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VIA BPU E-FILING SYSTEM & ELECTRONIC MAIL

May 30, 2025

In the Matter of Public Service Electric and Gas Company's 2025/2026
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____________

Sherri Lewis, Secretary
New Jersey Board of Public Utilities
44 South Clinton Avenue, 1st Floor
Post Office Box 350
Trenton, New Jersey 08625-0350

Dear Secretary Lewis:

Attached for electronic filing is Public Service Electric and Gas Company's ("Public Service") Motion, Testimony of David F. Caffery, 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 to increase the current BGSS default commodity charge applicable to residential customers for service rendered on and after October 1, 2025. The Company is also requesting a decrease in its Balancing Charge rate. The average monthly impact of the proposed RSG Commodity Rate and Balancing Charge change is an increase of approximately 3.0% for a typical residential gas heating customer using 172 therms in a winter month and 87 average monthly therms (1,040 annually).

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.

Furthermore, as directed by the Board's Order in Docket No. EO20030254, dated March 19, 2020, the Company hereby submits this filing via electronic delivery only to the Board Secretary, and will suspend submitting such filings as paper documents until the Board directs otherwise.

Very truly yours,

Stacey M. Mickles

Stacey M. Mickles, Esq.

C Attached Service List (electronic)

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BGSS 2025-2026

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1. <u>Motion, Supporting Testimony & Tariff Modifications</u>

Motion – dated May 30, 2025

Testimony of David F. Caffery – Attachment A

Tariff Sheets – Attachment B

STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

IN THE MATTER OF PUBLIC SERVICE ELECTRIC AND GAS COMPANY'S 2025/2026 ANNUAL BGSS COMMODITY CHARGE FILING FOR ITS RESIDENTIAL GAS CUSTOMERS UNDER ITS PERIODIC PRICING MECHANISM AND FOR CHANGES IN ITS BALANCING CHARGE	)))))))	MOTION DOCKET NO. GR____________

Public Service Electric and Gas Company ("PSE&G" or the "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 or before 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, in its January 16, 2003, Order Adopting Provisional Rates in Docket No. GR02090702, the Board 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 on Annual BGSS Minimum Filing Requirements 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 was 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.

2024/2025 ANNUAL BGSS COMMODITY CHARGE FILING

4) On May 31, 2024 the Company made its 2024/2025 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 2024/2025 BGSS filing the Company requested to decrease the then current BGSS Commodity Charge rate of $0.397497 per therm (including losses and Sales and Use Tax

("SUT")) to $0.327799 per therm (including losses and SUT) through September 30, 2025. 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 maintaining the BGSS rate.

6) The Company also requested an increase in its Balancing Charge, which recovers the cost of providing storage and peaking services. The Company requested a change in the Balancing Charge from $0.097914 per balancing therm (including losses and SUT) to $0.101236 per balancing use therm (including losses and SUT). The increase in the balancing charge was supported by Mr. Caffery.

7) The 2024/2025 filing by the Company estimated a BGSS revenue decrease of $98.8M (excluding losses and SUT) would be required for the period of October 1, 2024 through September 30, 2025.

8) Residential annual bills comparing the then current and proposed Balancing Charge, pursuant to the 2024/2025 filing were included in the form of public notice attached as Attachment C to that motion.

9) Notices setting forth the Company's May 31st, 2024 request to decrease the BGSS Commodity Charge and request to increase the Balancing Charge, including the date, time, and place of the public hearings, were placed in newspapers having a circulation within PSE&G's gas service territory, and were served on the county executives and clerks of all municipalities within its gas service territory.

10) Public hearings were scheduled and conducted virtually on September 4, 2024, at 4:30 p.m. and 5:30 p.m. Several members of the public appeared and did not speak at the 4:30 p.m.

public hearing. No members of the public attended the 5:30 p.m. public hearing. One (1) written comment was received by the Board objecting to any potential increase in fees.

11) PSE&G, Board Staff, and Rate Counsel agreed, on a provisional basis, to decrease the BGSS-RSG Commodity Charge and increase the Balancing Charge as of October 1, 2024, 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 25, 2024. As a result, 1) the Company's BGSS Commodity rate, tariff rate BGSS-RSG, was provisionally decreased to $0.327799 per therm (including losses and SUT) and 2) the BGSS Balancing Charge was provisionally increased to $0.101236 per balancing use therm (including losses and SUT) for service rendered on and after October 1, 2024.[1]

12) On October 9, 2024 the Board issued an Order approving the stipulation of settlement resolving PSE&G's 2024 Base Rate Case.[2] In the Base Rate Case Order the Board approved a pre-tax WACC of 9.14% (as opposed to the as-filed pre-tax value of 9.81%) to be effective on October 15, 2024. Consistent with the Base Rate Case Order, on October 10, 2024, PSE&G made a compliance filing that included a reduction to the provisional BGSS-RSG Commodity Charge rate to $0.326701 per therm (inclusive of losses and SUT) – to be effective October 15, 2024.

[1] In re the Petition of Public Service Electric and Gas Company's 2024/2025 Annual BGSS Commodity Charge Filing for its Residential Gas Customers Under Its Periodic Pricing Mechanism and for Changes in its Balancing Charge, BPU Docket No. GR24050364, Order dated September 25, 2024.

[2] In re the Petition of Public Service Electric and Gas Company For Approval of an Increase in Electric and Gas Rates for Changes in the Tariffs for Electric and Gas Service, B.P.U.N.J. No. 17 Electric and B.P.U.N.J. No. 17 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, BPU Docket Nos. ER23120924 & GR23120925, Order dated October 9, 2024 ("Base Rate Case Order").

13) On October 21, 2024 the Board transmitted this matter to the Office of Administrative Law as a contested case, where it was subsequently assigned to the Honorable Irene Jones, Administrative Law Judge ("ALJ"). ALJ Jones held a telephonic prehearing conference on November 26, 2024.

14) On November 20, 2024 PSE&G made a filing further reducing the BGSS-RSG Commodity Charge and Balancing Charge rates to reflect the Board-approved pre-tax WACC of 9.14% in the derivation of the Storage Inventory Carrying Charge and the Revenue Requirement on Gas Production Plant Charge components of the BGSS-RSG Commodity Charge and/or the Balancing Charge rates, effective December 1, 2024 ("November 2024 Filing"). Additionally, included in those rates was an adjustment to credit customers for the difference between the costs associated with the WACC utilized in the provisional rates versus the Board-approved WACC for the period October 1, 2024 – November 30, 2024. Pursuant to the November 2024 Filing, the Company's BGSS Commodity Service, tariff rate BGSS-RSG, was provisionally decreased to $0.326205 per therm (including losses and SUT) through September 30, 2025 subject to refund, with interest on any net over-recovered BGSS-RSG balance; and 2) the Company's Balancing Charge was provisionally decreased to $0.100751 per balancing therm (including losses and SUT), subject to refund, with interest on any net over- or under-recovered balance.

15) PSE&G, Board Staff, and Rate Counsel subsequently completed their review of the Company's 2024/2025 BGSS filing, and agreed that: (a) the Company's BGSS Commodity Service, tariff rate for BGSS-RSG of $0.326205 per therm (including losses and SUT) would be deemed final and; (b) the Balancing Charge of $0.100751 per balancing use therm would

be deemed final. On March 3, 2025 PSE&G filed with the Board a Stipulation for Final Rates for the 2024/2025 BGSS year, and the Board approved this stipulation for final rates on April 23, 2025.

16) On April 23, 2025 the Board issued an Order approving the Infrastructure Advancement Program Stipulation ("IAP Order")[3]. On April 28, 2025, PSE&G made a compliance filing that, due to the impacts of the IAP Order, included a reduction to the BGSS-RSG Commodity Charge rate to $0.326190 per therm (inclusive of losses and SUT) – to be effective May 1, 2025.

2025/2026 ANNUAL BGSS COMMODITY CHARGE FILING

1) The Company is making this 2025/2026 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.

2) In this Motion the Company is requesting to increase the current BGSS rate of $0.326190 per therm (including losses and SUT) to $0.363539 per therm (including losses and SUT) through September 30, 2026. This request is supported by the direct testimony of David F. Caffery attached hereto as Attachment A, in which he addresses the Minimum Filing Requirements and explains and supports the Company's request to increase the current BGSS-RSG rate.

[3] *In the Matter of the Petition of Public Service Electric and Gas Company for the Approval of Electric and Gas Rate Adjustments pursuant to the Infrastructure Advancement Program*, Docket Nos. ER24110838 and GR24110839, Order Approving Stipulation for Settlement (dated April 23, 2025).

3) The Company is also requesting a decrease in its Balancing Charge, which recovers the cost of providing storage, peaking services, and a share of its Storage Inventory Carrying Charge. See Attachment D of the filing. The Company requests a change in the Balancing Charge from $0.100751 per balancing use therm (including losses and SUT) to $0.097699 per balancing use therm (including losses and SUT). The decrease in the balancing charge is supported by Mr. Caffery (Attachment A). As detailed below, the overall impact of the BGSS Rate increase and Balancing Charge decrease is a customer bill increase.

4) Natural gas prices have been volatile during the most recent BGSS period, following the relative stability experienced during 2023. NYMEX prompt month daily prices have traded between $1.57/Dth in March 2024, to a high of $4.50 in March 2025, followed by a dramatic decline to about $2.95 in late April 2025. The June prompt month price is $3.59/Dth. The forward (May 8th) NYMEX strip used by the Company in this filing (see Item 8) shows that average prices are 40% higher than last year's NYMEX strip. Based upon the forward strip, prices are expected to increase $1.26/Dth above the June price by December 2025, as well as an additional $0.29/Dth in January of 2026, followed by a decrease from $5.14/Dth to an average of about $4.10/Dth during April 2026 through September 2026, the end of this BGSS period.

5) In response to the increased demand and resultant higher prices, US gas production has recently set an all-time peak of 106.5 Bcf/d. US national storage levels are currently 3% greater than the five-year average after having fallen to 20% below the five-year average during January 2025. Feedgas volumes for the US' eight LNG export facilities have recently averaged approximately 15.5 Bcf/d, a sizeable increase over the 12 Bcf/d average at

this time last year. The feedgas volume is expected to further increase in late 2025 and 2026 as additional facility expansions come on line and the approval of new LNG export facilities is facilitated under the Trump administration. As a result, while overall demand for natural gas is expected to increase during the upcoming BGSS period, today's higher price levels are likely to incent producers to increase production to satisfy those increased demands and keep the market in a relative balance.

6) The Company estimates that an increase in BGSS revenue of approximately $49.1 million (excluding losses and SUT) is required for the period of October 1, 2025 through September 30, 2026. As stated in the testimony of Mr. Caffery and shown in Item 7, the Company is requesting an increase in the current rate of $0.326190 per therm (including losses and SUT) to $0.363539 per therm (including losses and SUT) to eliminate the projected under-recovery.

7) Residential average monthly winter bills comparing the current and proposed BGSS Commodity Rate and Balancing Charge are included in the form of public notice attached hereto as Attachment C. The impact of the requested Commodity and Balancing Charge changes for a typical residential gas heating customer using 172 therms in a winter month and 87 average monthly therms (1,040 annually) is an increase in the winter monthly bill of approximately 3.0%. 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, 2025 and February 1, 2026. The impact of such potential self-implementing increases on an average residential bill (1,200 therms annually) would be an increase of approximately $11.62 per winter month on

December 1, 2025 and an additional approximate increase of $11.62 per winter month on February 1, 2026.

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

9) The Company is also requesting approval to execute an amendment to the Requirements Contract with PSEG Energy Resources & Trade LLC ("ER&T) providing for a five-year extension, continuing on a year-to-year basis thereafter, subject to a two-year termination notice requirement. In a BPU Order finalizing the Company's 2013/2014 BGSS proceeding dated March 19, 2014 in Docket No. GR13060447, in order to promote certainty, the Board directed that the Requirements Contract be extended for an additional term of five years to March 31, 2019 and continue on a year-to-year basis thereafter with a two-year termination notice. In a BPU Order finalizing the Company's 2021/2022 BGSS proceeding dated April 6, 2022 in Docket No. GR21060878, in order to promote certainty, the Board further directed that the Requirements Contract be extended for an additional term of five years to March 31, 2027 and continue on a year-to-year basis thereafter with a two-year termination notice. Consistent with the Board's March 19, 2014 and April 6, 2022 Orders, in order to once again promote certainty with respect to BGSS procurement, the Company and ER&T propose to execute an amendment to the Requirements Contract to provide that the term of the Requirements Contract be extended for an additional term of five (5) years from April 1, 2027 to March 31, 2032 continuing on a year-to-year basis thereafter with a two-year termination notice requirement. The Company is requesting an extension of the term of the Requirements Contract at this time to ensure that the Board has sufficient time to review and approve the

term extension prior to the end of the current term on April 1, 2027. If approved, the Company will file a copy of the executed amendment with the Board no more than thirty (30) days after the date of a written Board Order approving this BGSS filing.

10) Contained herein in Attachment C is a draft Form of Notice of Filing and of Public Hearings. This Form of Notice sets forth the requested changes to the gas rates and will be placed in newspapers having a circulation within the Company's gas service territory upon receipt, scheduling, and publication of public hearing dates. A Notice will be served on the County Executives and Clerks of all municipalities within the Company's gas service territory upon scheduling of public hearing dates. In accordance with the Board's Covid-19[4] order, notice of this filing, the Petition, testimony, and schedules will be served upon the Department of Law and Public Safety, 124 Halsey Street, P.O. Box 45029, Newark, New Jersey 07101 and upon the Director, Division of Rate Counsel, 140 East Front Street 4th Floor, Trenton, N.J. 08625 by electronic mail. Electronic copies of the Petition, testimony, and schedules will also be sent to the persons identified on the service list provided with this filing.

CONCLUSION

WHEREFORE, Public Service hereby requests that the Board issue a written Order by October 1, 2025 approving:

(1) the Company's proposal to change its current BGSS-RSG Commodity Charge to $0.363539 per therm (including losses and SUT), with the costs presented herein as the basis of the cost

[4] See In the matter of the New Jersey Board of Public Utilities' Response to the Covid-19 Pandemic for a Temporary Waiver of the Requirements for Certain Non-Essential Obligations, Docket No. EO20030254, dated March 19, 2020.

of BGSS-RSG supply. This charge is requested to remain in effect from October 1, 2025 through September 30, 2026 or the effective date of the Company's next periodic BGSS Commodity Charge filing, subject to the potential self-implementing increases discussed in this Motion.

(2) a change in the Balancing Charge to $0.097699 per balancing use therm (including losses and SUT) effective with the billing of month of October 2025;

(3) the Company's proposal to execute an amendment to the Requirements Contract providing for a five-year extension, continuing on a year-to-year basis thereafter, subject to a two-year termination notice requirement.

(4) the modifications to the Tariff for Gas Service, B.P.U.N.J. No. 17 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

BY: Stacey M. Mickles

Stacey M. Mickles
Associate Counsel – State Regulatory
PSE&G
80 Park Plaza, T20
Newark, New Jersey 07102

DATED: May 30, 2025
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 Public Service 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.

DAVID F. CAFFERY

Sworn to and subscribed to
before me this 30th day of
May, 2025

CAITLYN M. WHITE
Notary Public, State of New Jersey
Comm. # 50113049
My Commission Expires 09/19/2029

CAITLYN M. WHITE
Notary Public
State of New Jersey
My Commission Expires September 19, 2029
ID# 50113049

ATTACHMENT A

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 (Public Service, the Company) Motion to increase the current Basic Gas Supply Service (BGSS) default Commodity Charge applicable to residential customers. The requested increase for the BGSS-RSG Commodity rate is from the current charge of $0.326190 per therm (including losses and New Jersey Sales and Use Tax, SUT) to a charge of $0.363539 per therm (including losses and SUT). This charge is requested to remain in effect from October 1, 2025 through September 30, 2026 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 Company is also requesting a decrease in its Balancing Charge, which recovers the cost of providing storage, peaking services, and a share of its Storage Inventory Carrying Charge. The decreased charge reflects a projected decrease in the costs of interstate pipeline transportation services that make up the Company's gas supply portfolio, as well as increased peaking-related costs, and costs associated with the Storage Inventory Carrying Charge component of the Balancing Charge. The average monthly impact of the proposed RSG Commodity Rate and Balancing Charge change is an increase of approximately 3.0% for a typical residential gas heating customer using 172 therms in a winter month and 87 average monthly therms (1,040 annually).

The RSG customer class is expected to be over-recovered by $122.4M by September 30, 2025 (see Item 7). This period began in October of 2024 with an over recovery of $162.2M (including interest rollover). As directed by BPU Staff, the Company utilized May 8, 2025 NYMEX forward prices for the computations included in this filing, resulting in a projected under-recovery at the end of September 2025 of $49.1M (excluding losses and SUT as shown on Item 7).

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*

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

Item 2 of the filing, Computation of BGSS Commodity Charge for RSG, shows that a rate of $0.363539 per therm (including losses and SUT), would be required to reduce the projected under-collection of $49.1M (excluding losses and SUT) to zero by September 30, 2026, based on May 8th NYMEX prices.

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 (Item 2) computes the BGSS Commodity Charge to residential gas customers based on all the forecasted gas cost components and applicable credits using forecasted send-out. 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 $9.8M of interest has been included.

Natural gas prices have been volatile during the most recent BGSS period, following the relative stability experienced during 2023. NYMEX prompt month daily prices have traded between $1.57/Dth in March 2024, to a high of $4.50 in March 2025, followed by a dramatic decline to about $2.95 in late April 2025. The June prompt month price is $3.59/Dth. The forward (May 8th) NYMEX strip used by the Company in this filing (see Item 8) shows that average prices are 40% higher than last year's NYMEX strip. Based upon the forward strip, prices are expected to increase $1.26/Dth above the June price by December 2025, as well as an additional $0.29/Dth in January of 2026, followed by a decrease from $5.14/Dth to an average of about $4.10/Dth during April 2026 through September 2026, the end of this BGSS period.

In response to the increased demand and resultant higher prices, US gas production has recently set an all-time peak of 106.5 Bcf/d. US national storage levels are currently 3% greater than the five-year average after having fallen to 20% below the five-year average during January 2025. Feedgas volumes for the US' eight LNG export facilities have recently averaged approximately 15.5 Bcf/d, a sizeable increase over the 12 Bcf/d average at this time last year. The feedgas volume is expected to further increase in late 2025 and 2026 as additional facility expansions come on line and the approval of new LNG export facilities is facilitated under the Trump administration. As a result, while overall demand for natural gas is expected to increase during the upcoming BGSS period, today's higher price levels are likely to incent producers to increase production to satisfy those increased demands and keep the market in a relative balance.

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 change to the current BGSS-RSG rate and the proposed change to the balancing charge on typical residential gas bills at various winter therm utilization levels. The Notice includes a table showing the impacts at various utilization levels and also a reference to the possibility of self-implementing BGSS Commodity increases of up to 5% of the average rate based on a typical residential customer's monthly bill of 100 therms on average (or 1,200 therms annually) on December 1, 2025 and February 1, 2026, respectively, with the impact of those possible increases.

4. <u>Actual and Forecasted Refund Amounts</u>

The first schedule of Item 4 shows actual supplier refunds, totaling approximately \$0.2M, that were credited to BGSS-RSG recovery costs from May 2024 through April 2025. The second schedule shows that the Company has included two refunds estimated to total \$17.6M associated with the anticipated settlement of both the Transco and Columbia rate case proceedings.

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 send-out 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 send-out and are trued up when the actual firm send-out 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 the New Jersey generation facilities formerly owned by PSEG Power 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. BGSS Contribution and Credit Offsets

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 residential customers 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 2024 to September 2025 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: the first schedule shows the projected over/(under) recovery based on the current BGSS rate. The second schedule is based on the BGSS rate that would be necessary to achieve a zero balance at September 2026 based on the May 8, 2025 NYMEX prices. Also included are supporting work papers 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 2025 and the projected period through September 2026 along with a comparison of these prices with the prices included in the current BGSS rate (from last year's BGSS filing) which indicates an increase of approximately 40%. These estimates reflect the future NYMEX prices on May 8, 2025, when this analysis was done.

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

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

10. Historic Service Interruptions

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. Gas Price Hedging Activities

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.

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 hedged approximately 99% of its planned volume for the 2025 summer period, approximately 68% of its planned volume for the 2025-2026 winter period and approximately 42% of its planned volume for the 2026 summer period. Hedging for the winter 2026-2027 period has just begun in May 2025. 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. Storage Gas Volumes, Prices and Utilization

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. As noted in Item 13, the Term of the Requirements Contract has been extended for a five-year period through March 31, 2027. The Company requested the Term extension in its June 1, 2021 Annual BGSS Filing, and the Board approved the same in its Order dated April 6, 2022. As is described further below, the Company is again requesting that the Requirements Contract be extended for an additional term of five (5) years, from April 1, 2027 to March 31, 2032.

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 is the most recent peak day forecast and the supplies to be utilized to meet these requirements. Included are the details for the current winter season concerning any changes to interstate pipeline contracts and PSE&G's peaking supplies (entitlements, storage capacities, daily deliverability, or transportation) and the forecast for the next four (4) 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 those dockets and included a listing of any filings or testimony made by or on behalf of the Company.

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

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 includes the supporting information for a decrease in the Balancing Charge based on the 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).

The Balancing Charge is applicable to rate schedules RSG, GSG, LVG, and CSG where applicable and recovers the cost of providing storage, peaking services, and a share of its Storage Inventory Carrying Charge. The requested change is from the current Balancing Charge of $0.100751 per balancing therm (including losses and SUT) to a Balancing Charge of $0.097699 per balancing therm (including losses and SUT). Attachment D provides the detail and support for this change, which is summarized on the bottom of page 1. The requested Balancing Charge is applicable in the billing months of October through May.

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 $0.080820 per balancing therm (excluding losses and SUT), which is a decrease from the previous charge of $0.084589 per balancing therm (excluding losses and SUT).

The Storage Inventory Carrying Charge is shown on page 2 and is recovered in the balancing and commodity charges. The requested charge is $0.003362 per balancing therm (excluding losses & SUT) for the balancing portion and $0.005697 per therm (excluding losses & SUT) for the commodity portion (included in Item 2) using the applicable billing determinants for each. The current charges are $0.003049 per balancing therm (excluding losses & SUT) for the balancing portion and $0.005149 per therm for the commodity portion (excluding losses and SUT).

The revenue requirement on Production Plant is shown on page 3 and the requested charge is $0.005614 per balancing use therm (excluding losses & SUT), which is an increase from the previous charge of $0.004963 per balancing use therm (excluding losses and SUT).

Also included in Attachment D is an increase in the A&G charge. This change is reflected in Item 2. The current rate is $0.004085 per therm (excluding losses & SUT) and the updated rate is $0.004569 per therm (excluding losses & SUT). This rate recovers the administrative cost associated with PSEG Energy Resources & Trade's provision of gas supply services to PSE&G.

Requirements Contract

The Company's natural gas supply function is managed by PSEG Energy Resources & Trade LLC ("ER&T") pursuant to a Requirements Contract. In a BPU Order finalizing the Company's 2013/2014 BGSS proceeding dated March 19, 2014 in Docket No. GR13060447, in order to promote certainty, the Board directed that the Requirements Contract be extended for an additional term of five years to March 31, 2019 and continue on a year-to-year basis thereafter with a two-year termination notice. In a BPU Order finalizing the Company's 2021/2022 BGSS proceeding dated April 6, 2022 in Docket No. GR21060878, in order to promote certainty, the Board further directed that the Requirements Contract be extended for an additional term of five years from April 1, 2022 to March 31, 2027 and continue on a year-to-year basis thereafter with a two-year termination notice. Consistent with the Board's March 19, 2014 and April 6, 2022 Orders, in order to once again promote certainty with respect to BGSS procurement, the Company and ER&T propose to execute an amendment to the Requirements Contract to provide that the term of the Requirements Contract be extended for an additional term of five (5) years from April 1, 2027 to March 31, 2032, continuing on a year-to-year basis thereafter with a two-year termination notice requirement. The Company will file a copy of the executed amendment with the Board no more than thirty (30) days after the date of a written Board Order approving this BGSS filing.

CONCLUSION

The Company's filing should be approved as reasonable and fully supported. The Company stands ready to respond to any reasonable requests for additional data. The Company seeks a Board Order by October 1, 2025 or earlier, should the Board deem it appropriate, approving: (1) the Company's proposal to increase the current BGSS Commodity

Charge of $0.326190 per therm (including losses and SUT) to $0.363539 per therm (including losses and SUT) to be charged to BGSS-RSG customers, with the costs presented herein as the basis of the cost of BGSS-RSG supply, (2) a decrease in the Balancing Charge to $0.097699 per balancing use therm (including losses and SUT) and (3) the Company's proposal to execute an amendment to the Requirements Contract providing for a five-year extension, continuing on a year-to-year basis thereafter, subject to a two-year termination notice requirement.

SCHEDULE DFC-1

PROFESSIONAL QUALIFICATIONS
OF
DAVID F. CAFFERY
<u>VICE PRESIDENT – GAS SUPPLY</u>

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 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.

