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PSEG
Services Corporation

VIA BPU ELECTRONIC MAIL

June 1, 2021

In the Matter of Public Service Electric and Gas Company's 2021/2022
Annual BGSS Commodity Charge Filing for its Residential Gas Customers
Under its Periodic Pricing Mechanism and for Changes in its Balancing Charge

Docket No. GR_____________

Aida Camacho-Welch, Secretary
New Jersey Board of Public Utilities
44 South Clinton Avenue, 9th Floor
Post Office Box 350
Trenton, New Jersey 08625-0350

Dear Secretary Camacho-Welch:

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 maintain the current BGSS default commodity charge applicable to residential customers for service rendered on and after October 1, 2021. The Company is also requesting an increase in its Balancing Charge rate. The impact of the proposed change to the Balancing Charge on a typical residential heating customer using 172 therms per month during the winter months and 1,040 therms on an annual basis is an annual increase of approximately 0.60%.

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,

Matthew Weissman

Matthew M. Weissman

C Attached Service List (electronic)

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

Motion – dated June 1, 2021

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 2021/2022 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 November 1st and

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

MINIMUM FILING REQUIREMENTS

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

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

2020/2021 ANNUAL BGSS COMMODITY CHARGE FILING

4) On June 1, 2020, the Company made its 2020/2021 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 2020/2021 BGSS filing the Company requested to maintain the then current BGSS Commodity Charge rate of $0.320127 cents per therm (including losses and SUT) through

September 30, 2021. This request was supported by the direct testimony of David F. Caffery, in which he addressed all of the Minimum Filing Requirements and provided the basis for the decrease in the BGSS rate.

6) The Company also requested a decrease in its Balancing Charge, which recovers the cost of providing storage and peaking services. The Company requested a change in the Balancing Charge from \$0.098620 per balancing therm (including losses and SUT) to the current charge of \$0.085723 per balancing use therm (including losses and SUT). The decrease in the balancing charge was supported by Mr. Caffery.

7) Additionally, the Company requested a change in its Storage Inventory Carrying Charge, which is recovered through the balancing and commodity charges. The requested charge was \$0.003201 per balancing use therm (excluding losses & SUT) for the balancing portion and \$0.005397 per therm (excluding losses & SUT) for the commodity portion using the applicable billing determinants for each.

8) The 2020/2021 filing by the Company estimated a BGSS revenue increase of \$31M (exluding losses and SUT) would be required for the period of October 1, 2020 through September 30, 2021. However, based on the testimony of Mr. Caffery, the Company filed to maintain the then current BGSS rate..

9) Subsequent to PSE&G's June 1, 2020 filing in this matter, on July 15, 2020 the Company made a compliance filing in response to the Board's Orders *In the Matter of the Petition of Public Service Electric and Gas Company for Approval the Next Phase of the Gas System Modernization Program and Associated Cost Recovery (December 2019 GSMP II Rate Filing)* in BPU Docket No. GR19120002. In that matter, the BGSS-RSG Commodity Charge

was decreased from $0.320127 per therm (including losses and SUT) to $0.320069 per therm (including losses and SUT) effective July 16, 2020.

10) Residential annual bills comparing the then current and proposed Balancing Charge, pursuant to the 2020/2021 filing were included in the form of public notice attached as Attachment C to that motion.

11) Notices setting forth the Company's June 1, 2020 request to maintain the BGSS Commodity Charge and request to decrease 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.

12) Public hearings were scheduled and conducted telephonically on August 31, 2020, at 4:30 p.m. and 5:30 p.m. No member of the public appeared and/or spoke at the public hearings.

13) PSE&G, Board Staff, and Rate Counsel agreed, on a provisional basis, to maintain the BGSS-RSG Commodity Charge and decrease the Balancing Charge as of October 1, 2020, 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 23, 2020. As a result, the BGSS Balancing Charge was provisionally decreased from $0.098620 per balancing use therm (including losses and SUT) to $0.085723 per balancing use therm (including losses and SUT) for service rendered on and after October 1, 2020.

14) On October 5, 2020, the Board transmitted this matter to the Office of Administrative Law as a contested case, where it was subsequently assigned to the Honorable Gail Cookson, Administrative Law Judge ("ALF"). ALJ Cookson held a telephonic prehearing conference on November 20, 2020.

15) Subsequent to the September Order, on November 23, 2020 the Company made a compliance filing in response to the Board's Orders *In the Matter of the Petition of Public Service Electric and Gas Company for Approval the Next Phase of the Gas System Modernization Program and Associated Cost Recovery Mechanism ("GSMP II") (June 2020 GSMP II Rate Filing)* in BPU Docket No. GR20060464. In that matter, the BGSS-RSG Commodity Charge was decreased from $0.320069 per therm (including losses and SUT) to $0.320004 per therm (including losses and SUT) effective December 1, 2020.

16) PSE&G, Board Staff, and Rate Counsel subsequently completed their review of the Company's 2020/2021 BGSS filing, and agreed that the Company's: (a) BGSS Commodity Service, tariff rate BGSS-RSG of $0.320004 per therm (including losses and SUT) shall be maintained and would be deemed final; (b) the Balancing Charge of $0.085723 per balancing use therm (including losses and SUT) would remain in effect and also be deemed final. The Board approved this stipulation for final rates on March 3, 2021.

17) Subsequent to the March Order, on May 19, 2021 the Company made a compliance filing in response to the Board's Orders *In the Matter of the Petition of Public Service Electric and Gas Company for Approval of the Next Phase of the Gas System Modernization Program and Associated Cost Recovery Mechanism ("GSMP II") (December 2020 GSMP II Rate Filing)* in BPU Docket No. GR20120771. In that matter, the BGSS-RSG Commodity Charge was

decreased from $0.320004 per therm (including losses and SUT) to $0.319937 per therm (including losses and SUT) effective June 1, 2021.

2021/2022 ANNUAL BGSS COMMODITY CHARGE FILING

18) The Company is making this 2021/2022 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.

19) In this Motion the Company is requesting to maintain the current Board approved BGSS rate of $0.319937 cents per therm (including losses and SUT) through September 30, 2022. 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 maintain the current BGSS-RSG rate.

20) The Company is also requesting an increase in its Balancing Charge, which recovers the cost of providing storage and peaking services. The Company requests a change in the Balancing Charge from $0.085723 per balancing use therm (including losses and SUT) to $0.093477 per balancing use therm (including losses and SUT). The increase in the balancing charge is supported by Mr. Caffery (Attachment A).

21) The Company is also requesting a change in its Storage Inventory Carrying Charge, which is shown on page 2 of Attachment D and is recovered through the Balancing and Commodity Charges. The requested charge is $0.002778 per balancing use therm (excluding losses and SUT) for the balancing portion and $0.004610 per therm (excluding losses and SUT) for the commodity portion using the applicable send out for each. The current charges are $0.003201

cents per balancing therm (excluding losses and SUT) for the balancing portion and $0.005397 cents per therm (excluding losses and SUT) for the commodity portion.

22) Natural gas prices during the most recent period have increased from the levels experienced at this time last year. NYMEX prompt month daily prices have traded between approximately $2.50/Dth and $3.25/Dth since the middle of January 2021, with current prices about $3.00/Dth. This compares with a NYMEX price of $1.72/Dth at this time last year. The forward (May 6th) NYMEX strip used by the Company in this filing (see Item 8) shows that prices are 15.5% higher than last year's NYMEX strip. Based upon the forward strip, prices are expected to remain essentially flat through the rest of 2021, followed by a modest increase during the winter months and then a reduction for the balance of the BGSS period. This relative stability in forward prices largely has occurred due to a recent supply/demand balance in the market with demand recovering from last year's Covid related declines and production increasing to pre-Covid levels to meet demand increases. Historically, producers have shown an inclination to increase production quickly in anticipation of higher market prices, which results in a moderation of prices, and we have seen some of that increased production beginning to occur. This, combined with the uncertainty presently priced into the market, indicates that the current level of the NYMEX strip near or above $3.00/Dth may be overly bullish, supporting the Company's proposal to maintain the current BGSS-RSG rate.

23) The Company estimates that an increase in BGSS revenue of approximately $49 million (excluding losses and SUT) would be required for the period of October 1, 2021 through September 30, 2022. However, as stated in the testimony of Mr. Caffery, the Company is

requesting to maintain the current Board approved rate of $0.319937 per therm (including losses and SUT) due to the current state of the natural gas market.

24) Residential annual bills (inclusive of the current Board approved BGSS-RSG rate) comparing the current and proposed Balancing Charge are included in the form of public notice attached hereto as Attachment C. The impact of the requested Balancing Charge change for a typical residential gas heating customer using 172 therms per month during the winter months and 1,040 therms on an annual basis is an increase in the winter monthly bill of approximately 0.78% and on an annual basis the impact is an increase of approximately 0.60%. 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, 2021 and February 1, 2022. The impact of such potential self-implementing increases on an average residential bill (1,200 therms annually) would be an increase of approximately $8.57 per winter month on December 1, 2021 and an additional approximate increase of $8.58 per winter month on February 1, 2022.

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

26) The Company is also requesting approval to potentially procure RNG, and include the supply and costs in the BGSS-RSG portfolio. The Company has recently begun to explore the potential to incorporate renewable natural gas (RNG) supplies into its gas supply mix in an effort to help meet the NJ State's 2018 Clean Energy Act targets as well the targeted methane reduction goals set forth in the State's Energy Master Plan (EMP). RNG has started to make inroads into the gas supply mix in several areas of the US from landfill sources, wastewater

treatment plants, and from the use of anaerobic digesters, which turn food and farm waste into pipeline quality RNG. For example, Vermont Gas Systems offers a separate rate adder for customers who opt-in to RNG supply, while the Oregon Public Utility Commission has adopted rules to allow utility companies to recover prudently incurred RNG implementation costs, up to a voluntary percentage of overall supply costs. While the Company does not currently purchase any RNG, it has been in discussions with one customer regarding the potential to accept RNG into its distribution system as part of its gas supply mix, and anticipates that additional customers and/or project developers may approach the Company with similar requests to interconnect and sell RNG supply to the Company. This project(s) would be supportive and is aligned with Goal 2.3.7 of the EMP, which aims to maximize the use of organic waste through anaerobic digestion for natural gas pipeline injection (or electric production). In addition, the Company has met with several of its major pipeline suppliers over the past several months, all of which are exploring the introduction of RNG into their pipeline systems. The Company is assessing both the gas quality differences associated with RNG as well as the higher price (it is the Company's understanding that RNG can cost several times as much as natural gas) as it considers the potential introduction of RNG supplies. The Company has not included any RNG supplies or costs in the instant BGSS filing. While the Company's consideration of introducing modest amounts of RNG into its gas supply mix is in the early stages, the Company anticipates that this may be an area of growing importance as it strives to meet its Environmental, Social, and Governance goals and further reduce methane emissions. Additionally, as the Company anticipates that the volumes of RNG will be modest in relation to its non-RNG supplies, it would expect that the impact on its overall weighted average cost of supply in the near term to be small. As an example, the Company's current discussions regarding RNG involves approximately 1,000 Dth/d of supply. To put this in perspective, the Company's projected RSG sendout in the instant filing is about 150 Bcf. A supply of 1,000 Dth per day of RNG would equate to 0.365 Bcf per year, or about 0.24% of the Company's total RSG supply. Because the introduction of RNG is a new feature of the Company's BGSS filing, the Company believes it appropriate to cap the amount of RNG that the Company could procure to not exceed 4,000 Dth/d, or 1% of its annual gas supply.

27) 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. Consistent with the Board's March 19, 2014 Order, 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, 2022 to March 31, 2027, 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.

28) 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[1] 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.

[1] 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.

