOV}\end{array}} + \boxed{\text{SEP B> OCT}} - \boxed{\text{SEP B> OCT}} \qquad [2]$$

Rearranging the r.h.s. of [2] yields:

$$\text{October Calendar} = \boxed{\begin{array}{l}\text{OCT B> OCT}\\ \text{SEP B> OCT}\end{array}} + \boxed{\text{OCT B> NOV}} - \boxed{\text{SEP B> OCT}} \qquad [3]$$

Substituting [1] into the l.h.s. of [3] yields:

$$\boxed{\begin{array}{l}\text{OCT B> OCT}\\ \text{OCT B> NOV}\end{array}} = \boxed{\begin{array}{l}\text{OCT B> OCT}\\ \text{SEP B> OCT}\end{array}} + \boxed{\text{OCT B> NOV}} - \boxed{\text{SEP B> OCT}} \qquad [4]$$

This is the familiar:

October Calendar = October Billed + October Unbilled – September Unbilled[3] [5]

This formula for the accrual of calendar-month sales and revenues is preferred to any direct estimation of calendar-month sales because any error in the unbilled estimate is
"reversed out" in the following month. The advantage of this is that, as the calendar time period extends, the potential error resulting from unbilled estimates is reduced. This can be seen by summing up [5] over the 2008 calendar-year as:

$$\text{Calendar-Year 2008} = \sum_{i=JAN08}^{DEC08} \text{Billed}_i + \sum_{i=JAN08}^{DEC08} \text{Unbilled}_i - \sum_{i=DEC07}^{NOV08} \text{Unbilled}_i \qquad [6]$$

[3] The difference between the current month's unbilled and the previous month's is often referred to as
the "net unbilled".

Where:

$Billed_i$ = Billing-month sales in month i,
$Unbilled_i$ = Unbilled sales in month i.

That simplifies to:

$$\text{Calendar-Year 2008} = \sum_{i=JAN08}^{DEC08} Billed_i + Unbilled_{DEC08} - Unbilled_{DEC07} \qquad [7]$$

The key result from [7] is that the annual calendar-year sales are the annual billed sales, a very large real number, and the difference between two monthly unbilled estimates. Since the error that can be expected in the difference between the two monthly unbilled estimates can be assumed to be quite small compared to the annual billed total, the calendar-year estimate, as a result, can be expected to be very accurate.

The same general results described in this simple example apply to PSE&G's more complicated meter reading schedule that is described below.

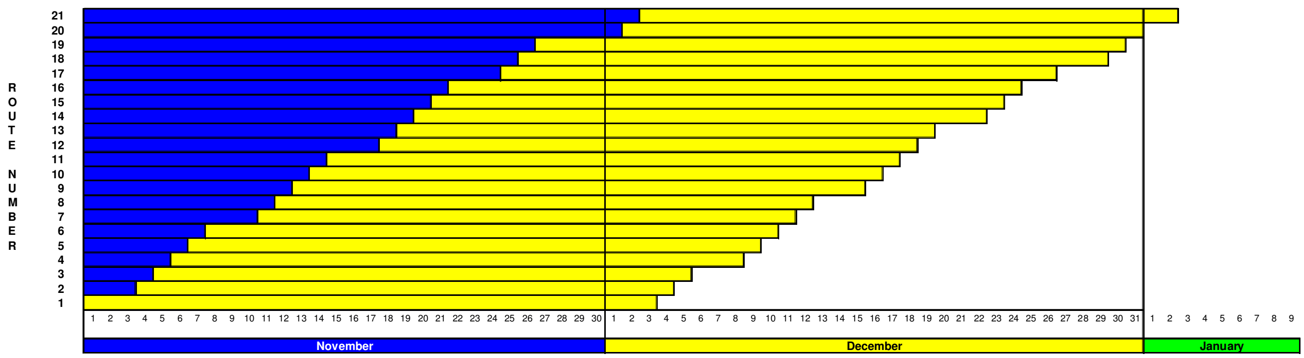
A More General Example

Unlike the hypothetical October billing-month, discussed above, that spanned two months, September and October, the PSE&G billing-month can encompass as many as four months. For example, the December 2008 PSE&G billing month, illustrated in Figure 2. has meter reading dates ranging from October 31st to January 2nd. As a result, it spans four months, October, November, December, and January[4].

[4] This is the original PSE&G December 2008 meter reading schedule. It has since been "compressed" to accommodate the implementation of iPower, the new billing and customer information system.

Figure 2

PSE&G December 2008 Billing-Month



Therefore, to develop a general algorithm applicable to PSE&G, the definition of billed, unbilled, and calendar sales must be expanded to include the potential of having sales from two additional calendar months reflected in a billing-month. December 2008 billing month, for example, is defined as:

December Billed = OCT B> DEC / NOV B> DEC / DEC B> DEC / JAN B> DEC [8]

Given the additional components of the billed, OCT B> DEC , i.e. the “under billed” sales, and JAN B> DEC , the “excess billed” sales, the addition of the current unbilled and subtraction of the previous month’s unbilled to the December billed, as defined in the simple example above, will overstate December calendar-month sales by the sum of under billed and excess billed sales. As a result, the December unbilled needs to be redefined as:

December Unbilled = DEC B> JAN / DEC B> FEB + NOV B> JAN - JAN B> DEC [9]

December Unbilled = December Unbilled + January Underbilled – December Excess Billed[10]

December calendar can then be defined as December billed plus the new

December unbilled less the equivalent November unbilled or:

$$\begin{aligned}\boxed{\begin{array}{l}\text{DEC B> OCT}\\ \text{DEC B> NOV}\\ \text{DEC B> DEC}\\ \text{DEC B> JAN}\end{array}} &= \boxed{\begin{array}{l}\text{OCT B> DEC}\\ \text{NOV B> DEC}\\ \text{DEC B> DEC}\\ \text{JAN B> DEC}\end{array}}\\ &+ \boxed{\begin{array}{l}\text{DEC B> JAN}\\ \text{DEC B> FEB}\end{array}} + \boxed{\text{NOV B> JAN}} - \boxed{\text{JAN B> DEC}}\\ &- \boxed{\begin{array}{l}\text{NOV B> DEC}\\ \text{NOV B> JAN}\end{array}} - \boxed{\text{OCT B> DEC}} + \boxed{\text{DEC B> NOV}} \qquad [11]\end{aligned}$$

or, in words:

December Calendar = December Billed
+ December Unbilled
- November Unbilled [12]

This is the general formula that is used to calculate unbilled sales at PSE&G.

The PSE&G Gas Calendar-Month Estimation

The estimation of calendar-month gas sales at PSE&G is based on the notion that gas sales can be divided into two components: a weather sensitive component and a non-weather sensitive component. The weather sensitive component is affected by the winter weather as measured by heating degree days (HDD). The non-weather component is simply a function of the number of days in the sales period. As a result, sales during the unbilled periods can be estimated based on the HDD and number of days during the unbilled periods and the estimates of the weather-sensitive sales per HDD and non-weather sensitive sales per day.

The estimate of the weather-sensitive sales per HDD for each rate, the HDD coefficient, is the sum of the coefficients associated with its model's independent variables that have a HDD component divided by the number of days in the billing period. In the case of RSG that, unlike the other rates, is modeled on a use per customer basis, this result is multiplied by the number of customers.

The estimate of the non-weather sensitive sales per day for each rate, the base coefficient, is the value of the model equation with all of the coefficients associated with HDD set to zero and divided by the number of days in the billing period. As in the case of the HDD coefficient, the RSG result is multiplied by the number of customers.

Given the structure of the models, these coefficients will vary by month and by year. The current estimates for 2008 and 2009 are shown in Table 1 below.[5]

Table 1

Unbilled Weather and Base Coefficients, 2008-2009

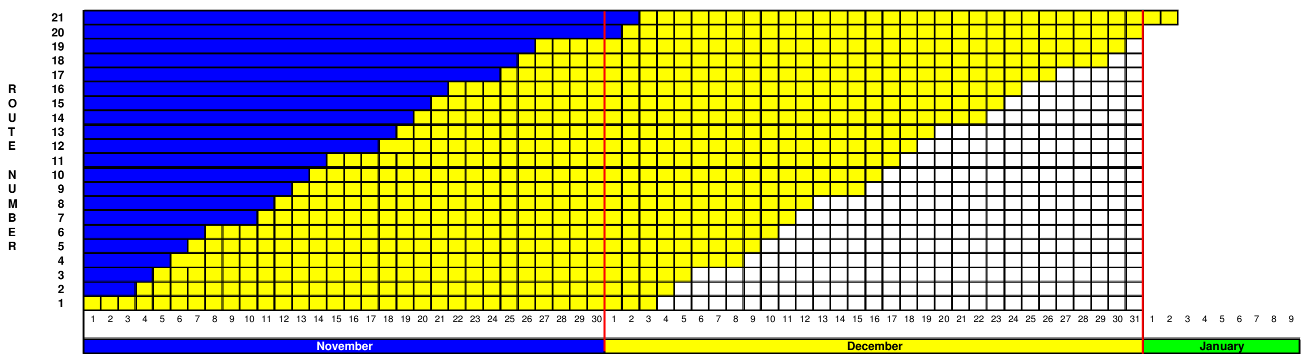
	RSG				GSG-Commercial				GSG-Industrial				LVG - Non Vehicle			
Billing	Heating		Non-heating		Heating		Non-heating		Heating		Non-heating		Commercial		Industrial	
Month	Base	HDD	Base	HDD	Base	HDD	Base	HDD	Base	HDD	Base	HDD	Base	HDD	Base	HDD
Jan-08	1,477,624	246,082	218,393	4,689	56,941	45,607	168,133	3,942	(15,873)	3,333	2,978	501	1,047,971	79,608	145,023	8,767
Feb-08	1,554,914	253,674	234,372	4,811	69,746	45,607	175,674	3,942	(15,256)	3,333	3,786	501	1,172,070	79,608	167,056	8,767
Mar-08	1,343,904	249,936	236,373	4,737	25,553	45,607	158,654	3,942	(16,832)	3,333	2,893	501	1,053,237	79,608	138,433	8,767
Apr-08	1,337,980	248,305	190,526	4,692	13,895	45,607	150,129	3,942	(15,769)	3,333	5,681	501	1,076,058	79,608	159,387	8,767
May-08	1,267,108	251,443	164,912	4,741	146,976	45,607	117,463	3,942	332	3,333	4,166	501	838,647	79,608	137,277	8,767
Jun-08	1,086,639	250,233	135,407	4,714	126,187	45,607	95,849	3,942	2,561	3,333	3,704	501	708,324	79,608	129,981	8,767
Jul-08	984,641	248,954	116,905	4,704	135,270	45,607	94,660	3,942	3,907	3,333	2,680	501	610,707	79,608	119,171	8,767
Aug-08	912,999	249,456	104,709	4,666	103,926	45,607	80,601	3,942	2,045	3,333	2,578	501	613,535	79,608	119,770	8,767
Sep-08	940,487	252,748	111,693	4,746	108,515	45,607	84,252	3,942	2,953	3,333	2,730	501	581,470	79,608	129,852	8,767
Oct-08	809,244	249,439	113,383	4,671	115,541	45,607	90,002	3,942	3,184	3,333	1,932	501	728,815	79,608	116,580	8,767
Nov-08	1,076,293	250,792	138,927	4,687	(9,962)	45,607	107,114	3,942	(7,929)	3,333	5,262	501	769,823	79,608	112,495	8,767
Dec-08	1,191,333	252,604	187,367	4,690	(9,608)	45,607	130,211	3,942	(18,805)	3,333	2,214	501	902,036	79,608	120,543	8,767
Jan-09	1,481,212	248,163	214,955	4,643	56,601	45,745	153,926	3,711	(15,827)	3,259	2,952	490	1,041,705	79,850	144,156	8,190
Feb-09	1,548,542	252,236	228,920	4,692	69,856	45,745	171,980	3,711	(15,254)	3,259	3,796	490	1,173,921	79,850	167,320	8,190
Mar-09	1,393,454	253,517	239,084	4,687	26,121	45,745	168,175	3,711	(17,054)	3,259	2,980	490	1,076,642	79,850	141,509	8,190
Apr-09	1,331,091	250,149	185,138	4,617	13,721	45,745	148,255	3,711	(15,497)	3,259	5,622	490	1,062,628	79,850	157,398	8,190
May-09	1,266,433	253,309	160,992	4,665	145,815	45,745	116,535	3,711	352	3,259	4,136	490	832,022	79,850	136,193	8,190
Jun-09	1,094,707	252,091	133,240	4,638	126,187	45,745	95,849	3,711	2,565	3,259	3,704	490	708,324	79,850	129,981	8,190
Jul-09	987,359	250,802	114,502	4,629	134,644	45,745	94,222	3,711	3,889	3,259	2,668	490	607,880	79,850	118,620	8,190
Aug-09	925,740	251,308	103,701	4,591	104,600	45,745	81,124	3,711	2,058	3,259	2,595	490	617,512	79,850	120,546	8,190
Sep-09	953,382	254,625	110,592	4,670	109,193	45,745	84,778	3,711	2,971	3,259	2,747	490	585,098	79,850	130,662	8,190
Oct-09	808,699	251,291	110,672	4,596	114,612	45,745	89,279	3,711	3,169	3,259	1,918	490	722,957	79,850	115,643	8,190
Nov-09	1,077,388	252,654	135,835	4,612	(9,899)	45,745	106,433	3,711	(7,834)	3,259	5,235	490	764,927	79,850	111,779	8,190
Dec-09	1,203,734	254,479	184,915	4,615	(9,637)	45,745	130,597	3,711	(18,750)	3,259	2,238	490	904,708	79,850	120,900	8,190

[5] While the coefficient is called the "base" coefficient, it really does not measure base use per day. Rather it is the intercept term in a simple regression. As a result, it can be negative reflecting the intercept of a regression that is outside of the relevant range.