2. Computation of Proposed BGSS Rate

Effective October 1, 2025

COMPUTATION OF BGSS COMMODITY CHARGE FOR RSG OCTOBER 2025 - SEPTEMBER 2026

($-000)

	$000	$/DTh
FIXED COSTS:		
FT DEMAND COST	$ 195,807	$1.2861
STORAGE DEMAND/CAPACITY COSTS	91,732	$0.6025
STORAGE INJ & W/D COSTS	6,897	$0.0453
PEAKING COSTS	18,491	$0.1215
	312,927	**$2.0553**
CONTRIBUTIONS	(29,713)	($0.1952)
PIPELINE REFUNDS	(17,565)	($0.1154)
OFF-SYSTEM SALES MARGIN	(94,298)	($0.6194)
LEGACY ELECTRIC CONTIBUTION - CSG	(3,851)	($0.0253)
NET TOTAL FIXED COST	**$ 167,499**	**$1.10020**
FIRM RSG SENDOUT (MDTh) 10/24 - 9/25	**152,250**	
TOTAL NON-GULF COAST COST ($/DTh)		**$1.10020**
Removal of Balancing Cost (incl. above)		(0.62771)
Inventory Carrying Charge Allocation		0.05697
Gas Supply A&G		0.04569
Total Adjustments		**($0.52506)**
ADJUSTED NON-GULF COAST COST ($/DTh)		**$0.57514**
(OVER)/UNDER RECOVERY @ 9/30/25 - INCL. INT.	**($132,176)**	**($0.86810)**
GULF COAST COST OF GAS ($/DTh)		
FT COMMODITY AND FUEL		0.00000
COST OF GAS		**3.63428**
TOTAL GULF COAST COST		**$3.63428**

SUMMARY OF CHARGE COMPONENTS

	(cents/therm) BGSS-RSG	(dollars/therm) BGSS-RSG
Estimated Non-Gulf Coast Cost of Gas	5.7514	$ 0.057514
Estimated Gulf Coast Cost of Gas	36.3428	$ 0.363428
Adjustment to Gulf Coast Cost of Gas	-	$ -
Prior Period (Over)/Under Recovery	(8.6810)	$ (0.086810)
Adjusted Cost of Gas	33.4132	$ 0.334132
COMMODITY CHARGE (after application of losses 2.0%)	**34.0951**	**$ 0.340951**
COMMODITY CHARGE (including SUT)	**36.3539**	**$ 0.363539**

3. Public Notice with Proposed Impact on Bills

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 2025/2026 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 Public Hearings

Docket No. XXXXXXXXXX

PLEASE TAKE NOTICE that, on May 30, 2025, Public Service Electric and Gas Company ("Public Service", "PSE&G," or "Company") filed a petition and supporting testimony with the New Jersey Board of Public Utilities ("Board" or "BPU") requesting that the Board permit Public Service to increase its Basic Gas Supply Service ("BGSS-RSG") Commodity Charge applicable to its Residential Service ("RSG") customers and to decrease its Balancing Charge, which is based on winter gas usage, to customers receiving service under RSG, General Service ("GSG"), Large Volume Service ("LVG") and Contract Service ("CSG") where applicable effective October 1, 2025, or earlier should the Board deem it appropriate ("Petition"). Approval of the Company's request would result in an increase in annual BGSS-RSG revenues of approximately $49.1 million (excluding losses and New Jersey Sales and Use Tax or "SUT"). The requested increase in the BGSS-RSG Commodity Charge is from $0.326190 per therm (including losses and SUT) to $0.363539 per therm (including losses and SUT), and the requested decrease in the Balancing Charge is from $0.100751 per balancing use therm (including losses and SUT) to $0.097699 per balancing use therm (including losses and SUT).

Based upon rates effective June 1, 2025, the combined effects of the requested increase in the BGSS-RSG and Balancing Charges on typical residential gas winter monthly bills, if approved by the Board, are shown in Table #1.

Based on the filing, the average monthly impact of the proposed rates to the typical residential gas customer using 172 therms in a winter month and 87 average monthly therms (1,040 annually) would be an increase in the average monthly bill from $100.70 to $103.74 or $3.04, or approximately 3.0%. On an annual basis, the typical residential customer using 1,040 therms annually would see an increase in their annual bill from $1,208.40 to $1,244.88, or $36.48, or approximately 3.0%.

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, 2025, and/or February 1st of next year, 2026, on a self-implementing basis; each increase is subject to a maximum rate increase of 5% of the average rate based on a typical residential customer's monthly bill of 100 therms on average (or 1,200 therms annually). Such rate increases shall be preconditioned upon written notice by Public Service to BPU Staff and the New Jersey Division of Rate Counsel ("Rate Counsel") no later than November 1, 2025 and/or January 1, 2026 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 requested and implemented, would be in accordance with the Board-approved methodology.

Should it become necessary to apply the December 1, 2025 self-implementing 5% increase, the bill impact would be an increase as illustrated in Table #2. Further, if a February 1, 2026 self-implementing 5% increase becomes necessary, then there would be an additional increase as also shown in Table #2.

The above requests will not result in any profit to the Company.

The Board has statutory authority pursuant to N.J.S.A. 48:2-21, to establish the BGSS-RSG and Balancing charges at levels it finds just and reasonable. Therefore, the Board may establish the BGSS-RSG and Balancing charges at levels other than that proposed by Public Service. As a result, the described charges may increase or decrease based upon the Board's decision. The Company's electric and gas costs addressed in the Petition and subsequent updates will remain subject to audit by the Board, and Board approval shall not preclude or prohibit the Board from taking any such actions deemed appropriate as a result of any such audit.

A copy of this Notice of Filing and Public Hearings on the Petition is being served upon the clerk, executive or administrator of each municipality and county within the Company's service territory. The Petition is available for review online at the Public Service website at http://www.pseg.com/pseandgfilings and has been sent to Rate Counsel, who will represent the interests of all Public Service customers in this proceeding. The Petition is also available to review online through the Board's website, https://publicaccess.bpu.state.nj.us, where you can search by the above-captioned docket number. The Petition and Board file may also be reviewed at the Board located at 44 South Clinton Avenue, Trenton, NJ, with an appointment. To make an appointment, please call (609) 913-6298.

PLEASE TAKE FURTHER NOTICE that virtual public hearings are scheduled on the following date and times so that members of the public may present their views on the Petition:

DATE: TBD
TIMES: 4:30 p.m. and 5:30 p.m
There are two options for joining.
Either go to this website:
https://www.microsoft.com/en-us/microsoft-teams/join-a-meeting

and enter the following information:

Meeting ID: 992 979 119 781
Passcode: 3X59PZ

-or-

Join by Phone
Dial In: (973) 536-2286
Phone conference ID: 537 811 425#

Representatives from the Company, Board Staff, and the New Jersey Division of Rate Counsel will participate in the virtual public hearings. Members of the public are invited to participate by utilizing the link or dial-in number set forth above and may express their views on the Petition. All comments will be made a part of the final record of the proceeding and will be considered by the Board. In order to encourage full participation in this opportunity for public comment, please submit any requests for needed accommodations, such as interpreters and/or listening assistance, 48 hours prior to the above hearings to the Board Secretary at board.secretary@bpu.nj.gov.
The Board is also accepting written and electronic comments. Comments may be submitted directly to the specific docket listed above using the "Post Comments" button on the Board's Public Document Search tool: (https://publicaccess.bpu.state.nj.us).
Comments may be submitted directly to the specific docket listed above using the "Post Comments" button on the Board's Public Documents Search tool https://publicaccess.bpu.state.nj.us. Comments are considered public documents for purposes of the State's Open Public Records Act. Only public documents should be submitted using the "Post Comments" button on the Board's Public Document Search tool. Any confidential information should be submitted in accordance with the procedures set forth in N.J.A.C. 14:1-12.3. In addition to hard copy submissions, confidential information may also be filed electronically via the Board's e-filing system or by email to the Secretary of the Board. Please include "Confidential Information" in the subject line of any email. Instructions for confidential e-filing are found on the Board's webpage at https://www.nj.gov/bpu/agenda/efiling/.

Emailed and/or written comments may also be submitted to:
Sherri L. Lewis, Secretary of the Board
44 South Clinton Ave.
PO Box 350
Trenton, NJ 08625-0350
Phone: 609-913-6241
Email: board.secretary@bpu.nj.gov

All emailed or mailed comments should include reference to "BPU Docket No. XXXXXXXXXX"

Table # 1
Residential Gas Service – Monthly Winter Bill

If 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:
25	$35.80	$36.70	$0.90	2.5%
50	61.58	63.36	1.78	2.9
100	115.91	119.37	3.46	3.0
172	192.18	198.15	5.97	3.0
198	219.78	226.64	6.86	3.1
300	327.72	338.12	10.40	3.2

(1) Based upon Delivery Rates and Basic Gas Supply Service (BGSS-RSG) in effect June 1, 2025, 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

If Your Monthly Winter Therm Use Is:	Self-Implementing 5% Increases		
	December 1, 2025 Monthly Winter Increase Would Be:	February 1, 2026 Monthly Winter Increase Would Be:	Total Increase If both 5% Self-Implementing Increases Are Put Into Effect:
25	$ 1.47	$ 1.46	$ 2.93
50	2.93	2.93	5.86
100	5.87	5.87	11.74
172	10.09	10.09	20.18
198	11.62	11.62	23.24
300	17.60	17.61	35.21

(1) Self-implementing monthly changes would be in addition to any monthly winter bill change amounts.

Stacey M. Mickles
Associate Counsel – State Regulatory

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

4. Actual and Forecasted Refund Amounts

Item 4

NATURAL GAS PIPELINE REFUNDS RECEIVED MAY 2024 - APRIL 2025

(000)

MONTH	SUPPLIER	AMOUNT	TOTAL
June 2024			
	Texas Eastern	$ 15.1	
	Texas Eastern	$ 65.0	
	Eatern Gas	$ 38.6	
	Tennessee	$ 14.6	
			$ 133.3
Sep 2024	Transco	$ 36.9	
			$ 36.9
Oct 2024	Tennessee	$ 0.3	
			$ 0.3
Nov 2024			
	Algonquin	$ 1.5	
	Columbia	$ 0.003	
	Texas Eastern	$ 24.1	
	Texas Eastern	$ 6.4	
	Transco	$ 1.5	
			$ 33.5
Jan 2025			
	Algonquin	$ 0.2	
			$ 0.2
Feb 2025			
	Algonquin	$ 0.4	**$ 0.4**
Mar 2025	Algonquin	$ 0.2	**$ 0.2**
	Total	$ 205	**$ 205**

Item 4

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

DOCKET	SUPPLIER	STATUS
RP24-1035	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 $16.7 million.
RP24-1103	Columbia	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 $865 thousand.

5. Cost of Gas Sendout by Component

ACTUAL COST OF BGSS-RSG GAS SENDOUT BY COMPONENT

	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	Total
Beginning Inventory Price $000	$226,664	$243,008	$239,041	$194,225	$137,838	$96,923	$87,981	
Fixed Pipeline Charge $000	$23,378	$25,468	$25,175	$25,345	$23,377	$22,196	$26,420	
Gas Purchases and Hedges $000	$19,721	$30,580	$44,053	$75,045	$55,746	$48,836	$41,065	
Receipt Value $000	$43,099	$56,048	$69,228	$100,390	$79,123	$71,032	$67,485	$486,405
Total Inventory Value $000	$269,762	$299,056	$308,269	$294,615	$216,961	$167,955	$155,466	
Total $/dth	$4.36	$4.49	$4.56	$4.80	$4.88	$5.10	$4.95	
Beginning Inventory Volume MDth	52,072	55,771	53,293	42,580	28,753	19,781	17,198	
Receipt Volume MDth	9,824	10,820	14,294	18,756	15,670	13,124	14,213	96,701
Total Inventory Volume MDth	61,897	66,591	67,586	61,336	44,423	32,905	31,412	
RSG Sendout MDth	6,146	13,399	24,999	32,703	24,431	15,614	9,895	127,189
Total RSG Sendout Cost $000	$26,786	$60,176	$114,025	$157,082	$119,323	$79,699	$48,975	$606,065
Ending Inventory Rebalance								
Volume	21	101	(7)	120	(211)	(92)	72	
Amount	$31	$161	($19)	$304	($715)	($275)	$229	

FORECASTED COST OF BGSS-RSG GAS SENDOUT BY COMPONENT

	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Total Oct - Sept
Beginning Inventory Cost $000	$106,719	$149,825	$173,991	$198,496	$221,738	$260,055	$288,750	$267,678	$199,310	$117,963	$61,426	$12,821	$17,969	$52,764	$100,936	$148,525	$191,192	
Receipt Value $000	$63,992	$43,178	$38,488	$37,399	$53,917	$65,210	$67,194	$68,543	$98,221	$92,066	$75,029	$63,951	$62,376	$66,259	$60,299	$54,808	$56,922	$830,878
Total Inventory Value $000	$170,711	$193,002	$212,479	$235,896	$275,655	$325,265	$355,944	$336,221	$297,531	$210,029	$136,456	$76,772	$80,345	$119,023	$161,235	$203,332	$248,114	
Total $/dth	$4.69	$5.07	$5.49	$5.84	$5.69	$5.34	$5.41	$5.63	$5.81	$5.92	$5.92	$5.24	$5.04	$4.96	$5.08	$5.17	$5.10	
Beginning Inventory Volume MDth	21,589	31,932	34,343	36,143	37,945	45,706	54,118	49,446	35,410	20,304	10,384	2,165	3,431	10,470	20,343	29,218	36,969	
Receipt Volume MDth	14,794	6,164	4,345	4,225	10,503	15,256	11,632	10,288	15,802	15,200	12,664	12,493	12,511	13,519	11,375	10,099	11,707	152,545
Total Inventory Volume MDth	36,383	38,096	38,689	40,368	48,448	60,962	65,750	59,734	51,212	35,504	23,047	14,658	15,942	23,989	31,718	39,316	48,676	
RSG Sendout MDth	4,451	3,753	2,546	2,423	2,742	6,844	16,305	24,324	30,908	25,120	20,882	11,227	5,473	3,645	2,500	2,347	2,675	152,250
Total RSG Sendout Cost $000	$20,886	$19,011	$13,983	$14,158	$15,600	$36,516	$88,266	$136,912	$179,568	$148,603	$123,635	$58,803	$27,581	$18,087	$12,711	$12,141	$13,637	$856,455

6. BGSS Contribution and Credit Offsets

Actual BGSS Contribution and Credit Offsets

($000)

			Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25 Est	Total
(1)	**BGSS-I Contribution**		$63	$118	($270)	$414	$139	$401	$122	$986
(2)	**Cogeneration Contribution**		$877	($440)	$1,883	$749	$1,155	$466	$47	$4,736
(3)	**TSG-F Contribution**		$162	$587	$504	$416	$326	$260	($77)	$2,178
(4)	**"Contribution"**	Sum of (1) through (4)	$1,102	$265	$2,117	$1,578	$1,620	$1,127	$92	$7,900
(5)	**Off-System Contribution**		$2,182	$2,424	$16,182	$43,984	$17,663	$3,548	$3,167	$89,150
(6)	**Electric Contribution**		$259	$266	$206	$135	$149	$289	$687	$1,992
(7)	**FT-S Balancing Credit**		$482	$2,040	$3,807	$5,127	$4,124	$2,834	$1,595	$20,008
(8)	**Pipeline Refunds**		$37	$0	$34	$0	$0	$0	$0	$72

Forecasted BGSS Contribution and Credit Offsets

		May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Total Oct - Sept
(1)	**BGSS-RSG Sendout, Mdth**	4,451	3,753	2,546	2,423	2,742	6,844	16,305	24,324	30,908	25,120	20,882	11,227	5,473	3,645	2,500	2,347	2,675	152,250
(2)	**BGSS-F Sendout, Mdth**	1,739	1,334	1,095	1,191	1,147	2,215	5,104	8,311	9,613	8,123	8,105	4,428	2,155	1,317	1,095	1,177	1,135	52,778
(3)	**Total Firm Sendout, Mdth**	6,191	5,087	3,641	3,613	3,889	9,059	21,408	32,635	40,521	33,243	28,986	15,656	7,627	4,962	3,596	3,525	3,810	205,028
(4)	**Annual % BGSS-RSG of Firm Sendout**	74.3%	74.3%	74.3%	74.3%	74.3%	74.3%	74.3%	74.3%	74.3%	74.3%	74.3%	74.3%	74.3%	74.3%	74.3%	74.3%	74.3%	74.3%
(5)	**BGSS-I Contribution**	$79.5	$84.0	$32.0	$44.6	$39.7	$61.4	$115.4	($268.9)	$402.6	$136.6	$413.3	$125.9	$79.7	$84.3	$32.2	$44.9	$39.8	$1,267.3
(6)	**Cogeneration Contribution, $000**	$261.0	$376.8	$541.8	($250.1)	$465.3	$525.9	($73.5)	$1,370.6	$134.3	$226.3	($316.7)	($72.6)	$261.6	$378.4	$544.8	($251.8)	$467.2	$3,194.5
(7)	**TSG-F Contribution**	$94.9	$88.3	$47.9	$119.4	$95.6	$159.2	$572.1	$502.2	$404.7	$320.7	$267.8	($79.6)	$95.1	$88.7	$48.2	$120.2	$96.0	$2,595.1
(8)	**CSG**	$196.8	$440.0	$499.1	$911.4	$273.2	$254.1	($270.7)	$376.4	$453.4	$686.5	$574.3	$87.0	$196.8	$440.0	$499.1	$911.4	$273.2	$4,481.5
(9)	**"Contribution"**	$632.2	$989.1	$1,120.8	$825.3	$873.8	$1,000.6	$343.2	$1,980.4	$1,395.0	$1,370.1	$938.6	$60.7	$633.1	$991.4	$1,124.3	$824.7	$876.3	$11,538.4
(10)	**Off-System Contribution, $000**	$2,760.4	$3,598.9	$4,345.0	$4,644.3	$3,837.3	$3,884.6	$14,412.6	$14,412.6	$14,412.6	$14,412.6	$14,412.6	$2,592.5	$2,510.6	$3,106.3	$3,637.2	$3,585.4	$2,918.4	$94,298.1
(11)	**Legacy Electric Contribution, $000**	$270.2	$336.8	$654.5	$383.0	$214.8	$259.4	$266.4	$205.8	$135.0	$148.9	$289.0	$687.0	$270.2	$336.8	$654.5	$383.0	$214.8	$3,850.9
(12)	**Pipeline Refund, $000**	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$865.1	$16,700.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$17,565.1
(13)	**FT-S Balancing Use, Mdth**	555.5	0.0	0.0	0.0	0.0	602.8	3,757.1	4,919.4	6,440.3	5,416.2	5,445.9	2,595.4	1,106.8	0.0	0.0	0.0	0.0	
(14)	**Balancing Charge, $/dth**	$0.8459	$0.0000	$0.0000	$0.0000	$0.0000	$0.8082	$0.8082	$0.8082	$0.8082	$0.8082	$0.8082	$0.8082	$0.8082	$0.0000	$0.0000	$0.0000	$0.0000	
(15)	**FT-S Balancing Credit, $000**	$555.5	$0.0	$0.0	$0.0	$0.0	$361.8	$2,254.9	$2,952.4	$3,865.2	$3,250.5	$3,268.4	$1,557.6	$664.3	$0.0	$0.0	$0.0	$0.0	$18,175.1
(16)	**BGSS-RSG Balancing Use, Mdth**	1,164	0	0	0	0	3,931	13,486	21,411	27,995	22,489	17,969	8,409	2,560	0	0	0	0	
(17)	**Balancing Charge, $/dth**	$0.8459	$0.0000	$0.0000	$0.0000	$0.0000	$0.8082	$0.8082	$0.8082	$0.8082	$0.8082	$0.8082	$0.8082	$0.8082	$0.0000	$0.0000	$0.0000	$0.0000	
(18)	**BGSS-RSG Balancing Rev., $000**	$984.6	$0.0	$0.0	$0.0	$0.0	$3,177.1	$10,899.2	$17,304.5	$22,625.7	$18,175.9	$14,522.6	$6,795.8	$2,068.9	$0.0	$0.0	$0.0	$0.0	$95,569.6

BGSS-RSG MARGIN FROM GAS TRANSPORTATION FOR ELECTRIC GENERATION

	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	Total
BGSS Asset Charge ($000)	$0	$0	$0	$0	$0	$0	$0	$0
CSG Transportation Revenues ($000)	$259	$266	$206	$135	$149	$289	$687	$1,992
Total BGSS-RSG Margin ($000)	$259	$266	$206	$135	$149	$289	$687	$1,992

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

MONTHLY RECOVERIES COMPARED TO EXCESS COST
OCTOBER 2024 - SEPTEMBER 2025

(000)

		TOTAL RECOVERY	LESS: TOTAL EXPENSE	MONTHLY OVER/(UNDER) RECOVERY
Balance September 30, 2024				**$153,595**
Interest Adjustment				**8,619**
October 1, 2024 Adjusted Balance				**$162,214**
October 2024		$ 21,004	$ 28,467	(7,463)
November		51,717	58,177	(6,459)
December		97,693	103,838	(6,145)
January 2025		131,083	118,411	12,672
February		101,470	112,518	(11,048)
March		69,004	74,157	(5,152)
April		39,766	45,807	(6,041)
May	**(Est.)**	13,965	16,668	(2,703)
June	**(Est.)**	10,942	14,086	(3,144)
July	**(Est.)**	7,424	7,862	(438)
August	**(Est.)**	7,065	8,305	(1,241)
September	**(Est.)**	7,995	10,674	(2,679)
Total				**$122,369**

INTEREST
COMPUTED AT 6.99% ROR FOR OCTOBER 1, 2024 - OCTOBER 14,2024
COMPUTED AT 7.07% ROR FOR OCTOBER 15, 2024 - SEPTEMBER 2025
(000)

		OVER/(UNDER) RECOVERIES			
		Monthly	Cumulative	Average Balance	INTEREST
Balance September 30, 2024			**$153,595**		
Interest Adjustment			**8,619**		
October 1, 2024 Adjusted Balance			**$162,214**		
October 2024		$ (7,463)	154,751	$ 158,482	$ 929
November		(6,459)	148,291	$ 151,521	$ 893
December		(6,145)	142,146	145,218	$ 856
January 2025		12,672	154,817	148,482	$ 875
February		(11,048)	143,769	149,293	$ 880
March		(5,152)	138,617	141,193	$ 832
April		(6,041)	132,575	135,596	$ 799
May	**(Est.)**	(2,703)	129,872	131,224	$ 773
June	**(Est.)**	(3,144)	126,728	128,300	$ 756
July	**(Est.)**	(438)	126,289	126,509	$ 745
August	**(Est.)**	(1,241)	125,049	125,669	$ 740
September	**(Est.)**	(2,679)	122,370	123,709	$ 729
Total					**$ 9,807**

BGSS-RSG 2025-2026

NYMEX====>>> May 8, 2025

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-25	Act													$132,575	$2.91592
May-25	Est.	4,451	$20,886	$0	($632)	($2,760)	($270)	($556)	$16,668	$985	$13,964.54	$2,703	($2,703)	$129,872	$2.91592
Jun-25	Est.	3,753	$19,011	$0	($989)	($3,599)	($337)	$0	$14,086	$0	$10,942.07	$3,144	($3,144)	$126,727	$2.91592
Jul-25	Est.	2,546	$13,983	$0	($1,121)	($4,345)	($654)	$0	$7,862	$0	$7,423.98	$438	($438)	$126,289	$2.91592
Aug-25	Est.	2,423	$14,158	$0	($825)	($4,644)	($383)	$0	$8,305	$0	$7,064.60	$1,241	($1,241)	$125,048	$2.91592
Sep-25	**Est.**	**2,742**	**$15,600**	**$0**	**($874)**	**($3,837)**	**($215)**	**$0**	**$10,674**	**$0**	**$7,994.59**	**$2,679**	**($2,679)**	**$122,369**	$2.91592
Oct-25	Est.	6,844	$36,516	$0	($1,001)	($3,885)	($259)	($362)	$31,009	$3,177	$23,133.26	$7,876	($7,876)	$114,493	$2.91592
Nov-25	Est.	16,305	$88,266	($865)	($343)	($14,413)	($266)	($2,255)	$70,123	$10,899	$58,441.83	$11,682	($11,682)	$102,812	$2.91592
Dec-25	Est.	24,324	$136,912	($16,700)	($1,980)	($14,413)	($206)	($2,952)	$100,660	$17,305	$88,231.16	$12,429	($12,429)	$90,383	$2.91592
Jan-26	Est.	30,908	$179,568	$0	($1,395)	($14,413)	($135)	($3,865)	$159,760	$22,626	$112,750.46	$47,010	($47,010)	$43,373	$2.91592
Feb-26	Est.	25,120	$148,603	$0	($1,370)	($14,413)	($149)	($3,251)	$129,420	$18,176	$91,424.36	$37,996	($37,996)	$5,377	$2.91592
Mar-26	Est.	20,882	$123,635	$0	($939)	($14,413)	($289)	($3,268)	$104,726	$14,523	$75,412.27	$29,314	($29,314)	($23,937)	$2.91592
Apr-26	Est.	11,227	$58,803	$0	($61)	($2,593)	($687)	($1,558)	$53,905	$6,796	$39,533.80	$14,371	($14,371)	($38,308)	$2.91592
May-26	Est.	5,473	$27,581	$0	($633)	($2,511)	($270)	($664)	$23,502	$2,069	$18,026.45	$5,476	($5,476)	($43,784)	$2.91592
Jun-26	Est.	3,645	$18,087	$0	($991)	($3,106)	($337)	$0	$13,652	$0	$10,629.37	$3,023	($3,023)	($46,806)	$2.91592
Jul-26	Est.	2,500	$12,711	$0	($1,124)	($3,637)	($654)	$0	$7,295	$0	$7,290.94	$4	($4)	($46,810)	$2.91592
Aug-26	Est.	2,347	$12,141	$0	($825)	($3,585)	($383)	$0	$7,347	$0	$6,845.10	$502	($502)	($47,312)	$2.91592
Sep-26	**Est.**	**2,675**	**$13,637**	**$0**	**($876)**	**($2,918)**	**($215)**	**$0**	$9,627	**$0**	$7,800.82	$1,826	($1,826)	($49,139)	$2.91592
Oct-25 to Sept-26		**152,250**	**$856,455**	**($17,565)**	**($11,538)**	**($94,298)**	**($3,851)**	**($18,175)**	**$711,028**	**$95,570**	**$539,520**	**$171,508**			