CONCLUSION

WHEREFORE, Public Service hereby requests that the Board issue a written Order by October 1, 2021 approving:

(1) the Company's proposal to maintain its current Board approved BGSS-RSG Commodity Charge of $0.319937 per therm (including losses and SUT), with the costs presented herein as the basis of the cost of BGSS-RSG supply;

(2) a change in the Balancing Charge from $0.085723 per balancing use therm (including losses and SUT) to $0.093477 per balancing use therm (including losses and SUT) effective with the billing of month of October;

(3) the Company's proposal to potentially acquire up to 4,000 dth/d (1% of total supply) for inclusion in the Company's BGSS-RSG gas supply, with costs included in the Company's BGSS-RSG weighted average cost of supply in future BGSS filings;

(4) 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;

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

Respectfully submitted,

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

BY: Matthew Weissman

Matthew Weissman
Managing Counsel – State Regulatory
PSEG Services Corporation
80 Park Plaza, T5G
Newark, New Jersey 07102

DATED: June 1, 2021
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

DAVID F. CAFFERY

Sworn to and subscribed to
before me this 1st day of
June, 2021

Deborah Marks

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

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 maintain the current Basic Gas Supply Service (BGSS) default Commodity Charge applicable to residential customers. The BGSS-RSG Commodity rate would remain at the current Board approved charge of $0.319937 per therm (including losses and New Jersey Sales and Use Tax, SUT). This charge is requested to remain in effect from October 1, 2021 through September 30, 2022 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 an increase in its Balancing Charge, which recovers the cost of providing storage and peaking services. The increased charge reflects a projected increase in the costs of interstate pipeline transportation services that make up the Company's gas supply portfolio. This projected increase is the result of two factors: the absence of sizeable pipeline refunds included in last year's filing following the settlement of the Transco and Texas Eastern rate cases, as well as a projected Texas Eastern rate case filing expected to be made before the end of this year. As a result, the Company requests a change in the Balancing Charge from $0.085723 per balancing use therm (including losses and SUT) to $0.093477 per balancing use therm (including losses and SUT). The annual bill impact of the proposed Balancing Charge change is an increase of approximately 0.60% for a typical residential gas heating customer using 172 therms per month during the winter and 1,040 therms annually.

As directed by Staff, the Company utilized May 6th NYMEX prices for the computations included in this filing, resulting in a projected under-recovery at the end of September 2022 of $49M (excluding losses and SUT - as shown in Item 7). This would permit the Company to file for an increase in the BGSS-RSG rate effective October 1st. However, because of certain factors discussed further in my testimony, and the potential impact of those factors on the projected under-recovery, the Company is proposing to keep the current BGSS-RSG rate in effect for the upcoming BGSS period through September 2022.

The RSG customer class is expected to be over-recovered by $30.4 million by September 30, 2021. This period began in October of 2020 with an over recovery of $16.1 million (there was no interest rollover).

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

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

- *Gas Procurement Objectives*
- *Current and Forecasted Gas Service Requirements*
- *Projected Sources of Capacity*
- *Affiliate Relationships/Asset Management*
- *Hedging Plan and Strategy*
- *Capacity Releases/Off-System Sales*

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 $0.353406 per therm (including losses and SUT), would be required to reduce the projected under-collection of $49M (excluding losses and SUT) to zero based on May 6th NYMEX prices. As noted above, however, the Company is requesting to maintain the current Board-approved rate of $0.319937 per therm (including losses and SUT).

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 $1.8M of interest has been included.

Natural gas prices during the most recent period have increased from the levels experienced at this time last year. NYMEX prompt month daily prices have traded between approximately $2.50/Dth and $3.25/Dth since the middle of January 2021, with current prices about $3.00/Dth. This compares with a NYMEX price of $1.72/Dth at this time last year. The forward (May 6th) NYMEX strip used by the Company in this filing (see Item 8) shows that prices are 15.5% higher than last year's NYMEX strip. Based upon the forward strip, prices are expected to remain essentially flat through the rest of 2021, followed by a modest increase during the winter months and then a reduction for the balance of the BGSS period. This relative stability in forward prices largely has occurred due to a recent supply/demand balance in the market with demand recovering from last year's Covid related declines and production increasing to pre-Covid levels to meet demand increases. Historically, producers have shown an inclination to increase production quickly in anticipation of higher market prices, which results in a moderation of prices, and we have seen some of that increased production beginning to occur. This, combined with the uncertainty presently priced into the market, indicates that the current level of the NYMEX strip near or above $3.00/Dth may be overly bullish, supporting the Company's proposal to maintain the current BGSS-RSG rate.

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 maintaining 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% on December 1, 2021 and February 1, 2022, 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 $52.7M, that were credited to BGSS-RSG recovery costs from May 2020 through April 2021. The second schedule shows that the Company has included one refund estimated to be $1 million associated with the anticipated settlement of a Transcontinental Gas Pipe Line Company, LLC proceeding.

5. Cost of Gas Sendout by Component

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

6. 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.

With respect to the CSG credits from the NJ generation facilities, in July of 2020 PSEG Power announced that it was undertaking a Strategic Review of its Fossil generation portfolio. That review is currently underway and may result in the sale of PSEG Power's NJ generation facilities. Should the facilities be sold, that transaction is expected to be finalized sometime during this BGSS filing period. Given the uncertainty associated with the final outcome of this review, any effect of this potential transaction on contributions to BGSS-RSG will be reflected in next year's BGSS-RSG filing.

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 2020 to September 2021 period is positive and, therefore, has been included in the calculation of the new BGSS charge on Item 2. There are two schedules that include data shown for the projected period: one of these schedules shows the projected over/(under) recovery based on the current BGSS rate. The second is based on the BGSS rate that would be necessary to achieve a zero balance at September 2022 based on the May 6, 2021 NYMEX prices. Also included are supporting workpapers for the reconciliation period.

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

This schedule details the monthly gas prices for the end of the reconciliation period through September 2021 and the projected period through September 2022 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 15.5%. These estimates reflect the future NYMEX prices on May 6, 2021, 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. <u>Historic Service Interruptions</u>

This schedule provides the details of all service interruptions during the past 12 months. Included are all of the interruptible transportation and sales services, as well as the date and duration of the interruption and the number of customers affected. There were no service interruptions for operational purposes during the past 12 months.

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

Included in this Item are the Company's last four quarterly hedging reports as filed with the Board. The reports provide gas purchase volume requirements and price-hedged volumes broken down into the Non-Discretionary Method and the Dollar Budget Method. As agreed to in the Settlement of the 2009/2010 BGSS proceeding, the Company has revised the Quarterly Hedging Report beginning with the June 30, 2010 report. The revised report provides more detail, including data on targets and a comparison of the two hedging methods.

The Company continues to utilize hedging as a means to stabilize the price of gas to the residential customer. The consistent goal of the program is to assure a reasonable level of price stability, not necessarily achieving the lowest possible price. The Company to date has hedged approximately 96% of its planned volume for the 2021 summer period, approximately 59% of its planned volume for the 2021-2022 winter period and approximately 37% of its planned volume for the 2022 summer period. Hedging for the winter 2022-2023 period has just begun in May 2021. 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. Affiliate Gas Supply Transactions

As agreed to in the Settlement of the 2017/18 BGSS proceeding Item 13 now outlines all the principal terms of the Gas Requirements Contract between PSE&G and PSEG ER&T which provides BGSS services for all of PSE&G's gas customers. There have been no changes to any of the terms and provisions of the Gas Requirements Contract since last year's BGSS Filing.

14. Supply and Demand Data

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. Actual Peak Day Supply and Demand

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. Capacity Contract Changes

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 (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. FERC Pipeline Activities

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. Gas Supply Plan

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

OTHER CHARGES

Attachment D includes the supporting information for an increase in the Balancing Charge based on the 8 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 and peaking services. The requested change is from the current Balancing Charge of $0.085723 cents per balancing therm (including losses and SUT) to a Balancing Charge of $0.093477 cents 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 $0.080193 cents per balancing therm (excluding losses and SUT), which is an increase from the previous charge of $0.073905 cents 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 $0.002778 cents per balancing therm (excluding losses & SUT) for the balancing portion and $0.004610 cents per therm (excluding losses & SUT) for the commodity portion (included in Item 2) using the applicable billing determinants for each. The current charges are $0.003201 cents per balancing therm (excluding losses & SUT) for the balancing portion and $0.005397 cents 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 $0.002945 cents per balancing use therm (excluding losses & SUT), which is an increase from the previous charge of $0.001683 cents 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 $0.03592 per dth and the updated rate is $0.03969 per dth. This rate recovers the administrative cost associated with PSEG Energy Resources & Trade's provision of gas supply services to PSE&G.

Renewable Natural Gas

The Company has recently begun to explore the potential to incorporate renewable natural gas (RNG) supplies into its gas supply mix in an effort to help meet the NJ State's 2018 Clean Energy Act targets as well the targeted methane reduction goals set forth in the State's Energy Master Plan (EMP). RNG has started to make inroads into the gas supply mix in several areas of the US both from landfill sources, wastewater treatment plants, as well as from the use of anaerobic digesters, which turn food and farm waste into pipeline quality RNG. For example, Vermont Gas Systems offers a separate rate adder for customers who opt-in to RNG supply, while the Oregon Public Utility Commission has adopted rules to allow utility companies to recover prudently incurred RNG implementation, up to a voluntary percentage of overall supply costs.

While the Company does not currently purchase any RNG, it has been in discussions with one customer regarding the potential to accept RNG into its distribution system as part of its gas supply mix, and anticipates that additional customers and/or project developers may approach the Company with similar requests to interconnect and sell RNG supply to the Company. This project(s) would be supportive and is aligned with Goal 2.3.7 of the EMP, which aims to maximize the use of organic waste through anaerobic digestion for natural gas pipeline injection (or electric production). In addition, the Company has met with several of its major pipeline suppliers over the past several months, all of which are exploring the introduction of RNG into their pipeline systems. The Company is assessing both the gas quality differences associated with RNG as well as the higher price (it is the Company's understanding that RNG can cost several times as much as natural gas) as it considers the potential introduction of RNG supplies. The Company has not included any RNG supplies or costs in the instant BGSS filing.

While the Company's consideration of introducing modest amounts of RNG into its gas supply mix is in the early stages, the Company anticipates that this may be an area of growing importance as it strives to meet its Environmental, Social, and Governance goals and further reduce methane emissions. Additionally, as the Company anticipates that the volumes of RNG will be modest in relation to its non-RNG supplies, it would expect that the impact on its overall weighted average cost of supply in the near term to be small. As an example, the Company's current discussions regarding RNG involves approximately 1,000 Dth/d of supply. To put this in perspective, the Company's projected RSG sendout in the instant filing is about 150 Bcf. A supply of 1,000 Dth per day of RNG would equate to 0.365 Bcf per year, or about 0.24% of the Company's total RSG supply. Because the introduction of RNG is a new feature of the Company's BGSS filing, the Company believes it appropriate to cap the amount of RNG that the Company could procure to not exceed 4,000 Dth/d, or 1% of its annual gas supply.

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. Consistent with the Board's March 19, 2014 Order, 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, 2022 to March 31, 2027, 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, 2021 or earlier, should the Board deem it appropriate, approving: (1) the Company's proposal to maintain the current BGSS Commodity Charge of $0.319937 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) an increase in the

Balancing Charge to $0.093477 per balancing use therm (including losses and SUT), (3) the Company's proposal to acquire RNG supply up to 4,000 Dth/d (1% of total supply) for inclusion in the Company's BGSS-RSG gas supply, with the costs included in the Company's BGSS-RSG weighted average cost of supply in future BGSS filings, and (4) 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
VICE PRESIDENT – GAS SUPPLY

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

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

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

2. Computation of Proposed BGSS Rate

Effective October 1, 2021

COMPUTATION OF
BGSS COMMODITY CHARGE FOR RSG
OCTOBER 2021 - SEPTEMBER 2022

($-000)

	$000	$/DTh
FIXED COSTS:		
FT DEMAND COST	$ 161,350	$1.0605
STORAGE DEMAND/CAPACITY COSTS	78,090	$0.5133
STORAGE INJ & W/D COSTS	6,021	$0.0396
PEAKING COSTS	16,106	$0.1059
	261,568	**$1.7193**
CONTRIBUTIONS	(29,446)	($0.1935)
PIPELINE REFUNDS	(752)	($0.0049)
OFF-SYSTEM SALES MARGIN	(28,934)	($0.1902)
ELECTRIC CONTIBUTION - CSG	(7,105)	($0.0467)
NET TOTAL FIXED COST	**$ 195,330**	**$1.28390**
FIRM RSG SENDOUT (MDTh) 10/21 - 9/22	**152,138**	
TOTAL NON-GULF COAST COST ($/DTh)		**$1.28390**
Removal of Balancing Cost (incl. above)		(0.59537)
Inventory Carrying Charge Allocation		0.04610
Gas Supply A&G		0.03969
Total Adjustments		**($0.50958)**
ADJUSTED NON-GULF COAST COST ($/DTh)		**$0.77432**
(OVER)/UNDER RECOVERY @ 9/30/21 - INCL. INT.	**($32,179)**	**($0.21150)**
GULF COAST COST OF GAS ($/DTh)		
FT COMMODITY AND FUEL		0.00000
COST OF GAS		**2.68537**
TOTAL GULF COAST COST		**$2.68537**

SUMMARY OF CHARGE COMPONENTS

	(cents/therm) BGSS-RSG	(dollars/therm) BGSS-RSG
Estimated Non-Gulf Coast Cost of Gas	7.7432	$ 0.077432
Estimated Gulf Coast Cost of Gas	26.8537	$ 0.268537
Adjustment to Gulf Coast Cost of Gas	-	$ -
Prior Period (Over)/Under Recovery	(2.1150)	$ (0.021150)
Adjusted Cost of Gas	32.4819	$ 0.324819
COMMODITY CHARGE (after application of losses 2.0%)	**33.1448**	**$ 0.331448**
COMMODITY CHARGE (including SUT)	**35.3406**	**$ 0.353406**

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

Notice (including Typical Bills) – Attachment C

NOTICE TO PUBLIC SERVICE ELECTRIC AND GAS COMPANY GAS CUSTOMERS

IN THE MATTER OF PUBLIC SERVICE ELECTRIC AND GAS COMPANY'S 2021/2022 ANNUAL BGSS COMMODITY CHARGE FILING FOR ITS RESIDENTIAL GAS CUSTOMERS UNDER ITS PERIODIC PRICING MECHANISM AND FOR CHANGES IN ITS BALANCING CHARGE

Notice of Filing and Notice of Public Hearings

Docket No. XXXXXXXXXX

TAKE NOTICE that, on June 1, 2021, Public Service Electric and Gas Company ("Public Service" or "the 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 maintain the current default Basic Gas Supply Service ("BGSS-RSG") Commodity Charge applicable to its Residential Service ("RSG") customers and to increase its Balancing Charge to customers receiving service under RSG, General Service ("GSG"), Large Volume Service ("LVG") and Contract Service ("CSG") where applicable effective October 1, 2021, or earlier should the Board deem it appropriate. The requested increase in the Balancing Charge is from $0.085723 per therm (including SUT) to $0.093477 per therm (including SUT).