The billed, unbilled, excess billed, and underbilled days and heating degree days are derived from the meter reading schedule and daily weather data. The measure used is the Average Route Days (ARD). The ARD are defined as the number of days across all routes for a given period divided by 21, the total number of routes. This concept is illustrated in Figure 3, a slightly different version of the December 2008 billing-month, shown below.

Figure 3

PSE&G December 2008 Billing-Month



Each square represents an ARD.[6] The total yellow blocks in each row represent the number of days in that particular route during the December billing-month. The sum of all the yellow blocks, 677, divided by 21 represent the average number of days in the December billing-month, i.e., the average number of days across the 21 routes or 32.24.

The number of excess billed days, $\boxed{\text{JAN B> DEC}}$, is:

1.5 (January 1st and half of January 2nd) / 21 = 0.07 [13]

HDD for each period are a weighted sum of the daily HDD where the weight is the ARD associated with that day. For example, from the diagram it can be seen that on December 21st, the sales to 8 routes, routes 14-21, will be in the

[6] Well, not exactly. Remember that it is assumed that the meters are read at noon. As a result the last yellow block to the right of each row counts as a half day. On the other hand, the last blue block on the right of each row also counts as a half day in the December billing-month so, the math works for the billing-month but, the half needs to be taken into account when discussing portions of the unbilled and billed periods. For a clearer discussion, however, the half days will be, for the most part, ignored.

December billing-month while sales to the first thirteen routes will be in the January billing-month. As a result , 8/21 or 38 percent of the HDD on December 20th will be assigned to the December billing month and 62 percent will be assigned to the January billing month.

HDD for underbilled and excess billed periods are assigned in a similar manner.

From Table 2 below that shows the normal monthly billed an unbilled HDD and days by type, it can be seen that underbilled days and HDD occur rarely while excess billed days are quite common.

Table 2

Billed and Unbilled Days and Weather
2008-2009

Billing Month	Heating Degree Days: Billed	Heating Degree Days: Unbilled	Heating Degree Days: Excess Billed	Heating Degree Days: Under Billed	Days: Billed	Days: Unbilled	Days: Excess Billed	Days: Under Billed
Jan-08	795.06	322.08	0.59	-	31.67	12.76	0.02	0.00
Feb-08	786.44	283.76	5.90	-	30.19	11.83	0.29	0.00
Mar-08	643.82	187.74	2.62	-	30.67	12.10	0.21	0.00
Apr-08	360.41	73.05	0.20	-	30.14	11.83	0.10	0.00
May-08	108.21	13.78	0.05	-	29.90	13.05	0.21	0.00
Jun-08	15.47	0.14	-	-	30.33	12.60	0.10	0.00
Jul-08	0.14	-	-	-	30.71	12.81	0.02	0.00
Aug-08	0.01	0.03	-	-	29.57	14.29	0.07	0.00
Sep-08	1.87	7.02	0.04	-	30.71	13.52	0.02	0.00
Oct-08	60.34	87.80	-	-	29.38	15.12	0.00	0.00
Nov-08	255.88	213.78	1.65	-	29.76	15.43	0.10	0.00
Dec-08	578.34	338.40	1.75	0.17	32.24	14.19	0.07	0.02
Jan-09	797.36	361.02	1.75	-	31.86	13.33	0.07	0.00
Feb-09	786.19	277.80	7.41	-	30.14	11.48	0.36	0.00
Mar-09	634.56	188.08	1.17	-	30.00	12.21	0.10	0.00
Apr-09	361.92	73.58	0.46	-	30.52	11.79	0.19	0.00
May-09	108.91	13.36	0.05	-	30.14	12.67	0.21	0.00
Jun-09	15.07	0.12	-	-	30.33	12.21	0.10	0.00
Jul-09	0.12	-	-	-	30.86	12.38	0.12	0.00
Aug-09	0.01	0.03	-	-	29.38	13.90	0.02	0.00
Sep-09	1.97	6.92	0.04	-	30.52	13.38	0.02	0.00
Oct-09	61.71	86.34	-	-	29.62	14.74	0.00	0.00
Nov-09	261.34	207.03	1.65	-	29.95	14.88	0.10	0.00
Dec-09	582.57	329.38	3.90	-	32.14	13.81	0.17	0.00

On a monthly basis, the necessary coefficient, weather, and day data are transmitted to PSE&G accounting services each month. They are used to calculate the actual current month unbilled sales, UnbilledTherms, using:

UnbilledTherms = UnbilledDays x BASECoef + UnbilledHDD x HDDCoef [14]

Where:

	UnbilledDays =	the number of route days in the unbilled period
as		defined by [9],
	Unbilled HDD =	the number of HDD in the unbilled period as defined by [9],
	BASECoef =	the Base coefficient,
	HDDCoef =	the HDD coefficient.

The results of this calculation, with the previous month's unbilled results, are used to calculate calendar-month sales.

Unbilled, and as a consequence, calendar-month revenue is calculated by pricing the unbilled therms at the projected tariff rates. Adding the net unbilled revenue to the billing-month revenues results in the estimate of calendar-month revenue.

B. Summary Tables

Delivered Gas Sales As Billed
2015-2026
(MDth)

Class	Rate	Category	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Residential	RSG	Heating	143,469	125,945	130,512	138,465	140,248	141,925	143,902	145,449	147,650	149,371	151,934	154,639
		Non-Heating	9,598	8,549	8,860	8,983	9,162	9,083	9,031	8,982	8,953	8,916	8,886	8,852
	Total		153,067	134,494	139,371	147,447	149,410	151,007	152,934	154,431	156,602	158,286	160,820	163,491
Commercial	GSG	Heating	24,044	21,075	22,541	23,239	23,894	24,154	24,247	24,185	24,126	24,045	24,110	24,476
		Non-Heating	4,193	3,819	3,939	4,109	4,108	4,109	4,111	4,106	4,106	4,106	4,108	4,106
		Total	28,237	24,894	26,480	27,348	28,002	28,264	28,358	28,291	28,232	28,150	28,218	28,582
	LVG		65,580	58,437	61,091	63,422	63,794	64,052	64,284	64,326	64,436	64,388	64,582	64,830
	TSG	Firm	1,066	945	941	1,088	1,088	1,088	1,088	1,088	1,088	1,088	1,088	1,088
		Non-Firm	17,324	16,683	10,062	12,880	12,880	12,880	12,880	12,880	12,880	12,880	12,880	12,880
		Total	18,390	17,628	11,003	13,967	13,967	13,967	13,967	13,967	13,967	13,967	13,967	13,967
	CIG		3,724	3,242	3,595	4,387	4,387	4,387	4,387	4,387	4,387	4,387	4,387	4,387
	CSG		15,922	16,728	16,341	13,236	13,236	13,236	13,236	13,236	13,236	13,236	13,236	13,236
	Total		131,852	120,930	118,510	122,360	123,387	123,906	124,233	124,208	124,259	124,128	124,391	125,002
Industrial	GSG	Heating	969	803	871	922	914	901	888	878	868	857	847	836
		Non-Heating	164	148	153	165	164	163	161	160	158	157	156	154
		Total	1,133	950	1,025	1,087	1,078	1,063	1,049	1,038	1,027	1,014	1,003	990
	LVG		7,731	6,788	7,043	7,256	7,241	7,183	7,130	7,091	7,049	6,999	6,961	6,914
	TSG	Firm	1,522	1,415	1,511	1,547	1,547	1,547	1,547	1,547	1,547	1,547	1,547	1,547
		Non-Firm	19,899	20,937	17,374	5,994	5,994	5,994	5,994	5,994	5,994	5,994	5,994	5,994
		Total	21,421	22,351	18,886	7,542	7,542	7,542	7,542	7,542	7,542	7,542	7,542	7,542
	CIG		1,119	688	564	934	934	934	934	934	934	934	934	934
	CSG		125,946	113,324	83,737	96,355	96,355	96,355	96,355	96,355	96,355	96,355	96,355	96,355
	Contract		36,053	25,237	8,822	-	-	-	-	-	-	-	-	-
	Total		193,403	169,339	120,075	113,174	113,150	113,076	113,010	112,960	112,906	112,843	112,794	112,735
Lighting	SLG		68	64	66	66	66	66	66	66	66	66	66	66
Total			478,391	424,827	378,023	383,047	386,013	388,056	390,242	391,664	393,834	395,323	398,071	401,294

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
GSG	29,370	25,844	27,505	28,435	29,081	29,327	29,408	29,329	29,259	29,164	29,220	29,572
LVG	73,311	65,225	68,134	70,678	71,036	71,235	71,414	71,417	71,486	71,386	71,543	71,744
TSG	2,587	2,359	2,452	2,635	2,635	2,635	2,635	2,635	2,635	2,635	2,635	2,635
	37,223	37,620	27,437	18,874	18,874	18,874	18,874	18,874	18,874	18,874	18,874	18,874

Supplied Gas Sales As Billed
2015-2026
(MDth)

Class	Rate	Category	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Residential	RSG	Heating	134,729	119,460	124,075	132,289	133,994	135,595	137,486	138,966	141,069	142,713	145,163	147,749
		Non-Heating	8,995	8,064	8,362	8,520	8,691	8,616	8,567	8,520	8,492	8,457	8,430	8,397
	Total		143,724	127,524	132,437	140,810	142,684	144,210	146,053	147,486	149,561	151,170	153,593	156,146
Commercial	GSG	Heating	18,565	16,082	17,387	17,888	18,397	18,598	18,672	18,626	18,582	18,521	18,573	18,856
		Non-Heating	3,035	2,757	2,965	2,998	2,998	2,998	3,000	2,996	2,996	2,996	2,997	2,996
		Total	21,600	18,839	20,352	20,887	21,395	21,596	21,671	21,622	21,578	21,516	21,570	21,852
	LVG		27,301	21,264	24,578	23,867	25,629	24,119	24,213	25,857	24,277	25,899	24,343	26,086
	TSG	Firm	-	-	-	-	-	-	-	-	-	-	-	-
		Non-Firm	919	723	942	675	675	675	675	675	675	675	675	675
		Total	919	723	942	675	675	675	675	675	675	675	675	675
	CIG		3,724	3,242	3,595	4,387	4,387	4,387	4,387	4,387	4,387	4,387	4,387	4,387
	CSG		-	-	-	-	-	-	-	-	-	-	-	-
	Total		53,544	44,068	49,467	49,816	52,086	50,777	50,947	52,540	50,917	52,477	50,975	53,001
Industrial	GSG	Heating	778	639	689	727	721	711	701	693	685	676	668	659
		Non-Heating	123	108	113	124	123	122	120	119	118	117	116	115
		Total	902	747	802	851	844	832	821	812	803	793	785	775
	LVG		2,013	1,637	1,864	1,975	1,971	1,954	1,937	1,925	1,911	1,897	1,885	1,871
	TSG	Firm	-	-	-	-	-	-	-	-	-	-	-	-
		Non-Firm	55	151	108	113	113	113	113	113	113	113	113	113
		Total	55	151	108	113	113	113	113	113	113	113	113	113
	CIG		1,119	688	564	934	934	934	934	934	934	934	934	934
	CSG		-	-	-	-	-	-	-	-	-	-	-	-
	Contract		2,590	2,114	1,301	-	-	-	-	-	-	-	-	-
	Total		6,679	5,337	4,638	3,874	3,862	3,833	3,806	3,784	3,762	3,738	3,717	3,693
Lighting	SLG		28	26	26	26	26	26	26	26	26	26	26	26
Total			203,975	176,956	186,568	194,525	198,658	198,846	200,831	203,837	204,266	207,411	208,311	212,865