BGSS-RSG 2025-2026
NYMEX====>>> May 8, 2025

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-25 Act.													**$132,575**	$2.91592
May-25 Est.	4,451	$20,886	$0	($632)	($2,760)	($270)	($556)	$16,668	$985	$13,965	$2,703	($2,703)	$129,872	$2.91592
Jun-25 Est.	3,753	$19,011	$0	($989)	($3,599)	($337)	$0	$14,086	$0	$10,942	$3,144	($3,144)	$126,727	$2.91592
Jul-25 Est.	2,546	$13,983	$0	($1,121)	($4,345)	($654)	$0	$7,862	$0	$7,424	$438	($438)	$126,289	$2.91592
Aug-25 Est.	2,423	$14,158	$0	($825)	($4,644)	($383)	$0	$8,305	$0	$7,065	$1,241	($1,241)	$125,048	$2.91592
Sep-25 Est.	**2,742**	**$15,600**	**$0**	**($874)**	**($3,837)**	**($215)**	**$0**	**$10,674**	**$0**	**$7,995**	**$2,679**	**($2,679)**	**$122,369**	$2.91592
Oct-25 Est.	6,844	$36,516	$0	($1,001)	($3,885)	($259)	($362)	$31,009	$3,177	$25,342	$5,667	($5,667)	$116,702	$3.23867
Nov-25 Est.	16,305	$88,266	($865)	($343)	($14,413)	($266)	($2,255)	$70,123	$10,899	$63,704	$6,419	($6,419)	$110,283	$3.23867
Dec-25 Est.	24,324	$136,912	($16,700)	($1,980)	($14,413)	($206)	($2,952)	$100,660	$17,305	$96,082	$4,579	($4,579)	$105,704	$3.23867
Jan-26 Est.	30,908	$179,568	$0	($1,395)	($14,413)	($135)	($3,865)	$159,760	$22,626	$122,726	$37,034	($37,034)	$68,670	$3.23867
Feb-26 Est.	25,120	$148,603	$0	($1,370)	($14,413)	($149)	($3,251)	$129,420	$18,176	$99,532	$29,889	($29,889)	$38,782	$3.23867
Mar-26 Est.	20,882	$123,635	$0	($939)	($14,413)	($289)	($3,268)	$104,726	$14,523	$82,152	$22,574	($22,574)	$16,207	$3.23867
Apr-26 Est.	11,227	$58,803	$0	($61)	($2,593)	($687)	($1,558)	$53,905	$6,796	$43,157	$10,747	($10,747)	$5,460	$3.23867
May-26 Est.	5,473	$27,581	$0	($633)	($2,511)	($270)	($664)	$23,502	$2,069	$19,793	$3,710	($3,710)	$1,750	$3.23867
Jun-26 Est.	3,645	$18,087	$0	($991)	($3,106)	($337)	$0	$13,652	$0	$11,806	$1,846	($1,846)	($96)	$3.23867
Jul-26 Est.	2,500	$12,711	$0	($1,124)	($3,637)	($654)	$0	$7,295	$0	$8,098	($803)	$803	$708	$3.23867
Aug-26 Est.	2,347	$12,141	$0	($825)	($3,585)	($383)	$0	$7,347	$0	$7,603	($255)	$255	$963	$3.23867
Sep-26 Est.	**2,675**	**$13,637**	**$0**	**($876)**	**($2,918)**	**($215)**	**$0**	**$9,627**	**$0**	**$8,664**	**$963**	**($963)**	**$0**	$3.23867
Oct-25 to Sept-26	**152,250**	**$856,455**	**($17,565)**	**($11,538)**	**($94,298)**	**($3,851)**	**($18,175)**	**$711,028**	**$95,570**	**$588,659**	**$122,369**			

PSE&G
FOR PERIOD OCT24 TO SEP25

	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25
Beginning Balance	162,213,774	154,750,568	148,291,108	142,145,749	154,817,366.48	143,769,184.05	138,616,961.77
FUEL REVENUES							
Fuel Revenues	19,643,052.30	51,185,871.96	95,369,857.26	129,370,141.20	99,700,754.96	67,588,668.31	38,987,264.95
Interruptible Contribution	1,361,123.98	531,496.52	2,322,668.75	1,712,732.56	1,768,997.36	1,415,823.87	778,717.92
PSEG Holding's Affiliation Fee							
Total Fuel Revenues	21,004,176.28	51,717,368.48	97,692,526.01	131,082,873.77	101,469,752.32	69,004,492.18	39,765,982.87
FUEL EXPENSE							
Gas Purchases	28,504,296.89	58,177,149.10	103,871,414.15	118,411,256.54	$112,518,159.88	$74,157,156.17	45,807,663.49
Refunds	($36,914.45)	($320.56)	($33,529.77)	$0.00	($225.12)	($441.71)	($191.34)
Total Fuel Expense	28,467,382.44	58,176,828.54	103,837,884.38	118,411,256.54	112,517,934.76	74,156,714.46	45,807,472.15
OVER / (UNDER) RECOVERY	(7,463,206.16)	(6,459,460.06)	(6,145,358.37)	12,671,617.23	(11,048,182.43)	(5,152,222.28)	(6,041,489.28)
Cumulative Effect of Aug Adj JE							
Cumulative Effect of Aug Adj JE BGSSR/MAC							
Cumulative Recovery	154,750,567.69	148,291,107.63	142,145,749.26	154,817,366.48	143,769,184.05	138,616,961.77	132,575,472.49

BGSSR
CALCULATION OF FUEL REVENUES
FOR PERIOD OCT24 TO SEP25

	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25
RSG Fuel Revenues	$16,777,330	$39,405,097	$70,377,609	$95,235,530	$73,310,659	$50,363,229	$29,906,411
RSGM Fuel Revenues	$314,906	$759,754	$1,418,137	$1,941,253	$1,496,436	$1,068,106	$641,807
Subtotal	$17,092,237	$40,164,851	$71,795,747	$97,176,783	$74,807,095	$51,431,335	$30,548,219
FT Balancing Revenues	$1,588,114	$6,588,797	$19,847,125	$29,149,834	$28,885,961	$19,590,423	$11,236,996
FT Balancing Revenues (Unbilled Calc)	962,702	5,394,926	9,121,912	12,165,436	8,173,134	4,740,044	1,942,095
FT Balancing Revenues (Prior Unbilled Calc)	0	-962,702	-5,394,926	-9,121,912	-12,165,436	-8,173,134	-4,740,044
Manual Rev Accrual not part of BGSSR							
Total BGSSR Fuel Recovery	$19,643,052	$51,185,872	$95,369,857	$129,370,141	$99,700,755	$67,588,668	$38,987,265
Bill Credits							
Billed Revenues							
Current Unbilled Usage							
Prior Unbilled Usage							
Net Unbilled Usage							
Rate							
Subtotal Unbilled Revenues							
Total Bill Credits							

	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25
Interruptible Contributions:							
ISG (BGSS-I):							
ISG (BGSS-I) Sales Therms	322,498.13	730,870.62	463,102.90	2,137,570.06	1,104,049.14	1,579,466.51	286,950.89
ISG BGSS-I) Gross Revenues	151,398.23	331,779.85	253,385.13	1,199,336.43	753,915.98	798,139.53	250,758.16
ISG (BGSS-I) Cost	62,975.25	173,467.92	432,117.38	744,270.38	561,540.13	329,864.71	99,897.94
PSEG Power's share of Contribution	$25,911.46	$39,927.50	$91,144.33	$41,540.93	$53,395.15	$67,340.60	$29,248.65
ISG Interuptible Contribution to BGSSR	62,511.52	118,384.44	(269,876.58)	413,525.12	138,980.70	400,934.22	121,611.56
CIG:							
CIG SBC Rate adjustment (line 84)							
CIG Sales Therms	2,636,805.19	827,302.57	5,328,537.92	3,756,902.51	3,291,721.21	589,480.72	1,112,406.94
CIG Gross Revenues	$1,156,799	$537,553	$3,071,660	$2,174,626	$1,923,174	$641,124	$729,161
CIG SBC/GPRC Revenues	211,548.24	66,373.66	427,503.27	307,863.13	271,504.46	48,936.33	92,347.57
CIG Cost	321,212.96	451,433.12	1,107,854.29	1,693,775.42	1,349,534.39	785,902.13	585,130.01
CIG TAC revenues	975.10	17,462.27	-	-	-	-	-
PSEG Power's share of Contribution	$88,053.08	$77,677.98	$160,602.10	$34,992.75	$71,845.45	$113,517.09	$121,794.16
CIG Interuptible Contribution to BGSSR	535,009.82	(75,393.70)	1,375,700.39	137,994.69	230,289.71	(307,231.55)	(70,111.15)
TSG-F:							
TSG-F SBC Rate adjustment (line 84)							
TSG-F Sales Therms	1,330,867.81	2,630,725.12	2,599,136.74	3,076,795.49	1,969,587.28	2,063,300.87	1,728,066.56
TSG-F Gross Revenues	302,532.39	865,323.33	970,975.56	869,806.51	681,693.21	658,552.24	158,061.15
TSG-F SBC/GPRC Revenues	106,774.19	211,060.45	208,526.14	252,131.08	162,453.53	171,286.99	143,457.17
TSG-F TAC Revenues	1,511.77	2,999.38	-	-	-	-	-
TSG-F MAC Revenues	(7,873.41)	(15,563.37)	(15,376.49)	(18,202.32)	(11,652.08)	(13,444.47)	(11,260.08)
TSG-F PSEG Power's share of Contribution	$40,186.19	$80,113.89	$270,944.87	$223,831.72	$204,581.18	$240,939.13	$102,783.12
ESS Cost	-	-	2,239.75	(2,935.54)	-	-	-
PSEG Power's share of Contribution	-	-	543.75	(713.86)	-	-	-
TSG-F Interuptible Contribution to BGSSR	161,933.64	586,712.98	504,097.54	415,695.43	326,310.59	259,770.60	(76,919.06)
CSG NON-Power:							
CSG Non-Power Therms	45,128,328.14	47,334,971.88	40,570,636.40	26,295,242.03	11,927,290.93	47,708,730.35	92,107,764.36
CSG Non-Power Revenues	$622,840	($50,898)	$752,482	$781,404	$1,099,850	$1,093,017	$851,886
CSG Non Power SBC Revenues	10,412.11	13,560.03	10,352.05	8,464.71	6,621.65	7,194.38	11,655.69
CSG TAC Revenues Power and NON-Power	(12,927.77)	2,913.18	13,229.36	186.96	-	-	-
CSG Non-Power ER&T's share of Contribution	$23,686.48	$30,835.93	$16,153.03	$27,235.07	$19,811.78	$23,471.70	$36,093.33
CSG Non-Power Contribution to BGSSR	601,669.00	(98,207.20)	712,747.40	745517.3242	1073416.361	1062350.6	804136.566
Total Interruptible Contributions	1,361,123.98	531,496.52	2,322,668.75	1,712,732.56	1,768,997.36	1,415,823.87	778,717.92
SBC & GPRC rate-CIG & TSG-F (CHECK tariff pages for rate chan	**0.080229**	**0.080229**	**0.080229**	**0.081946**	**0.082481**	**0.083016**	**0.083016**
TEFA rate-TSG-F (Reduced 25% 2012 & 25% 2013, zero out 2014)							
Cogen Contract RAC rate (separate schedule beginning 12/02)							
MAC rate-TSG-F (Per MAC CALC Worksheet)	**(0.005916)**	**(0.005916)**	**(0.005916)**	**(0.005916)**	**(0.005916)**	**(0.006516)**	**(0.006516)**
PSEG Holding's Affliliation Fee							
Current Month Estimate - Gas Purchases (1) See below row 96	27,976,754.06	60,373,397.24	104,184,376.09	120,110,701.72	111,670,806.06	79,708,430.20	47,381,950.67
Prior Month Actual - Gas Purchases (1) See below row 105	11,657,460.44	25,780,185.35	60,026,905.54	102,484,930.91	120,957,830.41	106,119,090.31	78,133,951.69
Prior Month Estimate - Gas Purchases See below row 115	11,166,832.06	27,976,754.06	60,373,397.24	104,184,376.09	120,110,701.72	111,670,806.06	79,708,430.20
Gas Purchases	28,467,382.44	58,176,828.54	103,837,884.38	118,411,256.54	112,517,934.76	74,156,714.46	45,807,472.15
Gas Refunds							
ISG (BGSS-I) Cost Est. (2)	63,510.65	174,299.93	423,329.15	736,980.13	547,540.55	326,218.23	106,274.03
PSEG Power's share of Contribution CMnth Est. (2)	$27,030.91	$37,497.02	$91,189.46	$41,603.23	$56,136.39	$60,104.37	$26,643.56

	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25
ISG (BGSS-I) Cost Pr Mnth Act. (2)	27,129.97	62,678.63	183,088.16	430,619.40	750,979.70	551,187.04	319,842.14
PSEG Power's share of Contribution Pr Mnth Act. (2)	$10,814.07	$29,461.39	$37,451.88	$91,127.17	$38,861.98	$63,372.63	$62,709.46
ISG (BGSS-I) Cost PrMnth Est.	27,665.37	63,510.65	174,299.93	423,329.15	736,980.13	547,540.55	326,218.23
PSEG Power's share of Contribution PrMnth Est.	$11,933.53	$27,030.91	$37,497.02	$91,189.46	$41,603.23	$56,136.39	$60,104.37
CIG Cost (3) - CMnth Est. (3)	325,725.28	454,682.94	1,103,661.63	1,668,405.13	1,306,835.26	787,381.94	600,522.09
PSEG Power's share of Contribution - CMnth Est. (3)	$93,540.83	$62,834.28	$163,446.52	$36,094.81	$81,094.05	$103,303.66	$116,211.44
CIG Cost (3) - PrMnth Act. (3)	237,898.32	322,475.46	458,875.61	1,129,031.92	$1,711,104.26	$1,305,355.45	$771,989.86
PSEG Power's share of Contribution - PrMnth Act. (3)	$58,968.57	$108,384.53	$59,989.85	$162,344.47	$26,846.20	$91,307.49	$108,886.37
CIG Cost - PrMnth Est.	242,410.65	325,725.28	454,682.94	1,103,661.63	1,668,405.13	1,306,835.26	787,381.94
PSEG Power's share of Contribution - PrMnth Est.	$64,456.32	$93,540.83	$62,834.28	$163,446.52	$36,094.81	$81,094.05	$103,303.66
TSG-F PSEG Power's share of Contribution CMth Est. (4)	$44,641.37	$76,475.32	$187,824.81	$218,677.68	$193,677.06	$217,339.38	$99,822.86
TSG-F PSEG Power's share of Contribution PrMth Actual (4)	$36,444.69	$48,279.94	$159,595.38	$192,978.85	$229,581.79	$217,276.81	$220,299.64
TSG-F PSEG Power's share of Contribution PrMth Est.	$40,899.87	$44,641.37	$76,475.32	$187,824.81	$218,677.68	$193,677.06	$217,339.38
ESS (BGSS-I) Cost Pr Mnth Act. (2)	-	-	2,239.75	(2,935.54)	-	-	-
PSEG Power's share of Contribution Pr Mnth Act. (2)	$0.00	$0.00	$543.75	($713.86)	$0.00	$0.00	$0.00
CSC Non-Power Cost & PSEG Power's share of Contribution CMt	$37,002.84	$27,893.10	$16,971.04	$26,755.77	$18,495.97	$21,220.67	$35,822.81
CSC Non-Power Cost & PSEG Power's share of Contribution PMt	$23,195.80	$39,945.67	$27,075.09	$17,450.33	$28,071.58	$20,747.00	$21,491.19
CSC Non-Power Cost & PSEG Power's share of Contribution PMt	$36,512.15	$37,002.84	$27,893.10	$16,971.04	$26,755.77	$18,495.97	$21,220.67
BGSS-RSG Prior Month Actual	11,992,271.39	26,303,185.36	60,769,094.54	104,294,404.47	123,485,622.56	108,130,312.92	79,397,379.52
FTS Balancing/BGSS-RSG Cogen Contracts Prior Month Actual (	$0.00	$315,072.88	$632,794.24	$1,257,974.62	$1,527,399.89	$1,450,725.88	$1,026,956.14
BGSS-RSG TSG Cashouts Prior Mnth Actuals	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Subtotal	11,992,271.39	26,618,258.24	61,401,888.77	105,552,379.08	125,013,022.44	109,581,038.80	80,424,335.66
Total BGSS-RSG Actual Bill	**$11,995,207.72**	**$26,542,905.36**	**$60,838,299.11**	**$104,487,351.26**	**$121,997,481.18**	**$108,476,263.29**	**$79,532,565.89**
Difference							
BGSS-RSG Current Month Estimate	28,486,561.72	61,102,711.41	105,966,002.86	122,593,785.01	113,662,412.32	80,985,438.39	48,231,601.79
BGSS-RSG Cogen Contracts Prior Month Estimate (6)	-	-	-	-			
Subtotal	28,486,561.72	61,102,711.41	105,966,002.86	122,593,785.01	113,662,412.32	80,985,438.39	48,231,601.79
Total BGSS-RSG Estimate Bill	**28,486,561.72**	**61,102,711.41**	**105,966,002.86**	**122,593,785.01**	**113,662,412.32**	**80,985,438.39**	**48,231,601.79**
Difference							
<u>Gas Purchases Details:</u>							
Current Month Estimate							
BGSS-RSG GAS COMMODITY VOLUMES MDTh	6,664,246.00	13,465,773.00	25,422,696.00	32,961,368.00	25,645,185.00	15,876,009.00	9,900,553.00
BGSS-RSG GAS COMMODITY COST	29,043,361.36	60,477,488.02	115,893,947.62	158,021,590.45	125,475,738.81	81,286,046.32	48,981,442.48
BGSS-RSG Balancing	$987,405.03	$2,374,399.35	$4,449,716.14	$5,874,325.17	$4,544,134.62	$2,700,975.49	$1,589,539.25
BGSS-RSG Off System Sales	($2,054,012.33)	($2,478,490.13)	($16,159,287.68)	($44,133,379.09)	($18,351,334.02)	($4,278,646.05)	($3,189,031.06)
Electric Reservation Charge							
Non Compliance Penalty	$0.00	$0.00	$0.00	$348,165.18	$ 2,266.65	$ 54.44	$ -
CSG Revenues	-	-	-	-	-	-	-
Credit for Pipeline Refunds	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total	27,976,754.06	60,373,397.24	104,184,376.09	120,110,701.72	111,670,806.06	79,708,430.20	47,381,950.67
Prior Actual							
BGSS-RSG GAS COMMODITY VOLUMES MDTh	3,314,587.00	6,152,215.00	13,406,903.00	25,012,752.00	32,807,521.00	24,456,652.00	15,620,017.00
BGSS-RSG GAS COMMODITY COST	$14,400,478.67	$26,853,813.73	$60,183,907.45	$114,104,073.77	$157,765,678.90	$119,396,995.19	$79,716,506.28
BGSS-RSG Balancing	$302,555.50	$926,659.01	$2,377,279.72	$4,390,325.66	$5,822,624.78	$4,339,535.58	$2,673,946.75
BGSS-RSG Off System Sales	($3,008,659.28)	($1,999,490.03)	($2,500,751.86)	($16,009,468.51)	($43,445,343.10)	($17,620,790.02)	($4,256,350.93)
Electric Reservation Charge	-	-	-	-	-	-	-
CSG Revenues	-	-	-	-	-	-	-
Non Compliance Penalty	$ -	$ (476.79)	$ -	$ -	$ 4,420.86	$ 1,624.05	$ 40.92
Credit for Pipeline Refunds	($36,914.45)	($320.56)	($33,529.77)	$0.00	$ (225.12)	$ (441.71)	$ (191.34)

	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25
Residential Share of Propane Contract Deficiency Charges	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Residential Share of Property Taxes Paid	$ -	$ -	$ -	$ -	$ 445,379.43	$ -	$ -
PPA Penalties	-	-	-	-	-		
Residential Share of Hattisburg Tax Payment	-	-	-	-	-	-	-
Other	-	-	-	-	$365,294.66	$ 2,167.22	$ -
Total	11,657,460.44	25,780,185.35	60,026,905.54	102,484,930.91	120,957,830.41	106,119,090.31	78,133,951.69
Prior Estimate							
BGSS-RSG GAS COMMODITY VOLUMES MDTh	3,164,397.00	6,664,246.00	13,465,773.00	25,422,696.00	32,961,368.00	25,645,185.00	15,876,009.00
BGSS-RSG GAS COMMODITY COST	13,758,332.98	29,043,361.36	60,477,488.02	115,893,947.62	158,021,590.45	125,475,738.81	81,286,046.32
BGSS-RSG Balancing	288,846.16	987,405.03	2,374,399.35	4,449,716.14	5,874,325.17	4,544,134.62	2,700,975.49
BGSS-RSG Off System Sales	(2,880,347.08)	(2,054,012.33)	(2,478,490.13)	(16,159,287.68)	(44,133,379.09)	(18,351,334.02)	(4,278,646.05)
Electric Reservation Charge	-	-	-	-	-	-	-
Other	$0.00	$0.00	$0.00	$0.00	$348,165.18	$2,266.65	$54.44
Prior CSG Revenues	-	-	-	-	-	-	-
Credit for Pipeline Refunds	-	-	-	-	-	-	-
Total	11,166,832.06	27,976,754.06	60,373,397.24	104,184,376.09	120,110,701.72	111,670,806.06	79,708,430.20
Net							
BGSS-RSG GAS COMMODITY VOLUMES MDTh	6,814,436.00	12,953,742.00	25,363,826.00	32,551,424.00	25,491,338.00	14,687,476.00	9,644,561.00
BGSS-RSG GAS COMMODITY COST	29,685,507.05	58,287,940.39	115,600,367.05	156,231,716.60	125,219,827.26	75,207,302.70	47,411,902.44
BGSS-RSG Balancing	1,001,114.38	2,313,653.33	4,452,596.51	5,814,934.69	4,492,434.23	2,496,376.45	1,562,510.51
BGSS-RSG Off System Sales	(2,182,324.53)	(2,423,967.83)	(16,181,549.41)	(43,983,559.93)	(17,663,298.03)	(3,548,102.04)	(3,166,735.94)
Electric Reservation Charge	-	-	-	-	-	-	-
Other	$0.00	($476.79)	$0.00	$348,165.18	$469,196.42	$1,579.06	($13.52)
CSG Revenues	-	-	-	-	-	-	-
Credit for Pipeline Refunds	($36,914.45)	($320.56)	($33,529.77)	$0.00	($225.12)	($441.71)	($191.34)
Total	28,467,382.44	58,176,828.54	103,837,884.38	118,411,256.54	112,517,934.76	74,156,714.46	45,807,472.15
BGSS-RSG GAS COMMODITY VOLUMES MDTh	6,814,436.00	12,953,742.00	25,363,826.00	32,551,424.00	25,491,338.00	14,687,476.00	9,644,561.00
NET SALES VOLUMES RESIDENTIAL	5,533,081.73	13,128,555.23	23,482,547.70	31,779,781.54	24,468,569.37	16,832,058.28	9,984,582.07
Diff	1,281,354.27	(174,813.23)	1,881,278.30	771,642.46	1,022,768.63	(2,144,582.28)	(340,021.07)

INTEREST CALCULATION
FOR PERIOD OCT24 TO SEP25

BGSSR BPU VERSION

	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25
CUMULATIVE OVER/(UNDER) RECOVERY PRIOR MONTH	$162,213,774	$154,750,568	$148,291,108	$142,145,749	$154,817,366	143,769,184.05	138,616,961.77
CUMULATIVE OVER/(UNDER) RECOVERY CURRENT MONTH	$154,750,568	$148,291,108	$142,145,749	154,817,366.48	143,769,184.05	138,616,961.77	132,575,472.49
AVERAGE BALANCE	$158,482,171	$151,520,838	$145,218,428	$148,481,558	$149,293,275	$141,193,073	$135,596,217
MONTHLY INTEREST (Income)/Expense	**$928,952.62**	**$892,710.27**	**$855,578.57**	**$874,803.85**	**$879,586.21**	**$831,862.52**	**$798,887.71**
Cumulative Effect of June Adj JE							
INTEREST ACCUMULATED, (Income)/Expense	$928,952.62	$1,821,662.89	$2,677,241.46	$3,552,045.30	$4,431,631.52	$5,263,494.04	$6,062,381.75

8. Wholesale Gas Pricing Assumptions

Item 8

A Comparison of the Forecasted Cost of Gas as represented by the NYMEX
June 2025 Filing versus June 2024 Filing

($/Mbtu)

		June '25 Filing Nymex - 5/8/2025	June '24 Filing Nymex - 5/8/2024	Difference	Percentage Difference
2025	**May**	$3.170	$1.614	$1.556	96.4%
	June	$3.592	$2.187	$1.405	64.2%
	July	$3.933	$2.474	$1.459	59.0%
	August	$4.018	$2.575	$1.443	56.0%
	September	$3.997	$2.574	$1.423	55.3%
	October	$4.063	$2.652	$1.411	53.2%
	November	$4.364	$3.017	$1.347	44.6%
	December	$4.852	$3.522	$1.330	37.8%
2026	**January**	$5.139	$3.785	$1.354	35.8%
	February	$4.812	$3.612	$1.200	33.2%
	March	$4.262	$3.203	$1.059	33.1%
	April	$3.897	$2.983	$0.914	30.6%
	May	$3.889	$3.020	$0.869	28.8%
	June	$4.045	$3.200	$0.845	26.4%
	July	$4.219	$3.392	$0.827	24.4%
	August	$4.253	$3.440	$0.813	23.6%
	September	$4.207	$3.409	$0.798	23.4%
	Average	$4.160	$2.980	$1.180	39.6%

9. GCUA Recoveries and Balances

N/A

10. Historical Service Interruptions

Item 10

HISTORICAL SERVICE INTERRUPTIONS

The following details any service interruptions during the past 12 months. These interruptions occurred in the winter heating season for operational reasons.