Based on rates effective June 1, 2021, the effect of the requested increase in the Balancing Charge on typical residential gas bills, if approved by the Board, is shown in Table #1.

Under the Company's proposal, a residential heating customer using 100 therms per month during the winter months and 610 therms on an annual basis would see an increase in their annual bill from $568.00 to $571.14, or $3.14 or approximately 0.55%. Moreover, under the Company's proposal, a typical residential heating customer using 172 therms per month during the winter months and 1,040 therms on an annual basis would see an increase in their annual bill from $895.42 to $900.80, or $5.38 or approximately 0.60%.

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, 2021, and/or February 1st of next year, 2022, 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 to the New Jersey Division of Rate Counsel no later than November 1, 2021 and/or January 1, 2022 of its intention to apply a December 1st or a February 1st self-implementing rate increase, respectively, and the approximate amount of the increases based upon then current market data. These increases, if implemented, would be in accordance with the Board-approved methodology.

Should it become necessary to apply the December 1, 2021 self-implementing 5% increase, the bill impact would be an increase as illustrated in Table #2. Further, if a February 1, 2022 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.

Any final rate adjustments with resulting changes in bill impacts found by the Board to be just and reasonable as the result of the Company's filing may be modified and/or allocated by the Board in accordance with the provisions of N.J.S.A 48:2-21 and for other good and legally sufficient reasons to any class or classes of customers of the Company. Therefore, the described charges may increase or decrease based upon the Board's decision.

The Company's filing is available for review online at the PSEG website at http://www.pseg.com/pseandgfilings.

Please take further notice that due to the COVID-19 pandemic, telephonic public hearings have been scheduled on the following date and times so that members of the public may present their views on the Company's filing.

Date:
Time:

Dial In:
Access Code:

Representatives from the Company, Board Staff, and the New Jersey Division of Rate Counsel will participate in the public hearings. Members of the public are invited to listen, and if they choose, express their views on this filing. Such comments will be made part of the final record of the proceeding to 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, 48 hours prior to the above hearings to the Board Secretary at board.secretary@bpu.nj.gov.

The Board will also accept written and emailed comments. Although both will be given equal consideration, the preferred method of transmittal is via email to ensure timely receipt while the Board continues to work remotely due to the COVID-19 pandemic. Emailed comments may be filed with the Secretary of the Board, in pdf or Word format to board.secretary@bpu.nj.gov or through the Board's External Access Portal after obtaining a MyNewJersey Portal ID. Once an account is established, you will need an authorization code which can be obtained upon request by emailing the Board's IT Helpdesk at BPUITHELPDESK@bpu.nj.gov. Detailed instructions for e-Filing can be found on the Board's home page at https://www.nj.gov/bpu/agenda/efiling.

Written comments may be submitted to the Board Secretary, Aida Camacho-Welch, at the Board of Public Utilities, 44 South Clinton Avenue, 9th Floor, P.O. Box 350, Trenton, NJ 08625-0350.

All comments should include the name of the petition and the docket number. Written and emailed comments will be provided the same weight as statements made at the hearings.

Table # 1
Residential Gas Service

If Your Annual Therm Use Is:	And Your Monthly Winter Therm Use Is:	Then Your Present Monthly Winter Bill (1) Would Be:	And Your Proposed Monthly Winter Bill (2) Would Be:	Your Monthly Winter Bill Change Would Be:	And Your Monthly Percent Change Would Be:
170	25	$27.77	$27.91	$0.14	0.50%
340	50	46.95	47.23	0.28	0.60
610	100	86.18	86.82	0.64	0.74
1,040	172	142.06	143.17	1.11	0.78
1,200	201	164.63	165.93	1.30	0.79
1,816	300	241.32	243.25	1.93	0.80

(1) Based upon Delivery Rates and Basic Gas Supply Service (BGSS-RSG) in effect June 1, 2021, 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 Annual Therm Use Is:	And Your Monthly Winter Therm Use Is:	Self-Implementing 5% Increases		
		December 1, 2021 Monthly Winter Change Would Be:	February 1, 2022 Monthly Winter Change Would Be:	Total If both 5% Self-Implementing Increases Are Put Into Effect
170	25	$1.07	$1.06	$2.13
340	50	2.13	2.13	4.26
610	100	4.27	4.27	8.54
1,040	172	7.34	7.34	14.68
1,200	201	8.57	8.58	17.15
1,816	300	12.80	12.80	25.60

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

Katherine E. Smith
Associate Counsel - Regulatory

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

4. Actual and Forecasted Refund Amounts

Item 4

NATURAL GAS PIPELINE REFUNDS RECEIVED - May 2020 - April 2021
(000)

MONTH	SUPPLIER	AMOUNT	TOTAL
May 2020	Texas Eastern	$ 19,232	**$ 19,232**
June 2020	Texas Eastern	$ 138	
	Transco	$ 1,256	**$ 1,394**
July 2020	Transco	$ 29,558	
	Transco	$ 4	
	Texas Eastern	$ (13)	**$ 29,549**
August 2020		$ -	**$ -**
September 2020	Texas Eastern	$ 1,912	**$ 1,912**
October 2020		$ -	**-**
November 2020	Algonquin	$ 2	
	Tennessee	$ 3	
	Transco	$ 9	**$ 14**
December 2020	Texas Eastern	$ 43	
	Texas Eastern	$ 2	
	Texas Eastern	$ 14	**$ 59**
January 2021	Texas Eastern	$ 489	**$ 489**
February 2021	Transco	$ 3	**$ 3**
March 2021		$ -	**$ -**
April 2021	Texas Eastern	$ 87	**$ 87**
Total		$ 52,739	**$ 52,739**

Item 4

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

DOCKET	SUPPLIER	STATUS
RP21-24	Transco	Transco cashout surcharge rates went into effect on November 1, 2020, subject to refund. A settlement in principle has been reached, and settlement documents are expected to be filed at FERC by the end of May 2021. We estimate that settlement rates will be effective November 1, 2021. Our estimated refund is $1.1 million, not including interest.

5. Cost of Gas Sendout by Component

ACTUAL COST OF BGSS-RSG GAS SENDOUT BY COMPONENT

	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	Total
Beginning Inventory Price $000	$196,772	$208,826	$205,811	$168,276	$119,808	$80,999	$58,834	
Fixed Pipeline Charge $000	$20,887	$21,274	$21,619	$20,920	$20,385	$20,328	$19,614	
Gas Purchases and Hedges $000	$17,911	$24,717	$32,063	$34,977	$41,340	$27,025	$25,782	
Receipt Value $000	$38,798	$45,991	$53,682	$55,897	$61,726	$47,353	$45,396	$348,843
Total Inventory Value $000	$235,570	$254,817	$259,493	$224,174	$181,534	$128,352	$104,230	
Total $/dth	$3.73	$3.69	$3.69	$3.70	$3.87	$3.96	$3.77	
Beginning Inventory Volume MDth	50,854	55,816	55,822	45,726	32,360	20,981	14,813	
Receipt Volume MDth	12,219	13,298	14,482	14,836	14,507	11,465	12,860	93,667
Total Inventory Volume MDth	63,073	69,114	70,304	60,562	46,867	32,445	27,673	
RSG Sendout MDth	7,047	13,292	24,803	28,183	26,029	17,499	10,153	127,006
Total RSG Sendout Cost $000	$26,320	$49,005	$91,549	$104,322	$100,820	$69,227	$38,241	$479,484
Ending Inventory Rebalance								
Volume	(209)	(0)	225	(19)	143	(133)	282	
Amount	($424)	($1)	$332	($43)	$285	($291)	$571	

FORECASTED COST OF BGSS-RSG GAS SENDOUT BY COMPONENT

	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Total Oct - Sept
Beginning Inventory Cost $000	$66,560	$83,930	$126,877	$155,912	$176,382	$207,136	$227,588	$217,780	$160,330	$94,058	$44,989	$19,144	$19,497	$42,180	$92,018	$127,614	$155,099	
Receipt Value $000	$37,376	$59,668	$41,685	$31,795	$44,512	$48,141	$55,574	$55,624	$66,945	$66,695	$63,034	$49,761	$45,964	$66,682	$48,244	$38,616	$51,178	$656,459
Total Inventory Value $000	$103,936	$143,597	$168,562	$187,707	$220,894	$255,278	$283,162	$273,404	$227,275	$160,753	$108,023	$68,905	$65,461	$108,862	$140,262	$166,231	$206,277	
Total $/dth	$3.77	$3.93	$4.10	$4.25	$4.32	$4.36	$4.41	$4.49	$4.48	$4.46	$4.35	$4.34	$4.38	$4.04	$4.15	$4.29	$4.28	
Beginning Inventory Volume MDth	17,802	22,273	32,257	38,028	41,502	47,941	52,242	49,373	35,740	20,985	10,083	4,405	4,496	9,629	22,775	30,718	36,193	
Receipt Volume MDth	9,781	14,235	8,856	6,138	9,624	10,657	11,954	11,572	14,968	15,043	14,774	11,483	10,447	17,315	10,988	8,072	11,947	149,221
Total Inventory Volume MDth	27,582	36,508	41,113	44,166	51,125	58,598	64,196	60,946	50,707	36,029	24,857	15,889	14,943	26,944	33,763	38,790	48,140	
RSG Sendout MDth	5,309	4,251	3,085	2,665	3,184	6,356	14,823	25,206	29,722	25,946	20,452	11,393	5,314	4,169	3,044	2,598	3,115	152,138
Total RSG Sendout Cost $000	$20,007	$16,720	$12,650	$11,326	$13,757	$27,690	$65,382	$113,074	$133,217	$115,764	$88,879	$49,409	$23,281	$16,844	$12,647	$11,131	$13,348	$670,666

6. BGSS Contribution and Credit Offsets

Actual BGSS Contribution and Credit Offsets

($000)

			Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	Total
(1)	**BGSS-I Contribution**		($58)	$417	$183	$400	$88	$54	$113	$1,197
(2)	**Cogeneration Contribution**		$528	$1,182	$462	$1,141	$782	($138)	($801)	$3,155
(3)	**TSG-F Contribution**		$155	$652	$35	$356	$308	$313	($159)	$1,660
(4)	**"Contribution"**	Sum of (1) through (4)	$625	$2,251	$681	$1,896	$1,178	$229	($847)	$6,012
(5)	**Off-System Contribution**		$684	$1,778	$5,479	$4,790	$11,045	$1,743	$969	$26,488
(6)	**Electric Contribution**		$917	$1,377	$655	$849	$926	$548	$493	$5,766
(7)	**FT-S Balancing Credit**		$374	$1,331	$2,598	$3,585	$4,298	$3,274	$1,842	$17,303
(8)	**Pipeline Refunds**		$0	$14	$59	$489	$4	$0	$87	$654