Supplied Share of Delivered Gas Sales As Billed
2015-2026
(percent)

Class	Rate	Category	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Residential	RSG	Heating	94%	95%	95%	96%	96%	96%	96%	96%	96%	96%	96%	96%
		Non-Heating	94%	94%	94%	95%	95%	95%	95%	95%	95%	95%	95%	95%
	Total		94%	95%	95%	95%	95%	95%	96%	96%	96%	96%	96%	96%
Commercial	GSG	Heating	77%	76%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%
		Non-Heating	72%	72%	75%	73%	73%	73%	73%	73%	73%	73%	73%	73%
		Total	76%	76%	77%	76%	76%	76%	76%	76%	76%	76%	76%	76%
	LVG		42%	36%	40%	38%	40%	38%	38%	40%	38%	40%	38%	40%
	TSG	Firm	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
		Non-Firm	5%	4%	9%	5%	5%	5%	5%	5%	5%	5%	5%	5%
		Total	5%	4%	9%	5%	5%	5%	5%	5%	5%	5%	5%	5%
	CIG		100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
	CSG		0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	Total		41%	36%	42%	41%	42%	41%	41%	42%	41%	42%	41%	42%
Industrial	GSG	Heating	80%	80%	79%	79%	79%	79%	79%	79%	79%	79%	79%	79%
		Non-Heating	75%	73%	74%	75%	75%	75%	75%	75%	75%	75%	75%	75%
		Total	80%	79%	78%	78%	78%	78%	78%	78%	78%	78%	78%	78%
	LVG		26%	24%	26%	27%	27%	27%	27%	27%	27%	27%	27%	27%
	TSG	Firm	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
		Non-Firm	0%	1%	1%	2%	2%	2%	2%	2%	2%	2%	2%	2%
		Total	0%	1%	1%	2%	2%	2%	2%	2%	2%	2%	2%	2%
	CIG		100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
	CSG		0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	Contract		7%	8%	15%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	Total		3%	3%	4%	3%	3%	3%	3%	3%	3%	3%	3%	3%
Lighting	SLG		41%	41%	39%	39%	39%	39%	39%	39%	39%	39%	39%	39%
Total			43%	42%	49%	51%	51%	51%	51%	52%	52%	52%	52%	53%

Delivered Gas Sales Calendar-Year
2015-2026
(MDth)

Class	Rate	Category	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Residential	RSG	Heating	140,336	130,626	131,801	135,538	140,049	142,449	143,574	145,361	147,396	149,997	151,693	154,398
		Non-Heating	9,413	8,788	8,866	8,828	9,160	9,104	9,004	8,971	8,932	8,942	8,866	8,832
	Total		149,749	139,414	140,667	144,366	149,209	151,553	152,578	154,332	156,328	158,939	160,559	163,231
Commercial	GSG	Heating	23,418	21,873	22,771	22,856	23,896	24,248	24,182	24,157	24,063	24,139	24,056	24,436
		Non-Heating	4,114	3,914	4,040	4,074	4,101	4,119	4,102	4,102	4,099	4,116	4,100	4,098
		Total	27,532	25,786	26,811	26,930	27,997	28,367	28,283	28,259	28,162	28,255	28,156	28,534
	LVG		63,808	60,401	61,513	62,504	63,706	64,254	64,132	64,265	64,308	64,596	64,458	64,708
	TSG	Firm	1,038	958	951	1,088	1,088	1,088	1,088	1,088	1,088	1,088	1,088	1,088
		Non-Firm	14,957	15,183	9,668	12,880	12,880	12,880	12,880	12,880	12,880	12,880	12,880	12,880
		Total	15,995	16,141	10,618	13,967	13,967	13,967	13,967	13,967	13,967	13,967	13,967	13,967
	CIG		3,651	3,166	3,408	4,333	4,387	4,387	4,387	4,387	4,387	4,387	4,387	4,387
	CSG		11,685	13,634	8,509	14,221	13,236	13,236	13,236	13,236	13,236	13,236	13,236	13,236
	Total		122,671	119,128	110,859	121,955	123,293	124,211	124,006	124,114	124,060	124,441	124,205	124,833
Industrial	GSG	Heating	952	823	875	914	912	903	885	877	865	859	844	833
		Non-Heating	144	152	155	164	164	163	161	159	158	157	155	154
		Total	1,096	975	1,030	1,078	1,076	1,066	1,045	1,036	1,023	1,017	999	987
	LVG		7,526	6,995	7,093	7,154	7,228	7,196	7,110	7,082	7,034	7,013	6,946	6,899
	TSG	Firm	1,505	1,393	1,574	1,609	1,547	1,547	1,547	1,547	1,547	1,547	1,547	1,547
		Non-Firm	19,620	21,872	15,878	5,994	5,994	5,994	5,994	5,994	5,994	5,994	5,994	5,994
		Total	21,125	23,265	17,451	7,604	7,542	7,542	7,542	7,542	7,542	7,542	7,542	7,542
	CIG		1,164	687	557	940	934	934	934	934	934	934	934	934
	CSG		118,452	108,304	72,331	96,012	96,355	96,355	96,355	96,355	96,355	96,355	96,355	96,355
	Contract		35,878	25,913	6,342	-	-	-	-	-	-	-	-	-
	Total		185,242	166,140	104,804	112,787	113,134	113,091	112,986	112,949	112,888	112,859	112,776	112,717
Lighting	SLG		68	64	66	66	66	66	66	66	66	66	66	66
Total			457,730	424,746	356,396	379,175	385,703	388,921	389,636	391,461	393,342	396,305	397,606	400,846

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
GSG	28,628	26,762	27,841	28,008	29,073	29,433	29,328	29,295	29,185	29,272	29,156	29,521
LVG	71,334	67,396	68,606	69,658	70,934	71,449	71,242	71,347	71,342	71,608	71,404	71,607
TSG	2,543	2,351	2,524	2,697	2,635	2,635	2,635	2,635	2,635	2,635	2,635	2,635
	34,578	37,055	25,545	18,874	18,874	18,874	18,874	18,874	18,874	18,874	18,874	18,874
CIG	4,815	3,853	3,965	5,273	5,321	5,321	5,321	5,321	5,321	5,321	5,321	5,321
CSG	130,137	121,938	80,840	110,233	109,590	109,590	109,590	109,590	109,590	109,590	109,590	109,590
Contract	35,878	25,913	6,342	-	-	-	-	-	-	-	-	-

Supplied Gas Sales Calendar-Year
2015-2026
(MDth)

Class	Rate	Category	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Residential	RSG	Heating	132,140	124,069	125,315	129,087	133,803	136,096	137,172	138,882	140,826	143,311	144,933	147,519
		Non-Heating	8,837	8,297	8,365	8,345	8,689	8,635	8,541	8,510	8,473	8,483	8,410	8,378
	Total		140,977	132,367	133,680	137,432	142,493	144,731	145,714	147,392	149,300	151,793	153,344	155,897
Commercial	GSG	Heating	18,146	16,764	17,569	17,423	18,398	18,670	18,621	18,604	18,533	18,594	18,531	18,826
		Non-Heating	2,995	2,833	2,976	2,947	2,993	3,006	2,993	2,993	2,991	3,003	2,992	2,990
		Total	21,142	19,597	20,545	20,370	21,391	21,676	21,614	21,597	21,524	21,597	21,523	21,816
	LVG		26,549	21,882	24,708	23,475	25,594	24,200	24,152	25,832	24,225	25,983	24,293	26,037
	TSG	Firm	-	-	-	-	-	-	-	-	-	-	-	-
		Non-Firm	910	789	892	675	675	675	675	675	675	675	675	675
		Total	910	789	892	675	675	675	675	675	675	675	675	675
	CIG		3,651	3,166	3,408	4,333	4,387	4,387	4,387	4,387	4,387	4,387	4,387	4,387
	CSG		-	-	-	-	-	-	-	-	-	-	-	-
	Total		52,251	45,434	49,553	48,852	52,047	50,939	50,828	52,491	50,810	52,642	50,878	52,915
Industrial	GSG	Heating	768	656	692	718	719	712	698	692	683	678	666	657
		Non-Heating	108	112	115	121	123	122	120	119	118	118	116	115
		Total	875	768	806	840	842	834	818	811	801	796	782	772
	LVG		1,928	1,677	1,877	1,972	1,967	1,957	1,931	1,922	1,907	1,901	1,881	1,866
	TSG	Firm	-	-	-	-	-	-	-	-	-	-	-	-
		Non-Firm	55	196	59	113	113	113	113	113	113	113	113	113
		Total	55	196	59	113	113	113	113	113	113	113	113	113
	CIG		1,164	687	557	940	934	934	934	934	934	934	934	934
	CSG		-	-	-	-	-	-	-	-	-	-	-	-
	Contract		2,712	2,585	759	-	-	-	-	-	-	-	-	-
	Total		6,735	5,913	4,058	3,865	3,856	3,839	3,797	3,780	3,755	3,744	3,710	3,686
Lighting	SLG		28	26	26	26	26	26	26	26	26	26	26	26
Total			199,992	183,740	187,316	190,175	198,421	199,534	200,363	203,689	203,891	208,205	207,957	212,524

Supplied Share of Delivered Gas Sales Calendar Year 2015-2026 (percent)

Class	Rate	Category	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Residential	RSG	Heating	94%	95%	95%	95%	96%	96%	96%	96%	96%	96%	96%	96%
		Non-Heating	94%	94%	94%	95%	95%	95%	95%	95%	95%	95%	95%	95%
	Total		94%	95%	95%	95%	95%	95%	96%	96%	96%	96%	96%	96%
Commercial	GSG	Heating	77%	77%	77%	76%	77%	77%	77%	77%	77%	77%	77%	77%
		Non-Heating	73%	72%	74%	72%	73%	73%	73%	73%	73%	73%	73%	73%
		Total	77%	76%	77%	76%	76%	76%	76%	76%	76%	76%	76%	76%
	LVG		42%	36%	40%	38%	40%	38%	38%	40%	38%	40%	38%	40%
	TSG	Firm	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
		Non-Firm	6%	5%	9%	5%	5%	5%	5%	5%	5%	5%	5%	5%
		Total	6%	5%	8%	5%	5%	5%	5%	5%	5%	5%	5%	5%
	CIG		100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
	CSG		0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	Total		43%	38%	45%	40%	42%	41%	41%	42%	41%	42%	41%	42%
Industrial	GSG	Heating	81%	80%	79%	79%	79%	79%	79%	79%	79%	79%	79%	79%
		Non-Heating	75%	74%	74%	74%	75%	75%	75%	75%	75%	75%	75%	75%
		Total	80%	79%	78%	78%	78%	78%	78%	78%	78%	78%	78%	78%
	LVG		26%	24%	26%	28%	27%	27%	27%	27%	27%	27%	27%	27%
	TSG	Firm	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
		Non-Firm	0%	1%	0%	2%	2%	2%	2%	2%	2%	2%	2%	2%
		Total	0%	1%	0%	1%	2%	2%	2%	2%	2%	2%	2%	2%
	CIG		100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
	CSG		0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	Contract		8%	10%	12%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	Total		4%	4%	4%	3%	3%	3%	3%	3%	3%	3%	3%	3%
Lighting	SLG		41%	41%	39%	39%	39%	39%	39%	39%	39%	39%	39%	39%
Total			44%	43%	53%	50%	51%	51%	51%	52%	52%	53%	52%	53%