Rate Schedule CIG:
Number of Customers: 12 (including 4 CEGs)

- Event #5: 1/20/2025 10AM – 1/22/2025 10AM

Rate Schedule TSG-NF (BGSS-I):
Number of Customers: 25

- Event #5: 1/20/2025 10AM – 1/22/2025 10AM

Rate Schedule TSG-NF (Third Party Suppliers):
Number of Customers: 128

- Event #5: 1/20/2025 10AM – 1/22/2025 10AM

Rate Schedule CSG-I (Third Party Suppliers):
Number of Customers: 3

- Event #5: 1/20/2025 10AM – 1/22/2025 10AM

Rate Schedule CSG-I (Power Generation Stations):
Number of Customers: 3

- Event #1: 12/21/2024 10AM – 12/24/2024 10AM
- Event #2: 12/25/2024 10AM – 12/27/2024 10AM
- Event #3: 1/6/2025 10AM – 1/10/2025 10AM
- Event #4: 1/14/2025 10AM – 1/17/2025 10AM
- Event #5: 1/19/2025 10AM – 1/26/2025 10AM
- Event #6: 2/1/2025 10AM – 2/2/2025 10AM
- Event #7: 2/10/2025 10AM – 2/11/2025 10AM
- Event #8: 2/17/2025 10AM – 2/22/2025 10AM
- Event #9: 3/2/2025 10AM – 3/3/2025 10AM

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

Reports Dated:

April 14, 2025

January 15, 2025

October 16, 2024

July 16, 2024

Matthew M. Weissman
Special Counsel – State Regulatory

Law Department
PSEG Services Corporation
80 Park Plaza – T5, Newark, New Jersey 07102-4194
tel : 973-430-7052 fax: 973-430-5983
email: matthew.weissman@pseg.com

VIA ELECTRONIC MAIL

July 16, 2024

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

Stacy Peterson, Acting Director
Division of Water and Energy
Board of Public Utilities
44 South Clinton Avenue, 9th Floor
Trenton, New Jersey, 08625-0350

RE: PSE&G GAS HEDGING QUARTERLY REPORT – SECOND QUARTER 2024

Dear Ms. 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, 2024.

As shown on the attached schedules, hedging for the 2024/2025 winter season was 86% of plan and 54% of the plan has been completed for 2025 summer. Hedging for the 2025/2026 winter season is at 8% and the 2025 summer season has not yet begun. 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 Alice Bator
Brian Lipman
Ben Witherell

PSE&G Residential Hedging Report November 2024 - October 2025 As of June 30, 2024	Bcf Target*	Bcf Hedged	% Hedged Target		% Hedged Actual	Current Price/ MMBtu
WINTER - Nov 24-Mar 25 Hedge Volume						
(230,000/ day) (151 days)						
Non-Discretionary Volume	17.500	**12.835**	72%	78%	73%	**$3.210**
Dollar Budget Method	17.500	**17.093**	$3.909M/mo.		98%	**$3.172**
Total Winter Hedge Volume	35.000	**29.928**			86%	**$3.188**
			Nymex Settle 06/28/24			**$3.475**
SUMMER - Apr 25-Oct 25 Hedge Volume						
(160,000/ day) (214 days)						
Non-Discretionary Volume	17.500	**8.560**	44%	50%	49%	**$2.364**
Dollar Budget Method	17.500	**10.272**	$2.695M/mo		59%	**$2.343**
Total Summer Hedge Volume	35.000	**18.832**			54%	**$2.35**
			Nymex Settle 06/28/24			**$3.294**

Total Non-Discretionary Method	35.000	**21.395**				**$2.872**
Total Dollar Budget Method	35.000	**27.365**				**$2.861**
					Difference	**($0.011)**
					Percent	**-0.4%**

PSE&G Residential Hedging Report November 2025 - October 2026 As of June 30, 2024	Bcf Target*	Bcf Hedged	% Hedged Target		% Hedged Actual	Current Price/ MMBtu
WINTER - Nov 25-Mar 26 Hedge Volume						
(230,000/ day) (151 days)						
Non-Discretionary Volume	17.500	**1.510**	6%	11%	9%	**$3.415**
Dollar Budget Method	17.500	**1.435**	$3.485M/mo.		8%	**$3.375**
Total Winter Hedge Volume	35.000	**2.945**			8%	**$3.396**
			Nymex Settle 06/28/24			**$4.086**
SUMMER - Apr 26-Oct 26 Hedge Volume						
(160,000/ day) (214 days)						
Non-Discretionary Volume	17.500	**0.000**	0%	0%	0%	**$0.000**
Dollar Budget Method	17.500	**0.000**	0%		0%	**$0.000**
Total Summer Hedge Volume	35.000	**0.000**			0%	**#DIV/0!**
Total Non-Discretionary Method	35.000	**1.510**				**$3.415**
Total Dollar Budget Method	35.000	**1.435**				**$3.375**
					Difference	**($0.040)**
					Percent	**-1.2%**

Matthew M. Weissman
Special Counsel – State Regulatory

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PSEG
Services Corporation

VIA ELECTRONIC MAIL

October 16, 2024

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

Stacy Peterson
Deputy Executive Director
Board of Public Utilities
44 South Clinton Avenue, 9th Floor
Trenton, New Jersey, 08625-0350

RE: PSE&G GAS HEDGING QUARTERLY REPORT – THIRD QUARTER 2024

Dear Ms. 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, 2024.

As shown on the attached schedules, hedging for the 2024/2025 winter season was 95% of plan and 73% of the plan has been completed for 2025 summer. Hedging for the 2025/2026 winter season is at 27% and the 2026 summer season has not yet begun. 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 Brian Lipman
Ben Witherell

PSE&G Residential Hedging Report November 2024 - October 2025 As of September 30, 2024	Bcf Target*	Bcf Hedged	% Hedged Target		% Hedged Actual	Current Price/ MMBtu
WINTER - Nov 24-Mar 25 Hedge Volume						
(230,000/ day) (151 days)						
Non-Discretionary Volume	17.500	**15.855**	89%	94%	91%	**$3.094**
Dollar Budget Method	17.500	**17.486**	$3.909M/mo.		100%	**$3.161**
Total Winter Hedge Volume	35.000	**33.341**			95%	**$3.129**
			Nymex Settle 09/30/24			**$3.307**
SUMMER - Apr 25-Oct 25 Hedge Volume						
(160,000/ day) (214 days)						
Non-Discretionary Volume	17.500	**11.770**	61%	67%	67%	**$2.319**
Dollar Budget Method	17.500	**13.953**	$2.695M/mo		80%	**$2.298**
Total Summer Hedge Volume	35.000	**25.723**			73%	**$2.31**
			Nymex Settle 09/30/24			**$3.246**

Total Non-Discretionary Method	35.000	**27.625**				**$2.764**
Total Dollar Budget Method	35.000	**31.439**				**$2.778**
					Difference	**$0.014**
					Percent	**0.5%**

PSE&G Residential Hedging Report November 2025 - October 2026 As of September 30, 2024	Bcf Target*	Bcf Hedged	% Hedged Target		% Hedged Actual	Current Price/ MMBtu
WINTER - Nov 25-Mar 26 Hedge Volume						
(230,000/ day) (151 days)						
Non-Discretionary Volume	17.500	**5.285**	22%	28%	30%	**$3.269**
Dollar Budget Method	17.500	**4.334**	$3.485M/mo		25%	**$3.267**
Total Winter Hedge Volume	35.000	**9.619**			27%	**$3.268**
			Nymex Settle 09/30/2024			**$3.886**
SUMMER - Apr 26-Oct 26 Hedge Volume						
(160,000/ day) (214 days)						
Non-Discretionary Volume	17.500	**0.000**	0%	0%	0%	**$0.000**
Dollar Budget Method	17.500	**0.000**	0%		0%	**$0.000**
Total Summer Hedge Volume	35.000	**0.000**			0%	**#DIV/0!**

Total Non-Discretionary Method	35.000	**5.285**				**$3.269**
Total Dollar Budget Method	35.000	**4.334**				**$3.267**
					Difference	**($0.002)**
					Percent	**0.0%**

Matthew M. Weissman
Special Counsel – State Regulatory

Law Department
PSEG Services Corporation
80 Park Plaza – T20, Newark, New Jersey 07102-4194
email: matthew.weissman@pseg.com

VIA ELECTRONIC MAIL ONLY

January 15, 2025

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

Stacy Peterson, Deputy Executive Director
New Jersey Board of Public Utilities
44 South Clinton Avenue
P.O. Box 350
Trenton, New Jersey, 08625
Stacy.Peterson@bpu.nj.gov

RE: PSE&G GAS HEDGING QUARTERLY REPORT – FOURTH QUARTER 2024

Dear Ms. 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, 2024.

As shown on the attached schedules, hedging for the 2024/2025 winter season is 100% of plan and 90% of the plan has been completed for 2025 summer. Hedging for the 2025/2026 winter season is at 45% and the 2026 summer season is currently 17%. 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 M. Weissman

Attachment

C Maura Caroselli
Brian Lipman
Alice Bator
Ben Witherell

PSE&G Residential Hedging Report November 2024 - October 2025 As of 12/31/2024	Bcf Target*	Bcf Hedged	% Hedged Target		% Hedged Actual	Current Price/ MMBtu
WINTER - Nov 24-Mar 25 Hedge Volume						
(230,000/ day) (151 days)						
Non-Discretionary Volume	17.500	**17.365**	94%	100%	99%	**$3.044**
Dollar Budget Method	17.500	**17.486**	$3.909M/mo.		100%	**$3.161**
Total Winter Hedge Volume	35.000	**34.851**			100%	**$3.103**
			Nymex Settle 12/31/24			**$3.204**
SUMMER - Apr 25-Oct 25 Hedge Volume						
(160,000/ day) (214 days)						
Non-Discretionary Volume	17.500	**13.910**	78%	83%	79%	**$2.313**
Dollar Budget Method	17.500	**17.484**	$2.695M/mo		100%	**$2.289**
Total Summer Hedge Volume	35.000	**31.394**			90%	**$2.300**
			Nymex Settle 12/31/24			**$3.401**
Total Non-Discretionary Method	35.000	**31.275**				**$2.719**
Total Dollar Budget Method	35.000	**34.970**				**$2.725**
					Difference	**$0.006**
					Percent	**0.2%**

PSE&G Residential Hedging Report November 2025 - October 2026 As of 12/31/2024	Bcf Target*	Bcf Hedged	% Hedged Target		% Hedged Actual	Current Price/ MMBtu
WINTER - Nov 25-Mar 26 Hedge Volume						
(230,000/ day) (151 days)						
Non-Discretionary Volume	17.500	**8.305**	39%	44%	47%	**$3.306**
Dollar Budget Method	17.500	**7.444**	$3.485M/mo		43%	**$3.301**
Total Winter Hedge Volume	35.000	**15.749**			45%	**$3.303**
			Nymex Settle 12/31/24			**$4.209**
SUMMER - Apr 26-Oct 26 Hedge Volume						
(160,000/ day) (214 days)						
Non-Discretionary Volume	17.500	**3.210**	11%	17%	18%	**$2.505**
Dollar Budget Method	17.500	**2.825**	$2.446/mo		16%	**$2.575**
Total Summer Hedge Volume	35.000	**6.035**			17%	**$2.538**
			Nymex Settle 12/31/24			**$3.656**

Total Non-Discretionary Method	35.000	**11.515**				**$3.083**
Total Dollar Budget Method	35.000	**10.269**				**$3.101**
					Difference	**$0.018**
					Percent	**0.6%**

Matthew M. Weissman
Special Counsel - State Regulatory

Public Service Electric and Gas Company
80 Park Plaza – T20, Newark, New Jersey 07102-4194
Office - 973-430-7052 Cell – 973-900-2242
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PSEG

VIA ELECTRONIC MAIL

April 14, 2025

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

Stacy Peterson, Acting Director
Division of Water and Energy
Board of Public Utilities
44 South Clinton Avenue, 9th Floor
Trenton, New Jersey, 08625-0350

RE: PSE&G GAS HEDGING QUARTERLY REPORT – FIRST QUARTER 2025

Dear Ms. 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, 2025.

As shown on the attached schedules, hedging for the 2024/2025 winter season is 100% of plan and 99% of the plan has been completed for 2025 summer. Hedging for the 2025/2026 winter season is at 59% and the 2026 summer season is currently 34%. 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 M. Weissman

Attachment

C Alice Bator
Brian Lipman
Malike Cummings
Ben Witherell

PSE&G Residential Hedging Report November 2024 - October 2025 As of 3/31/2025	Bcf Target*	Bcf Hedged	% Hedged Target		% Hedged Actual	Current Price/ MMBtu
WINTER - Nov 24-Mar 25 Hedge Volume						
(230,000/ day) (151 days)						
Non-Discretionary Volume	17.500	**17.365**	94%	100%	99%	**$3.044**
Dollar Budget Method	17.500	**17.486**	$3.909M/mo.		100%	**$3.161**
Total Winter Hedge Volume	35.000	**34.851**			100%	**$3.103**
			Nymex Settle 03/31/2025			**$3.346**
SUMMER - Apr 25-Oct 25 Hedge Volume						
(160,000/ day) (214 days)						
Non-Discretionary Volume	17.500	**17.120**	94%	100%	98%	**$2.463**
Dollar Budget Method	17.500	**17.484**	$2.695M/mo		100%	**$2.289**
Total Summer Hedge Volume	35.000	**34.604**			99%	**$2.375**
			Nymex Settle 03/31/2025			**$4.341**

Total Non-Discretionary Method	35.000	**34.485**				**$2.755**
Total Dollar Budget Method	35.000	**34.970**				**$2.725**
					Difference	**($0.030)**
					Percent	**-1.1%**

PSE&G Residential Hedging Report November 2025 - October 2026 As of 3/31/2025	Bcf Target*	Bcf Hedged	% Hedged Target		% Hedged Actual	Current Price/ MMBtu
WINTER - Nov 25-Mar 26 Hedge Volume						
(230,000/ day) (151 days)						
Non-Discretionary Volume	17.500	**10.570**	56%	61%	60%	**$3.465**
Dollar Budget Method	17.500	**9.966**	$3.485M/mo		57%	**$3.502**
Total Winter Hedge Volume	35.000	**20.536**			59%	**$3.483**
			Nymex Settle 03/31/2025			**$4.990**
SUMMER - Apr 26-Oct 26 Hedge Volume						
(160,000/ day) (214 days)						
Non-Discretionary Volume	17.500	**6.420**	28%	33%	37%	**$2.724**
Dollar Budget Method	17.500	**5.393**	$2.446/mo		31%	**$2.688**
Total Summer Hedge Volume	35.000	**11.813**			34%	**$2.71**
			Nymex Settle 03/31/2025			**$4.149**
Total Non-Discretionary Method	35.000	**16.990**				**$3.185**
Total Dollar Budget Method	35.000	**15.359**				**$3.216**
					Difference	**$0.031**
					Percent	**1.0%**

12. Storage Gas Volumes, Prices and Utilization

Ending Storage Inventory by Contract

Mdth

Storage Contract	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25 *Est
DTI GSS	16,124.2	14,793.0	10,877.6	6,417.5	3,497.5	3,219.0	5,143.9
ARLINGTON	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TR GSS	15,528.9	15,095.7	12,681.4	8,626.8	6,015.5	5,426.2	6,433.4
TR S-2	6,026.5	5,797.6	4,285.5	2,365.5	1,207.8	760.1	1,109.0
TR LSS	4,950.9	4,591.7	3,500.5	2,271.2	1,367.7	749.9	1,271.3
TENN FS-MA	6,150.4	5,930.9	4,351.8	2,683.3	1,905.4	2,132.2	2,804.7
DTI GSS-TE	14,056.4	13,131.9	10,178.6	6,445.5	3,596.0	3,338.4	4,659.9
TE SS-1 / SS	3,688.0	3,427.2	2,857.5	1,920.0	1,238.5	1,196.2	1,450.9
TE SS1	1,438.0	1,353.5	1,124.8	748.8	469.1	459.8	583.1
TR ESS	1,125.2	1,186.5	850.8	591.4	802.4	1,009.3	1,066.6
GULF SOUTH	738.5	959.6	903.0	581.0	506.4	0.0	0.0
TR LNG	1,295.6	1,302.8	1,162.8	1,185.1	1,160.5	1,227.5	1,333.8
TR LNG New	15.5	15.5	15.5	15.5	15.5	15.5	15.5
BOBCAT	0.0	0.0	0.0	0.0	0.0	0.0	447.2
Total	71,138.0	67,585.9	52,789.9	33,851.7	21,782.4	19,534.0	26,319.5
Ending Inventory Cost ($/Dth)	$4.36	$4.49	$4.56	$4.79	$4.90	$5.13	$4.94

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-22	45	$526	79	$1,015	67	$926	63	$579
Feb-22	45	$526	79	$1,015	67	$926	63	$579
Mar-22	45	$526	79	$1,015	29	$398	63	$579
Apr-22	45	$526	77	$988	25	$347	63	$579
May-22	45	$526	77	$988	25	$347	63	$579
Jun-22	45	$526	77	$988	25	$347	63	$579
Jul-22	45	$526	77	$988	25	$347	63	$579
Aug-22	45	$526	77	$988	25	$347	63	$579
Sep-22	45	$526	77	$988	25	$347	63	$579
Oct-22	48	$563	103	$1,366	55	$814	63	$579
Nov-22	48	$563	103	$1,366	65	$973	63	$579
Dec-22	46	$534	82	$1,091	78	$1,179	62	$574
Jan-23	45	$529	80	$1,065	57	$852	62	$574
Feb-23	45	$527	80	$1,065	57	$852	62	$574
Mar-23	42	$493	73	$971	57	$852	62	$574
Apr-23	42	$493	73	$971	57	$852	62	$574
May-23	42	$493	73	$971	57	$852	62	$574
Jun-23	42	$493	73	$971	57	$852	62	$574
Jul-23	42	$493	73	$971	57	$852	62	$574
Aug-23	42	$493	73	$971	57	$852	62	$574
Sep-23	42	$493	73	$971	57	$852	62	$574
Oct-23	42	$493	73	$971	57	$852	62	$574
Nov-23	47	$559	84	$1,119	80	$1,173	62	$574
Dec-23	45	$538	83	$1,104	79	$1,159	61	$567

LPG INVENTORY VOLUMES AND COST BY LOCATION
(000)

	Camden		Central		Harrison		Linden	
Month	**Dth**	**Dollars**	**Dth**	**Dollars**	**Dth**	**Dollars**	**Dth**	**Dollars**
Jan-24	45	$535	81	$1,084	74	$1,081	61	$567
Feb-24	45	$535	81	$1,084	74	$1,081	61	$567
Mar-24	24	$283	50	$665	37	$546	61	$567
Apr-24	19	$224	50	$665	37	$546	61	$567
May-24	19	$224	50	$665	70	$848	29	$265
Jun-24	18	$215	50	$665	70	$848	29	$265
Jul-24	15	$179	50	$665	70	$848	29	$265
Aug-24	15	$179	50	$665	70	$848	29	$265
Sep-24	15	$179	50	$665	70	$848	29	$265
Oct-24	15	$179	50	$665	70	$848	29	$265
Nov-24	12	$147	82	$1,105	73	$895	67	$768
Dec-24	42	$587	82	$1,104	73	$887	64	$738
Jan-25	41	$573	81	$1,085	68	$825	64	$738
Feb-25	32	$441	58	$785	34	$416	64	$738
Mar-25	26	$369	58	$785	34	$416	64	$738
Apr-25 est	25	$353	72	$942	61	$731	23	$267
May-25 est	25	$353	72	$942	61	$731	23	$267
Jun-25 est	25	$353	72	$942	61	$731	23	$267
Jul-25 est	25	$353	72	$942	61	$731	23	$267
Aug-25 est	25	$353	72	$942	61	$731	23	$267
Sep-25 est	25	$353	72	$942	61	$731	23	$267
Oct-25 est	25	$353	72	$942	61	$731	23	$267
Nov-25 est	25	$353	72	$942	61	$731	23	$267
Dec-25 est	25	$353	72	$942	61	$731	23	$267

LNG INVENTORY VOLUMES AND COST
(000)

Month	Dth	Dollars	Month	Dth	Dollars
Jan-22	227	$222	Jan-24	284	$210
Feb-22	167	$163	Feb-24	277	$205
Mar-22	149	$145	Mar-24	269	$199
Apr-22	198	$193	Apr-24	287	$255
May-22	234	$245	May-24	280	$249
Jun-22	227	$238	Jun-24	273	$243
Jul-22	219	$230	Jul-24	266	$236
Aug-22	211	$222	Aug-24	259	$230
Sep-22	203	$213	Sep-24	252	$224
Oct-22	224	$205	Oct-24	302	$282
Nov-22	254	$197	Nov-24	345	$351
Dec-22	229	$249	Dec-24	334	$340
Jan-23	244	$239	Jan-25	260	$265
Feb-23	190	$209	Feb-25	231	$235
Mar-23	180	$197	Mar-25	223	$267
Apr-23	172	$188	Apr-25 est	216	$258
May-23	166	$182	May-25 est	216	$258
Jun-23	224	$250	Jun-25 est	216	$258
Jul-23	217	$241	Jul-25 est	216	$258
Aug-23	209	$233	Aug-25 est	216	$258
Sep-23	318	$228	Sep-25 est	216	$258
Oct-23	334	$220	Oct-25 est	216	$258
Nov-23	340	$260	Nov-25 est	216	$258
Dec-23	334	$248	Dec-25 est	216	$258

13. Affiliate Gas Supply Transactions

Item 13

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

1. Effective Date: May 1, 2002, as amended March 31, 2007, April 1, 2014, and April 1, 2022.
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, 2027, 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
  - Further revised term was to March 31, 2019, 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 2022- September 2023)

	Oct-22	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Total
Gas Supplies (MDTh)													
Beginning Inventory	**67,629**	77,960	76,061	66,650	51,604	36,769	24,739	32,671	44,893	51,571	54,837	57,678	
Natural Gas Receipt	20,979	17,616	24,132	14,306	13,019	13,813	19,353	19,638	11,779	7,329	6,987	14,650	183,602
	-------------	-------------	-------------	-------------	-------------	-------------	-------------	-------------	-------------	-------------	-------------	-------------	
Total Inventory Available	88,608	95,575	100,193	80,956	64,623	50,582	44,093	52,309	56,672	58,900	61,824	72,328	
Gas Demand (MDTh)													
Firm Sendout	10,649	19,514	33,543	29,352	27,854	25,843	11,422	7,416	5,101	4,063	4,147	4,530	183,433
	-------------	-------------	-------------	-------------	-------------	-------------	-------------	-------------	-------------	-------------	-------------	-------------	
Ending Inventory MDTh	77,960	76,061	66,650	51,604	36,769	24,739	32,671	44,893	51,571	54,837	57,678	67,798	

FIRM GAS SUPPLY AND DEMAND DATA (October 2023- September 2024)

	Oct-23	Nov-23	Dec-23	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Total
Gas Supplies (MDTh)													
Beginning Inventory	**67,798**	76,944	72,322	66,350	46,774	33,171	24,501	33,150	45,365	55,701	59,953	63,777	
Natural Gas Receipt	18,300	17,771	21,047	16,797	15,735	13,191	22,689	19,125	14,770	8,191	7,838	10,909	186,363
Total Inventory Available	86,098	94,715	93,369	83,147	62,509	46,362	47,189	52,274	60,136	63,892	67,790	74,686	
Gas Demand (MDTh)													
Firm Sendout	9,154	22,392	27,020	36,373	29,338	21,862	14,039	6,909	4,434	3,940	4,013	4,410	183,884
Ending Inventory MDTh	76,944	72,322	66,350	46,774	33,171	24,501	33,150	45,365	55,701	59,953	63,777	70,276	

FIRM GAS SUPPLY AND DEMAND DATA (October 2024- September 2025)

	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Total
Gas Supplies (MDTh)													
Beginning Inventory	**70,276**	75,268	71,923	57,466	38,805	26,696	23,211	29,243	43,671	46,757	49,109	51,545	
Natural Gas Receipt	13,333	14,029	19,303	25,096	21,657	18,366	19,857	20,618	8,172	5,994	6,049	14,683	187,158
Total Inventory Available	83,610	89,298	91,226	82,561	60,462	45,062	43,068	49,862	51,843	52,751	55,158	66,228	
Gas Demand (MDTh)													
Firm Sendout	8,341	17,375	33,760	43,756	33,766	21,851	13,824	6,191	5,087	3,641	3,613	3,889	195,095
Ending Inventory MDTh	75,268	71,923	57,466	38,805	26,696	23,211	29,243	43,671	46,757	49,109	51,545	62,339	