Forecasted BGSS Contribution and Credit Offsets

		May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Total Oct - Sept
(1)	**BGSS-RSG Sendout, Mdth**	5,309	4,251	3,085	2,665	3,184	6,356	14,823	25,206	29,722	25,946	20,452	11,393	5,314	4,169	3,044	2,598	3,115	152,138
(2)	**BGSS-F Sendout, Mdth**	2,140	965	1,128	1,347	1,072	1,901	4,515	7,656	9,739	8,465	6,794	4,182	2,154	999	1,170	1,393	1,097	50,065
(3)	**Total Firm Sendout, Mdth**	7,449	5,216	4,213	4,012	4,257	8,257	19,338	32,862	39,461	34,411	27,246	15,575	7,468	5,168	4,215	3,990	4,212	202,203
(4)	**Annual % BGSS-RSG of Firm Sendout**	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%
(5)	**BGSS-I Contribution**	$135.1	$5.2	$170.7	($51.1)	$361.1	($56.8)	$409.6	$179.9	$399.1	$87.5	$54.0	$116.6	$135.3	$5.3	$173.1	($52.2)	$365.3	$1,816.7
(6)	**Cogeneration Contribution, $000**	$76.2	($15.5)	$230.7	$213.5	$595.3	($16.3)	$988.3	$278.5	$805.4	$535.6	($122.6)	($824.4)	$76.4	($15.7)	$233.8	$217.8	$602.1	$2,759.0
(7)	**TSG-F Contribution**	$111.8	$182.7	$173.7	$85.8	($85.2)	$151.5	$640.4	$34.2	$355.6	$307.7	$313.8	($163.8)	$112.0	$184.6	$176.1	$87.5	($86.2)	$2,113.5
(8)	**CSG**	$323.2	$323.2	$323.2	$323.2	$323.2	$323.2	$323.2	$323.2	$323.2	$323.2	$323.2	$323.2	$323.2	$323.2	$323.2	$323.2	$323.2	$3,878.6
(9)	**"Contribution"**	$646.4	$495.6	$898.3	$571.4	$1,194.4	$401.6	$2,361.6	$815.8	$1,883.4	$1,254.0	$568.4	($548.4)	$646.9	$497.4	$906.2	$576.4	$1,204.5	$10,567.8
(10)	**Off-System Contribution, $000**	$1,961.6	$1,961.6	$1,961.6	$1,961.6	$1,961.6	$1,128.3	$4,155.0	$4,155.0	$4,155.0	$4,155.0	$4,155.0	$1,171.8	$1,171.8	$1,171.8	$1,171.8	$1,171.8	$1,171.8	$28,934.1
(11)	**Electric Contribution, $000**	$1,175.0	$956.7	$902.9	$744.1	$774.6	$779.5	$642.4	$668.7	$715.6	$643.7	$686.1	$653.5	$707.1	$885.6	$1,220.0	$1,014.4	$825.9	$9,442.5
(12)	**Pipeline Refund, $000**	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$752.4	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$752.4
(13)	**FT-S Balancing Use, Mdth**	374.9	0.0	0.0	0.0	0.0	944.3	2,550.9	5,238.4	7,283.5	6,232.6	5,714.3	2,863.6	461.8	0.0	0.0	0.0	0.0	
(14)	**Balancing Charge, $/dth**	$0.7391	$0.0000	$0.0000	$0.0000	$0.0000	$0.8019	$0.8019	$0.8019	$0.8019	$0.8019	$0.8019	$0.8019	$0.8019	$0.0000	$0.0000	$0.0000	$0.0000	
(15)	**FT-S Balancing Credit, $000**	$374.9	$0.0	$0.0	$0.0	$0.0	$569.7	$1,539.1	$3,160.6	$4,394.5	$3,760.4	$3,447.7	$1,727.7	$278.6	$0.0	$0.0	$0.0	$0.0	$18,878.4
(16)	**BGSS-RSG Balancing Use, Mdth**	3,686	0	0	0	0	3,006	11,581	21,855	26,372	22,919	17,102	8,151	1,964	0	0	0	0	
(17)	**Balancing Charge, $/dth**	$0.7391	$0.0000	$0.0000	$0.0000	$0.0000	$0.8019	$0.8019	$0.8019	$0.8019	$0.8019	$0.8019	$0.8019	$0.8019	$0.0000	$0.0000	$0.0000	$0.0000	
(18)	**BGSS-RSG Balancing Rev., $000**	$2,723.8	$0.0	$0.0	$0.0	$0.0	$2,410.4	$9,286.8	$17,526.6	$21,148.4	$18,379.8	$13,714.4	$6,536.3	$1,575.0	$0.0	$0.0	$0.0	$0.0	$90,577.5

BGSS-RSG MARGIN FROM GAS TRANSPORTATION FOR ELECTRIC GENERATION

	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	Total
BGSS Asset Charge ($000)	$802	$764	$672	$722	$771	$500	$467	$4,697
CSG Transportation Revenues ($000)	$115	$613	($17)	$127	$155	$46	$29	$1,069
Total BGSS-RSG Margin ($000)	$917	$1,377	$655	$849	$926	$546	$496	$5,766

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

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 2020 - SEPTEMBER 2021

(000)

		TOTAL RECOVERY	LESS: TOTAL EXPENSE	MONTHLY OVER/(UNDER RECOVERY
Balance September 30, 2020				**$16,081**
Interest Adjustment				**0**
October 1, 2020 Adjusted Balance				**$16,081**
October 2020		$ 23,098	$ 26,778	(3,680)
November		49,485	49,332	153
December		91,086	86,570	4,516
January 2021		110,554	105,898	4,656
February		102,537	91,531	11,006
March		67,050	70,592	(3,542)
April		36,729	34,895	1,833
May	**(Est.)**	17,812	15,849	1,963
June	**(Est.)**	12,080	13,306	(1,226)
July	**(Est.)**	8,768	8,887	(119)
August	**(Est.)**	7,573	8,049	(476)
September	**(Est.)**	9,049	9,827	(778)
Total				**$30,388**

INTEREST
COMPUTED AT 6.99% ROR FOR October 2020 - SEPTEMBER 2021
(000)

		OVER/(UNDER) RECOVERIES			
		Monthly	Cumulative	Average Balance	INTEREST
Balance September 30, 2020			**$16,081**		
Interest Adjustment			**0**		
October 1, 2020 Adjusted Balance			**$16,081**		
October 2020		$ (3,680)	12,401	$ 14,241	$ 83
November		153	12,554	$ 12,478	$ 73
December		4,516	17,070	14,812	$ 86
January 2021		4,656	21,726	19,398	$ 113
February		11,006	32,732	27,229	$ 159
March		(3,542)	29,191	30,961	$ 180
April		1,833	31,024	30,107	$ 175
May	**(Est.)**	1,963	32,987	32,006	$ 186
June	**(Est.)**	(1,226)	31,761	32,374	$ 189
July	**(Est.)**	(119)	31,642	31,702	$ 185
August	**(Est.)**	(476)	31,166	31,404	$ 183
September	**(Est.)**	(778)	30,388	30,777	$ 179
Total					**$ 1,791**

BGSS-RSG 2021-2022
NYMEX====>>> May 6, 2021

NO CHANGE IN RATES

	BGSS-RSG MDTh (1)	BGSS-RSG COST (2)	REFUNDS (3)	CONTRIB (4)	OFF-SYS Margin (5)	Electric Contribution (6)	FT Balancing Credit (7)	ADJ COST (8)=(2).+.(7)	RSG Bal. Revenue (9)	BGSS RECOVERY (10)=(1)*(14)+(9)	EXCESS COST (11)=(10)-(8)	OVER/(UNDER) RECOVERY Month (12)=-(11)	OVER/(UNDER) RECOVERY Cumulative (13)	RSG Rate $/dth (14)
Apr-21 Act													**$31,024**	$2.8418
May-21 Est.	5,309	$20,007	$0	($646)	($1,962)	($1,175)	($375)	$15,849	$2,724	$17,812	($1,963)	$1,963	$32,987	$2.8418
Jun-21 Est.	4,251	$16,720	$0	($496)	($1,962)	($957)	$0	$13,306	$0	$12,080	$1,226	($1,226)	$31,761	$2.8418
Jul-21 Est.	3,085	$12,650	$0	($898)	($1,962)	($903)	$0	$8,887	$0	$8,768	$119	($119)	$31,642	$2.8418
Aug-21 Est.	2,665	$11,326	$0	($571)	($1,962)	($744)	$0	$8,049	$0	$7,573	$476	($476)	$31,166	$2.8418
Sep-21 Est.	**3,184**	**$13,757**	**$0**	**($1,194)**	**($1,962)**	**($775)**	**$0**	**$9,827**	**$0**	**$9,049**	**$778**	**($778)**	**$30,388**	$2.8418
Oct-21 Est.	6,356	$27,690	$0	($402)	($1,128)	($779)	($570)	$24,811	$2,410	$20,473	$4,338	($4,338)	$26,051	$2.8418
Nov-21 Est.	14,823	$65,382	$0	($2,362)	($4,155)	($642)	($1,539)	$56,684	$9,287	$51,410	$5,273	($5,273)	$20,777	$2.8418
Dec-21 Est.	25,206	$113,074	($752)	($816)	($4,155)	($669)	($3,161)	$103,522	$17,527	$89,157	$14,365	($14,365)	$6,412	$2.8418
Jan-22 Est.	29,722	$133,217	$0	($1,883)	($4,155)	($716)	($4,394)	$122,069	$21,148	$105,613	$16,456	($16,456)	($10,044)	$2.8418
Feb-22 Est.	25,946	$115,764	$0	($1,254)	($4,155)	($644)	($3,760)	$105,951	$18,380	$92,112	$13,839	($13,839)	($23,883)	$2.8418
Mar-22 Est.	20,452	$88,879	$0	($568)	($4,155)	($686)	($3,448)	$80,022	$13,714	$71,835	$8,186	($8,186)	($32,069)	$2.8418
Apr-22 Est.	11,393	$49,409	$0	$548	($1,172)	($654)	($1,728)	$46,404	$6,536	$38,913	$7,491	($7,491)	($39,560)	$2.8418
May-22 Est.	5,314	$23,281	$0	($647)	($1,172)	($707)	($279)	$20,476	$1,575	$16,677	$3,799	($3,799)	($43,359)	$2.8418
Jun-22 Est.	4,169	$16,844	$0	($497)	($1,172)	($886)	$0	$14,289	$0	$11,847	$2,442	($2,442)	($45,801)	$2.8418
Jul-22 Est.	3,044	$12,647	$0	($906)	($1,172)	($1,220)	$0	$9,349	$0	$8,652	$698	($698)	($46,499)	$2.8418
Aug-22 Est.	2,598	$11,131	$0	($576)	($1,172)	($1,014)	$0	$8,369	$0	$7,382	$987	($987)	($47,486)	$2.8418
Sep-22 Est.	**3,115**	**$13,348**	**$0**	**($1,204)**	**($1,172)**	**($826)**	**$0**	$10,146	**$0**	$8,853	$1,294	($1,294)	($48,779)	$2.8418
Oct-21 to Sept-22	**152,138**	**$670,666**	**($752)**	**($10,568)**	**($28,934)**	**($9,443)**	**($18,878)**	**$602,091**	**$90,577**	**$522,923**	**$79,167**			