17. FERC Pipeline Activities

Item 17

FERC Pipeline Activities

Pipeline	Docket No.	Description
Transco	RP18-1126	On August 31, 2018 Transco filed a general Section 4 rate increase case seeking a $2.5 billion annual cost of service for their jurisdictional transportation, storage and gathering services. In addition, Transco proposed a new Emissions Reduction Surcharge Program to fund the replacement of many of its compressor stations through annual limited NGA Section 4 filings. Facing an overall 30% cost increase to its rates, the Company protested the application, and is an active intervenor in this matter, forming and leading a large group of firm customers jointly seeking to decrease the magnitude of the proposed rate increase. The group has retained an expert witness and a group counsel to assist them in their pursuit of cost of service issues. In addition, the Company has teamed with another local distribution company to jointly retain the services of an expert witness on cost allocation and rate design issues. Settlement discussions are currently being pursued. For this BGSS Filing, the Company has projected a settlement of the case with a rate reduction below the level of the rates currently being paid subject to refund to become effective May

		1, 2020 and refunds for the locked-in rate period to be received by July 1, 2020.
Texas Eastern	RP19-343	On November 30, 2018, Texas Eastern filed a general Section 4 rate increase seeking a $1.9 billion annual cost of service, its first rate case in decades. The Company protested the application, and is an active intervenor in this matter. PSEG is the largest member in a group of firm customers jointly seeking to decrease the magnitude of the proposed rate increase. The group has retained an expert witness and a group counsel to assist them in their pursuit of cost of service issues. Settlement discussions are currently being pursued. For this BGSS Filing, the Company has projected a settlement of the case with a rate reduction below the level of the rates currently being paid subject to refund to become effective July 1, 2020 and refunds for the locked-in rate period to be received by October 1, 2020.
FERC	Order 849	On July 18, 2018, FERC issued a Final Rule adopting procedures for determining which jurisdictional natural gas pipelines may be collecting unjust and unreasonable rates in light of the income tax reductions provided by the Tax Cuts and Jobs Act. The Final Rule established a requirement that all interstate natural gas companies, with cost-based rates must submit a Form 501-G informational filing to create a forum for the purpose of evaluating the tax impact, and also to encourage pipelines to voluntarily reduce their rates to reflect the income tax reductions and

		changes in tax allowance. Each pipeline was required to elect one of four options: • File a limited NGA section 4 rate reduction proceeding; • Commit to file a general rate case in the near future; • Explain why no rate change was needed; or • Take no action. The Company has been an active participant in proceedings established for each of the pipelines serving PSEG.
Tennessee	RP19-351	Tennessee Gas Pipeline was required to file its Form 501-G by April 5, 2019, but after engaging in successful settlement negotiations with its customers, instead filed a Rate Settlement establishing new rates that provide for a reduction from their currently effective rates: • An 8.5% reduction effective November 1, 2019; • An additional 2% reduction effective November 1, 2020; • An additional 2% reduction effective November 1, 2021; and • An additional 1% reduction effective November 1, 2022. The Settlement also requires Tennessee to file cost and revenue studies at specified dates in the future to provide shippers and the Commission with an opportunity to evaluate Tennessee's rates if an NGA Section 4 or Section 5 proceeding has not already been initiated.
Columbia	RP19-406	On April 4, 2019 FERC issued an order terminating the Form 501-G proceeding for Columbia Gas Transmission, largely

		because the pipeline has a settlement in place which already required it to make the necessary rate reductions associated with the income tax reductions provided by the Tax Cuts and Jobs Act. A group of Columbia's customers (including PSEG) filed comments agreeing that no rate change is necessary at this time, but seeking clarifications that will preserve customer rights in future proceedings.
Dominion	RP19-62	On March 8, 2019, FERC issued an order terminating the Form 501-G proceeding for Dominion Energy Transmission, Inc. Dominion's Form No. 501-G showed an indicated percentage cost-of-service reduction of 7.3 percent. Dominion asserted that no rate adjustment was appropriate. Despite protests by PSEG and other parties, FERC determined that Dominion's ROE did not appear to be sufficiently excessive to justify initiating a Section 5 investigation.
Texas Eastern	CP18-26	On December 7, 2017, Texas Eastern applied for approval of the Lambertville East Expansion Project, which includes an incremental firm daily quantity of 30,000 dekatherms/day to the Company at its Hillsborough and Jamesburg stations. Acting to meet increasing market demand from its firm customers, the Company worked with the pipeline as an anchor shipper for the project, which received its FERC certificate on November 26, 2018, and has an in-service date of November 2019.

Transco	CP18-18	On November 15, 2017, Transco applied for approval of the Gateway Expansion Project, which is designed to provide an incremental firm daily quantity of 54,000 dekatherms/day to the Company at its Ridgefield and Paterson stations. Acting to meet increasing market demands from its firm customers, the Company has worked with the pipeline as an anchor shipper for the project, which received its FERC certification on December 12, 2018, and has an in-service date of November 2020.
Columbia	RP19-515	On December 31, 2018, Columbia filed for the implementation of its Modernization II Settlement by resetting Columbia's base transportation recourse rates. The Modernization II Settlement preserves and extends the core elements of the 2012 settlement between Columbia and its shippers that addressed modernization issues on Columbia's system. Also, the Modernization II Settlement extends Columbia's ability to recover the costs of eligible projects via the CCRM Rate for a new term. FERC authorization was granted on January 23, 2019.

18. <u>Gas Supply Plan</u>

Gas Procurement Objectives

Current & Forecasted Gas Service Requirements

Projected Sources of Capacity

Affiliate Relationship / Asset Management

Hedging Plan & Strategy

Capacity Releases / Off-System Sales

Item 18

Gas Supply Plan

1. Gas Procurement Objectives

As discussed in the body of the testimony of David F. Caffery herein, natural gas prices have decreased from the levels experienced at this time last year. From a historical perspective, prices continue to remain reasonably priced with, at the time of this BGSS Filing, the NYMEX prompt month trading at approximately $2.58 /Dth. Prices have traded in a relatively tight range between approximately $2.50/Dth and $2.90/Dth since the middle of January 2019. The forward NYMEX strip used by the Company shows that prices are expected to rise modestly from current levels through the first quarter of 2020, followed by a reduction for the balance of the BGSS period. Overall, the NYMEX strip through September 2020 used for this year's BGSS Filing is approximately 3% below last year's (see the NYMEX forward strip included as Item 8). One of the primary drivers of this moderation in prices is the record natural gas production witnessed over the past 12 months. Additional pipeline takeaway capacity placed into service during 2018, primarily from the Marcellus/Utica region, has motivated producers to increase production levels significantly. In fact, an all-time production record of over 87 Bcf/d was achieved just recently. This represents an increase of over 9 Bcf/d (about 11%) above the year ago levels and accounts for much of the reason why prices have remained moderate despite national storage levels being below the 5 year average by greater than 20%. As a result of these market dynamics, the Company expects adequate supply at reasonable price levels to continue to exist throughout the upcoming BGSS period.

2. Current and Forecasted Gas Service Requirements

The Company's forecasted natural gas supply requirements are included herein as Item 16. Item 16 consists of two parts. First, Schedule F illustrates the Company's Peak Day Gas Requirements and Supply over the next five winter periods. This schedule illustrates both the forecasted peak day supply by winter period as well as the pipeline transportation, storage and peaking supplies that the Company will rely upon to meet those forecasted requirements. The second part of Item 16 is the

Company's updated Natural Gas Sales Forecast for 2019. This document provides the Company's natural gas sales forecast, as well as the current forecast methodology, the econometric sales models and the forecast assumptions.

3. Projected Sources of Capacity

The Company periodically reviews its pipeline transportation, storage and peaking capacity supplies to ensure that the optimal mix of capacity assets are maintained to meet its forecasted peak day and seasonal requirements at the lowest possible cost. Several changes in the Company's pipeline capacity portfolio have been made which are reflected in the instant BGSS Filing.

As mentioned in last year's BGSS filing, the Company has taken certain steps to ensure that it continues to meet its projected peak day capacity requirements to serve its firm customers. As illustrated on Item 16, based on the Company's latest forecast, it is projected that the Company will experience a shortfall in peak day supply in 2019/2020 which will increase throughout the five year forecast period.

The Company has taken several steps to meet the increased peak day capacity requirements. First, the Company has entered into a transportation service agreement with Texas Eastern to provide 30,000 Dth/d of incremental firm transportation capacity. A portion of this capacity, 16,329 Dth/d, consists of existing capacity that the Company was able to obtain during 2017 and is reflected in the supply numbers included on Item 16. The balance of the capacity, 13,671 Dth/d, is projected to be available on November 1, 2019 to help meet the anticipated shortfall in peak day supply in the 2019/2020 winter.

In addition to this Texas Eastern capacity, the Company has entered into a transportation service agreement with Algonquin to add an additional 15,000 Dth/d of incremental firm transportation capacity to help meet its increased peak day requirements. This capacity is also expected to be in-service for November 1, 2019, and will help meet the anticipated shortfall in peak day supply for the 2019/2020 winter.

The Company has also entered into a transportation service agreement with Transco to obtain incremental firm transportation capacity to further help meet its projected peak day shortfall. The agreement with Transco provides for 54,000 Dth/d of incremental firm capacity. This capacity is anticipated to be in-service on November

1, 2020 and will help meet the projected shortfall in peak day supply for the 2020/2021 winter.

In addition, the Company renegotiated two companion Dominion FT agreements numbered 200316 and 200317, which were formerly a storage injection service for 31,936 Dth/day and a storage withdrawal service for 41,813 Dth/day, respectively. For contract number 200316, the old service has been replaced with an FT agreement with an entitlement of 41,813 Dth/day that can be used more flexibly, and is no longer limited to just storage-related transactions. In light of this contract reconfiguration, agreement 200317 has been terminated. Both changes were effective April 1, 2018.

Also, the Company recently participated in an open season for Transco's Regional Energy Access Project which provides for an expansion of the Transco system between the Marcellus supply region in northeast Pennsylvania and central and southern New Jersey. The Company is working with Transco to develop a precedent agreement providing for 50,000 Dth/d of new transportation capacity to help meet the projected shortfall in peak day supply for the 2023/2024 winter, and to meet increased gas requirements in the Mount Laurel area of its distribution system.

Finally, the Company is a shipper in the PennEast project which will provide increased capacity from the Marcellus shale region, as well as provide a new independent source of pipeline supply, and thereby increase the reliability of the Company's portfolio of firm pipeline transportation capacity. PennEast received its FERC Certificate on January 19, 2018, and is currently seeking the required state and local permits to provide for construction to commence. Given this timeline, PennEast is targeting a late 2020 in-service date. As such, costs associated with the PennEast capacity are not included in the instant BGSS Filing.