FIRM GAS SUPPLY AND DEMAND DATA (October 2025- September 2026)

	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Total
Gas Supplies (MDTh)													
Beginning Inventory	**62,339**	73,308	67,172	48,341	28,537	15,409	4,001	5,258	14,563	27,539	39,739	50,733	
Natural Gas Receipt	20,027	15,273	13,803	20,717	20,115	17,579	16,913	16,932	17,939	15,795	14,519	16,128	205,740
Total Inventory Available	82,366	88,580	80,975	69,058	48,652	32,987	20,914	22,190	32,502	43,335	54,258	66,860	
Gas Demand (MDTh)													
Firm Sendout	9,059	21,408	32,635	40,521	33,243	28,986	15,656	7,627	4,962	3,596	3,525	3,810	205,028
Ending Inventory MDTh	73,308	67,172	48,341	28,537	15,409	4,001	5,258	14,563	27,539	39,739	50,733	63,051	

FIRM GAS SUPPLY AND DEMAND DATA (October 2026- September 2027)

	Oct-26	Nov-26	Dec-26	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27	Sep-27	Total
Gas Supplies (MDTh)													
Beginning Inventory	**63,051**	73,808	68,343	50,304	31,033	18,544	7,601	8,226	16,996	29,481	41,131	51,642	
Natural Gas Receipt	19,729	15,978	14,129	21,021	20,465	17,780	16,178	16,291	17,301	15,191	13,951	15,537	203,553
	-------------	-------------	-------------	-------------	-------------	-------------	-------------	-------------	-------------	-------------	-------------	-------------	
Total Inventory Available	82,779	89,786	82,472	71,325	51,498	36,324	23,779	24,517	34,297	44,673	55,083	67,180	
Gas Demand (MDTh)													
Firm Sendout	8,972	21,442	32,169	40,291	32,955	28,724	15,553	7,521	4,816	3,541	3,441	3,711	203,135
	-------------	-------------	-------------	-------------	-------------	-------------	-------------	-------------	-------------	-------------	-------------	-------------	
Ending Inventory MDTh	73,808	68,343	50,304	31,033	18,544	7,601	8,226	16,996	29,481	41,131	51,642	63,469	

15. Actual Peak Day Supply and Demand

Item 15 - Actual Peak Day Supply and Demand

		NEWARK AVG.	LOAD (000 DTh)			SUPPLY SOURCES (000 DTh)		
						NATURAL GAS		LPA
	DATE	TEMP (F)	TOTAL	FIRM	INTERR.	HLF TRANSP.	STORAGE / LNG	
2024 / 2025 WINTER								
	21-Jan-25	15.5	2450	2345	193	1337	1095	18
	22-Dec-24	16.7	2517	2195	322	1289	1228	0
	22-Jan-25	17.9	2445	2282	237	1322	1113	10
	20-Jan-25	18.0	2369	2171	198	1393	960	16
	21-Dec-24	22.9	2210	1919	291	1283	927	0
2023 / 2024 WINTER								
	17-Jan-24	22.1	2342	2065	277	1279	1046	17
	20-Jan-24	22.5	2200	2045	155	1104	1082	14
	16-Jan-24	24.5	2338	1953	384	1307	1019	12
	19-Jan-24	25.3	1985	1870	116	1160	814	11
	21-Jan-24	27.3	2103	1934	169	1108	995	0
2022 / 2023 WINTER								
	3-Feb-23	15.0	2551	2315	236	1196	1350	5
	24-Dec-22	15.5	2456	2326	130	1238	1204	14
	23-Dec-22	17.6	2272	2111	161	1336	936	0
	25-Dec-22	23.1	2131	2010	121	1198	933	0
	4-Feb-23	25.1	2102	1993	108	808	1292	1

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

Including Gas Sales Forecast Support

SCHEDULE F

May-25

SUPPLY		2025-2026	2026-2027	2027-2028	2028-2029	2029-2030
Transco FT		432.4	432.4	432.4	432.4	432.4
Transco FT (DTI)		32.3	32.3	32.3	32.3	32.3
Transco FT (Cove Point)		20.0	20.0	20.0	20.0	20.0
Transco FT (Gateway)		54.0	54.0	54.0	54.0	54.0
Transco REA		60.0	60.0	60.0	60.0	60.0
Tetco ATM II		20.2	25.0	25.0	25.0	25.0
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	180.5	180.5	180.5	180.5	180.5
	DTI/Transco	49.7	49.7	49.7	49.7	49.7
	Columbia	12.5	12.5	12.5	12.5	12.5
	Subtotal	242.7	242.7	242.7	242.7	242.7
Transco/Tetco FT (Leidy)		330.0	330.0	330.0	330.0	330.0
Columbia (Hanover)		18.8	18.8	18.8	18.8	18.8
Algonquin		15.0	15.0	15.0	15.0	15.0
Pipeline Firm Transportation		1,508.3	1,513.1	1,513.1	1,513.1	1,513.1
Refinery Gas		0.0	0.0	0.0	0.0	0.0
Total Firm FT Supply		1,508.3	1,513.1	1,513.1	1,513.1	1,513.1
Storage		894.2	894.2	894.2	894.2	894.2
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		81.5	81.5	81.5	81.5	81.5
LPA		212.6	212.6	212.6	212.6	212.6
Total Peaking Supply		582.8	582.8	582.8	582.8	582.8
PSEG Firm Supply Subtotal		2,985.3	2,990.1	2,990.1	2,990.1	2,990.1
FTS DCQ 1./		281.0	279.4	271.9	261.2	244.3
[a] Total PSEG Gas Supply		3,266.3	3,269.4	3,262.0	3,251.2	3,234.4
Peak Day Sendout Forecast 2./		2,997.0	2,988.0	2,982.0	2,987.0	2,988.0
[b] Total Peak Day Capacity Requirements	3./	3,155.5	3,145.8	3,136.7	3,138.6	3,132.5
[a]-[b] Surplus / (Deficiency)	3./	110.8	123.6	125.2	112.7	101.9

1./ Forecasted FT-S DCQ (January)

2./ Based on Corporate Energy Forecast, Gas -2025

3./ 3% Loss of Load Probability

Item 16

Natural Gas Sales Forecast - 2025

Public Service Electric & Gas Company

Finance Department

Electric and Gas Sales and Revenue Forecasting Group

September 2024

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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 2025 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 reflect the economic well-being of the majority of our customers more accurately. 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:

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

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.

RSG Heating model was estimated using monthly data from January 2010 to December 2023 period while RSG No-Heating model was estimated using monthly data from January 2019 to December 2023. 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, its impact is relatively small.

Figure 1
RSG Space Heating Model
Actual vs. Fitted Values

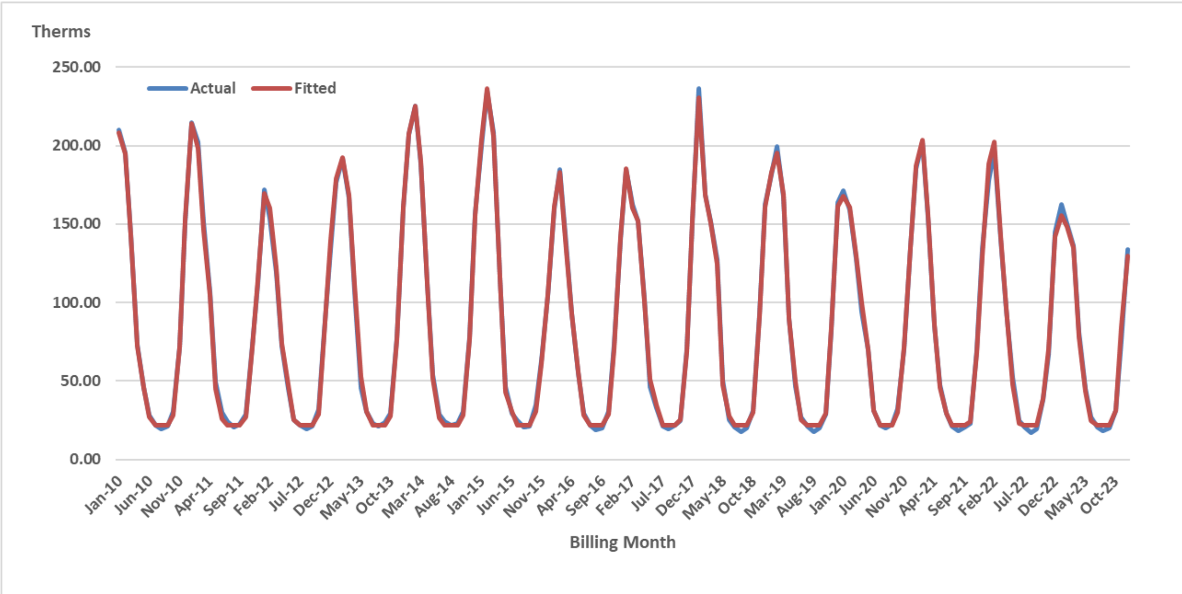
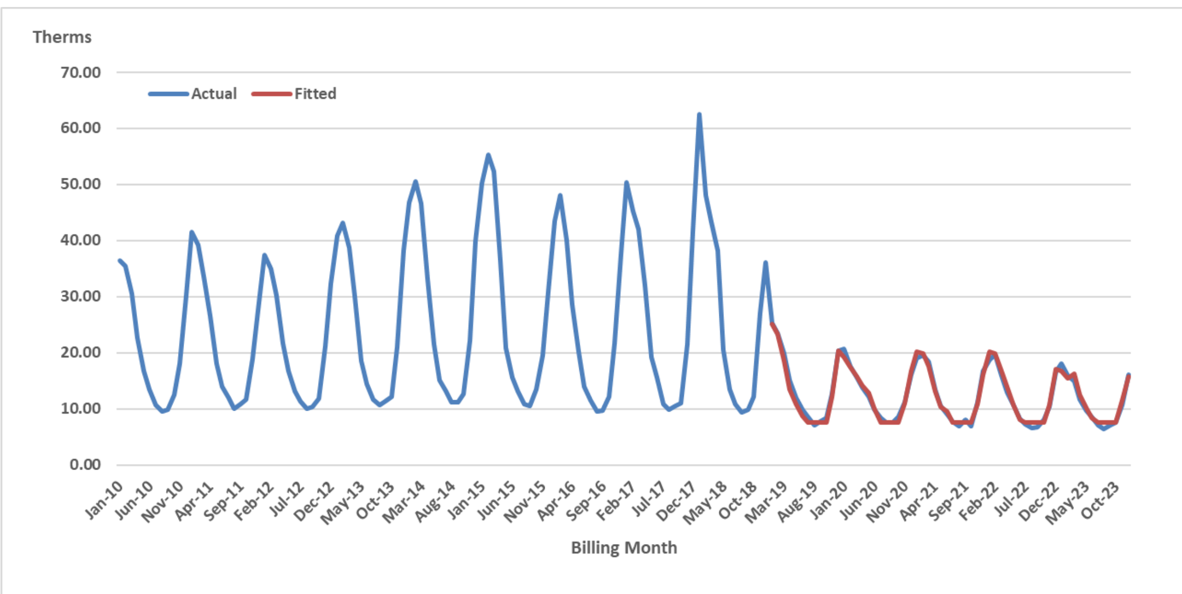


Figure 2
RSG Non-Space Heating Model
Actual vs. Fitted Values



The price elasticity estimates were estimated to be -0.0114 and -0.2639 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 influence 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	NOV	DEC	R2	DW	n
HEATING											
HDD	0.19847 (0.007)	0.19294 (0.006)	0.19472 (0.006)	0.18662 (0.010)	0.14232 (0.005)	0.18780 (0.022)	0.06856 (0.007)	0.18293 (0.008)	0.998	1.664	168
PRICE x HDD		**DJF*** -0.00432 (0.002)		**COVID x HDD**		**A** 0.0113 (0.010) **C** 0.0011 (0.002)					
WAGE x HDD		**ON**** 0.00099 (0.000)									

*** Dec-Jan-Feb**
**** Oct-Nov**

	JAN	FEB	MAR	APR	MAY	JUNE	NOV	DEC	R2	DW	n
NON-HEATING											
HDD	0.03248 (0.003)	0.02586 (0.003)	0.01338 (0.001)	0.01392 (0.001)	0.01682 (0.002)	0.04933 (0.013)	0.01055 (0.001)	0.02038 (0.003)	0.978	1.325	60
PRICE x HDD	-0.01254 (0.002)	-0.00903 (0.002)						-0.00465 (0.002)			

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:

$$\text{THERMS} = f(\text{PRICEGAS, OUTPUT, HDD}) \qquad [3]$$

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:

$$\text{OUTPUT} = f(\text{INCOME, HSH}) \qquad [4]$$

Substituting [4] into [3] yields:

$$\text{THERMS} = f(\text{PRICEGAS, INCOME, HSH, HDD}) \qquad [5]$$

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. Time period for GSG Heating model and GSG Non-Heating model set from January 2010 to December 2023 period and from January 2011 to December 2023 for the model estimations, respectively. The larger commercial customers are served under rate LVG. These are also modeled separately. LVG model was estimated for customers in the commercial sector using monthly billing data from January 2011 to December 2023 period.

Historical annual household estimates for New Jersey are 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]:

$$THERMS_t = f(\overline{MONTH} \times HDD_t \times PRICEGAS_{a-1}, \overline{MONTH} \times HDD_t \times INCOME_{a-1}, \overline{MONTH} \times HDD_t \times HSH_{a-1}, HDD_t) \quad [6]$$

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 is sensitive to price, with an estimated elasticity of -0.1587 the non-space heating customers are not, and the large commercial LVG customers are sensitive to price, with an estimated elasticity of -0.0869. 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

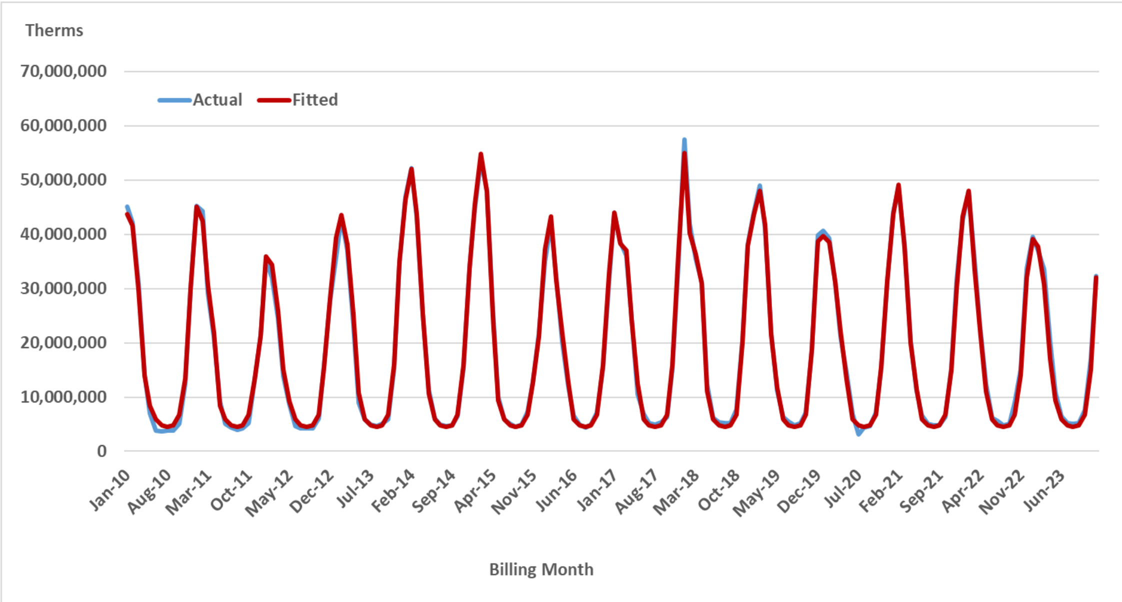


Figure 4
GSG Commercial Non-Space Heating Model
Actual vs. Fitted Values

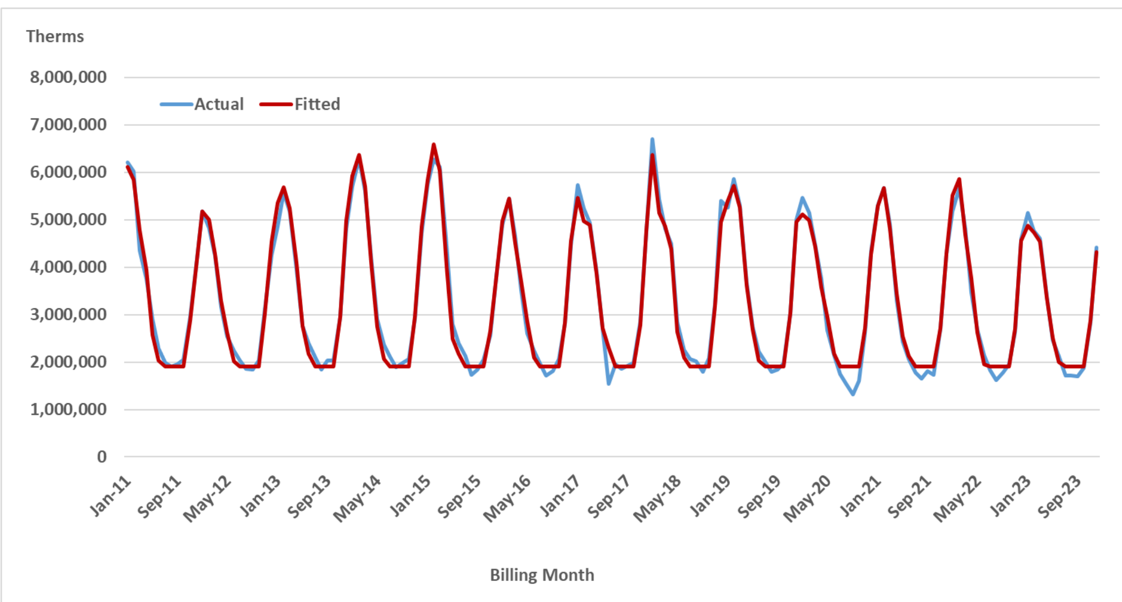


Figure 5
LVG Commercial Model
Actual vs. Fitted Values

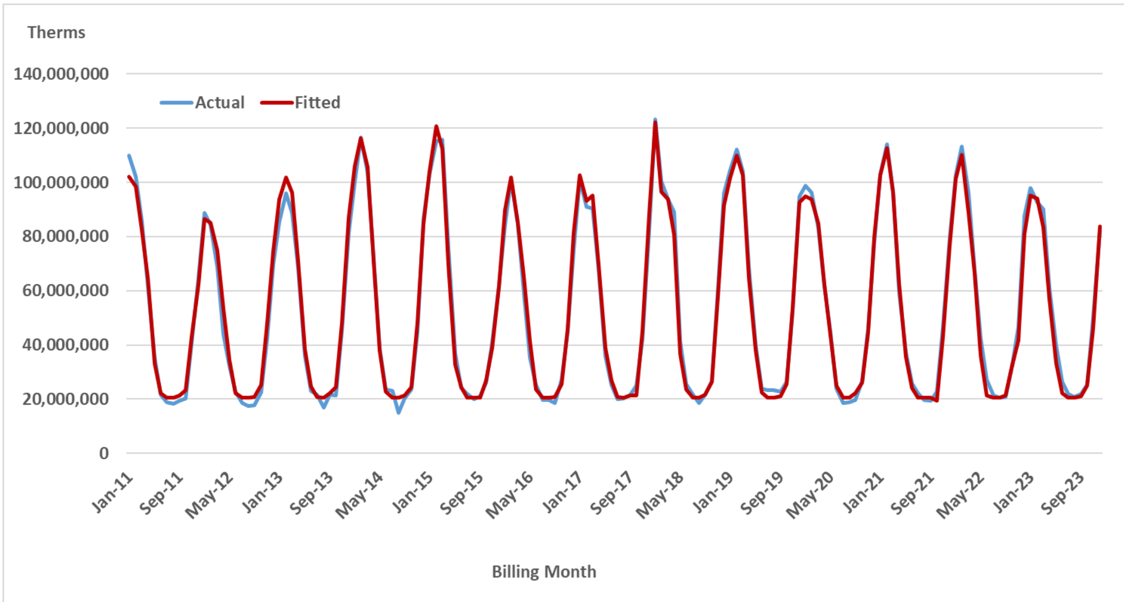


Table 2

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

	JAN	FEB	MAR	APR	MAY	JUN	NOV	DEC	R2	DW	n
HEATING											
PRICE x HDD	-6740 (1,649)	-7364 (1,745)	-7146 (2,243)	-7154 (3,810)	-30364 (10,597)		-15455 (4,292)	-12407 (2,270)	0.996	1.333	168
CUST x HDD	16.30 (0.7)	16.98 (0.7)	17.09 (0.9)	17.35 (1.4)	16.28 (3.0)		14.18 (2.1)	17.77 (0.9)			
	A	B									
COVID x HDD	-4345 (2,271)	-78 (675)									
NON-HEATING											
HDD	3915 (64)	4013 (65)	4088 (79)	4097 (129)	3941 (300)	5527 (1,535)	2645 (160)	3749 (84)	0.984	1.387	156
	A	B									
COVID x HDD	-587 (360)	-192 (114)									

Table 3

Estimated Coefficients of the LVG Commercial Gas Sales Models

(standard errors in parentheses)

HDD x PRICE	HDD x CUST	COVID x HDD A	COVID x HDD B	R2	DW	n
-17681	30	-14763	-152	0.990	0.951	156
(3,741)	(1)	(6,326)	(2,204)			

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:

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

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:

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

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. GSG Heating and Non-Heating model is estimated for using monthly billing data from January 2011 to December 2023 period. 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. The larger industrial customers are served under rate LVG. The model was estimated for customers in the industrial sector using monthly billing data from January 2011 to December 2023 period.