BGSS-RSG 2021-2022
NYMEX====>>> May 6, 2021

ZERO BALANCE

	BGSS-RSG MDTh (1)	COST (2)	REFUNDS (3)	CONTRIB (4)	OFF-SYS Margin (5)	Electric Contribution (6)	FT Balancing Credit (7)	ADJ COST (8)=(2).+.(7)	RSG Bal. Revenue (9)	BGSS RECOVERY (10)=(1)*(14)+(9)	EXCESS COST (11)=(10)-(8)	OVER/(UNDER) RECOVERY Month (12)=-(11)	Cumulative (13)	RSG Rate $/dth (14)
Apr-21 Act.													**$31,024**	$2.8418
May-21 Est.	5,309	$20,007	$0	($646)	($1,962)	($1,175)	($375)	$15,849	$2,724	$17,812	($1,963)	$1,963	$32,987	$2.8418
Jun-21 Est.	4,251	$16,720	$0	($496)	($1,962)	($957)	$0	$13,306	$0	$12,080	$1,226	($1,226)	$31,761	$2.8418
Jul-21 Est.	3,085	$12,650	$0	($898)	($1,962)	($903)	$0	$8,887	$0	$8,768	$119	($119)	$31,642	$2.8418
Aug-21 Est.	2,665	$11,326	$0	($571)	($1,962)	($744)	$0	$8,049	$0	$7,573	$476	($476)	$31,166	$2.8418
Sep-21 Est.	**3,184**	**$13,757**	**$0**	**($1,194)**	**($1,962)**	**($775)**	**$0**	**$9,827**	**$0**	**$9,049**	**$778**	**($778)**	**$30,388**	$2.8418
Oct-21 Est.	6,356	$27,690	$0	($402)	($1,128)	($779)	($570)	$24,811	$2,410	$22,511	$2,300	($2,300)	$28,089	$3.1624
Nov-21 Est.	14,823	$65,382	$0	($2,362)	($4,155)	($642)	($1,539)	$56,684	$9,287	$56,163	$521	($521)	$27,568	$3.1624
Dec-21 Est.	25,206	$113,074	($752)	($816)	($4,155)	($669)	($3,161)	$103,522	$17,527	$97,238	$6,284	($6,284)	$21,284	$3.1624
Jan-22 Est.	29,722	$133,217	$0	($1,883)	($4,155)	($716)	($4,394)	$122,069	$21,148	$115,143	$6,926	($6,926)	$14,358	$3.1624
Feb-22 Est.	25,946	$115,764	$0	($1,254)	($4,155)	($644)	($3,760)	$105,951	$18,380	$100,431	$5,520	($5,520)	$8,838	$3.1624
Mar-22 Est.	20,452	$88,879	$0	($568)	($4,155)	($686)	($3,448)	$80,022	$13,714	$78,393	$1,629	($1,629)	$7,209	$3.1624
Apr-22 Est.	11,393	$49,409	$0	$548	($1,172)	($654)	($1,728)	$46,404	$6,536	$42,566	$3,838	($3,838)	$3,371	$3.1624
May-22 Est.	5,314	$23,281	$0	($647)	($1,172)	($707)	($279)	$20,476	$1,575	$18,381	$2,095	($2,095)	$1,276	$3.1624
Jun-22 Est.	4,169	$16,844	$0	($497)	($1,172)	($886)	$0	$14,289	$0	$13,184	$1,105	($1,105)	$171	$3.1624
Jul-22 Est.	3,044	$12,647	$0	($906)	($1,172)	($1,220)	$0	$9,349	$0	$9,628	($278)	$278	$449	$3.1624
Aug-22 Est.	2,598	$11,131	$0	($576)	($1,172)	($1,014)	$0	$8,369	$0	$8,215	$154	($154)	$295	$3.1624
Sep-22 Est.	**3,115**	**$13,348**	**$0**	**($1,204)**	**($1,172)**	**($826)**	**$0**	**$10,146**	**$0**	**$9,851**	**$295**	**($295)**	**$0**	$3.1624
Oct-21 to Sept-22	**152,138**	**$670,666**	**($752)**	**($10,568)**	**($28,934)**	**($9,443)**	**($18,878)**	**$602,091**	**$90,577**	**$571,702**	**$30,388**			

PSE&G
FOR PERIOD OCT20 TO SEP21

	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21
Beginning Balance	16,080,965	12,400,958	12,554,042	17,070,123	21,725,754	32,732,157	29,190,634
FUEL REVENUES							
Fuel Revenues	22,472,481	47,233,678	90,405,564	108,662,312	101,359,326	66,821,597	37,504,375
Interruptible Contribution	625,065	2,251,478	680,673	1,891,464	1,177,630	228,744	(775,814)
Total Fuel Revenues	23,097,547	49,485,156	91,086,237	110,553,776	102,536,956	67,050,342	36,728,562
FUEL EXPENSE							
Gas Purchases	26,777,553	49,346,512	86,629,557	106,387,512	91,534,144	70,591,937	34,982,270
Refunds	0	(14,440)	(59,402)	(489,368)	(3,590)	(72)	(87,186)
Total Fuel Expense	26,777,553	49,332,072	86,570,156	105,898,144	91,530,554	70,591,865	34,895,083
OVER / (UNDER) RECOVERY	(3,680,006)	153,084	4,516,081	4,655,631	11,006,403	(3,541,523)	1,833,478
Cumulative Recovery	12,400,958	12,554,042	17,070,123	21,725,754	32,732,157	29,190,634	31,024,112

BGSSR
CALCULATION OF FUEL REVENUES
FOR PERIOD OCT20 TO SEP21

	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21
RSG Fuel Revenues	$19,434,580	$36,889,984	$70,175,274	$83,427,664	$76,900,680	$51,500,565	$29,847,692
RSGM Fuel Revenues	$345,864	$789,076	$1,456,286	$1,670,778	$1,603,383	$1,090,450	$663,743
Subtotal	$19,780,444	$37,679,061	$71,631,560	$85,098,442	$78,504,063	$52,591,015	$30,511,436
FT Balancing Revenues	1,617,752	6,723,195	15,098,223	21,697,868	24,501,797	$18,111,003	$8,818,084
FT Balancing Revenues (Unbilled Calc)	1,074,286	3,905,709	7,581,489	9,447,491	7,800,956	3,920,536	2,095,391
FT Balancing Revenues (Prior Unbilled Calc)	0	-1,074,286	-3,905,709	-7,581,489	-9,447,491	-7,800,956	-3,920,536
Manual Rev Accrual not part of BGSSR							
Total BGSSR Fuel Recovery	$22,472,481	$47,233,678	$90,405,564	$108,662,312	$101,359,326	$66,821,597	$37,504,375
Bill Credits							
Billed Revenues							
Current Unbilled Usage							
Prior Unbilled Usage							
Net Unbilled Usage							
Rate							
Subtotal Unbilled Revenues							
Total Bill Credits							

	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21
Interruptible Contributions:							
ISG (BGSS-I):							
ISG (BGSS-I) Sales Therms	142,509	1,309,527	1,269,821	1,589,618	929,089	758,543	324,769
ISG BGSS-I) Gross Revenues	$ 58,399	$ 586,211	$ 541,120	$ 704,667	$ 452,405	$ 309,286	$ 213,563
ISG (BGSS-I) Cost	$ 80,547	$ 113,876	$ 271,790	$ 256,982	$ 331,850	$ 212,452	$ 71,387
PSEG Power's share of Contribution	$ 35,958	$ 55,067	$ 85,916	$ 48,130	$ 32,856	$ 42,947	$ 28,860
ISG Interuptible Contribution to BGSSR	$ (58,106)	$ 417,268	$ 183,414	$ 399,555	$ 87,699	$ 53,886	$ 113,317
CIG:							
CIG SBC Rate adjustment (line 84)							
CIG Sales Therms	551,572.43	3,303,316.45	1,958,592.78	3,083,713.50	3,858,108.02	2,433,832.02	(1,289,697.66)
CIG Gross Revenues	$ 184,275	$ 1,448,391	$ 832,451	$ 1,537,598	$ 1,650,630	$ 677,461	$ (522,721)
CIG SBC/GPRC Revenues	$ 28,639	$ 171,518	$ 101,696	$ 160,116	$ 200,325	$ 126,372	$ (66,965)
CIG Cost	$ 128,553	$ 231,506	$ 387,052	$ 543,203	$ 926,057	$ 628,508	$ 267,105
CIG TAC revenues	$ 4,829	$ (49,021)	$ (29,066)	$ (32,908)	$ (47,782)	$ (34,375)	$ 10,638
PSEG Power's share of Contribution	$ 38,914	$ 87,502	$ 88,830	$ 60,926	$ 35,328	$ 79,288	$ 67,994
CIG Interuptible Contribution to BGSSR	$ (16,660)	$ 1,006,886	$ 283,938	$ 806,262	$ 536,702	$ (122,331)	$ (801,493)
TSG-F:							
TSG-F SBC Rate adjustment (line 84)							
TSG-F Sales Therms	2,411,806.66	3,661,798.28	692,205.45	3,440,440.98	2,328,321.25	2,373,446.85	1,652,237.14
TSG-F Gross Revenues	$ 285,336	$ 884,150	$ 183,282	$ 582,087	$ 497,153	$ 486,388	$ (30,833)
TSG-F SBC/GPRC Revenues	$ 125,228	$ 190,132	$ 35,941	$ 178,638	$ 120,893	$ 123,236	$ 85,789
TSG-F TAC Revenues	$ (65,777)	$ (99,773)	$ (22,209)	$ (68,446)	$ (60,598)	$ (64,731)	$ (45,198)
TSG-F MAC Revenues	$ (15,286)	$ (23,208)	$ (4,387)	$ (21,806)	$ (14,757)	$ (15,043)	$ (10,472)
TSG-F PSEG Power's share of Contribution	$ 86,191	$ 164,525	$ 139,097	$ 137,713	$ 143,241	$ 129,894	$ 98,271
TSG-F Interuptible Contribution to BGSSR	$ 154,980	$ 652,475	$ 34,839	$ 355,988	$ 308,373	$ 313,031	$ (159,224)
CSG NON-Power:							
CSG Non-Power Therms	17,354,598.46	14,016,390.73	5,125,887.23	2,975,824.25	5,341,058.01	3,430,409.28	5,683,184.66
CSG Non-Power Revenues	$ 757,606	$ 355,351	$ 416,065	$ 376,979	$ 295,842	$ 232,325	$ 228,028
CSG Non Power SBC Revenues	$ 249,385	$ 201,925	$ 207,465	$ 198,385	$ 95,015	$ 168,065	$ 168,065
CSG TAC Revenues Power and NON-Power	$ (79,642)	$ (67,060)	$ 5,747	$ (164,840)	$ (57,237)	$ 61,085	$ (39,451)
CSG Non-Power ER&T's share of Contribution	$ 43,013	$ 45,639	$ 24,372	$ 13,775	$ 13,208	$ 19,018	$ 27,829
CSG Non-Power Contribution to BGSSR	$ 544,851	$ 174,848	$ 178,482	$ 329,659	$ 244,856	$ (15,843)	$ 71,586
Total Interruptible Contributions	$ 625,065	$ 2,251,478	$ 680,673	$ 1,891,464	$ 1,177,630	$ 228,744	$ (775,814)
SBC & GPRC rate-CIG & TSG-F (CHECK tariff pages for rate changes)	**0.051923**	**0.051923**	**0.051923**	**0.051923**	**0.051923**	**0.051923**	**0.051923**
TEFA rate-TSG-F (Reduced 25% 2012 & 25% 2013, zero out 2014)	-	-	-	-	-	-	-
Cogen Contract RAC rate (separate schedule beginning 12/02)	**n/a**	**n/a**	**n/a**	**n/a**	**n/a**	**n/a**	**n/a**
MAC rate-TSG-F (Per MAC CALC Worksheet)	**(0.006338)**	**(0.006338)**	**(0.006338)**	**(0.006338)**	**(0.006338)**	**(0.006338)**	**(0.006338)**
Current Month Estimate - Gas Purchases (1) See below row 96	$ 25,736,065	$ 49,960,741	$ 88,375,938	$ 105,979,972	$ 94,524,906	$ 72,332,229	$ 38,022,291
Prior Month Actual - Gas Purchases (1) See below row 105	$ 12,948,179	$ 25,107,396	$ 48,154,959	$ 88,294,110	$ 102,985,620	$ 92,784,542	$ 69,205,021
Prior Month Estimate - Gas Purchases See below row 115	$ 11,906,690	$ 25,736,065	$ 49,960,741	$ 88,375,938	$ 105,979,972	$ 94,524,906	$ 72,332,229
Gas Purchases	$ 26,777,553	$ 49,332,072	$ 86,570,156	$ 105,898,144	$ 91,530,554	$ 70,591,865	$ 34,895,083
Gas Refunds							
ISG (BGSS-I) Cost Est. (2)	$ 80,112	$ 114,742	$ 272,315	$ 245,202	$ 318,840	$ 207,604	$ 74,971
PSEG Power's share of Contribution CMnth Est. (2)	$ 43,026	$ 57,488	$ 81,673	$ 48,712	$ 30,558	$ 42,723	$ 22,074
ISG (BGSS-I) Cost Pr Mnth Act. (2)	$ 92,374	$ 79,246	$ 114,217	$ 284,095	$ 258,212	$ 323,688	$ 204,020
PSEG Power's share of Contribution Pr Mnth Act. (2)	$ 60,534	$ 40,605	$ 61,731	$ 81,091	$ 51,010	$ 30,783	$ 49,508
ISG (BGSS-I) Cost PrMnth Est.	$ 91,939	$ 80,112	$ 114,742	$ 272,315	$ 245,202	$ 318,840	$ 207,604
PSEG Power's share of Contribution PrMnth Est.	$ 67,603	$ 43,026	$ 57,488	$ 81,673	$ 48,712	$ 30,558	$ 42,723
CIG Cost (3) - CMnth Est. (3)	$ 127,758	$ 232,895	$ 388,157	$ 526,524	$ 899,667	$ 614,829	$ 251,283
PSEG Power's share of Contribution - CMnth Est. (3)	$ 48,591	$ 90,141	$ 82,034	$ 62,588	$ 35,209	$ 81,200	$ 50,048
CIG Cost (3) - PrMnth Act. (3)	$ 168,537	$ 126,370	$ 231,791	$ 404,835	$ 552,914	$ 913,346	$ 630,651
PSEG Power's share of Contribution - PrMnth Act. (3)	$ 82,224	$ 45,952	$ 96,938	$ 80,372	$ 62,706	$ 33,297	$ 99,147
CIG Cost - PrMnth Est.	$ 167,742	$ 127,758	$ 232,895	$ 388,157	$ 526,524	$ 899,667	$ 614,829
PSEG Power's share of Contribution - PrMnth Est.	$ 91,901	$ 48,591	$ 90,141	$ 82,034	$ 62,588	$ 35,209	$ 81,200