As agreed to in the Stipulation between the Parties in last year's BGSS Filing, in addition to the description of the contract changes above, the following table represents a listing of all contracts that have been extended pursuant to their evergreen provisions during the last BGSS Filing period:

Counterparty	Rate Schedule	Contract Number	Top Gas Quantity	Daily Contract Quantity
Texas Eastern	FT-1	910553		25,018
Texas Eastern	FTS	330840		12,315
Texas Eastern	FTS - 5	330915		45,084
Texas Eastern	FTS - 5	330181		10,508
Texas Eastern	FTS - 7	331007		97,915
Texas Eastern	FTS - 8	331017		60,069
Texas Eastern	SS - 1	400123	3,737,160	62,286
Texas Eastern	SS - 1	400241	1,453,340	20,762
Texas Eastern	FT - 1	800604		40,526
Texas Eastern	CDS	800600		120,000
Texas Eastern	FT - 1	800601		26,115
Texas Eastern	FT - 1	800605		110,000
Texas Eastern	FT - 1	800602		15,000
Texas Eastern	FT - 1	800606		30,000
Texas Eastern	FT - 1	800603		40,000
Texas Eastern	FT - 1	910611		50,000
Algonquin	AFT - 1	510393		12,500
Transco	FT	1006312		72,450
Transco	FT	1044211		50,000
Transco	FT	9009846		73,500
Transco	FT	9146335		9,400
Transco	FT	9146336		9,850
Transco	FT	1002228		6,440
Transco	FT	1003688		425,930
Transco	FT	1003835		198,950
Transco	FT	1005002		13,248
Transco	FT	1033145		48,240
Transco	FT	1041156		50,000
Transco	LNG	1000824	1,333,817	273,331
Transco	LNG	9127690	15,525	2,070
Transco	S - 2	1000823	6,158,589	68,514
Transco	ESS	1008564	1,186,535	141,544
Transco	FT	9066768		43,300
Dominion	FT	200316		41,813
Dominion	FTNN	525445		32,446
Dominion	GSSTE	600043	14,249,916	162,995
Dominion	FT	200391		22,019
Gulf South	FSS	661	1,000,000	100,000

4. Affiliate Relationships/Asset Management

The Company obtains its full natural gas requirements for BGSS Service pursuant to the Requirements Contract entered into between the Company and PSEG Energy Resources and Trade (PSEG ERT) effective May 2002. Under this agreement, PSEG ERT manages its portfolio of transportation, storage and peaking supply assets to meet the Company's natural gas requirements on an hourly, daily, weekly, monthly and annual basis. The Company meets with representatives of PSEG ERT as needed to provide oversight of the procurement of supplies pursuant to the Requirements Contract. PSEG ERT provides updates to the Company regarding changes to pipeline capacity under contract, hedging activities, supply and pricing trends, as well as market developments. In addition, the Company and PSEG ERT work together to prepare the information provided in the annual BGSS Filing. Item 13 in this BGSS Filing includes a summary of the principal terms of the Requirements Contract. There have been no changes to any of the terms and provisions since last year's BGSS Filing.

As a part of this year's annual BGSS filing, the Company proposes to extend the term of the Requirements Contract through March 31, 2025. The reason for the extension is to provide greater certainty to both of the parties regarding the provision of natural gas service to support PSE&G's BGSS business and to remove the contract from its current evergreen status. The current one-year evergreen and two-year termination provisions, as well as all of the other terms and conditions of the Contract, would remain unchanged.

5. Hedging Plan and Strategy

The Company has included as Item 11 in the instant BGSS Filing its PSE&G Quarterly Gas Hedging Reports, which have been filed with the NJBPU over the past year. As discussed in the testimony of David F. Caffery herein, the Company to date has hedged approximately 98% of its planned volume for the 2019 summer period, approximately 69% of its planned volume for the 2019-2020 winter period and approximately 41% of its planned volume for the 2020 summer period. Hedging for the winter 2020-2021 period has just begun.

In addition to its transportation and peaking assets, PSEG ERT maintains approximately 70 Bcf of storage assets under contract with various pipeline suppliers. These storage assets are used to supplement flowing gas supplies when customer demand on the Company's distribution system increases during the winter period. The Company typically injects gas into its storages during the April through October timeframe, targeting a level of approximately 97% full by October 31st. Item 12 included herein provides the list of storage services under contract as well as the monthly ending storage inventory by contract for the past winter period. This illustrates the manner in which each storage service was utilized over the 2018-2019 winter. The Company's extensive storage portfolio allows the Company to purchase gas supplies during the April through October timeframe and withdraw this gas for use during the peak winter months thereby providing a further hedge on behalf of its customers against winter price volatility.

6. Capacity Releases/Off-System Sales

The attached schedule provides a summary of the capacity release and off-system sales by the Company for the prior seven calendar years and for the first four months of 2019. For the upcoming BGSS period that is covered by this filing, the Company has a total of approximately $ 35 million in credits attributed to capacity release and off-system sales. As can be seen on the attached schedule, off-system sales margins for the 4 months ending April, 2019 total $ 12 million, approximately 18% of last year's 12-month total.

For the prior period, the Company has continued to experience decreased margins in off-system sales and capacity release transactions. A number of significant pipeline expansions from the Marcellus and Utica supply regions, representing over 9 Bcf/day of new capacity, have been placed into service over the past year, providing additional outlets for these shale gas supplies. The increased ability of these pipelines to move additional volumes to market has resulted in a decrease in the basis differentials between the Marcellus and Utica supply region and the Transco Z6 market, where the Company makes the majority of its off-system sales. The Company anticipates this extensive pipeline capacity buildout will continue to put significant downward pressure on capacity release and off-system sales margins throughout the upcoming BGSS period.

Item 18

Off System Sales -- Revenues, Costs and Margins

2012 - 2019

Year	BGSS-RSG OSS Revenue (1)	BGSS-RSG OSS Cost (2)	BGSS-RSG OSS Margins (3)
2012	$155,052,637	$102,869,794	$52,182,843
2013	$240,938,997	$120,566,928	$120,372,069
2014	$327,717,529	$143,452,710	$184,264,819
2015	$197,662,767	$61,941,827	$135,720,940
2016	$145,423,895	$86,729,138	$58,694,758
2017	$156,240,095	$96,425,765	$59,814,330
2018	$194,555,168	$124,011,106	$65,540,294
2019*	$42,803,572	$31,229,567	$11,574,005

*Note: Through April 2019

Attachment D-1

Support for Balancing Charge

& Storage Inventory Carrying Charge

(Including Update for A&G Charge)

8 months – October to May

Balancing Charge - Annual Allocated Cost

Firm Capacity Allocation:	Total (Mdth/day)	Capacity Used for Balancing (Mdth/day)	Percent Allocated to Balancing Use
Base FT	797.1	0.0	0.0%
Storage	895.5	464.2	51.8%
Balancing FT	432.4	432.4	100.0%
Peaking	541.3	541.3	100.0%
	2,666.3	1,437.9	

	Total Cost	Percent Allocated to Balancing Use	Allocated Cost
Fixed Cost Allocation:			
Base FT	$154,176.3	0.0%	$0.0
Storage	$118,360.2	51.8%	$61,355.8
Balancing FT	$72,376.8	100.0%	$72,376.8
Peaking	$10,681.4	100.0%	$10,681.4
Variable Cost Allocation:			
Base FT	$0.0	0.0%	$0.0
Storage	$7,063.9	51.8%	$3,661.8
Balancing FT	$0.0	100.0%	$0.0
Peaking	$1,410.8	100.0%	$1,410.8
Total Annual Allocated Costs ($000)	**$ 364,069.3**		**$ 149,486.5**

Balancing Use Billing Determinants - Oct - May (MDth)	177,221
Balancing Charge - Annual Allocated Cost ($/Dth)	$ 0.84350
Storage Inventory Carrying Charge ($/Dth) (page 2)	$ 0.03871
Revenue Requirement on Gas Production Plant Charge ($/Dth) (page 3)	$ 0.02421
Total Balancing Charge (excl. losses) ($/Dth)	$ 0.90642
Total Balancing Charge (incl. losses @ 2%) ($/Dth)	$ 0.92492
Total Balancing Charge (incl. SUT) ($/Dth)	**$ 0.98620**
Total Balancing Charge (incl. SUT) ($/Therm)	**$ 0.098620**

Note: Source of BGSS RSG Commodity Balancing Credit

Forecasted BGSS RSG Balancing Use Billing Determinants (MDth)	**108,394**
Forecasted BGSS RSG Balancing Charge Revenue	**$91,431**
Forecasted BGSS RSG Firm Sendout (MDth)	**146,848**
Balancing Charge Credit BGSS RSG Commodity	**(0.62262)**

Storage Inventory Carrying Charge

	12 Months Oct 2019- Sept 2020 (000)
RSG Inventory Cost	$ 172,508
BGSS-F Inventory Cost	$ 26,268
BGSS-F Fixed Cost Deferred	$ 15,704
LNG + LPA	$ 2,831
Total Inventory Cost	**$ 217,310**
Total Annual Storage Carrying Cost @ 9.02%	**$ 19,601**

Recovery %	**Recovery %**
Balancing	35.00%
Commodity	65.00%

Rate per Dth	MDth	Cost	**$/Dth**
Balancing	177,221	$ 6,860	**$ 0.03871**
Commodity	196,438	$ 12,741	**$ 0.06486**

Revenue Requirement on Gas Production Plants

		12 Months Oct 19 - Sep 20
2019	October	$ 837,026
	November	$ 200,276
	December	$ 200,276
2020	January	$ 200,276
	February	$ 200,276
	March	$ 200,276
	April	$ 825,401
	May	$ 825,401
	June	$ 200,276
	July	$ 200,276
	August	$ 200,276
	September	$ 200,276
Total		**$ 4,290,315**
Balancing Use Billing Determinants (MDth)		**177,221**
Revenue Requirement on Gas Production Plant Charge ($/Dth)		**$ 0.02421**

Gas Supply A&G

	12 Months Oct 19 - Sep 20
Direct Labor & Overhead	**$ 7,004,200**
Firm Sendout - Dth (000)	**196,438.3**
Gas Supply A&G Rate	**$ 0.03566**

Attachment D-2

Support for Balancing Charge

& Storage Inventory Carrying Charge

(Including Update for A&G Charge)

5 months – November to March

Balancing Charge - Annual Allocated Cost

Firm Capacity Allocation:	Total (Mdth/day)	Capacity Used for Balancing (Mdth/day)	Percent Allocated to Balancing Use
Base FT	797.1	0.0	0.0%
Storage	895.5	464.2	51.8%
Balancing FT	432.4	432.4	100.0%
Peaking	541.3	541.3	100.0%
	2,666.3	1,437.9	

	Total Cost	Percent Allocated to Balancing Use	Allocated Cost
Fixed Cost Allocation:			
Base FT	$154,176.3	0.0%	$0.0
Storage	$118,360.2	51.8%	$61,355.8
Balancing FT	$72,376.8	100.0%	$72,376.8
Peaking	$10,681.4	100.0%	$10,681.4
Variable Cost Allocation:			
Base FT	$0.0	0.0%	$0.0
Storage	$7,063.9	51.8%	$3,661.8
Balancing FT	$0.0	100.0%	$0.0
Peaking	$1,410.8	100.0%	$1,410.8
Total Annual Allocated Costs ($000)	**$ 364,069.3**		**$ 149,486.5**

Balancing Use Billing Determinants - Nov - Mar (MDth)	154,411
Balancing Charge - Annual Allocated Cost ($/Dth)	$ 0.96810
Storage Inventory Carrying Charge ($/Dth) (page 2)	$ 0.04443
Revenue Requirement on Gas Production Plant Charge ($/Dth) (page 3)	$ 0.02778
Total Balancing Charge (excl. losses) ($/Dth)	$ 1.04031
Total Balancing Charge (incl. losses @ 2%) ($/Dth)	$ 1.06154
Total Balancing Charge (incl. SUT) ($/Dth)	**$ 1.13187**
Total Balancing Charge (incl. SUT) ($/Therm)	**$ 0.113187**

Storage Inventory Carrying Charge

	12 Months Oct 2019- Sept 2020 (000)
RSG Inventory Cost	$ 172,508
BGSS-F Inventory Cost	$ 26,268
BGSS-F Fixed Cost Deferred	$ 15,704
LNG + LPA	$ 2,831
Total Inventory Cost	**$ 217,310**
Total Annual Storage Carrying Cost @ 9.02%	**$ 19,601**

Recovery %	**Recovery %**
Balancing	35.00%
Commodity	65.00%

Rate per Dth	MDth	Cost	**$/Dth**
Balancing	154,411	$ 6,860	**$ 0.04443**
Commodity	196,438	$ 12,741	**$ 0.06486**

Revenue Requirement on Gas Production Plants

		12 Months Oct 19 - Sep 20
2019	October	$ 837,026
	November	$ 200,276
	December	$ 200,276
2020	January	$ 200,276
	February	$ 200,276
	March	$ 200,276
	April	$ 825,401
	May	$ 825,401
	June	$ 200,276
	July	$ 200,276
	August	$ 200,276
	September	$ 200,276
Total		**$ 4,290,315**
Balancing Use Billing Determinants (MDth)		**154,411**
Revenue Requirement on Gas Production Plant Charge ($/Dth)		**$ 0.02778**