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 -0.0881 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

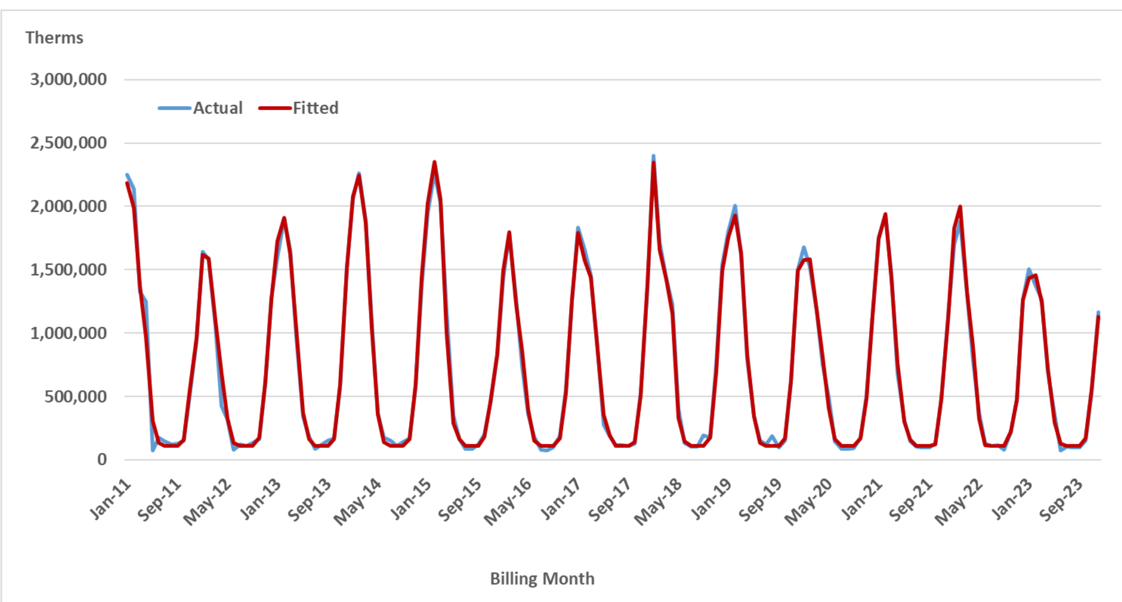


Figure 7

GSG Industrial Non-Space Heating Model

Actual vs. Fitted Values

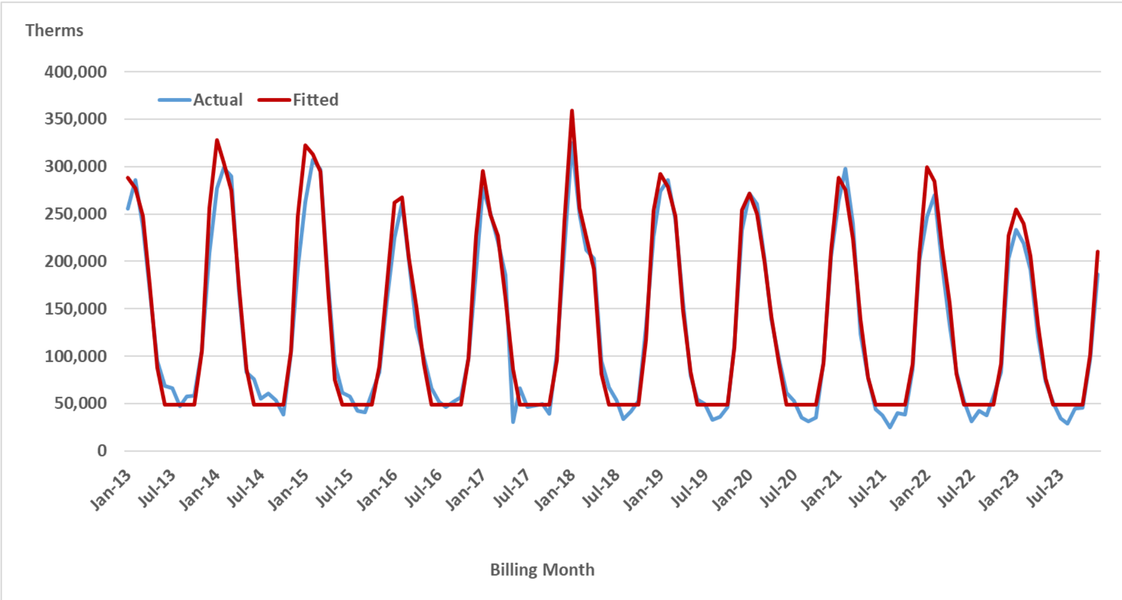


Figure 8

LVG Industrial Heating Model

Actual vs. Fitted Values

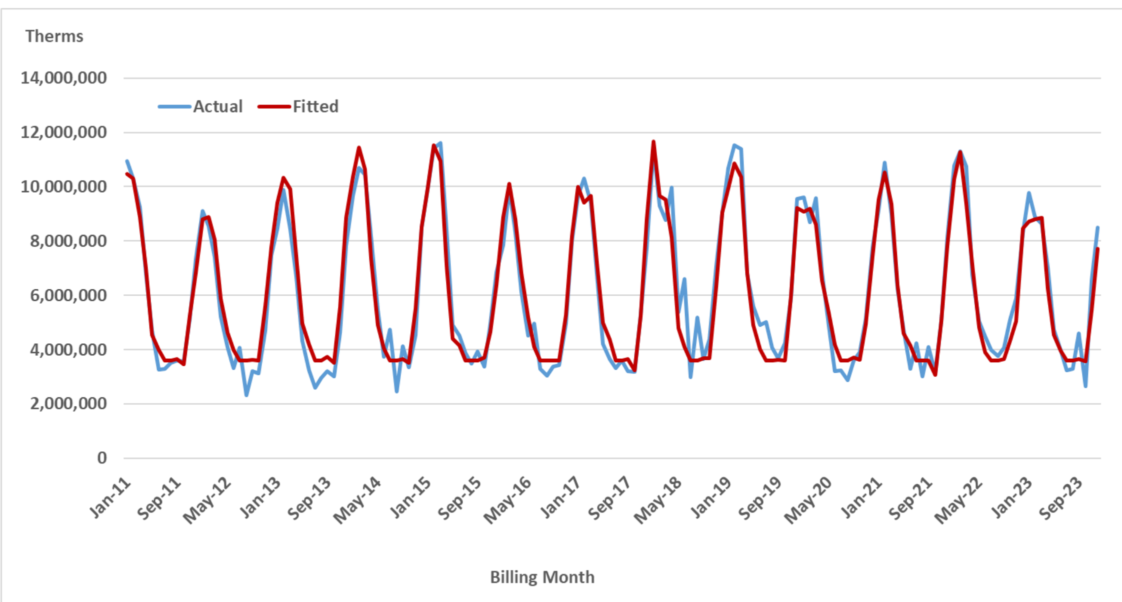


Table 4

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												
HDD	2379	1916	2206	1727	1204	1186	624	1219	2136	0.993	2.187	156
	(154)	(21)	(141)	(42)	(97)	(497)	(183)	(52)	(177)			
	A	B										
COVID x HDD	-252	-58										
	(114)	(36)										
NON-HEATING												
HDD	272	158	243	236	178			142	252	0.824	1.656	156
	(15)	(92)	(18)	(30)	(69)			(37)	(19)			
	A	B										
COVID x HDD	-40	-9										
	(85)	(27)										

Table 5

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

		COVID x HDD				
HDD x PRICE	**HDD x EMP**	**A**	**B**	**R2**	**DW**	**n**
-2256	39	-1076	-601	0.939	1.607	156
(906)	(4)	(1,241)	(446)			

II Forecast Assumptions

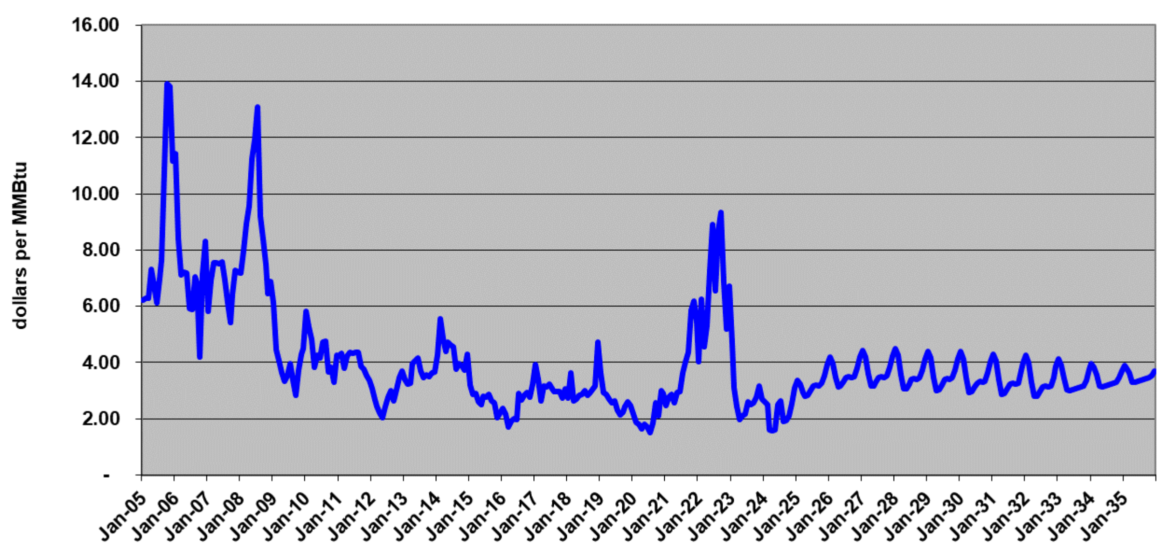
The models described above, in concert with assumptions about future prices and local economic and demographic parameters, were utilized to produce a forecast of billed natural gas delivered sales by rate for the residential, commercial, and industrial customer classes. The assumptions and the forecasts 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 forecast, the wholesale natural gas price was assumed to follow the NYMEX future prices as of July 25, 2024. As figure 9 shows, the wholesale price of gas is projected to stay relatively stable during the 2024-2035 periods.

Figure 9

NYMEX Natural Gas Futures Prices, July 25, 2024
($/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)

	Residential		Commercial			Industrial		
	RSG		GSG			GSG		
Year	Heating	Non-Heating	Heating	Non-Heating	LVG	Heating	Non-Heating	LVG
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	0.74	0.88	0.93	0.92	0.79	0.94	0.96	0.77
2019	0.81	1.25	0.94	0.92	0.78	0.94	0.97	0.73
2020	0.78	1.31	0.87	0.87	0.71	0.80	0.91	0.66
2021	0.82	1.36	1.02	1.04	0.84	1.01	1.07	0.77
2022	1.00	1.57	1.30	1.35	1.10	1.28	1.36	1.05
2023	1.11	1.69	1.14	1.12	0.90	1.15	1.19	0.84
2024	1.03	1.56	1.09	1.09	0.85	1.08	1.13	0.82
2025	1.10	1.62	1.24	1.23	0.98	1.23	1.27	0.95
2026	1.20	1.72	1.33	1.32	1.07	1.32	1.36	1.03
2027	1.21	1.73	1.39	1.37	1.09	1.37	1.41	1.06
2028	1.14	1.65	1.42	1.40	1.10	1.39	1.43	1.06
2029	1.39	1.91	1.52	1.49	1.14	1.49	1.53	1.10
2030	1.43	1.94	1.57	1.52	1.15	1.52	1.55	1.10
2031	1.49	2.01	1.61	1.55	1.15	1.55	1.58	1.11
2032	1.47	1.99	1.63	1.56	1.16	1.55	1.59	1.11
2033	1.51	2.03	1.70	1.63	1.19	1.62	1.65	1.14
2034	1.12	1.63	1.32	1.25	0.94	1.25	1.26	0.90
2035	1.12	1.63	1.32	1.25	0.94	1.25	1.26	0.90
2036	1.12	1.63	1.32	1.25	0.94	1.25	1.26	0.90
2037	1.12	1.63	1.32	1.25	0.94	1.25	1.26	0.90
2038	1.12	1.63	1.32	1.25	0.94	1.25	1.26	0.90
2039	1.12	1.63	1.32	1.25	0.94	1.25	1.26	0.90

Energy Efficiency and Electrification Impacts

In recent years, new technologies and state's saving programs have had significant impact on gas consumption to residential, commercial and industrial customer groups. The method of incorporating efficiency changes into the model estimation process when the changes are not driven by any of the economic explanatory variables is a two-step process.

The first step is to eliminate the impact of these programs in the historical series by adding the estimated impacts of these programs to the historical data, estimating the model, and then producing a forecast. This forecast will not have any impacts of the efficiency programs embedded in it.

The second step is to remove the impacts of the efficiency programs from both the history and the forecast. This reverts the historical data back to actual values and produces a forecast with the impacts of the efficiency programs correctly incorporated.

This methodology is used for RSG Heating, Commercial GSG Heating and LVG sales to incorporate the impacts of the current PSE&G efficiency programs and the estimated impacts of the proposed Clean Energy Future filing. These impacts are summarized in Table 7 below.

Mid – 2023, The Board of Public Utilities approved measures aimed at encouraging building owners to switch from natural gas to electric heat. The governor of NJ set a goal for the state to install emissions-free heating and cooling systems in 400,000 homes and 20,000 commercial properties or public spaces, and to make 10% of low-to-moderate income properties electrification-ready, all by 2030. The forecast assumes the share of the 400,000 residential buildings, approximately 220,000 to be electrified by 2030 within the PSEG territory. This result is expected to occur again over the next 10 years by 2040. These impacts are summarized in Table 7 below.

Table 7
Impacts of
Energy Master Plan – Energy Efficiency – Clean Energy Future
(therms)

	BILLING MONTH ASUMPTIONS			
	EMP	EE	CEF	Electrification
2010	14,596,330	1,014,482	-	
2011	16,831,360	3,286,510	-	
2012	12,618,148	4,213,546	-	
2013	14,974,182	5,039,977	-	
2014	17,382,618	6,586,486	-	
2015	17,361,247	6,989,516	-	
2016	27,228,971	7,495,738	-	
2017	30,109,455	8,348,880	-	
2018	31,927,340	9,278,342	-	
2019	32,622,853	8,941,105	-	
2020	33,017,270	10,475,843	967,729	
2021	35,146,133	9,957,697	7,473,556	
2022	37,038,542	-	22,074,122	
2023	39,023,824	-	42,143,763	
2024	39,532,857	-	57,417,226	
2025	40,714,913	-	69,074,876	9,373,789
2026	48,345,210	-	84,303,016	17,841,124
2027	49,406,263	-	99,929,605	30,982,600
2028	50,414,912	-	114,671,014	67,356,637
2029	53,853,369	-	129,259,854	117,407,196
2030	47,402,730	-	141,835,419	181,313,661
2031	47,939,333	-	147,293,164	198,339,631
2032	47,722,215	-	145,210,467	216,243,275
2033	47,526,146	-	139,950,864	234,159,685
2034	48,054,110	-	142,244,825	251,995,245
2035	47,839,201	-	144,018,250	269,838,799
2036	44,422,115	-	142,904,031	279,900,113
2037	41,005,030	-	142,500,284	289,961,426
2038	37,587,944	-	142,500,284	300,022,740
2039	34,170,858	-	142,500,284	310,084,053

Economic Projections

Economic and demographic forecast assumptions for the nation and New Jersey are from Moody's Economy June 2024 forecast. This forecast captures impact of COVID-19 on economy which assumes that, nationally, the economy will recover at a slow rate after pandemic. Tighter monetary and financial conditions to reduce stubbornly high inflation will slow economic growth. 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 8.

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, 2023.

Table 8

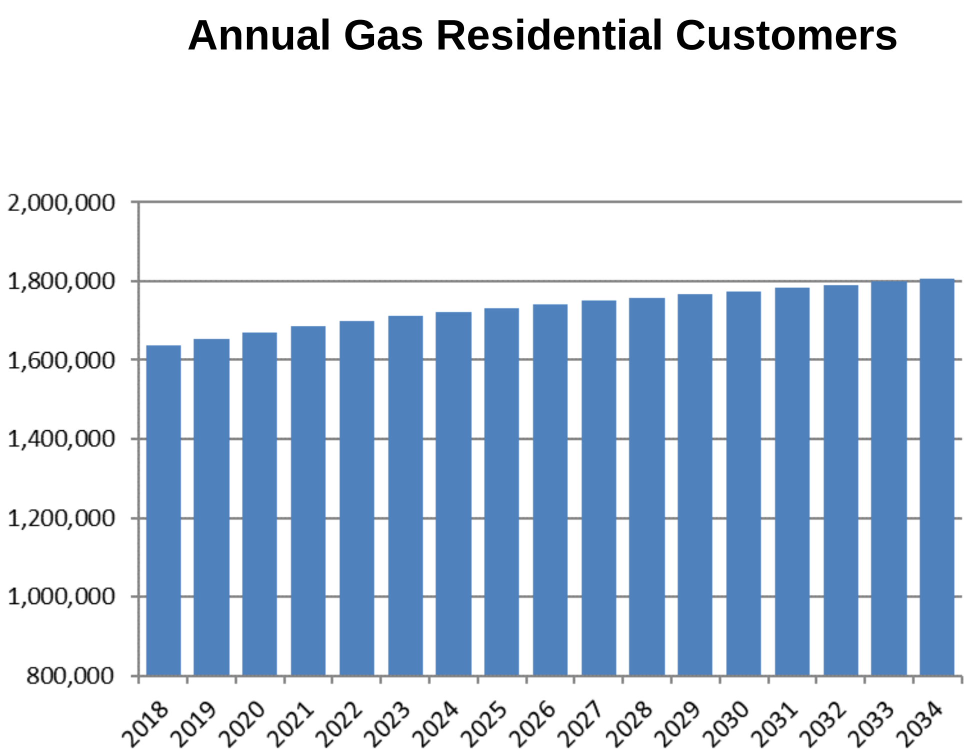
National and New Jersey Economic Forecast Assumptions

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
United States														
Gross Domestic Product, (Bil. USD, SAAR)	23,595	25,744	27,362	28,707	29,869	31,098	32,428	33,864	35,342	36,813	38,297	39,832	41,447	43,143
Industrial Production: Total, (Index 2012=100, SA)	99	103	103	103	105	105	107	108	110	112	115	117	119	122
Income: Personal - Total, (Bil. Ch. 2009 USD, SAAR)	19,658	18,822	19,074	19,475	19,852	20,267	20,729	21,238	21,745	22,233	22,702	23,176	23,658	24,137
Employment: Total Nonagricultural, (Mil. #, SA)	146	153	156	159	160	160	161	161	162	162	163	163	164	164
Household Survey: Unemployment Rate, (%, SA)	5.3	3.6	3.6	4.0	4.1	4.0	4.0	4.0	4.0	4.0	4.1	4.1	4.1	4.1
CPI: Urban Consumer - All Items, (Index 1982-84=100, SA)	271	293	305	314	322	330	337	345	352	360	368	376	384	392
Interest Rates: 3-Month Treasury Bills EBY, (% p.a., NSA)	0.0	2.1	5.2	5.2	4.1	3.2	2.9	2.9	2.9	2.6	2.6	2.6	2.6	2.6
Terms Conventional Mortgages: All Loans Fixed Effective Rate, (%, NSA)	3.8	5.0	6.8	7.2	6.8	6.5	6.4	6.3	6.3	6.2	6.2	6.1	6.1	6.1
New Jersey														
Real Personal Income, (Mil. 09$, SAAR)	647,244	616,171	623,002	637,684	647,266	657,612	668,701	680,889	692,940	704,492	715,789	727,504	739,461	751,240
Employment: Total Nonagricultural, (Ths., SA)	4,029	4,235	4,323	4,391	4,413	4,415	4,411	4,407	4,403	4,400	4,396	4,393	4,391	4,389
Employment: Total Manufacturing, (Ths., SA)	241	251	255	255	255	254	252	250	247	244	241	238	235	232
Employment: Total Non-Manufacturing, (Ths., SA)	3,788	3,984	4,068	4,137	4,158	4,161	4,159	4,157	4,157	4,156	4,156	4,156	4,156	4,157
Labor: Unemployment Rate, (%, SA)	6.7	3.9	4.4	4.7	4.4	4.3	4.3	4.3	4.3	4.3	4.3	4.4	4.4	4.4
Population: Total, (Ths.)	9,268	9,263	9,293	9,314	9,319	9,317	9,311	9,301	9,288	9,276	9,263	9,251	9,238	9,225
Households: Total, (Ths.)	3,387	3,416	3,424	3,433	3,445	3,451	3,454	3,457	3,461	3,465	3,470	3,474	3,478	3,479
Housing Starts: Single-family, (#, SAAR)	14,441	13,619	15,045	15,149	15,133	16,456	16,528	16,002	15,244	14,335	13,368	12,453	11,619	10,863

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 1.2 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. The model used seven weather stations in NJ as the measuring base for temperature. 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.

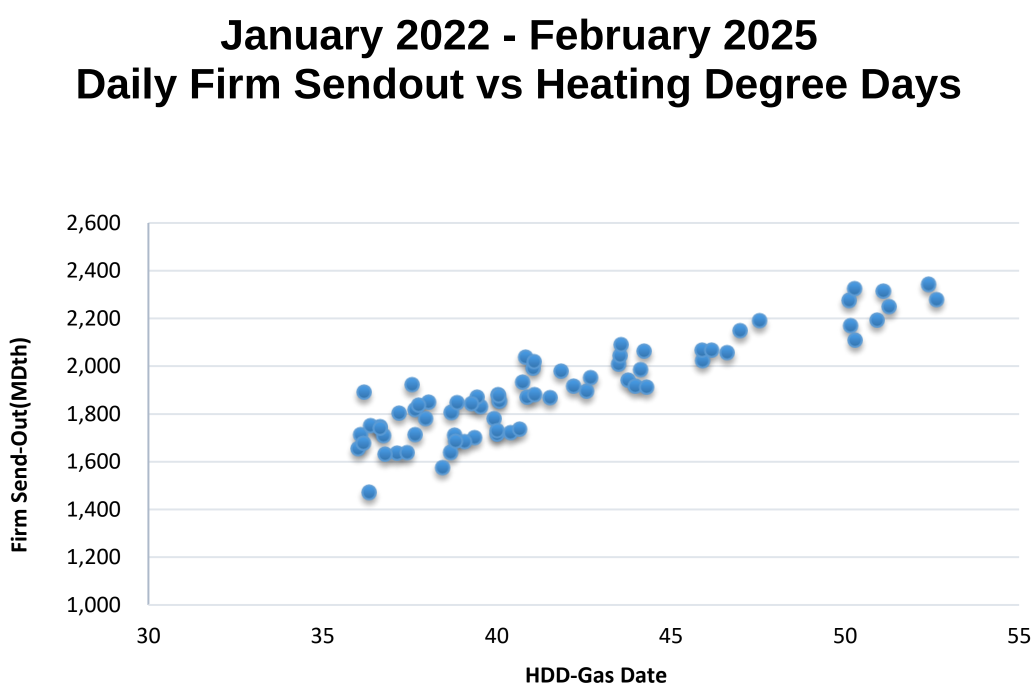
The firm sendout number accounts for gas deliveries to a diverse set of customers ranging from residential homes to large industrial sites. Since sales to different types of customers respond to weather differently, customer mix must be controlled for in any modeling effort. In addition, the behavior 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 forecasting issues, the data used in estimating the relationship between daily sendout and weather was limited to January 2022 to February 2025 where HDD greater than 36 during the period. Customer class mix will not change significantly in this short period and it contains the coldest months when the maximum sendout would most likely occur. Analysis of the data for these 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



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:

$$SENDOUT_t = f(HDD_t, HDD_{t-1}, \text{WIND-SPEED}, \text{SKY-CONDITIONS}\ WEEKDAY_t, HOLIDAY_t, SNOW_t) \quad [9]$$

Where:

HDD_t	=	Heating degree days on gas day t,
HDD_{t-1}	=	One day lag basis Heating degree days on gas day t-1,
WIND-SPEED	=	Daily average wind speed, MPH,
SKY-COND	=	Report of each cloud layer,
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

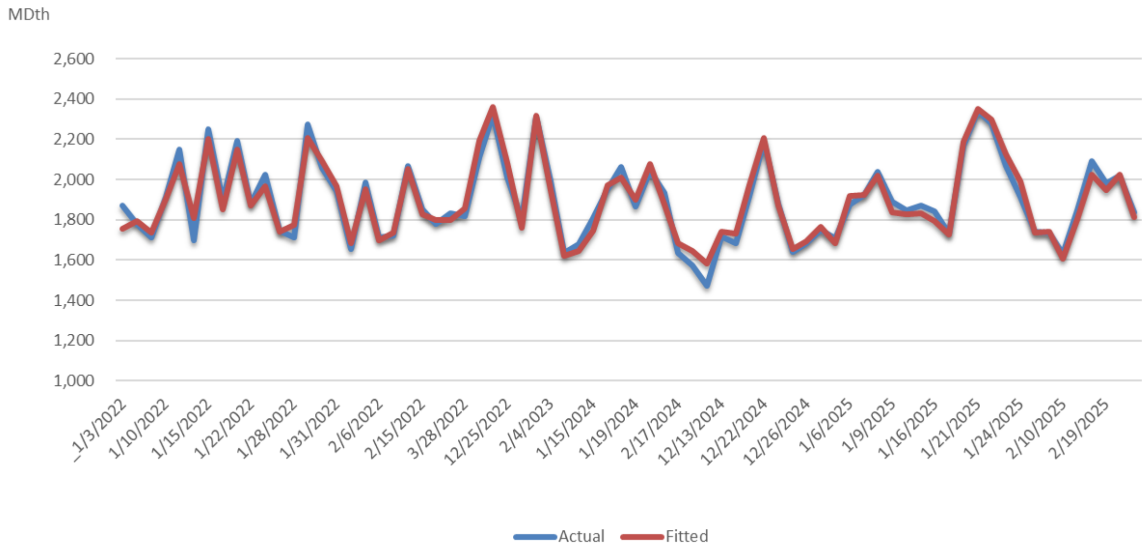
Estimated Coefficients of the Daily Sendout Model

(standard errors in parentheses)

	HDD									
Intercept	HDD	LAG	HOLIDAY	WEEKDAY	WIND-SPEED	SKY COND	SNOW	R2	DW	n
-52.74	34.55	9.24	0.03	0.33	18.05	6.42	-59.4	0.95	1.67	72.00

Figure 12

Daily Sendout Model
Actual vs. Fitted Values



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.

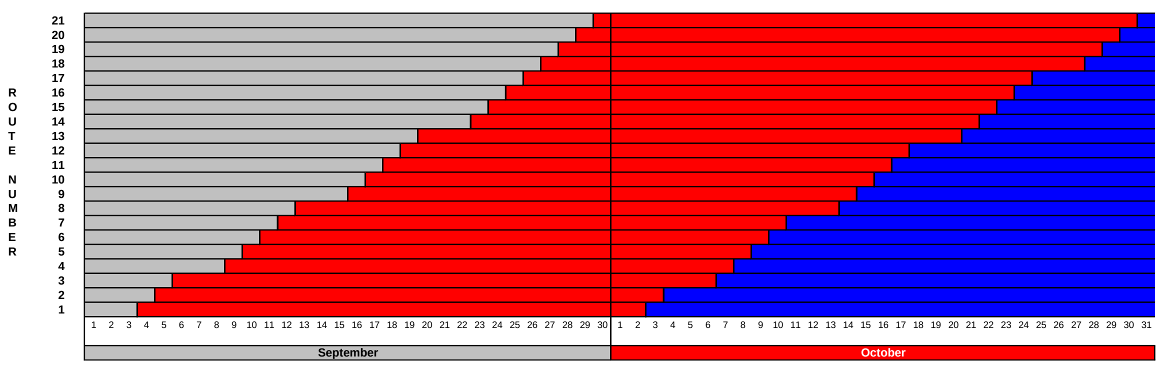
The Unbilled and Calendar-Month Estimation

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.

[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.

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

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

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

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

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

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

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

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:

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

[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.