	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21
TSG-F PSEG Power's share of Contribution CMth Est. (4)	$ 95,377	$ 171,456	$ 131,165	$ 134,098	$ 127,546	$ 123,488	$ 79,013
TSG-F PSEG Power's share of Contribution PrMth Actual (4)	$ 79,979	$ 88,445	$ 179,388	$ 134,780	$ 149,794	$ 133,952	$ 142,746
TSG-F PSEG Power's share of Contribution PrMth Est.	$ 89,165	$ 95,377	$ 171,456	$ 131,165	$ 134,098	$ 127,546	$ 123,488
CSC Non-Power Cost & PSEG Power's share of Contribution CMth Est. (6)	$ 46,957	$ 48,642	$ 20,893	$ 13,208	$ 13,208	$ 15,157	$ 25,778
CSC Non-Power Cost & PSEG Power's share of Contribution PMth Act. (6)	$ 34,362	$ 43,954	$ 52,120	$ 21,460	$ 13,208	$ 17,069	$ 17,208
CSC Non-Power Cost & PSEG Power's share of Contribution PMth Est.	$ 38,306	$ 46,957	$ 48,642	$ 20,893	$ 13,208	$ 13,208	$ 15,157
BGSS-RSG Prior Month Actual	$ 13,351,848	$ 25,399,569	$ 48,659,635	$ 89,144,504	$ 103,910,462	$ 94,085,655	$ 70,188,347
BGSS-RSG Cogen Contracts Prior Month Actual (6)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BGSS-RSG TSG Cashouts Prior Mnth Actuals	$ 98,999	$ 140,310	$ 312,301	$ 44,280	$ 223,780	$ 183,029	$ (36,738)
Subtotal	$ 13,557,183	$ 26,231,249	$ 49,070,510	$ 89,308,721	$ 104,254,128	$ 94,416,851	$ 70,651,494
Total BGSS-RSG Actual Bill	**$ 13,557,183**	**$ 26,231,249**	**$ 49,070,510**	**$ 89,308,721**	**$ 104,310,608**	**$ 94,530,495**	**$ 70,216,871**
Difference							
BGSS-RSG Current Month Estimate	$ 26,388,310	$ 50,730,289	$ 89,358,677	$ 107,029,051	$ 96,010,593	$ 73,377,749	$ 38,483,665
BGSS-RSG Cogen Contracts Prior Month Estimate (6)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Subtotal	$ 26,388,310	$ 50,730,289	$ 89,358,677	$ 107,029,051	$ 96,010,593	$ 73,377,749	$ 38,483,665
Total BGSS-RSG Estimate Bill	**$ 26,388,310**	**$ 50,730,289**	**$ 89,358,677**	**$ 107,029,051**	**$ 96,010,593**	**$ 73,377,749**	**$ 38,483,665**
Difference							
Gas Purchases Details:							
Current Month Estimate							
BGSS-RSG GAS COMMODITY VOLUMES MDTh	7,128,720	13,820,510	24,784,531	29,151,586	26,604,390	18,231,776	10,161,726
BGSS-RSG GAS COMMODITY COST	$ 26,692,713	$ 50,904,351	$ 91,220,155	$ 107,585,078	$ 102,963,486	$ 72,308,955	$ 38,280,148
BGSS-RSG Balancing	$ 860,988	$ 1,853,790	$ 3,497,064	$ 4,112,374	$ 3,736,597	$ 2,526,090	$ 1,321,056
BGSS-RSG Off System Sales	$ (662,028)	$ (1,764,558)	$ (5,512,010)	$ (4,834,760)	$ (11,202,165)	$ (1,901,330)	$ (1,049,213)
Electric Reservation Charge	$ (802,851)	$ (758,560)	$ (670,711)	$ (716,667)	$ (771,599)	$ (502,322)	$ (466,701)
Other	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CSG Revenues	**$ (352,758)**	**$ (274,283)**	**$ (158,560)**	**$ (166,053)**	**$ (201,413)**	**$ (99,164)**	**$ (62,999)**
Credit for Pipeline Refunds	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total	$ 25,736,065	$ 49,960,741	$ 88,375,938	$ 105,979,972	$ 94,524,906	$ 72,332,229	$ 38,022,291
Prior Actual							
BGSS-RSG GAS COMMODITY VOLUMES MDTh	3,613,535	7,052,619	13,297,976	24,812,591	28,219,260	26,072,678	17,508,218
BGSS-RSG GAS COMMODITY COST	$ 13,957,212	$ 26,429,572	$ 49,014,965	$ 91,561,216	$ 104,530,064	$ 101,058,835	$ 69,261,300
BGSS-RSG Balancing	$ 363,216	$ 867,012	$ 1,789,090	$ 3,485,236	$ 3,973,148	$ 3,689,560	$ 2,417,052
BGSS-RSG Off System Sales	$ (586,642)	$ (675,291)	$ (1,731,515)	$ (5,467,058)	$ (4,677,835)	$ (11,044,246)	$ (1,820,997)
Electric Reservation Charge	$ (679,272)	$ (808,086)	$ (759,606)	$ (675,979)	$ (716,281)	$ (771,369)	$ (499,885)
CSG Revenues	**$ (106,335)**	**$ (691,370)**	**$ (98,574)**	**$ (119,937)**	**$ (119,886)**	**$ (148,166)**	**$ (65,261)**
Credit for Pipeline Refunds	$ -	$ (14,440)	$ (59,402)	$ (489,368)	$ (3,590)	$ (72)	$ (87,186)
Residential Share of Property Taxes Paid	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total	$ 12,948,179	$ 25,107,396	$ 48,154,959	$ 88,294,110	$ 102,985,620	$ 92,784,542	$ 69,205,021
Prior Estimate							
BGSS-RSG GAS COMMODITY VOLUMES MDTh	3,401,626	7,128,720	13,820,510	24,784,531	29,151,586	26,604,390	18,231,776
BGSS-RSG GAS COMMODITY COST	$ 13,153,477	$ 26,692,713	$ 50,904,351	$ 91,220,155	$ 107,585,078	$ 102,963,486	$ 72,308,955
BGSS-RSG Balancing	$ 341,931	$ 860,988	$ 1,853,790	$ 3,497,064	$ 4,112,374	$ 3,736,597	$ 2,526,090
BGSS-RSG Off System Sales	$ (564,576)	$ (662,028)	$ (1,764,558)	$ (5,512,010)	$ (4,834,760)	$ (11,202,165)	$ (1,901,330)
Electric Reservation Charge	$ (680,134)	$ (802,851)	$ (758,560)	$ (670,711)	$ (716,667)	$ (771,599)	$ (502,322)
Other	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Prior CSG Revenues	$ (344,009)	$ (352,758)	$ (274,283)	$ (158,560)	$ (166,053)	$ (201,413)	$ (99,164)
Credit for Pipeline Refunds	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total	$ 11,906,690	$ 25,736,065	$ 49,960,741	$ 88,375,938	$ 105,979,972	$ 94,524,906	$ 72,332,229
Net							
BGSS-RSG GAS COMMODITY VOLUMES MDTh	7,340,629	13,744,409	24,261,997	29,179,646	25,672,064	17,700,064	9,438,168

		Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21
BGSS-RSG GAS COMMODITY COST		$ 27,496,448	$ 50,641,210	$ 89,330,770	$ 107,926,139	$ 99,908,472	$ 70,404,304	$ 35,232,492
BGSS-RSG Balancing		$ 882,273	$ 1,859,814	$ 3,432,363	$ 4,100,547	$ 3,597,370	$ 2,479,054	$ 1,212,017
BGSS-RSG Off System Sales		$ (684,094)	$ (1,777,821)	$ (5,478,968)	$ (4,789,809)	$ (11,045,240)	$ (1,743,411)	$ (968,880)
Electric Reservation Charge		$ (801,989)	$ (763,796)	$ (671,757)	$ (721,936)	$ (771,213)	$ (502,092)	$ (464,264)
Other		$ -	$ -	$ -	$ -	$ -	$ -	$ -
CSG Revenues		$ (115,085)	$ (612,895)	$ 17,149	$ (127,429)	$ (155,246)	$ (45,918)	$ (29,096)
Credit for Pipeline Refunds		$ -	$ (14,440)	$ (59,402)	$ (489,368)	$ (3,590)	$ (72)	$ (87,186)
	Total	$ 26,777,553	$ 49,332,072	$ 86,570,156	$ 105,898,144	$ 91,530,554	$ 70,591,865	$ 34,895,083
BGSS-RSG GAS COMMODITY VOLUMES MDTh		7,340,629	13,744,409	24,261,997	29,179,646	25,672,064	17,700,064	9,438,168
NET SALES VOLUMES RESIDENTIAL		6,594,477	10,005,359	23,871,227	28,358,798	26,160,987	17,590,249	10,172,898
	Diff	746,152	3,739,050	390,770	820,848	(488,923)	109,815	(734,730)

Ck

INTEREST CALCULATION
FOR PERIOD OCT20 TO SEP21

	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21
CUMULATIVE OVER/(UNDER) RECOVERY PRIOR MONTH	$16,080,965	$12,400,958	$12,554,042	$17,070,123	$21,725,754	$32,732,157	$29,190,634
CUMULATIVE OVER/(UNDER) RECOVERY CURRENT MONTH	$12,400,958	$12,554,042	$17,070,123	$21,725,754	$32,732,157	$29,190,634	$31,024,112
AVERAGE BALANCE	$14,240,961	$12,477,500	$14,812,083	$19,397,939	$27,228,956	$30,961,395	$30,107,373
MONTHLY INTEREST (Income)/Expense allowed rate of return of 6.99%	**$82,954**	**$72,681**	**$86,280**	**$112,993**	**$158,609**	**$180,350**	**$175,375**
INTEREST ACCUMULATED, (Income)/Expense	$82,954	$155,635	$241,915	$354,908	$513,517	$693,867	$869,243

8. Wholesale Gas Pricing Assumptions

Item 8

A Comparison of the Forecasted Cost of Gas as represented by the NYMEX
June 2021 Filing versus June 2020 Filing

($/Mbtu)

		June '21 Filing Nymex - 5/6/2021	June '20 Filing Nymex - 5/07/2020	Difference	Percentage Difference
2021	**May**	$2.925	$1.794	$1.131	63.0%
	June	$2.928	$1.894	$1.034	54.6%
	July	$2.974	$2.127	$0.847	39.8%
	August	$2.984	$2.202	$0.782	35.5%
	September	$2.971	$2.256	$0.715	31.7%
	October	$2.990	$2.342	$0.648	27.7%
	November	$3.052	$2.572	$0.480	18.7%
	December	$3.180	$2.893	$0.287	9.9%
2022	**January**	$3.263	$3.031	$0.232	7.7%
	February	$3.192	$2.991	$0.201	6.7%
	March	$2.993	$2.854	$0.139	4.9%
	April	$2.604	$2.559	$0.045	1.8%
	May	$2.548	$2.526	$0.022	0.9%
	June	$2.577	$2.564	$0.013	0.5%
	July	$2.612	$2.610	$0.002	0.1%
	August	$2.618	$2.617	$0.001	0.0%
	September	$2.602	$2.597	$0.005	0.2%
	Average	$2.883	$2.496	$0.387	15.5%

9. GCUA Recoveries and Balances

N/A

10. Historical Service Interruptions

Item 10

SERVICE INTERRUPTIONS

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

Note: All dates below represent heating season for year 2020-2021.