Gas Supply A&G

	12 Months Oct 19 - Sep 20
Direct Labor & Overhead	$ 7,004,200
Firm Sendout - Dth (000)	196,438.3
Gas Supply A&G Rate	$ 0.03566

Attachment B

Redlined Tariff Sheets

BGSS-RSG

BASIC GAS SUPPLY SERVICE-RSG

COMMODITY CHARGES APPLICABLE TO RATE SCHEDULE RSG

(Per Therm)

Estimated Non-Gulf Coast Cost of Gas	$ 0.060450 ~~0.056071~~
Estimated Gulf Coast Cost of Gas	0.254380 ~~0.250273~~
Adjustment to Gulf Coast Cost of Gas	0.000000
Prior period (over) or under recovery	(0.002130) ~~0.014480~~
Adjusted Cost of Gas	0.312700 ~~0.320824~~
Commodity Charge after application of losses: (Loss Factor = 2.0%)	$ 0.319082 ~~0.327371~~
Commodity Charge including New Jersey Sales and Use Tax (SUT)	$ 0.340221 ~~0.349059~~

The above Commodity Charge will be established on a level annualized basis immediately prior to the winter season of each year for the succeeding twelve-month period. The estimated average Non-Gulf and Gulf Coast Cost of Gas will be adjusted for any under- or over-recovery together with applicable interest thereon which may have occurred during the operation of the Company's previously approved Commodity Charge filing. Further, the Company will be permitted a limited self-implementing increase to the Commodity Charge on December 1 and February 1 of each year. These limited self-implementing increases, if applied, are to be in accordance with a Board of Public Utilities approved methodology. Commodity Charge decreases would be permitted at any time if applicable.

The difference between actual costs and Public Service's recovery of these costs shall be determined monthly. If actual costs exceed the recovery of these costs, an underrecovery or a negative balance will result. If the recovery of these costs exceeds actual costs, an overrecovery or a positive balance will result. Interest shall be applied monthly to the average monthly cumulative deferred balance, positive or negative, from the beginning to the end of the annual period. Monthly interest on negative deferred balances (underrecoveries) shall be netted against monthly interest on positive deferred balances (overrecoveries) for the annual period. A cumulative net positive interest balance at the end of the annual period is owed to customers and shall be returned to customers in the next annual period. A cumulative net negative interest balance shall be zeroed out at the end of the annual period. The sum of the calculated monthly interests shall be added to the overrecovery balance or subtracted from the underrecovery balance at the end of the annual period. The positive interest balance shall be rolled into the beginning under- or over-recovery balance of the subsequent annual period.

Pursuant to the Board's January 6, 2003 Order approving the BGSS price structure under Docket No. GX01050304 and the BGSS Pricing Proposal appended as Attachment A to and approved in that Order, Public Service Electric and Gas Company may issue a bill credit for its BGSS-RSG customers as detailed below.

Effective	BGSS-RSG Credit (per therm)	BGSS-RSG Credit including SUT (per therm)
April 1, 2018 through April 30, 2018	($0.140680)	($0.150000)
May 1, 2018	$0.000000	$0.000000

RATE SCHEDULE RSG
RESIDENTIAL SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Firm delivery service for residential purposes. Customers may either purchase gas supply from a Third Party Supplier (TPS) or from Public Service's Basic Gas Supply Service default service as detailed in this rate schedule.

DELIVERY CHARGES:

Service Charge:

$8.08 in each month [$8.62 including New Jersey Sales and Use Tax (SUT)].

Distribution Charges:

Charge	Charge Including SUT	
$0.345322	$0.368200	per therm

Balancing Charge:

Charge	Charge Including SUT	
$0.092492 ~~0.096436~~	$0.098620 ~~$0.102825~~	per Balancing Use Therm

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Societal Benefits include: 1) Social Programs, 2) Demand Side Management Programs, 3) Manufactured Gas Plant Remediation, 4) Consumer Education, and 5) Universal Service Fund. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Margin Adjustment Charge:

This charge shall credit net revenue associated with Rate Schedule Non-Firm Transportation Gas Service (TSG-NF) to customers on Rate Schedules RSG, GSG, LVG, SLG and TSG-F. Refer to the Margin Adjustment Charge sheet of this Tariff for the current charge.

Green Programs Recovery Charge:

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

Weather Normalization Charge:

This charge is designed to adjust base rate recoveries to offset the effects of abnormal weather on sales. The weather normalization charge applied in each winter period shall be based on the differences between actual and normal weather during the preceding winter period. Refer to the Weather Normalization Charge sheet of this Tariff for the current charge.

The Weather Normalization Charge will be combined with the Balancing Charge for billing.

RATE SCHEDULE RSG
RESIDENTIAL SERVICE
(Continued)

Basic Gas Supply Service:

Customers that do not receive gas supply from a TPS will be supplied under the Basic Gas Supply Service-RSG (BGSS-RSG) default service.

The BGSS-RSG Commodity Charge will be applied to all therms billed each month, except customers that receive Delivery Service under Special Provision (c) of this Rate Schedule where the therms used for all purposes in excess of 50 therms in any month during the Off-Peak Period shall be charged at the BGSS-RSGOP Commodity Charge.

Refer to the Basic Gas Supply Service – RSG sheets of this Tariff for the current charge for the BGSS-RSG commodity charge and the BGSS-RSGOP commodity charge.

OTHER CHARGES:

See Special Provisions (c) and (g) below.

BILLING DETERMINANTS:

Therms:

The number of therms used shall be determined by multiplying the number of hundred cubic feet used by the conversion factors which appear on every bill.

Balancing Use Therms:

During each of the billing months of October~~November~~ through May~~March~~, if the average daily usage of gas in any month exceeds the average daily usage during the preceding billing months of June through September, the therms used in such month in excess of the product of the average daily usage in the preceding months of June through September times the number of days in the billing month shall be the Balancing Use Therms and subject to the Balancing Charge. For new customers and for customers who install additional gas burning equipment, the average daily usage in the preceding June through September time period to be used in the above calculation shall be estimated by Public Service.

Daily Contract Quantity:

The Customer's Daily Contract Quantity (DCQ) for each month shall be calculated by Public Service for twelve (12) months by dividing customer's weather-normalized usage, adjusted for losses, for each of the most recent twelve (12) billing months by the total number of days in each billing month. Public Service may adjust customer's DCQ during the year, due to changes in customer's gas equipment or pattern of usage, or projected usage. For new customers, customer's initial DCQ will be estimated by Public Service, based upon the rating of the customer's gas equipment and expected utilization of the equipment. At the end of each billing period Public Service will calculate the difference between customer's actual usage, adjusted for losses, and actual TPS supply for the billing period, taking into consideration any adjustments from prior months, and will adjust the DCQ for the second succeeding month by that difference divided by the total number of days in the month, provided that such adjustment will not decrease that month's adjusted DCQ to a level less than zero. Any such adjustment that would result in a particular month's DCQ being less than zero will be carried to a future month.

RATE SCHEDULE GSG
GENERAL SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Firm delivery service for general purposes where: 1) customer does not qualify for RSG and 2) customer's usage does not exceed 3,000 therms in any month. Customers may either purchase gas supply from a Third Party Supplier (TPS) or from Public Service's Basic Gas Supply Service default service as detailed in this rate schedule.

DELIVERY CHARGES:

Service Charge:

$14.50 in each month [$15.46 including New Jersey Sales and Use Tax (SUT)].

Distribution Charges:

Pre-July 14, 1997 *		All Others		
Charge	Charge Including SUT	Charge	Charge Including SUT	
$0.280009	$0.298560	$0.280009	$0.298560	per therm

* Applicable to customers who have taken TPS supplied commodity service continuously since July 14, 1997.

Balancing Charge:

Charge	Charge Including SUT	
$0.092492	$0.098620	
~~$0.096436~~	~~$0.102825~~	per Balancing Use Therm

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Societal Benefits include: 1) Social Programs, 2) Demand Side Management Programs, 3) Manufactured Gas Plant Remediation, 4) Consumer Education, and 5) Universal Service Fund. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Margin Adjustment Charge:

This charge shall credit net revenue associated with Rate Schedule Non-Firm Transportation Gas Service (TSG-NF) to customers on Rate Schedules RSG, GSG, LVG, SLG and TSG-F. Refer to the Margin Adjustment Charge sheet of this Tariff for the current charge.

Green Programs Recovery Charge:

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

RATE SCHEDULE GSG
GENERAL SERVICE
(Continued)

If a customer is receiving Emergency Sales Service and does not wish to designate a TPS for future deliveries or customer, for any reason, no longer desires to receive gas supply from a TPS, the customer may receive gas supply pursuant to Public Service's Basic Gas Supply Service-Firm.

The conditions under which Emergency Sales Service will apply are detailed in Section 14 - Third Party Supply Service Provisions of the Standard Terms and Conditions of this Tariff, and the charges for this service are defined on the Emergency Sales Service sheet of this Tariff.

Basic Gas Supply Service:

Customers that do not receive gas supply from a TPS will be supplied under the Basic Gas Supply Service Firm (BGSS-F) default service, which will be applied to all therms billed each month. Refer to the Basic Gas Supply Service – Firm sheet of this Tariff for the current charge for BGSS-F commodity charge.

OTHER CHARGES:

See Special Provisions (b), (e) and (i) below.

BILLING DETERMINANTS:

Therms:

The number of therms used shall be determined by multiplying the number of hundred cubic feet used by the conversion factors which appear on every bill.

Balancing Use Therms:

During each of the billing months of October~~November~~ through May~~March~~, if the average daily usage of gas in any month exceeds the average daily usage during the preceding billing months of June through September, the therms used in such month in excess of the product of the average daily usage in the preceding months of June through September times the number of days in the billing month shall be the Balancing Use Therms and subject to the Balancing Charge. For new customers and for customers who install additional gas burning equipment, the average daily usage in the preceding June through September time period to be used in the above calculation shall be estimated by Public Service.

Daily Contract Quantity:

The Customer's Daily Contract Quantity (DCQ) for each month shall be calculated by Public Service for twelve (12) months by dividing customer's weather-normalized usage, adjusted for losses, for each of the most recent twelve (12) billing months by the total number of days in each billing month. Public Service may adjust customer's DCQ during the year, due to changes in customer's gas equipment or pattern of usage, or projected usage. For new customers, customer's initial DCQ will be estimated by Public Service, based upon the rating of the customer's gas equipment and expected utilization of the equipment. At the end of each billing period, Public Service will calculate the difference between customer's actual usage, adjusted for losses, and actual TPS supply for the billing period, taking into consideration any adjustments from prior months, and will adjust the DCQ for the second succeeding month by that difference divided by the total number of days in the month, provided that such adjustment will not decrease that month's adjusted DCQ to a level less than zero. Any such adjustment that would result in a particular month's DCQ being less than zero will be carried to a future month.

RATE SCHEDULE LVG
LARGE VOLUME SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Firm delivery service for general purposes. Customers may either purchase gas supply from a Third Party Supplier (TPS) or from Public Service's Basic Gas Supply Service default service as detailed in this rate schedule.

DELIVERY CHARGES:

Service Charge:

$128.76 in each month [$137.29 including New Jersey Sales and Use Tax (SUT)].

Demand Charge (Applicable in the months of November through March):

Charge	Charge Including SUT	
$ 3.9207	$ 4.1804	per Demand Therm

Distribution Charges:

Per therm for the first 1,000 therms used in each month		Per therm in excess of 1,000 therms used in each month	
Charges	Charges Including SUT	Charges	Charges Including SUT
$0.039047	$0.041634	$0.042397	$0.045206

Balancing Charge:

Charge	Charge Including SUT	
$0.092492	$0.098620	
~~$0.096436~~	~~$0.102825~~	per Balancing Use Therm

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Societal Benefits include: 1) Social Programs, 2) Demand Side Management Programs, 3) Manufactured Gas Plant Remediation, 4) Consumer Education, and 5) Universal Service Fund. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

RATE SCHEDULE LVG
LARGE VOLUME SERVICE
(Continued)

Balancing Use Therms:

During each of the billing months of October~~November~~ through May~~March~~, if the average daily usage of gas in any month exceeds the average daily usage during the preceding billing months of June through September, the therms used in such month in excess of the product of the average daily usage in the preceding months of June through September times the number of days in the billing month shall be the Balancing Use Therms and subject to the Balancing Charge. For new customers and for customers who install additional gas burning equipment, the average daily usage in the preceding June through September time period to be used in the above calculation shall be estimated by Public Service.