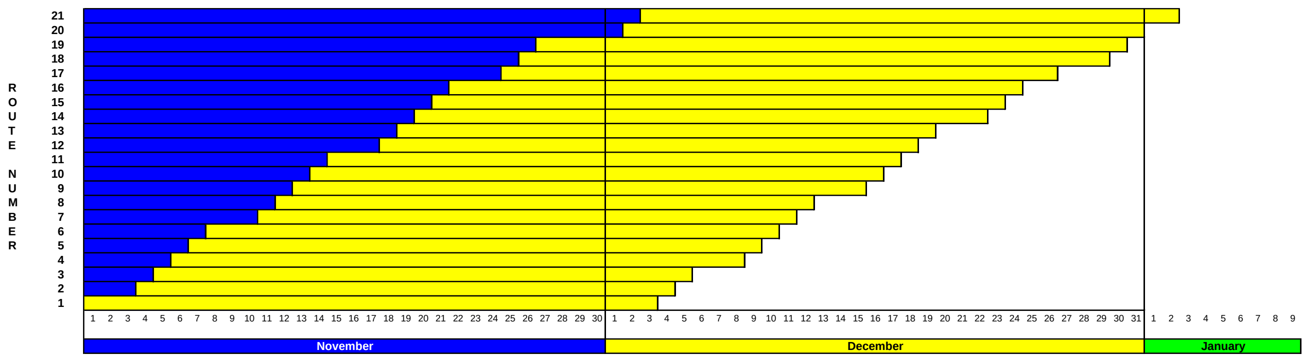
A More General Example

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:

$$\text{December Billed} = \boxed{\begin{array}{r}\text{OCT B> DEC}\\ \text{NOV B> DEC}\\ \text{DEC B> DEC}\\ \text{JAN B> DEC}\end{array}} \qquad [8]$$

Given the additional components of the billed, $\boxed{\text{OCT B> DEC}}$, i.e. the "under billed" sales, and $\boxed{\text{JAN B> DEC}}$, 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:

$$\text{December Unbilled} = \boxed{\begin{array}{l}\text{DEC B> JAN}\\ \text{DEC B> FEB}\end{array}} + \boxed{\text{NOV B> JAN}} - \boxed{\text{JAN B> DEC}} \qquad [9]$$

$$\text{December Unbilled} = \text{December Unbilled} + \text{January Underbilled} - \text{December Excess Billed} \qquad [10]$$

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

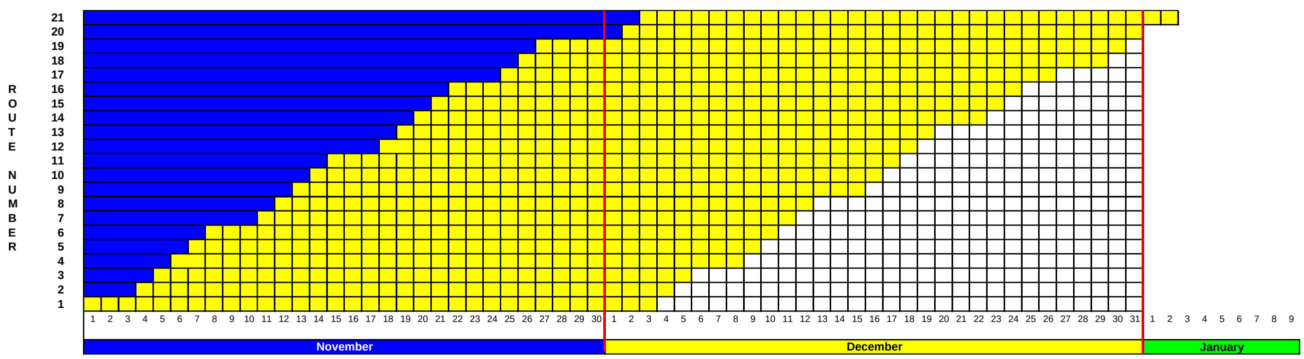
	RSG				GSG-Commercial				GSG-Industrial				LVG - Non Vehicle			
Billing	Heating		Non-heating		Heating		Non-heating		Heating		Non-heating		Commercial		Industrial	
Month	Base	HDD	Base	HDD	Base	HDD	Base	HDD	Base	HDD	Base	HDD	Base	HDD	Base	HDD
Jan-08	1,477,624	246,082	218,393	4,689	56,941	45,607	168,133	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:

$$1.5 \text{ (January } 1^{st} \text{ and half of January } 2^{nd}\text{) } / 21 = 0.07 \qquad [13]$$

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 21^{st}, 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

	Heating Degree Days				Days			
Billing Month	Billed	Unbilled	Excess Billed	Under Billed	Billed	Unbilled	Excess Billed	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
2024-2034
(MDth)

Class	Rate	Category	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Residential	RSG	Heating	150,611	150,357	149,382	148,558	147,285	146,053	145,409	146,291	147,742	149,171	150,344
		Non-Heating	3,110	3,156	3,109	3,040	3,015	3,026	2,904	2,869	2,826	2,811	2,779
	Total		153,721	153,514	152,491	151,598	150,300	149,079	148,313	149,159	150,567	151,982	153,123
Commercial	GSG	Heating	24,077	24,405	23,840	23,339	22,378	21,357	19,536	18,949	18,521	18,213	17,704
		Non-Heating	3,977	3,978	3,975	3,974	3,972	3,972	3,972	3,970	3,973	3,967	3,968
		Total	28,054	28,383	27,816	27,313	26,351	25,329	23,508	22,919	22,494	22,181	21,672
	LVG		67,792	68,358	67,242	66,654	64,825	62,490	58,880	58,065	57,298	56,455	55,521
	TSG	Firm	919	913	899	875	847	819	792	764	742	726	707
		Non-Firm	7,629	7,618	7,596	7,556	7,511	7,465	7,419	7,374	7,337	7,311	7,279
		Total	8,548	8,531	8,495	8,431	8,358	8,284	8,210	8,138	8,080	8,038	7,986
	CIG		2,261	2,261	2,261	2,261	2,261	2,261	2,261	2,261	2,261	2,261	2,261
	CSG		7,790	7,790	7,790	7,790	7,790	7,790	7,790	7,790	7,790	7,790	7,790
	Total		114,445	115,323	113,604	112,450	109,585	106,155	100,650	99,173	97,923	96,725	95,230
Industrial	GSG	Heating	895	895	895	896	893	894	895	894	895	892	893
		Non-Heating	149	149	149	149	148	148	149	149	149	148	148
		Total	1,044	1,044	1,044	1,044	1,041	1,042	1,043	1,043	1,044	1,041	1,042
	LVG		8,040	8,110	7,984	7,898	7,844	7,816	7,749	7,715	7,680	7,640	7,591
	TSG	Firm	1,270	1,260	1,240	1,204	1,162	1,121	1,079	1,038	1,005	981	952
		Non-Firm	4,627	4,619	4,604	4,578	4,547	4,517	4,486	4,456	4,432	4,415	4,393
		Total	5,897	5,880	5,845	5,782	5,710	5,638	5,565	5,494	5,437	5,396	5,345
	CIG		484	484	484	484	484	484	484	484	484	484	484
	CSG		64,955	64,955	64,955	64,955	64,955	64,955	64,955	64,955	64,955	64,955	64,955
	Contract		-	-	-	-	-	-	-	-	-	-	-
	Total		80,419	80,473	80,311	80,163	80,034	79,934	79,796	79,690	79,600	79,516	79,416
Lighting	SLG		68	68	68	68	68	68	68	68	68	68	68
Total			348,653	349,377	346,474	344,280	339,987	335,236	328,827	328,091	328,158	328,291	327,836

Supplied Gas Sales As Billed
2024-2034
(MDth)

Class	Rate	Category	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Residential	RSG	Heating	147,675	147,428	146,472	145,664	144,416	143,209	142,578	143,443	144,866	146,269	147,420
		Non-Heating	3,008	3,053	3,007	2,940	2,916	2,927	2,809	2,774	2,733	2,718	2,688
	Total		150,683	150,480	149,478	148,604	147,332	146,136	145,386	146,218	147,599	148,988	150,108
Commercial	GSG	Heating	19,609	19,878	19,420	19,016	18,235	17,407	15,926	15,452	15,106	14,856	14,445
		Non-Heating	3,149	3,149	3,147	3,146	3,144	3,144	3,145	3,143	3,145	3,141	3,141
		Total	22,758	23,026	22,567	22,162	21,379	20,551	19,071	18,595	18,251	17,997	17,586
	LVG		26,120	26,345	25,903	25,674	24,939	24,010	22,566	22,249	21,952	21,609	21,241
	TSG	Firm	-	-	-	-	-	-	-	-	-	-	-
		Non-Firm	664	664	664	664	664	664	664	664	664	664	664
		Total	664	664	664	664	664	664	664	664	664	664	664
	CIG		2,261	2,261	2,261	2,261	2,261	2,261	2,261	2,261	2,261	2,261	2,261
	CSG		-	-	-	-	-	-	-	-	-	-	-
	Total		51,803	52,297	51,396	50,761	49,243	47,487	44,562	43,769	43,128	42,531	41,752
Industrial	GSG	Heating	770	770	770	770	768	769	769	769	770	767	768
		Non-Heating	122	122	122	122	122	122	122	122	122	122	122
		Total	892	892	892	893	890	891	892	891	892	889	890
	LVG		2,092	2,112	2,074	2,048	2,031	2,023	2,002	1,992	1,982	1,969	1,954
	TSG	Firm	-	-	-	-	-	-	-	-	-	-	-
		Non-Firm	150	150	150	150	150	150	150	150	150	150	150
		Total	150	150	150	150	150	150	150	150	150	150	150
	CIG		484	484	484	484	484	484	484	484	484	484	484
	CSG		-	-	-	-	-	-	-	-	-	-	-
	Contract		-	-	-	-	-	-	-	-	-	-	-
	Total		3,618	3,639	3,600	3,574	3,555	3,547	3,528	3,517	3,508	3,492	3,478
Lighting	SLG		26	26	26	26	26	26	26	26	26	26	26
Total			206,130	206,442	204,501	202,966	200,157	197,196	193,503	193,530	194,262	195,037	195,364

Supplied Share of Delivered Gas Sales As Billed
2024-2034
(percent)

Class	Rate	Category	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Residential	RSG	Heating	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%
		Non-Heating	97%	97%	97%	97%	97%	97%	97%	97%	97%	97%	97%
	Total		98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%
Commercial	GSG	Heating	81%	81%	81%	81%	81%	82%	82%	82%	82%	82%	82%
		Non-Heating	79%	79%	79%	79%	79%	79%	79%	79%	79%	79%	79%
		Total	81%	81%	81%	81%	81%	81%	81%	81%	81%	81%	81%
	LVG		39%	39%	39%	39%	38%	38%	38%	38%	38%	38%	38%
	TSG	Firm	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
		Non-Firm	9%	9%	9%	9%	9%	9%	9%	9%	9%	9%	9%
		Total	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%
	CIG		100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
	CSG		0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	Total		45%	45%	45%	45%	45%	45%	44%	44%	44%	44%	44%
Industrial	GSG	Heating	86%	86%	86%	86%	86%	86%	86%	86%	86%	86%	86%
		Non-Heating	82%	82%	82%	82%	82%	82%	82%	82%	82%	82%	82%
		Total	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%
	LVG		26%	26%	26%	26%	26%	26%	26%	26%	26%	26%	26%
	TSG	Firm	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
		Non-Firm	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%
		Total	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%
	CIG		100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
	CSG		0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	Contract		0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	Total		4%	5%	4%	4%	4%	4%	4%	4%	4%	4%	4%
Lighting	SLG		39%	39%	39%	39%	39%	39%	39%	39%	39%	39%	39%
Total			59%	59%	59%	59%	59%	59%	59%	59%	59%	59%	60%

Delivered Gas Sales Calendar-Year
2024-2034
(MDth)

Class	Rate	Category	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Residential	RSG	Heating	153,119	150,047	149,004	148,128	147,992	145,812	145,055	145,979	148,240	149,102	150,009
		Non-Heating	3,130	3,154	3,100	3,029	3,025	3,023	2,891	2,862	2,830	2,809	2,772
	Total		156,248	153,201	152,105	151,157	151,017	148,836	147,946	148,841	151,070	151,911	152,781
Commercial	GSG	Heating	24,449	24,382	23,737	23,243	22,430	21,270	19,400	18,880	18,557	18,186	17,633
		Non-Heating	4,019	3,970	3,967	3,964	3,986	3,966	3,963	3,962	3,981	3,965	3,960
		Total	28,468	28,352	27,704	27,207	26,417	25,237	23,363	22,842	22,538	22,151	21,593
	LVG		68,637	68,256	67,027	66,447	64,987	62,270	58,563	57,908	57,399	56,375	55,358
	TSG	Firm	919	913	899	875	847	819	792	764	742	726	707
		Non-Firm	7,629	7,618	7,596	7,556	7,511	7,465	7,419	7,374	7,337	7,311	7,279
		Total	8,548	8,531	8,495	8,431	8,358	8,284	8,210	8,138	8,080	8,038	7,986
	CIG		2,261	2,261	2,261	2,261	2,261	2,261	2,261	2,261	2,261	2,261	2,261
	CSG		7,790	7,790	7,790	7,790	7,790	7,790	7,790	7,790	7,790	7,790	7,790
	Total		115,704	115,190	113,277	112,137	109,813	105,842	100,188	98,939	98,068	96,615	94,987
Industrial	GSG	Heating	906	893	893	893	897	892	892	892	898	891	891
		Non-Heating	150	148	148	148	149	148	148	148	149	148	148
		Total	1,056	1,041	1,041	1,041	1,046	1,040	1,041	1,040	1,047	1,039	1,039
	LVG		8,155	8,099	7,959	7,873	7,868	7,802	7,727	7,698	7,694	7,634	7,573
	TSG	Firm	1,270	1,260	1,240	1,204	1,162	1,121	1,079	1,038	1,005	981	952
		Non-Firm	4,627	4,619	4,604	4,578	4,547	4,517	4,486	4,456	4,432	4,415	4,393
		Total	5,897	5,880	5,845	5,782	5,710	5,638	5,565	5,494	5,437	5,396	5,345
	CIG		484	484	484	484	484	484	484	484	484	484	484
	CSG		64,955	64,955	64,955	64,955	64,955	64,955	64,955	64,955	64,955	64,955	64,955
	Contract		-	-	-	-	-	-	-	-	-	-	-
	Total		80,547	80,459	80,284	80,135	80,063	79,919	79,772	79,671	79,617	79,508	79,396
Lighting	SLG		68	68	68	68	68	68	68	68	68	68	68
Total			352,568	348,918	345,734	343,497	340,961	334,664	327,973	327,519	328,822	328,102	327,232

Supplied Gas Sales Calendar-Year
2024-2034
(MDth)

Class	Rate	Category	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Residential	RSG	Heating	150,126	147,123	146,101	145,242	145,109	142,973	142,231	143,138	145,355	146,201	147,091
		Non-Heating	3,027	3,050	2,999	2,930	2,926	2,924	2,796	2,768	2,737	2,717	2,681
	Total		153,153	150,173	149,100	148,172	148,035	145,897	145,027	145,906	148,092	148,918	149,773
Commercial	GSG	Heating	19,921	19,858	19,335	18,937	18,277	17,336	15,815	15,396	15,136	14,834	14,386
		Non-Heating	3,183	3,143	3,141	3,138	3,156	3,140	3,137	3,137	3,151	3,139	3,135
		Total	23,104	23,001	22,476	22,075	21,433	20,476	18,952	18,532	18,287	17,973	17,521
	LVG		26,701	26,302	25,811	25,586	25,008	23,917	22,431	22,182	21,995	21,574	21,171
	TSG	Firm	-	-	-	-	-	-	-	-	-	-	-
		Non-Firm	664	664	664	664	664	664	664	664	664	664	664
		Total	664	664	664	664	664	664	664	664	664	664	664
	CIG		2,261	2,261	2,261	2,261	2,261	2,261	2,261	2,261	2,261	2,261	2,261
	CSG		-	-	-	-	-	-	-	-	-	-	-
	Total		52,731	52,229	51,213	50,586	49,366	47,318	44,309	43,640	43,207	42,473	41,618
Industrial	GSG	Heating	779	768	768	768	771	767	767	767	772	766	766
		Non-Heating	124	122	122	122	123	122	122	122	123	122	122
		Total	903	890	890	890	894	889	889	889	895	888	888
	LVG		2,151	2,109	2,067	2,040	2,038	2,019	1,996	1,987	1,986	1,967	1,948
	TSG	Firm	-	-	-	-	-	-	-	-	-	-	-
		Non-Firm	150	150	150	150	150	150	150	150	150	150	150
		Total	150	150	150	150	150	150	150	150	150	150	150
	CIG		484	484	484	484	484	484	484	484	484	484	484
	CSG		-	-	-	-	-	-	-	-	-	-	-
	Contract		-	-	-	-	-	-	-	-	-	-	-
	Total		3,688	3,633	3,591	3,564	3,566	3,541	3,519	3,509	3,514	3,489	3,470
Lighting	SLG		26	26	26	26	26	26	26	26	26	26	26
Total			209,598	206,062	203,930	202,349	200,993	196,782	192,881	193,081	194,839	194,905	194,887

Supplied Share of Delivered Gas Sales Calendar Year 2024-2034 (percent)

Class	Rate	Category	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Residential	RSG	Heating	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%
		Non-Heating	97%	97%	97%	97%	97%	97%	97%	97%	97%	97%	97%
	Total		98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%
Commercial	GSG	Heating	81%	81%	81%	81%	81%	82%	82%	82%	82%	82%	82%
		Non-Heating	79%	79%	79%	79%	79%	79%	79%	79%	79%	79%	79%
		Total	81%	81%	81%	81%	81%	81%	81%	81%	81%	81%	81%
	LVG		39%	39%	39%	39%	38%	38%	38%	38%	38%	38%	38%
	TSG	Firm	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
		Non-Firm	9%	9%	9%	9%	9%	9%	9%	9%	9%	9%	9%
		Total	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%
	CIG		100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
	CSG		0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	Total		46%	45%	45%	45%	45%	45%	44%	44%	44%	44%	44%
Industrial	GSG	Heating	86%	86%	86%	86%	86%	86%	86%	86%	86%	86%	86%
		Non-Heating	82%	82%	82%	82%	82%	82%	82%	82%	82%	82%	82%
		Total	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%
	LVG		26%	26%	26%	26%	26%	26%	26%	26%	26%	26%	26%
	TSG	Firm	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
		Non-Firm	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%
		Total	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%
	CIG		100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
	CSG		0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	Contract		0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	Total		5%	5%	4%	4%	4%	4%	4%	4%	4%	4%	4%
Lighting	SLG		39%	39%	39%	39%	39%	39%	39%	39%	39%	39%	39%
Total			59%	59%	59%	59%	59%	59%	59%	59%	59%	59%	60%

17. FERC Pipeline Activities

Item 17

FERC Pipeline Activities

Pipeline	Docket No.	Description
Transcontinental Gas Pipe Line Company, LLC	CP21-94	On March 26, 2021, Transcontinental Gas Pipe Line Company, LLC ("Transco") applied for approval of the Regional Energy Access ("REA") Project that includes incremental firm transportation of 60,000 dekatherms/day to the Company. The REA Project is in full service as of August 1, 2024.
Texas Eastern Transmission, LP	CP22-486 CP25-24	The Texas Eastern Transmission, LP ("TETCO") Appalachia to Market II ("A2M2") Project has a total project capacity of 55,000 Dth/d from the Appalachia supply basin. The Company has executed a binding 15-year 25,000/day precedent agreement calling for delivery of 19,810 dth/day at South Plainfield and 5,190/day at Jamesburg. The Company has also executed a negotiated rate agreement for the term of the precedent agreement with opportunities for an extension if deemed necessary at that time. In November 2024, TETCO filed an abbreviated application to amend the A2M2 Project to allow for a different scope of work at the Entriken compressor station. There are no proposed changes to the Company's final volume. FERC certificate expected by June 2025.
Columbia Gas Transmission, LLC.	RP20-1060	Columbia Gas Transmission, LLC ("Columbia") is actively pursuing multiple paths to address issues with its Low Pressure System ("LPS"). Based upon inadequate measures it would have taken to resolve losses

		on the pipeline's LPS, the Company joined with other Local Distribution Company ("LDC") customers to protest Columbia's proposal, and advocated for a Commission order to compel the pipeline to act expeditiously to address those issues. The Company also remains an active participant in ongoing settlement discussions. In November 2024, Columbia refiled a non-consensus LPS plan to address concerns raised by customers and FERC. FERC accepted Columbia's plan in February 2025.
Transcontinental Gas Pipe Line Company, LLC	RP24-1035	On August 30, 2024 Transco filed a section 4 rate case. On September 4, 2024, PSEG ER&T intervened in the docket and filed a protest against Transco's proposed rate increases. PSEG ER&T formed a LDC group and retained Energy Consultants Inc. as the group's consultant. Settlement negotiations are currently ongoing.
Columbia Gas Transmission, LLC	RP24-1103 AC25-45	On September 30, 2024 Columbia filed a section 4 rate case. In October 2024, PSEG ER&T intervened in the docket and filed a protest against Columbia's rate increases and changing tariff provisions. PSEG ER&T also entered into a Joint Defense and Common Interest Agreement with several other LDC participants to better advocate for PSEG ER&T's positions. Columbia submitted an Accumulated Deferred Income Taxes (ADIT) and Excess Deferred Income Taxes (EDIT) request to FERC under Docket No. AC25-45. PSEG ER&T joined a customer group protest on January 29, 2025. Currently, settlement conferences are ongoing.
Baltimore Gas	RP25-740	On March 25, 2025, Baltimore Gas and

and Electric Company, et al. v. Columbia Gas Transmission, LLC.		Electric Company filed a complaint against Columbia Gas Transmission, LLC. As set forth below, beginning during the preceding winter peak heating season ("2023-24 Winter Season") and ending September 17, 2024, Columbia: (i) failed to comply with its obligation to provide firm transportation, firm storage, and no-notice service to Complainants under Rate Schedules FTS, FSS, NTS, SST, and TPS, firm service agreements with Complainants, and Part 284 of the Commission's regulations, (ii) misinterpreted and misapplied several aspects of its FERC Gas Tariff ("Tariff") regarding force majeure work and reservation charge crediting, and (iii) without seeking advance authorization from the Commission, constructively abandoned firm certificated service obligations to Complainants by engaging in unscheduled, non-routine, and non-emergency maintenance in the form of reducing pressure to run pigging through the pipeline at locations beyond any force majeure requirements imposed on it. On March 11, 2025, PSET ER&T filed an intervention and is monitoring the proceeding.
Tennessee Gas Pipeline Company, L.L.C.	RP25-673	On February 28, 2025, Tennessee Gas Pipeline Company proposed tariff changes to revise its curtailment practice from adjusting scheduled quantities to a pro-rata adjustment of firm entitlements and to update its Reservation Charge Crediting Mechanism (RCCM) to align with these changes. Tennessee's proposed RCCM uses a seven-day average prior to a curtailment to determine a shipper's service needs for reservation charge credits, aiming to ensure fairness. PSEG ER&T, a significant customer of Tennessee, submitted comments on March 12,

		2025, supporting the curtailment practice improvement but expressed concerned that the seven-day average may not accurately reflect shippers' needs during extended curtailments, especially with changing market or weather conditions, potentially leading to unfair credit calculations. PSEG ER&T urged Tennessee and the Commission to explore more equitable alternatives to the seven-day average method. FERC rejected Tennessee's filing based on scheduling priority language conflicting with FERC policy.
Columbia Gas Transmission, LLC	RP24-896	On July 05, 2025, Columbia proposed to revise Section 4.1(a) (Right of First Refusal Process) of its General Terms and Conditions ("GT&C") of its Tariff to extend the deadline by which a shipper must provide written notice to Columbia of its intent to exercise its Right of First Refusal ("ROFR") from six (6) months to eleven (11) months prior to the termination of its Long-Term Service Agreement ("ROFR Notice"). On July 11, 2025, PSET ER&T intervened. FERC accepted Columbia's proposed change.
Algonquin Gas Transmission, LLC	RP24-781	On May 30, 2024, Algonquin Gas Transmission, LLC submitted its Sixth Revised Volume No. 1 and Second Revised Volume No. 2, as revised tariff records, which effectuate changes in the rates applicable to Algonquin's FERC-jurisdictional services. On June 5, 2024, PSET ER&T intervened. Settlement was achieved in February 2025.

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

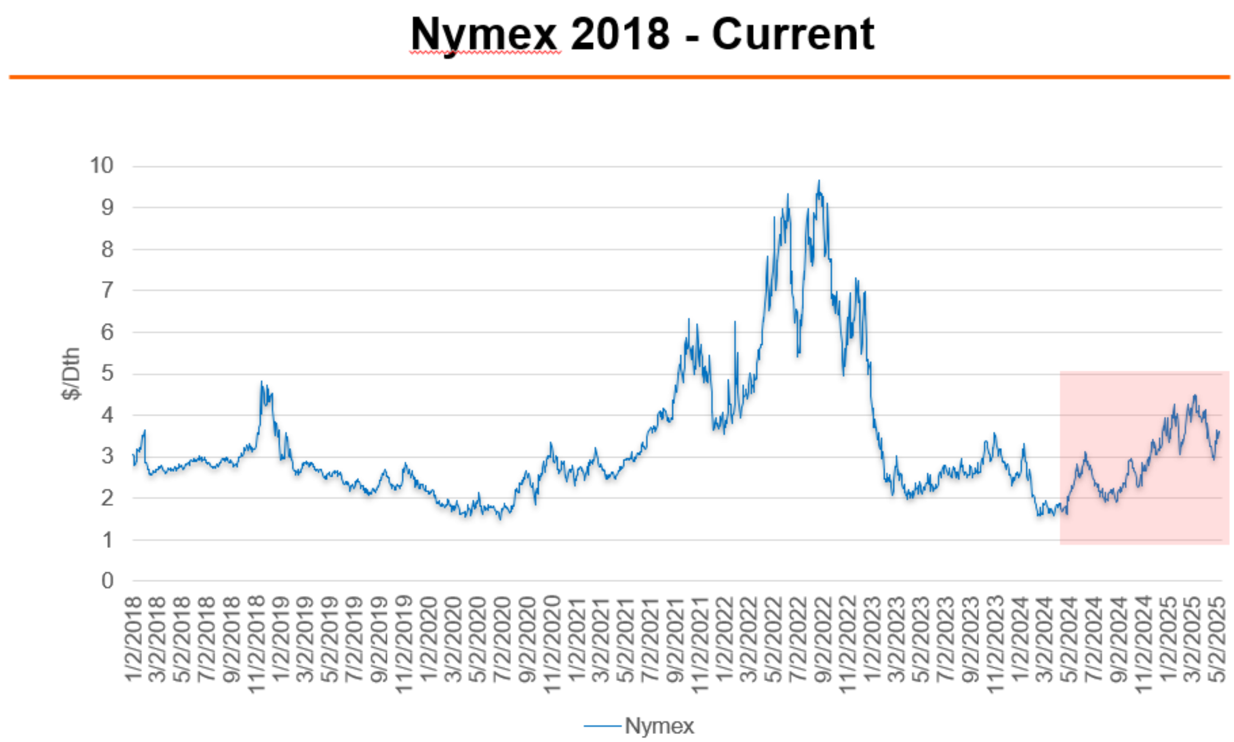
Capacity Releases / Off-System Sales

Gas Supply Plan

1. Gas Procurement Objectives

As discussed in the body of the testimony of David F. Caffery herein, natural gas prices have been volatile during the most recent BGSS period, following the relative stability experienced during 2023. NYMEX prompt month daily prices have traded between $1.57/Dth in March 2024, to a high of $4.50 in March 2025, followed by a dramatic decline to about $2.95 in late April 2025. The June prompt month price is $3.59/Dth. The forward (May 8th) NYMEX strip used by the Company in this filing (see Item 8) shows that average prices are 40% higher than last year's NYMEX strip. Based upon the forward strip, prices are expected to increase $1.26/Dth above the June price by December 2025, as well as an additional $0.29/Dth in January of 2026, followed by a decrease from $5.14/Dth to an average of about $4.10/Dth during April 2026 through September 2026, the end of this BGSS period.