Rate Schedule CIG:
Number of Customers: 12 (including 3 CEGs)

- No events
- CEG was not offered

Rate Schedule TSG-NF (BGSS-I):
Number of Customers: 15

- No events

Rate Schedule TSG-NF (Third Party Suppliers):
Number of Customers: 142

- No events

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

- No events

There were no interruptions done for operational reasons.

11. Gas Price Hedging Activities

Reports Dated:

April 15, 2021

January 14, 2021

October 19, 2020

July 15, 2020

Matthew M. Weissman
Managing Counsel – State Regulatory

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

VIA ELECTRONIC MAIL

April 15, 2021

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, Director
Division of 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 2021

Dear Director Peterson:

Enclosed please find Public Service Electric and Gas Company's ("Public Service" or the "Company") quarterly status report which is filed pursuant to the Board's March 30, 2001 Decision and Order in the above-referenced matter. This quarterly report identifies the Company's outstanding hedging positions as of March 31, 2021.

As shown on the attached schedules, hedging for the 2020/2021 winter season is at 98% of plan and 96% of the plan has been completed for 2021 summer. Hedging for the 2021/2022 winter season is at 54% and 30% of the plan has been completed for the 2022 summer. All of these periods are based on a plan of approximately 70bcf with an even split between winter and summer.

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

Very truly yours,

Matthew M. Weissman

Attachment

C Stefanie A. Brand
Alice Bator
Felicia Thomas-Friel
Ben Witherell

PSE&G Residential Hedging Report November 2020 - October 2021 As of 03/31/2021	Bcf Target*	Bcf Hedged	% Hedged Target		% Hedged Actual	Current Price/ MMBtu

WINTER - Nov 20-Mar 21 Hedge Volume

(230,000/ day) (151 days)

Non-Discretionary Volume	17.500	**17.365**	94%	100%	99%	**$2.31**
Dollar Budget Method	17.500	**17.078**	$2.228M/mo.		98%	**$2.32**
Total Winter Hedge Volume	35.000	**34.443**			98%	**$2.31**
			Actual Nymex Settles			**$2.79**

SUMMER - Apr 21-Oct 21 Hedge Volume

(160,000/ day) (214 days)

Non-Discretionary Volume	17.500	**17.120**	94%	100%	98%	**$2.00**
Dollar Budget Method	17.500	**16.564**	$1.856M/mo.		95%	**$1.99**
Total Summer Hedge Volume	35.000	**33.684**			96%	**$1.99**
			3/31/21 Nymex Settles			**$2.69**

Total Non-Discretionary Method	35.000	**34.485**				**$2.15**
Total Dollar Budget Method	35.000	**33.642**				**$2.16**
					Difference	**$0.00**
					Percent	**0.2%**

PSE&G Residential Hedging Report November 2021 - October 2022 As of 03/31/2021	Bcf Target*	Bcf Hedged	% Hedged Target		% Hedged Actual	Current Price/ MMBtu

WINTER - Nov 21-Mar 22 Hedge Volume

(230,000/ day) (151 days)

Non-Discretionary Volume	17.500	**10.193**	56%	61%	58%	**$2.45**
Dollar Budget Method	17.500	**8.818**	$2.130M/mo.		50%	**$2.47**
Total Winter Hedge Volume	35.000	**19.011**			54%	**$2.46**
			3/31/21 Nymex Settles			**$2.93**

SUMMER - Apr 22-Oct 22 Hedge Volume

(160,000/ day) (214 days)

Non-Discretionary Volume	17.500	**5.350**	28%	33%	31%	**$1.93**
Dollar Budget Method	17.500	**5.286**	$1.653M/mo.		30%	**$1.85**
Total Summer Hedge Volume	35.000	**10.636**			30%	**$1.89**
			3/31/21 Nymex Settles			**$2.49**

Total Non-Discretionary Method	35.000	**15.543**				**$2.27**
Total Dollar Budget Method	35.000	**14.104**				**$2.24**
					Difference	**($0.03)**
					Percent	**-1.3%**

Matthew M. Weissman
Managing Counsel – State Regulatory

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PSEG Services Corporation
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PSEG
Services Corporation

VIA ELECTRONIC MAIL

January 14, 2021

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

RE: PSE&G GAS HEDGING QUARTERLY REPORT – FOURTH QUARTER 2020

Dear Director Peterson:

Enclosed please find Public Service Electric and Gas Company's ("Public Service" or the "Company") quarterly status report which is filed pursuant to the Board's March 30, 2001 Decision and Order in the above-referenced matter. This quarterly report identifies the Company's outstanding hedging positions as of December 31, 2020.

As shown on the attached schedules, hedging for the 2020/2021 winter season is at 98% of plan and 79% of the plan has been completed for 2021 summer. Hedging for the 2021/2022 winter season is at 38% and 17% of the plan has been completed for the 2022 summer. All of these periods are based on a plan of approximately 70bcf with an even split between winter and summer.

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

Very truly yours,

Matthew Weissman

Matthew M. Weissman

Attachment

C Stefanie A. Brand
Alice Bator
Felicia Thomas-Friel
Ben Witherell

PSE&G Residential Hedging Report November 2020 - October 2021 As of December 31, 2020	Bcf Target*	Bcf Hedged	% Hedged Target		% Hedged Actual	Current Price/ MMBtu
WINTER - Nov 20-Mar 21 Hedge Volume						
(230,000/ day) (151 days)						
Non-Discretionary Volume	17.500	**17.365**	94%	100%	99%	**$2.31**
Dollar Budget Method	17.500	**17.078**	$2.228M/mo.		98%	**$2.32**
Total Winter Hedge Volume	35.000	**34.443**			98%	**$2.31**
			12/31/20 & Actual Nymex Settle			**$2.68**
SUMMER - Apr 21-Oct 21 Hedge Volume						
(160,000/ day) (214 days)						
Non-Discretionary Volume	17.500	**13.910**	78%	83%	79%	**$2.00**
Dollar Budget Method	17.500	**13.867**	$1.856M/mo.		79%	**$1.98**
Total Summer Hedge Volume	35.000	**27.777**			79%	**$1.99**
			12/31/20 Nymex Settles			**$2.65**
Total Non-Discretionary Method	35.000	**31.275**				**$2.17**
Total Dollar Budget Method	35.000	**30.945**				**$2.17**
					Difference	**($0.00)**
					Percent	**0.0%**

PSE&G Residential Hedging Report
November 2021 - October 2022
As of December 31, 2020

WINTER - Nov 21-Mar 22 Hedge Volume

(230,000/ day) (151 days)

	Bcf Target*	Bcf Hedged	% Hedged Target		% Hedged Actual	Current Price/ MMBtu
Non-Discretionary Volume	17.500	**7.173**	39%	44%	41%	**$2.49**
Dollar Budget Method	17.500	**6.131**	$2.130M/mo.		35%	**$2.53**
Total Winter Hedge Volume	35.000	**13.303**			38%	**$2.51**
			12/31/20 Nymex Settles			**$2.89**

SUMMER - Apr 22-Oct 22 Hedge Volume

(160,000/ day) (214 days)

	Bcf Target*	Bcf Hedged	% Hedged Target		% Hedged Actual	Current Price/ MMBtu
Non-Discretionary Volume	17.500	**3.467**	11%	17%	20%	**$1.96**
Dollar Budget Method	17.500	**2.568**	$1.653M/mo.		15%	**$1.91**
Total Summer Hedge Volume	35.000	**6.035**			17%	**$1.94**
			12/31/20 Nymex Settles			**$2.43**

	Bcf Target*	Bcf Hedged	% Hedged Target		% Hedged Actual	Current Price/ MMBtu
Total Non-Discretionary Method	35.000	**10.639**				**$2.32**
Total Dollar Budget Method	35.000	**8.699**				**$2.34**
					Difference	**$0.03**
					Percent	**1.2%**

Matthew M. Weissman
Managing Counsel – State Regulatory

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PSEG
Services Corporation

VIA ELECTRONIC MAIL

October 19, 2020

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

RE: PSE&G GAS HEDGING QUARTERLY REPORT – THIRD QUARTER 2020

Dear Director Peterson:

Enclosed please find Public Service Electric and Gas Company's ("Public Service" or the "Company") quarterly status report which is filed pursuant to the Board's March 30, 2001 Decision and Order in the above-referenced matter. This quarterly report identifies the Company's outstanding hedging positions as of September 30, 2020.

As shown on the attached schedules, hedging for the 2020/2021 winter season is at 94% of plan and 66% of the plan has been completed for 2021 summer. Hedging for the 2021/2022 winter season is at 23% and we have not begun to hedge for the 2022 summer. All of these periods are based on a plan of approximately 70bcf with an even split between winter and summer.

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

Very truly yours,

Matthew Weissman

Matthew M. Weissman

Attachment

C Stefanie A. Brand
Alice Bator
Felicia Thomas-Friel
Ben Witherell

PSE&G Residential Hedging Report November 2020 - October 2021 As of 9/30/2020	Bcf Target*	Bcf Hedged	% Hedged Target		% Hedged Actual	Current Price/ MMBtu
WINTER - Nov 20-Mar 21 Hedge Volume (230,000/ day) (151 days)						
Non-Discretionary Volume	17.500	**16.610**	89%	94%	95%	**$2.29**
Dollar Budget Method	17.500	**16.217**	$2.228M/mo.		93%	**$2.30**
Total Winter Hedge Volume	35.000	**32.827**			94%	**$2.30**
			9/30/20 Settles			**$3.05**
SUMMER - Apr 21-Oct 21 Hedge Volume (160,000/ day) (214 days)						
Non-Discretionary Volume	17.500	**11.770**	61%	67%	67%	**$1.95**
Dollar Budget Method	17.500	**11.342**	$1.856M/mo.		65%	**$1.94**
Total Summer Hedge Volume	35.000	**23.112**			66%	**$1.95**
			9/30/20 Settles			**$2.80**
Total Non-Discretionary Method	35.000	**28.380**				**$2.15**
Total Dollar Budget Method	35.000	**27.559**				**$2.16**
					Difference	**$0.01**
					Percent	**0.2%**

PSE&G Residential Hedging Report November 2021 - October 2022 As of 9/30/2020	Bcf Target*	Bcf Hedged	% Hedged Target		% Hedged Actual	Current Price/ MMBtu
WINTER - Nov 21-Mar 22 Hedge Volume						
(230,000/ day) (151 days)						
Non-Discretionary Volume	17.500	**4.153**	22%	28%	24%	**$2.45**
Dollar Budget Method	17.500	**3.745**	$2.130M/mo.		21%	**$2.46**
Total Winter Hedge Volume	35.000	**7.897**			23%	**$2.46**
			9/30/20 Settles			**$3.01**
SUMMER - Apr 22-Oct 22 Hedge Volume						
(160,000/ day) (214 days)						
Non-Discretionary Volume	17.500	**0.000**	0%	0%	0%	**$0.00**
Dollar Budget Method	17.500	**0.000**	$M/mo.		0%	**$0.00**
Total Summer Hedge Volume	35.000	**0.000**			0%	**$0.00**
						$2.40
Total Non-Discretionary Method	35.000	**4.153**				**$2.45**
Total Dollar Budget Method	35.000	**3.745**				**$2.46**
					Difference	**$0.02**
					Percent	**0.7%**

Matthew M. Weissman
Managing Counsel – State Regulatory

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PSEG Services Corporation

VIA ELECTRONIC MAIL

July 15, 2020

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, Director
Division of 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 2020

Dear Director Peterson:

Enclosed please find Public Service Electric and Gas Company's ("Public Service" or the "Company") quarterly status report which is filed pursuant to the Board's March 30, 2001 Decision and Order in the above-referenced matter. This quarterly report identifies the Company's outstanding hedging positions as of June 30, 2020.

As shown on the attached schedules, hedging for the 2020/2021 winter season is at 80% of plan and 50% of the plan has been completed for 2021 summer. Hedging for the 2021/2022 winter season is at 9% and we have not begun to hedge for the 2022 summer. All of these periods are based on a plan of approximately 70bcf with an even split between winter and summer.