Daily Contract Quantity:

The Customer's Daily Contract Quantity (DCQ) for each month shall be calculated by Public Service for twelve (12) months by dividing customer's weather-normalized usage, adjusted for losses, for each of the most recent twelve (12) billing months by the total number of days in each billing month. Public Service may adjust customer's DCQ during the year, due to changes in customer's gas equipment or pattern of usage, or projected usage. For new customers, customer's initial DCQ will be estimated by Public Service, based upon the rating of the customer's gas equipment and expected utilization of the equipment. At the end of each billing period, Public Service will calculate the difference between customer's actual usage, adjusted for losses, and actual TPS supply for the billing period, taking into consideration any adjustments from prior months, and will adjust the DCQ for the second succeeding month by that difference divided by the total number of days in the month, provided that such adjustment will not decrease that month's adjusted DCQ to a level less than zero. Any such adjustment that would result in a particular month's DCQ being less than zero will be carried to a future month.

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill and subject to a late payment charge at the rate of 1.416% per monthly billing period in accordance with Section 8.13 of the Standard Terms and Conditions. Service to a body politic will not be subject to a late payment charge.

TERM:

One year and thereafter until terminated by five days' notice.

Customers who transfer from third party supply to Basic Gas Supply Service may be subject to renewable one year terms. Refer to Section 14 of the Standard Terms and Conditions of this Tariff for additional limitations regarding the term of Basic Gas Supply Service.

SPECIAL PROVISIONS APPLICABLE TO ALL CUSTOMERS:

(a) Service under this rate schedule is not available for resale, except where service is for motor vehicle fuel supplied through compression equipment.

(b) Service supplied under this rate schedule shall be separately metered and shall not be combined with use under any other rate schedule for billing purposes. Customer shall not be eligible to receive service under this rate schedule and any other rate schedule for the same equipment or for equipment supplying a common steam header during the term of the Service Agreement.

RATE SCHEDULE CSG
CONTRACT SERVICE
(Continued)

ECONOMICALLY VIABLE BYPASS

DELIVERY CHARGES:

Service Charge:

$689.62 in each month [$735.31 including New Jersey Sales and Use Tax (SUT)]

Distribution Charge:

Net Alternative Delivery Cost multiplied by the applicable Net Alternative Delivery Cost Factor divided by the Contracted Monthly Therms rounded to the nearest $0.000000 per therm.

Maintenance Charges:

Equals the Alternative Delivery Cost multiplied by the applicable Alternative Delivery Cost Factor divided by the Contract Monthly Therms rounded to the nearest $0.000000 per therm.

Plus any customer site-specific ongoing or continuing cost not directly related to the operation, maintenance or inspection of the customer's planned by-pass pipeline. This shall include, but not be limited to, periodic payments for rights-of-way, easements, pipeline cost differentials, permits or other such costs. These charges shall be expressed on a monthly levelized basis over the term of service.

Public Service will also take into consideration any operational or deliverability differences that would be reasonably expected between the pipeline and/or service over Public Service's distribution system in determining Delivery Charges. In no event shall the Delivery Charges be lower than an amount sufficient to generate a return on the capital investments made by Public Service and recovery of marginal and embedded costs, including depreciation, to provide service to the customer over the term of each CSG agreement.

Balancing Charge:

Applicable only if the customer is provided Public Service's Basic Gas Supply Service – Firm (BGSS-F) default service.

Charge	Charge Including SUT	
$0.092492	$0.098620	per Balancing Use Therm
~~$0.096436~~	~~$0.102825~~	

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by government. In appropriate circumstances, the Board of Public Utilities may approve a discount from the Societal Benefits Charge. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge and applicable exemptions.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs as approved by the Board. In appropriate circumstances, the Board of Public Utilities may approve a discount from the Green Programs Recovery Charge. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge and applicable exceptions.

RATE SCHEDULE CSG
CONTRACT SERVICE
(Continued)

OTHER CHARGES:

See Special Provision (f).

MINIMUM ANNUAL DISTRIBUTION CHARGE:

If customer's annual usage is less than 50% of the customer's Contract Monthly Therms multiplied by 12, then the customer will be billed for the difference between the actual annual therms and 50% of the customer's Contract Monthly Therms multiplied by 12 and then multiplied by the Distribution Charge. The Minimum Annual Distribution Charge, if applicable, will be billed at the end of the customer's annualized period.

BILLING DETERMINANTS:

Therms:

The number of therms used shall be determined by multiplying the number of hundred cubic feet used by the conversion factor which appears on every bill. The conversion factor used for the "therm multiplier" shall be on the basis of the actual heating value of the gas used.

Balancing Use Therms:

Applicable only if the customer is provided Public Service's Basic Gas Supply Service – Firm (BGSS-F) default service.

During each of the billing months of October~~November~~ through May~~March~~, if the average daily usage of gas in any month exceeds the average daily usage during the preceding billing months of June through September, the therms used in such month in excess of the product of the average daily usage in the preceding months of June through September times the number of days in the billing month shall be the Balancing Use Therms and subject to the Balancing Charge. For new customers and for customers who install additional gas burning equipment, the average daily usage in the preceding June through September time period to be used in the above calculation shall be estimated by Public Service.

Contract Monthly Therms:

Estimated annual therm usage (see Item 3, Tariff Sheet 112) determined as reasonable by Public Service divided by 12 and rounded to the nearest therm.

Alternative Delivery Cost:

a) For Firm Delivery Service: The estimated total up-front cost of the customer's bypass plan, based on a detailed cost estimate provided by the applicable interstate pipeline.
b) For Interruptible Delivery Service: The sum of 90% of the estimated total up-front cost of the customer's bypass plan, based on a detailed cost estimate provided by the applicable interstate pipeline, plus 10% of the incremental installed cost for Public Service to provide interruptible delivery service as estimated by Public Service.

Net Alternative Delivery Cost:

The Net Alternative Delivery Cost is equal to the Alternative Delivery Cost net of any customer contribution made to Public Service to provide service under this Rate Schedule without Public Service tax gross-up effects.

Attachment B

Proposed Tariff Sheets

BGSS-RSG

BASIC GAS SUPPLY SERVICE-RSG

COMMODITY CHARGES APPLICABLE TO RATE SCHEDULE RSG

(Per Therm)

Estimated Non-Gulf Coast Cost of Gas	$ 0.060450
Estimated Gulf Coast Cost of Gas	0.254380
Adjustment to Gulf Coast Cost of Gas	0.000000
Prior period (over) or under recovery	(0.002130)
Adjusted Cost of Gas	0.312700
Commodity Charge after application of losses: (Loss Factor = 2.0%)	$ 0.319082
Commodity Charge including New Jersey Sales and Use Tax (SUT)	$ 0.340221

The above Commodity Charge will be established on a level annualized basis immediately prior to the winter season of each year for the succeeding twelve-month period. The estimated average Non-Gulf and Gulf Coast Cost of Gas will be adjusted for any under- or over-recovery together with applicable interest thereon which may have occurred during the operation of the Company's previously approved Commodity Charge filing. Further, the Company will be permitted a limited self-implementing increase to the Commodity Charge on December 1 and February 1 of each year. These limited self-implementing increases, if applied, are to be in accordance with a Board of Public Utilities approved methodology. Commodity Charge decreases would be permitted at any time if applicable.

The difference between actual costs and Public Service's recovery of these costs shall be determined monthly. If actual costs exceed the recovery of these costs, an underrecovery or a negative balance will result. If the recovery of these costs exceeds actual costs, an overrecovery or a positive balance will result. Interest shall be applied monthly to the average monthly cumulative deferred balance, positive or negative, from the beginning to the end of the annual period. Monthly interest on negative deferred balances (underrecoveries) shall be netted against monthly interest on positive deferred balances (overrecoveries) for the annual period. A cumulative net positive interest balance at the end of the annual period is owed to customers and shall be returned to customers in the next annual period. A cumulative net negative interest balance shall be zeroed out at the end of the annual period. The sum of the calculated monthly interests shall be added to the overrecovery balance or subtracted from the underrecovery balance at the end of the annual period. The positive interest balance shall be rolled into the beginning under- or over-recovery balance of the subsequent annual period.

Pursuant to the Board's January 6, 2003 Order approving the BGSS price structure under Docket No. GX01050304 and the BGSS Pricing Proposal appended as Attachment A to and approved in that Order, Public Service Electric and Gas Company may issue a bill credit for its BGSS-RSG customers as detailed below.

Effective	BGSS-RSG Credit (per therm)	BGSS-RSG Credit including SUT (per therm)
April 1, 2018 through April 30, 2018	($0.140680)	($0.150000)
May 1, 2018	$0.000000	$0.000000

RATE SCHEDULE RSG
RESIDENTIAL SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Firm delivery service for residential purposes. Customers may either purchase gas supply from a Third Party Supplier (TPS) or from Public Service's Basic Gas Supply Service default service as detailed in this rate schedule.

DELIVERY CHARGES:

Service Charge:

$8.08 in each month [$8.62 including New Jersey Sales and Use Tax (SUT)].

Distribution Charges:

Charge	Charge Including SUT	
$0.345322	$0.368200	per therm

Balancing Charge:

Charge	Charge Including SUT	
$0.092492	$0.098620	per Balancing Use Therm

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Societal Benefits include: 1) Social Programs, 2) Demand Side Management Programs, 3) Manufactured Gas Plant Remediation, 4) Consumer Education, and 5) Universal Service Fund. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Margin Adjustment Charge:

This charge shall credit net revenue associated with Rate Schedule Non-Firm Transportation Gas Service (TSG-NF) to customers on Rate Schedules RSG, GSG, LVG, SLG and TSG-F. Refer to the Margin Adjustment Charge sheet of this Tariff for the current charge.

Green Programs Recovery Charge:

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

Weather Normalization Charge:

This charge is designed to adjust base rate recoveries to offset the effects of abnormal weather on sales. The weather normalization charge applied in each winter period shall be based on the differences between actual and normal weather during the preceding winter period. Refer to the Weather Normalization Charge sheet of this Tariff for the current charge.

The Weather Normalization Charge will be combined with the Balancing Charge for billing.

RATE SCHEDULE RSG
RESIDENTIAL SERVICE
(Continued)

Basic Gas Supply Service:

Customers that do not receive gas supply from a TPS will be supplied under the Basic Gas Supply Service-RSG (BGSS-RSG) default service.

The BGSS-RSG Commodity Charge will be applied to all therms billed each month, except customers that receive Delivery Service under Special Provision (c) of this Rate Schedule where the therms used for all purposes in excess of 50 therms in any month during the Off-Peak Period shall be charged at the BGSS-RSGOP Commodity Charge.

Refer to the Basic Gas Supply Service – RSG sheets of this Tariff for the current charge for the BGSS-RSG commodity charge and the BGSS-RSGOP commodity charge.

OTHER CHARGES:

See Special Provisions (c) and (g) below.

BILLING DETERMINANTS:

Therms:

The number of therms used shall be determined by multiplying the number of hundred cubic feet used by the conversion factors which appear on every bill.

Balancing Use Therms:

During each of the billing months of October through May, if the average daily usage of gas in any month exceeds the average daily usage during the preceding billing months of June through September, the therms used in such month in excess of the product of the average daily usage in the preceding months of June through September times the number of days in the billing month shall be the Balancing Use Therms and subject to the Balancing Charge. For new customers and for customers who install additional gas burning equipment, the average daily usage in the preceding June through September time period to be used in the above calculation shall be estimated by Public Service.