The history of NYMEX prompt month prices since 2018 is illustrated in the chart below. The chart shows the period commencing with the June 1 2024 BGSS filing shaded in pink. As the chart illustrates, after bottoming in May 2024 following the much warmer than normal winter in 2023/2024, prices have increased steadily through the first quarter of 2025 before falling back in the beginning of the second quarter. Much of this increase can be attributed to the colder than normal 2024/2025 winter resulting in increased demand throughout the US. Also, the increased focus on the use of gas under the Trump administration as well as the projected electricity demand increases driven by data centers is supporting higher prices for natural gas.



In response to the increased demand and resultant higher prices, US gas production has recently set an all-time peak of 106.5 Bcf/d. US national storage levels are currently 3% greater than the five-year average after having fallen to 20% below the five-year average during January 2025. Feedgas volumes for the US' eight LNG export facilities have recently averaged approximately 15.5 Bcf/d, a sizeable increase over the 12 Bcf/d average at this time last year. The feedgas volume is expected to further increase in late 2025 and 2026 as additional facility expansions come on line and the approval of new LNG export facilities is facilitated under the Trump administration. As a result, while overall demand for natural gas is expected to increase during the upcoming BGSS period, today's higher price levels are likely to incent producers to increase production to satisfy those increased demands and keep the market in a relative balance.

The Company achieves its gas procurement objectives through its management and optimization of many factors. First and foremost, the Company manages a diverse contract portfolio of natural gas transportation, storage, and peaking capacity on seven different pipelines, in addition to both LNG and LPA (propane) supplies from facilities on the Company's distribution system used for peaking purposes. The Company has optimized its transportation capacity portfolio over the past ten years such that the majority of its gas supply (greater than 90%) over the course of the year is sourced from the lower priced Marcellus/Utica supply regions. Furthermore, the Company holds over 70 Bcf of storage capacity in the Marcellus/Utica region, which provides the ability to inject lower priced gas during the April through October period, and then withdraw this lower priced inventory in winter months in lieu of paying higher winter prices. Also, the Company hedges approximately 50% of the RSG sales volumes during the year, further insulating its customers from potential price spikes throughout the year. In addition, the Company aggressively utilizes any excess capacity that may exist from time to time above its firm customer requirements to make off system sales and capacity releases, from which the majority of the revenues flow back as a credit to the BGSS-RSG customers. Through the active and effective management of these resources, the Company consistently provides reliable, low-cost supply for its firm BGSS-RSG customers.

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 2024 update of the Natural Gas Sales Forecast. 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 reviews its pipeline transportation, storage, and peaking capacity supplies on an ongoing basis 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. As mentioned in prior BGSS Filings, 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 have adequate supply to meet its projected peak day requirements over the next several years.

The Company is a participant in 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. On December 12, 2019, the Company entered into a binding precedent agreement with Transco providing for 60,000 Dth/d of new firm transportation capacity to supplement its peak day supplies and to meet increased gas requirements in the Mount Laurel and Camden areas of its distribution system. Following its Transco's receipt of its FERC certificate, the Company began receiving REA service on August 1, 2024.

On December 31, 2021, the Company entered into a binding precedent agreement with Texas Eastern related to their Appalachia to Market II Project providing for 25,000 Dth/d of new firm transportation capacity to help meet incremental system peak day demand and increased gas requirements in the South Plainfield and Jamesburg areas of its gas distribution system. Texas Eastern's Appalachia to Market II Project provides for an expansion of Texas Eastern's system between the Marcellus/Utica supply regions in southwest Pennsylvania and central New Jersey through the replacement of older gas-fired compressor units with lower emission electric and more modern gas-fired compression in the state of Pennsylvania. Texas Eastern filed their FERC certificate application seeking approval of the Appalachia to Market II Project on July 6, 2022. The Project received its FERC certificate authorizing the project on October 23, 2023, and the in-service date of the Project is projected to be November 1, 2025. The initial volume that the Company will receive from the project will be 20,227 Dth/d effective November 1, 2025, which will then increase to the full volume of 25,000 Dth/d effective November 1, 2026.

Both the Regional Energy Access Project and the Appalachia to Market II Project will further enhance the Company's ability to efficiently access low-cost Marcellus/Utica supplies to the benefit of its customers.

Effective April 1, 2025, the Company replaced its Gulf South Petal storage contract with a new storage contract with Enbridge for their Bobcat Storage. Due to the increased demand for production area storage services in the Gulf Coast region to support the LNG export industry, Gulf South increased the price of the Petal storage service from $0.375/Dth to $0.44/Dth to effective November 1, 2024. The Company was able to contract for the new Bobcat storage service with Texas Eastern for a similar storage service at a rate of $0.21/Dth. The new contract is for a term of five (5) years and provides for a storage capacity of 2 Bcf in comparison to the 1 Bcf under the Petal storage contract. As a result, for less money, the Company was able to double the production area storage capacity under contract to both protect against supply disruptions as well as to increase the ability to make off-system sales into the Transco Zone 4 and 5 markets.

Additionally, as set forth by the Board in its April 25, 2018, order adopting the stipulation by the parties for final BGSS-RSG rates for the 2017-2018 BGSS-RSG period[1], the following table represents a listing of all contracts that have been extended pursuant to their evergreen provisions or terminated during the last BGSS Filing period:

Counterparty	Rate Schedule	Contract Number	Top Gas Quantity	Daily Contract Quantity (DTH)
Columbia	FTS	85029		18,750
Columbia	FTS	83272		12,500
EGTS	GSSTE	600043	14,249,916	162,995
EGTS	FTNN	525445		32,446
EGTS	FT	200316		63,832
EGTS (Combined with 200316)	FT	200391		22,019
Gulf South (Terminated)	FSS	56471	1,000,000	100,000
EGTS	FTNT	200482		50,000
Texas Eastern	FT-1	911682	-	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	400260	3,737,160	62,286
Texas Eastern	SS - 1	400259	1,453,340	20,762
Texas Eastern	FT - 1	911677	-	40,526
Texas Eastern	CDS	911679	-	120,000
Texas Eastern	FT - 1	911678	-	26,115
Texas Eastern	FT - 1	911680	-	110,000
Texas Eastern	FT - 1	911684	-	15,000
Texas Eastern	FT - 1	911683	-	30,000
Texas Eastern	FT - 1	911681	-	40,000
Texas Eastern	FT - 1	911685	-	50,000

[1] Board Order dated 4/25/2018 for the Decision and Order adopting initial decision and approving stipulation for final BGSS-RSG rates I/M/O PSE&G's 2017/2018 Annual BGSS commodity charge filing for its gas residential customers under its periodic pricing mechanism.

Texas Eastern	FT - 1	911938		25,000
Transco	FT	1006312	-	72,450
Transco	ESS	1008564	1,186,535	141,544
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	9090652/3	-	40,000
Transco	FT	9091058	-	10,000
Transco	FT	1041156	-	50,000
Transco	S - 2	1000823	6,158,589	68,514
Transco	FT	9066768	-	43,300

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.

The current term of the Requirements Contract ends on March 31, 2027. As discussed in the testimony of David F. Caffery herein, the Company is requesting a five-year extension to the term of the Requirements contract through March 31, 2032.

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 99% of its planned volume for the 2025 summer period, approximately 68% of its planned volume for the 2025-2026 winter period and approximately 42 % of its planned volume for the 2026 summer period. Hedging for the winter 2026-2027 period has just begun.

In addition to its transportation and peaking assets, PSEG ERT maintains approximately 73 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 31. 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 2024-2025 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 2025. For the upcoming BGSS period that is covered by this filing, the Company has projected $94.3 million in credits to its residential customers attributed to capacity release and off-system sales. As can be seen on the attached schedule, off-system sales credits for the 4 months ending April 2025 total $68.5 million, representing an increase of about 65% over the corresponding period last year. The Company's 2023 and 2024 winter period off-system sales were limited a bit due to the significantly warmer than normal weather, resulting in significant declines in prices and margins. In contrast, the months of January and February, 2025 were colder than normal resulting in higher gas demand and allowing the Company to realize significantly greater off-system sales through the optimization of its gas supply portfolio.

Off System Sales -- Revenues,
Costs and Margins

2018 - 2025

Year	BGSS-RSG OSS Revenue (1)	BGSS-RSG OSS Cost (2)	BGSS-RSG OSS Margins (3)
2018	$194,555,168	$124,011,106	$70,544,017
2019	$79,655,383	$59,067,798	$20,587,585
2020	$95,986,987	$75,386,530	$20,600,457
2021	$162,784,140	$123,967,006	$38,817,133
2022	$448,755,709	$299,602,376	$149,153,332
2023	$180,606,178	$108,964,826	$71,641,353
2024	$189,539,545	$111,896,562	$77,642,983
2025*	$131,784,859	$63,273,344	$68,511,515

*Note: Through April 2025
Estimate

Attachment D

Support for Balancing Charge
& Storage Inventory Carrying Charge
(Including Update for A&G Charge)

Balancing Charge - Annual Allocated Cost

Firm Capacity Allocation:	Total (Mdth/day)	Capacity Used for Balancing (Mdth/day)	Percent Allocated to Balancing Use
Base FT	866.2	0.0	0.0%
Storage	894.2	453.2	50.7%
Balancing FT	321.6	321.6	100.0%
Peaking	556.6	556.6	100.0%
	2,638.5	1,331.4	

	Total Cost	Percent Allocated to Balancing Use	Allocated Cost
Fixed Cost Allocation:			
Base FT	$211,703.0	0.0%	$0.0
Storage	$125,879.7	50.7%	$63,803.5
Balancing FT	$57,365.9	100.0%	$57,365.9
Peaking	$23,861.1	100.0%	$23,861.1
	$418,809.8		
Variable Cost Allocation:			
Base FT	$0.0	0.0%	$0.0
Storage	$9,288.0	50.7%	$4,707.7
Balancing FT	$0.0	100.0%	$0.0
Peaking	$1,468.8	100.0%	$1,468.8
	$10,756.9		
Total Annual Allocated Costs ($000)			**$ 151,207.1**

Balancing Use Billing Determinants - Oct - May (MDth)	187,091
Balancing Charge - Annual Allocated Cost ($/Dth)	$ 0.80820
Storage Inventory Carrying Charge ($/Dth) (page 2)	$ 0.03362
Revenue Requirement on Gas Production Plant Charge ($/Dth) (page 3)	$ 0.05614
Total Balancing Charge (excl. losses) ($/Dth)	$ 0.89796
Total Balancing Charge (incl. losses @ 2%) ($/Dth)	$ 0.91629
Total Balancing Charge (incl. SUT) ($/Dth)	**$ 0.97699**
Total Balancing Charge (incl. SUT) ($/Therm)	**$ 0.097699**

Storage Inventory Carrying Charge

	12 Months Oct 2025- Sept 2026 (000)
RSG Inventory Cost	$ 141,151
BGSS-F Inventory Cost	$ 32,670
BGSS-F Fixed Cost Deferred	$ 20,229
LNG + LPA	$ 2,551
Total Inventory Cost	**$ 196,600**
Total Annual Storage Carrying Cost @ 9.14%	**$ 17,969**

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

Rate per Dth	MDth	Cost	**$/Dth**
Balancing	187,091	$ 6,289	**$ 0.03362**
Commodity	205,028	$ 11,680	**$ 0.05697**

Revenue Requirement on Gas Production Plants

		12 Months Oct 25 - Sep 26
2025	October	$708,933
	November	$726,905
	December	$666,760
2026	January	$671,680
	February	$671,599
	March	$666,518
	April	$1,344,771
	May	$1,375,071
	June	$1,532,535
	July	$753,464
	August	$688,980
	September	$696,282
Total		**$ 10,503,498**
Balancing Use Billing Determinants (MDth)		**187,091**
Revenue Requirement on Gas Production Plant Charge ($/Dth)		**$ 0.05614**

Gas Supply A&G

	12 Months Oct 25 - Sep 26
Direct Labor & Overhead	$ 9,367,184
Firm Sendout - Dth (000)	205,028
Gas Supply A&G Rate	$ 0.04569

<u>Attachment B</u>

Redlined and Proposed Tariff Sheets

PUBLIC SERVICE ELECTRIC AND GAS COMPANY — **XXX Revised Sheet No. 54**
Superseding
B.P.U.N.J. No. 17 GAS — **XXX Revised Sheet No. 54**

BGSS-RSG
BASIC GAS SUPPLY SERVICE-RSG
COMMODITY CHARGES APPLICABLE TO RATE SCHEDULE RSG
(Per Therm)

Estimated Non-Gulf Coast Cost of Gas	$ 0.057514 ~~$0.090719~~
Estimated Gulf Coast Cost of Gas	0.363428 ~~0.309816~~
Adjustment to Gulf Coast Cost of Gas	0.000000
Prior period (over) or under recovery	(0.086810) ~~(0.100730)~~
Adjusted Cost of Gas	0.334132 ~~0.299805~~
Commodity Charge after application of losses: (Loss Factor = 2.0%)..........................	$ 0.340951 ~~0.305923~~
Commodity Charge including New Jersey Sales and Use Tax (SUT)	$0.363539 ~~0.326190~~

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)
February 1, 2020 through March 31, 2020	($0.070340)	($0.075000)
April 1, 2020	$0.000000	$0.000000

PUBLIC SERVICE ELECTRIC AND GAS COMPANY | **XXX Revised Sheet No. 60 Superseding**

B.P.U.N.J. No. 17 GAS | **XXX Revised Sheet No. 60**

INFRASTRUCTURE IMPROVEMENT PROGRAM CHARGES

Rate Schedule		Base Distribution Charges Including SUT*	Infrastructure Advancement Program Charges	Infrastructure Advancement Program Charges Including SUT	Total Charges Including SUT
RSG					
Service Charge	per Month	$10.00	$0.00	$0.00	$10.00
Distribution Charges	per therm	0.579658	0.001818	0.001938	0.581597
Balancing Charge	per Balancing therm	~~0.100751~~ 0.097699	0.000000	0.000000	~~0.100751~~ 0.097699
Off-Peak Use	per therm	0.289829	0.000909	0.000969	0.290798
GSG					
Service Charge	per Month	27.27	0.09	0.10	27.37
Distribution Charge - Pre July 14, 1997	per therm	0.471796	0.000194	0.000207	0.472003
Distribution Charge - All Others	per therm	0.471796	0.000194	0.000207	0.472003
Balancing Charge	per Balancing therm	~~0.100751~~ 0.097699	0.000000	0.000000	~~0.100751~~ 0.097699
Off-Peak Use Dist Charge - Pre July 14, 1997	per therm	0.235898	0.000097	0.000103	0.236002
Off-Peak Use Dist Charge - All Others	per therm	0.235898	0.000097	0.000103	0.236002
LVG					
Service Charge	per Month	242.23	0.81	0.86	243.09
Demand Charge	per Demand therm	4.9354	0.0000	0.0000	4.9354
Distribution Charge 0-1,000 pre July 14, 1997	per therm	0.126443	-0.001034	-0.001103	0.125341
Distribution Charge over 1,000 pre July 14, 1997	per therm	0.047170	0.000462	0.000493	0.047662
Distribution Charge 0-1,000 post July 14, 1997	per therm	0.126443	-0.001034	-0.001103	0.125341
Distribution Charge over 1,000 post July 14, 1997	per therm	0.047170	0.000462	0.000493	0.047662
Balancing Charge	per Balancing therm	~~0.100751~~ 0.097699	0.000000	0.000000	~~0.100751~~ 0.097699
SLG					
Single-Mantle Lamp	per Unit per Month	15.7500	0.0000	0.0000	15.7500
Double-Mantle Lamp, inverted	per Unit per Month	15.7500	0.0000	0.0000	15.7500
Double Mantle Lamp, upright	per Unit per Month	15.7500	0.0000	0.0000	15.7500
Triple-Mantle Lamp, prior to January 1, 1993	per Unit per Month	15.7500	0.0000	0.0000	15.7500
Triple-Mantle Lamp, on and after January 1, 1993	per Unit per Month	80.2980	0.0000	0.0000	80.2980
Distribution Therm Charge	per therm	0.076954	0.000086	0.000092	0.077046

PUBLIC SERVICE ELECTRIC AND GAS COMPANY — **XXX Revised Sheet No. 65**
Superseding
B.P.U.N.J. No. 17 GAS — **XXX Revised Sheet No. 65**

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:

$9.38 in each month [$10.00 including New Jersey Sales and Use Tax (SUT)].

Distribution Charges:

Charge	Charge Including SUT	
$ 0.545460	$ 0.581597	per therm

Balancing Charge:

Charge	Charge Including SUT	
$0.091629	$0.097699	
~~0.094491~~	~~$0.100751~~	per Balancing Use Therm

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 60 for details of these charges.

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

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:

$25.67 in each month [$27.37 including New Jersey Sales and Use Tax (SUT)].

Distribution Charges:

Pre-July 14, 1997 *		All Others		
Charge	Charge Including SUT	Charge	Charge Including SUT	
$0.442676	$0.472003	$0.442676	$0.472003	per therm

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

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 60 for details of these charges.

Balancing Charge:

Charge	Charge Including SUT	
$0.091629 ~~0.094491~~	$0.097699 ~~$0.100751~~	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.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY | **XXX Revised Sheet No. 79**
Superseding
B.P.U.N.J. No. 17 GAS | **XXX Revised Sheet No. 79**

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:

$227.99 in each month [$243.09 including New Jersey Sales and Use Tax (SUT)].

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

Charge	Charge Including SUT	
$4.6287	$4.9354	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
$ 0.117553	$ 0.125341	$ 0.044701	$ 0.047662

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 60 for details of these charges.

Balancing Charge:

Charge	Charge Including SUT	
$0.091629 ~~0.094491~~	$0.097699 ~~$0.100751~~	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.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY **XXX Revised Sheet No. 112A**
Superseding
B.P.U.N.J. No. 17 GAS **XXX Revised Sheet No. 112A**

RATE SCHEDULE CSG
CONTRACT SERVICE
(Continued)

ECONOMICALLY VIABLE BYPASS
DELIVERY CHARGES:

Service Charge:

$1,004.32 in each month [$1,070.86 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.

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 61 for details of these charges.

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	
$0.091629 ~~0.094491~~	$0.097699 ~~0.100751~~	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.

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

PUBLIC SERVICE ELECTRIC AND GAS COMPANY **XXX Revised Sheet No. 54**
Superseding
B.P.U.N.J. No. 17 GAS **XXX Revised Sheet No. 54**

BGSS-RSG
BASIC GAS SUPPLY SERVICE-RSG
COMMODITY CHARGES APPLICABLE TO RATE SCHEDULE RSG
(Per Therm)

Estimated Non-Gulf Coast Cost of Gas	$ 0.057514
Estimated Gulf Coast Cost of Gas	0.363428
Adjustment to Gulf Coast Cost of Gas	0.000000
Prior period (over) or under recovery..	(0.086810)
Adjusted Cost of Gas	0.334132
Commodity Charge after application of losses: (Loss Factor = 2.0%)..........................	$ 0.340951
Commodity Charge including New Jersey Sales and Use Tax (SUT)	$ 0.363539

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)
February 1, 2020 through March 31, 2020	($0.070340)	($0.075000)
April 1, 2020	$0.000000	$0.000000

PUBLIC SERVICE ELECTRIC AND GAS COMPANY **XXX Revised Sheet No. 60**
Superseding
B.P.U.N.J. No. 17 GAS **XXX Revised Sheet No. 60**

INFRASTRUCTURE IMPROVEMENT PROGRAM CHARGES

Rate Schedule		Base Distribution Charges Including SUT*	Infrastructure Advancement Program Charges	Infrastructure Advancement Program Charges Including SUT	Total Charges Including SUT
RSG					
Service Charge	per Month	$10.00	$0.00	$0.00	$10.00
Distribution Charges	per therm	0.579658	0.001818	0.001938	0.581597
Balancing Charge	per Balancing therm	0.097699	0.000000	0.000000	0.097699
Off-Peak Use	per therm	0.289829	0.000909	0.000969	0.290798
GSG					
Service Charge	per Month	27.27	0.09	0.10	27.37
Distribution Charge - Pre July 14, 1997	per therm	0.471796	0.000194	0.000207	0.472003
Distribution Charge - All Others	per therm	0.471796	0.000194	0.000207	0.472003
Balancing Charge	per Balancing therm	0.097699	0.000000	0.000000	0.097699
Off-Peak Use Dist Charge - Pre July 14, 1997	per therm	0.235898	0.000097	0.000103	0.236002
Off-Peak Use Dist Charge - All Others	per therm	0.235898	0.000097	0.000103	0.236002
LVG					
Service Charge	per Month	242.23	0.81	0.86	243.09
Demand Charge	per Demand therm	4.9354	0.0000	0.0000	4.9354
Distribution Charge 0-1,000 pre July 14, 1997	per therm	0.126443	-0.001034	-0.001103	0.125341
Distribution Charge over 1,000 pre July 14, 1997	per therm	0.047170	0.000462	0.000493	0.047662
Distribution Charge 0-1,000 post July 14, 1997	per therm	0.126443	-0.001034	-0.001103	0.125341
Distribution Charge over 1,000 post July 14, 1997	per therm	0.047170	0.000462	0.000493	0.047662
Balancing Charge	per Balancing therm	0.097699	0.000000	0.000000	0.097699
SLG					
Single-Mantle Lamp	per Unit per Month	15.7500	0.0000	0.0000	15.7500
Double-Mantle Lamp, inverted	per Unit per Month	15.7500	0.0000	0.0000	15.7500
Double Mantle Lamp, upright	per Unit per Month	15.7500	0.0000	0.0000	15.7500
Triple-Mantle Lamp, prior to January 1, 1993	per Unit per Month	15.7500	0.0000	0.0000	15.7500
Triple-Mantle Lamp, on and after January 1, 1993	per Unit per Month	80.2980	0.0000	0.0000	80.2980
Distribution Therm Charge	per therm	0.076954	0.000086	0.000092	0.077046

PUBLIC SERVICE ELECTRIC AND GAS COMPANY **XXX Revised Sheet No. 65**
Superseding
B.P.U.N.J. No. 17 GAS **XXX Revised Sheet No. 65**

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:

$9.38 in each month [$10.00 including New Jersey Sales and Use Tax (SUT)].

Distribution Charges:

Charge	Charge Including SUT	
$ 0.545460	$ 0.581597	per therm

Balancing Charge:

Charge	Charge Including SUT	
$0.091629	$0.097699	per Balancing Use Therm

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 60 for details of these charges.

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

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:

$25.67 in each month [$27.37 including New Jersey Sales and Use Tax (SUT)].

Distribution Charges:

Pre-July 14, 1997 *		All Others		
Charge	Charge Including SUT	Charge	Charge Including SUT	
$0.442676	$0.472003	$0.442676	$0.472003	per therm

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

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 60 for details of these charges.

Balancing Charge:

Charge	Charge Including SUT	
$0.091629	$0.097699	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.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY **XXX Revised Sheet No. 79**
Superseding
B.P.U.N.J. No. 17 GAS **XXX Revised Sheet No. 79**

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:

$227.99 in each month [$243.09 including New Jersey Sales and Use Tax (SUT)].

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

Charge	Charge Including SUT	
$4.6287	$4.9354	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
$ 0.117553	$ 0.125341	$ 0.044701	$ 0.047662

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 60 for details of these charges.

Balancing Charge:

Charge	Charge Including SUT	
$0.091629	$0.097699	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.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY **XXX Revised Sheet No. 112A**
Superseding
B.P.U.N.J. No. 17 GAS **XXX Revised Sheet No. 112A**

RATE SCHEDULE CSG
CONTRACT SERVICE
(Continued)

ECONOMICALLY VIABLE BYPASS
DELIVERY CHARGES:

Service Charge:
$1,004.32 in each month [$1,070.86 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.

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 61 for details of these charges.

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	
$0.091629	$0.097699	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.