Daily Contract Quantity:

The Customer's Daily Contract Quantity (DCQ) for each month shall be calculated by Public Service for twelve (12) months by dividing customer's weather-normalized usage, adjusted for losses, for each of the most recent twelve (12) billing months by the total number of days in each billing month. Public Service may adjust customer's DCQ during the year, due to changes in customer's gas equipment or pattern of usage, or projected usage. For new customers, customer's initial DCQ will be estimated by Public Service, based upon the rating of the customer's gas equipment and expected utilization of the equipment. At the end of each billing period Public Service will calculate the difference between customer's actual usage, adjusted for losses, and actual TPS supply for the billing period, taking into consideration any adjustments from prior months, and will adjust the DCQ for the second succeeding month by that difference divided by the total number of days in the month, provided that such adjustment will not decrease that month's adjusted DCQ to a level less than zero. Any such adjustment that would result in a particular month's DCQ being less than zero will be carried to a future month.

RATE SCHEDULE GSG
GENERAL SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Firm delivery service for general purposes where: 1) customer does not qualify for RSG and 2) customer's usage does not exceed 3,000 therms in any month. Customers may either purchase gas supply from a Third Party Supplier (TPS) or from Public Service's Basic Gas Supply Service default service as detailed in this rate schedule.

DELIVERY CHARGES:

Service Charge:

$14.50 in each month [$15.46 including New Jersey Sales and Use Tax (SUT)].

Distribution Charges:

Pre-July 14, 1997 *		All Others		
Charge	Charge Including SUT	Charge	Charge Including SUT	
$0.280009	$0.298560	$0.280009	$0.298560	per therm

* Applicable to customers who have taken TPS supplied commodity service continuously since July 14, 1997.

Balancing Charge:

Charge	Charge Including SUT	
$0.092492	$0.098620	per Balancing Use Therm

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Societal Benefits include: 1) Social Programs, 2) Demand Side Management Programs, 3) Manufactured Gas Plant Remediation, 4) Consumer Education, and 5) Universal Service Fund. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Margin Adjustment Charge:

This charge shall credit net revenue associated with Rate Schedule Non-Firm Transportation Gas Service (TSG-NF) to customers on Rate Schedules RSG, GSG, LVG, SLG and TSG-F. Refer to the Margin Adjustment Charge sheet of this Tariff for the current charge.

Green Programs Recovery Charge:

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

RATE SCHEDULE GSG
GENERAL SERVICE
(Continued)

If a customer is receiving Emergency Sales Service and does not wish to designate a TPS for future deliveries or customer, for any reason, no longer desires to receive gas supply from a TPS, the customer may receive gas supply pursuant to Public Service's Basic Gas Supply Service-Firm.

The conditions under which Emergency Sales Service will apply are detailed in Section 14 - Third Party Supply Service Provisions of the Standard Terms and Conditions of this Tariff, and the charges for this service are defined on the Emergency Sales Service sheet of this Tariff.

Basic Gas Supply Service:

Customers that do not receive gas supply from a TPS will be supplied under the Basic Gas Supply Service Firm (BGSS-F) default service, which will be applied to all therms billed each month. Refer to the Basic Gas Supply Service – Firm sheet of this Tariff for the current charge for BGSS-F commodity charge.

OTHER CHARGES:

See Special Provisions (b), (e) and (i) below.

BILLING DETERMINANTS:

Therms:

The number of therms used shall be determined by multiplying the number of hundred cubic feet used by the conversion factors which appear on every bill.

Balancing Use Therms:

During each of the billing months of October through May, if the average daily usage of gas in any month exceeds the average daily usage during the preceding billing months of June through September, the therms used in such month in excess of the product of the average daily usage in the preceding months of June through September times the number of days in the billing month shall be the Balancing Use Therms and subject to the Balancing Charge. For new customers and for customers who install additional gas burning equipment, the average daily usage in the preceding June through September time period to be used in the above calculation shall be estimated by Public Service.

Daily Contract Quantity:

The Customer's Daily Contract Quantity (DCQ) for each month shall be calculated by Public Service for twelve (12) months by dividing customer's weather-normalized usage, adjusted for losses, for each of the most recent twelve (12) billing months by the total number of days in each billing month. Public Service may adjust customer's DCQ during the year, due to changes in customer's gas equipment or pattern of usage, or projected usage. For new customers, customer's initial DCQ will be estimated by Public Service, based upon the rating of the customer's gas equipment and expected utilization of the equipment. At the end of each billing period, Public Service will calculate the difference between customer's actual usage, adjusted for losses, and actual TPS supply for the billing period, taking into consideration any adjustments from prior months, and will adjust the DCQ for the second succeeding month by that difference divided by the total number of days in the month, provided that such adjustment will not decrease that month's adjusted DCQ to a level less than zero. Any such adjustment that would result in a particular month's DCQ being less than zero will be carried to a future month.

RATE SCHEDULE LVG
LARGE VOLUME SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Firm delivery service for general purposes. Customers may either purchase gas supply from a Third Party Supplier (TPS) or from Public Service's Basic Gas Supply Service default service as detailed in this rate schedule.

DELIVERY CHARGES:

Service Charge:

$128.76 in each month [$137.29 including New Jersey Sales and Use Tax (SUT)].

Demand Charge (Applicable in the months of November through March):

Charge	Charge Including SUT	
$ 3.9207	$ 4.1804	per Demand Therm

Distribution Charges:

Per therm for the first 1,000 therms used in each month		Per therm in excess of 1,000 therms used in each month	
Charges	Charges Including SUT	Charges	Charges Including SUT
$0.039047	$0.041634	$0.042397	$0.045206

Balancing Charge:

Charge	Charge Including SUT	
$0.092492	$0.098620	per Balancing Use Therm

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Societal Benefits include: 1) Social Programs, 2) Demand Side Management Programs, 3) Manufactured Gas Plant Remediation, 4) Consumer Education, and 5) Universal Service Fund. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

RATE SCHEDULE LVG
LARGE VOLUME SERVICE
(Continued)

Balancing Use Therms:

During each of the billing months of October through May, if the average daily usage of gas in any month exceeds the average daily usage during the preceding billing months of June through September, the therms used in such month in excess of the product of the average daily usage in the preceding months of June through September times the number of days in the billing month shall be the Balancing Use Therms and subject to the Balancing Charge. For new customers and for customers who install additional gas burning equipment, the average daily usage in the preceding June through September time period to be used in the above calculation shall be estimated by Public Service.

Daily Contract Quantity:

The Customer's Daily Contract Quantity (DCQ) for each month shall be calculated by Public Service for twelve (12) months by dividing customer's weather-normalized usage, adjusted for losses, for each of the most recent twelve (12) billing months by the total number of days in each billing month. Public Service may adjust customer's DCQ during the year, due to changes in customer's gas equipment or pattern of usage, or projected usage. For new customers, customer's initial DCQ will be estimated by Public Service, based upon the rating of the customer's gas equipment and expected utilization of the equipment. At the end of each billing period, Public Service will calculate the difference between customer's actual usage, adjusted for losses, and actual TPS supply for the billing period, taking into consideration any adjustments from prior months, and will adjust the DCQ for the second succeeding month by that difference divided by the total number of days in the month, provided that such adjustment will not decrease that month's adjusted DCQ to a level less than zero. Any such adjustment that would result in a particular month's DCQ being less than zero will be carried to a future month.

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill and subject to a late payment charge at the rate of 1.416% per monthly billing period in accordance with Section 8.13 of the Standard Terms and Conditions. Service to a body politic will not be subject to a late payment charge.

TERM:

One year and thereafter until terminated by five days' notice.

Customers who transfer from third party supply to Basic Gas Supply Service may be subject to renewable one year terms. Refer to Section 14 of the Standard Terms and Conditions of this Tariff for additional limitations regarding the term of Basic Gas Supply Service.

SPECIAL PROVISIONS APPLICABLE TO ALL CUSTOMERS:

(a) Service under this rate schedule is not available for resale, except where service is for motor vehicle fuel supplied through compression equipment.

(b) Service supplied under this rate schedule shall be separately metered and shall not be combined with use under any other rate schedule for billing purposes. Customer shall not be eligible to receive service under this rate schedule and any other rate schedule for the same equipment or for equipment supplying a common steam header during the term of the Service Agreement.

RATE SCHEDULE CSG
CONTRACT SERVICE
(Continued)

ECONOMICALLY VIABLE BYPASS

DELIVERY CHARGES:

Service Charge:

$689.62 in each month [$735.31 including New Jersey Sales and Use Tax (SUT)]

Distribution Charge:

Net Alternative Delivery Cost multiplied by the applicable Net Alternative Delivery Cost Factor divided by the Contracted Monthly Therms rounded to the nearest $0.000000 per therm.

Maintenance Charges:

Equals the Alternative Delivery Cost multiplied by the applicable Alternative Delivery Cost Factor divided by the Contract Monthly Therms rounded to the nearest $0.000000 per therm.

Plus any customer site-specific ongoing or continuing cost not directly related to the operation, maintenance or inspection of the customer's planned by-pass pipeline. This shall include, but not be limited to, periodic payments for rights-of-way, easements, pipeline cost differentials, permits or other such costs. These charges shall be expressed on a monthly levelized basis over the term of service.

Public Service will also take into consideration any operational or deliverability differences that would be reasonably expected between the pipeline and/or service over Public Service's distribution system in determining Delivery Charges. In no event shall the Delivery Charges be lower than an amount sufficient to generate a return on the capital investments made by Public Service and recovery of marginal and embedded costs, including depreciation, to provide service to the customer over the term of each CSG agreement.

Balancing Charge:

Applicable only if the customer is provided Public Service's Basic Gas Supply Service – Firm (BGSS-F) default service.

Charge	Charge Including SUT	
$0.092492	$0.098620	per Balancing Use Therm

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by government. In appropriate circumstances, the Board of Public Utilities may approve a discount from the Societal Benefits Charge. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge and applicable exemptions.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs as approved by the Board. In appropriate circumstances, the Board of Public Utilities may approve a discount from the Green Programs Recovery Charge. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge and applicable exceptions.

RATE SCHEDULE CSG
CONTRACT SERVICE
(Continued)

OTHER CHARGES:

See Special Provision (f).

MINIMUM ANNUAL DISTRIBUTION CHARGE:

If customer's annual usage is less than 50% of the customer's Contract Monthly Therms multiplied by 12, then the customer will be billed for the difference between the actual annual therms and 50% of the customer's Contract Monthly Therms multiplied by 12 and then multiplied by the Distribution Charge. The Minimum Annual Distribution Charge, if applicable, will be billed at the end of the customer's annualized period.

BILLING DETERMINANTS:

Therms:

The number of therms used shall be determined by multiplying the number of hundred cubic feet used by the conversion factor which appears on every bill. The conversion factor used for the "therm multiplier" shall be on the basis of the actual heating value of the gas used.

Balancing Use Therms:

Applicable only if the customer is provided Public Service's Basic Gas Supply Service – Firm (BGSS-F) default service.

During each of the billing months of October through May, if the average daily usage of gas in any month exceeds the average daily usage during the preceding billing months of June through September, the therms used in such month in excess of the product of the average daily usage in the preceding months of June through September times the number of days in the billing month shall be the Balancing Use Therms and subject to the Balancing Charge. For new customers and for customers who install additional gas burning equipment, the average daily usage in the preceding June through September time period to be used in the above calculation shall be estimated by Public Service.

Contract Monthly Therms:

Estimated annual therm usage (see Item 3, Tariff Sheet 112) determined as reasonable by Public Service divided by 12 and rounded to the nearest therm.

Alternative Delivery Cost:

a) For Firm Delivery Service: The estimated total up-front cost of the customer's bypass plan, based on a detailed cost estimate provided by the applicable interstate pipeline.
b) For Interruptible Delivery Service: The sum of 90% of the estimated total up-front cost of the customer's bypass plan, based on a detailed cost estimate provided by the applicable interstate pipeline, plus 10% of the incremental installed cost for Public Service to provide interruptible delivery service as estimated by Public Service.

Net Alternative Delivery Cost:

The Net Alternative Delivery Cost is equal to the Alternative Delivery Cost net of any customer contribution made to Public Service to provide service under this Rate Schedule without Public Service tax gross-up effects.