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

Very truly yours,

Matthew Weissman

Matthew M. Weissman

Attachment

C Stefanie A. Brand
Alice Bator
Felicia Thomas-Friel
Ben Witherell

PSE&G Residential Hedging Report November 2020 - October 2021 As of 6/30/2020	Bcf Target*	Bcf Hedged	% Hedged Target		% Hedged Actual	Current Price/ MMBtu
WINTER - Nov 20-Mar 21 Hedge Volume						
(230,000/ day) (151 days)						
Non-Discretionary Volume	17.500	**14.345**	72%	78%	82%	**$2.27**
Dollar Budget Method	17.500	**13.515**	$2.228M/mo.		77%	**$2.27**
Total Winter Hedge Volume	35.000	**27.860**			80%	**$2.27**
			June 30, 2020 Settles			**$2.70**
SUMMER - Apr 21-Oct 21 Hedge Volume						
(160,000/ day) (214 days)						
Non-Discretionary Volume	17.500	**8.560**	44%	50%	49%	**$1.87**
Dollar Budget Method	17.500	**8.774**	$1.856M/mo.		50%	**$1.89**
Total Summer Hedge Volume	35.000	**17.334**			50%	**$1.88**
			June 30, 2020 Settles			**$2.51**
Total Non-Discretionary Method	35.000	**22.905**				**$2.12**
Total Dollar Budget Method	35.000	**22.289**				**$2.12**
					Difference	**$0.00**
					Percent	**0.1%**

PSE&G Residential Hedging Report November 2021 - October 2022 As of 6/30/2020	Bcf Target*	Bcf Hedged	% Hedged Target		% Hedged Actual	Current Price/ MMBtu
WINTER - Nov 21-Mar 22 Hedge Volume						
(230,000/ day) (151 days)						
Non-Discretionary Volume	17.500	**1.888**	6%	11%	11%	**$2.38**
Dollar Budget Method	17.500	**1.268**	$2.130M/mo.		7%	**$2.40**
Total Winter Hedge Volume	35.000	**3.156**			9%	**$2.38**
			June 30, 2020 Settles			**$2.72**
SUMMER - Apr 22-Oct 22 Hedge Volume						
(160,000/ day) (214 days)						
Non-Discretionary Volume	17.500	**0.000**	0%	0%	0%	**$0.00**
Dollar Budget Method	17.500	**0.000**	$M/mo.		0%	**$0.00**
Total Summer Hedge Volume	35.000	**0.000**			0%	**#DIV/0!**
						$0.00
Total Non-Discretionary Method	35.000	**1.888**				**$2.38**
Total Dollar Budget Method	35.000	**1.268**				**$2.40**
					Difference	**$0.02**
					Percent	**0.8%**

12. Storage Gas Volumes, Prices and Utilization

Ending Storage Inventory by Contract

Mdth

Storage Contract	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21
DTI GSS	16,132.9	15,865.0	11,694.4	7,479.2	5,180.5	2,392.9	3,843.2
ARLINGTON	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TR GSS	15,275.4	15,337.0	12,471.9	8,830.6	3,821.8	3,445.0	4,149.7
TR S-2	5,990.5	5,858.4	4,190.7	2,442.7	1,053.6	523.5	586.2
TR LSS	4,944.1	4,762.1	3,606.7	2,438.9	1,418.4	795.3	1,421.5
TENN FS-MA	4,732.4	5,150.6	3,879.2	2,407.2	1,448.4	1,016.9	1,583.8
DTI GSS-TE	14,024.9	14,043.5	11,083.1	7,891.2	4,714.4	2,826.0	3,530.9
TE SS-1 / SS	3,630.6	3,586.5	2,960.7	2,008.3	1,083.6	369.9	567.5
TE SS1	1,392.2	1,403.0	1,138.0	779.0	415.6	176.0	254.9
TR ESS	822.9	822.9	1,013.7	834.9	926.5	881.5	788.6
GULF SOUTH	593.7	722.6	819.6	521.2	471.1	366.2	296.7
TR LNG	1,333.5	1,333.5	1,333.5	1,290.1	1,207.5	1,254.2	1,254.2
TR LNG New	15.5	15.5	15.5	15.5	15.5	15.5	15.5
Total	68,888.5	68,900.5	54,207.2	36,938.9	21,756.9	14,063.0	18,292.9
Ending Inventory Cost ($/Dth)	$3.74	$3.69	$3.68	$3.70	$3.86	$3.97	$3.74

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)

Month	Camden Dth	Camden Dollars	Central Dth	Central Dollars	Harrison Dth	Harrison Dollars	Linden Dth	Linden Dollars
Jan-18	45	$510	88	$802	71	$698	60	$544
Feb-18	42	$480	65	$588	35	$342	60	$544
Mar-18	42	$480	65	$588	35	$342	60	$544
Apr-18	42	$480	65	$588	35	$342	60	$544
May-18	42	$480	65	$588	35	$342	60	$544
Jun-18	42	$480	65	$588	35	$342	60	$544
Jul-18	42	$480	65	$588	35	$342	60	$544
Aug-18	42	$480	65	$588	35	$342	60	$544
Sep-18	42	$480	65	$588	35	$342	60	$544
Oct-18	45	$512	71	$670	77	$922	62	$577
Nov-18	45	$512	83	$807	77	$922	62	$577
Dec-18	45	$512	83	$802	75	$898	62	$577
Jan-19	43	$495	80	$777	71	$849	62	$577
Feb-19	41	$474	79	$770	68	$822	61	$568
Mar-19	41	$474	79	$770	75	$896	61	$568
Apr-19	40	$455	75	$731	70	$841	61	$568
May-19	40	$455	75	$731	70	$841	61	$568
Jun-19	40	$455	75	$731	70	$841	61	$568
Jul-19	40	$455	75	$731	70	$841	61	$568
Aug-19	40	$455	75	$731	70	$841	61	$568
Sep-19	44	$485	84	$796	77	$893	61	$568
Oct-19	44	$485	84	$795	77	$893	63	$581
Nov-19	44	$485	84	$795	77	$893	63	$581
Dec-19	45	$496	85	$811	79	$910	64	$592

LPG INVENTORY VOLUMES AND COST BY LOCATION
(000)

Month	Camden Dth	Camden Dollars	Central Dth	Central Dollars	Harrison Dth	Harrison Dollars	Linden Dth	Linden Dollars
Jan-20	45	$493	85	$804	74	$857	64	$592
Feb-20	45	$493	85	$804	69	$800	64	$592
Mar-20	45	$493	55	$523	55	$631	64	$592
Apr-20	45	$493	55	$523	55	$631	64	$592
May-20	45	$493	55	$523	55	$631	64	$592
Jun-20	45	$493	55	$523	52	$594	64	$592
Jul-20	45	$493	55	$523	52	$594	64	$592
Aug-20	45	$493	55	$523	52	$594	64	$592
Sep-20	45	$493	55	$523	52	$594	64	$592
Oct-20	45	$493	90	$846	82	$887	64	$592
Nov-20	45	$493	99	$928	82	$885	64	$592
Dec-20	44	$482	89	$839	80	$860	64	$592
Jan-21	43	$477	89	$839	80	$860	64	$592
Feb-21	43	$472	86	$808	59	$639	64	$592
Mar-21	43	$472	63	$592	52	$565	64	$592
Apr-21 est	43	$472	62	$584	50	$534	64	$592
May-21 est	43	$472	62	$584	50	$534	64	$592
Jun-21 est	43	$472	62	$584	50	$534	64	$592
Jul-21 est	43	$472	62	$584	50	$534	64	$592
Aug-21 est	43	$472	62	$584	50	$534	64	$592
Sep-21 est	43	$472	62	$584	50	$534	64	$592
Oct-21 est	43	$472	62	$584	50	$534	64	$592
Nov-21 est	43	$472	62	$584	50	$534	64	$592
Dec-21 est	43	$472	62	$584	50	$534	64	$592

LNG INVENTORY VOLUMES AND COST
(000)

Month	Dth	Dollars	Month	Dth	Dollars
Jan-18	129	$136	Jan-20	294	$235
Feb-18	122	$128	Feb-20	236	$188
Mar-18	198	$207	Mar-20	228	$182
Apr-18	190	$199	Apr-20	220	$176
May-18	181	$190	May-20	213	$170
Jun-18	174	$182	Jun-20	206	$165
Jul-18	167	$175	Jul-20	199	$159
Aug-18	161	$169	Aug-20	285	$250
Sep-18	155	$162	Sep-20	299	$269
Oct-18	144	$151	Oct-20	292	$263
Nov-18	135	$142	Nov-20	284	$256
Dec-18	154	$162	Dec-20	271	$245
Jan-19	282	$152	Jan-21	246	$222
Feb-19	262	$141	Feb-21	217	$196
Mar-19	237	$128	Mar-21	209	$188
Apr-19	228	$123	Apr-21 est	201	$182
May-19	221	$119	May-21 est	201	$182
Jun-19	263	$115	Jun-21 est	201	$182
Jul-19	257	$168	Jul-21 est	201	$182
Aug-19	250	$164	Aug-21 est	201	$182
Sep-19	244	$159	Sep-21 est	201	$182
Oct-19	234	$153	Oct-21 est	201	$182
Nov-19	267	$199	Nov-21 est	201	$182
Dec-19	303	$242	Dec-21 est	201	$182

13. Affiliate Gas Supply Transactions

Item 13

Principal Terms of the Requirements Contract

between

PSE&G and PSEG Energy Resources & Trade (ER&T)

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

    - Natural gas, LNG, and propane inventories were transferred from PSE&G to ER&T at book value as of April 30, 2002
    - BPU order authorizing the transfer was entered April 17, 2002
  - ER&T provides administrative and management services to PSE&G related to the wholesale delivery of gas, including:
    - Load scheduling
    - Load balancing
    - Mitigation of price volatility
    - When appropriate, input into decisions regarding whether to interrupt service and when to call upon peak shaving
  - PSE&G maintains peak shaving facilities, for which ER&T pays operating and maintenance costs, and also return
  - Deliveries of BGSS services are to be made to PSE&G at pipeline or peak shaving interconnections
    - ER&T is responsible for transportation of gas to the Points of Delivery, and PSE&G is responsible for transportation of gas from the Points of Delivery
  - ER&T is the sole supplier of the BGSS full requirements
3. Term: Through March 31, 2019, and year-to-year thereafter, subject to cancellation by either party with 2 years notice
  - Original term was to March 31, 2004, with option to extend

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

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

14. Supply and Demand Data

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

	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Total
Gas Supplies (MDTh)													
Beginning Inventory	66,239	74,400	71,559	65,575	47,973	31,811	19,894	26,264	34,915	44,672	52,820	61,645	
Natural Gas Receipt	19,302	21,429	23,363	22,433	16,238	16,389	18,164	16,362	14,494	12,205	12,950	12,768	206,097
Total Inventory Available	85,540	95,829	94,922	88,007	64,211	48,199	38,058	42,626	49,410	56,877	65,770	74,413	
Gas Demand (MDTh)													
Firm Sendout	11,140	24,270	29,347	40,034	32,400	28,305	11,794	7,711	4,738	4,057	4,125	4,465	202,387
Ending Inventory MDTh	74,400	71,559	65,575	47,973	31,811	19,894	26,264	34,915	44,672	52,820	61,645	69,948	

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

	Oct-19	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Total
Gas Supplies (MDTh)													
Beginning Inventory	69,948	76,497	74,635	67,625	55,972	43,239	34,735	31,883	37,638	44,695	52,251	59,482	
Natural Gas Receipt	14,427	23,028	25,783	20,785	15,935	12,091	13,214	14,914	11,865	11,485	11,461	13,613	188,601
Total Inventory Available	84,375	99,525	100,418	88,410	71,907	55,330	47,950	46,797	49,503	56,180	63,712	73,094	
Gas Demand (MDTh)													
Firm Sendout	7,878	24,890	32,793	32,438	28,668	20,595	16,066	9,159	4,808	3,929	4,230	4,793	190,248
Ending Inventory MDTh	76,497	74,635	67,625	55,972	43,239	34,735	31,883	37,638	44,695	52,251	59,482	68,301	

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

	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Total
Gas Supplies (MDTh)													
Beginning Inventory	68,301	74,953	74,961	61,427	43,509	28,255	19,986	23,623	30,670	42,911	50,774	56,122	
Natural Gas Receipt	15,716	17,100	18,992	19,917	19,207	15,708	17,276	14,497	17,456	12,077	9,359	12,845	190,151
Total Inventory Available	84,018	92,053	93,953	81,343	62,716	43,963	37,262	38,119	48,126	54,988	60,134	68,967	
Gas Demand (MDTh)													
Firm Sendout	9,064	17,092	32,526	37,835	34,461	23,977	13,640	7,449	5,216	4,213	4,012	4,257	193,741
Ending Inventory MDTh	74,953	74,961	61,427	43,509	28,255	19,986	23,623	30,670	42,911	50,774	56,122	64,711	

FIRM GAS SUPPLY AND DEMAND DATA (October 2021- September 2022)

	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Total
Gas Supplies (MDTh)													
Beginning Inventory	**64,711**	70,332	66,589	48,814	29,236	14,783	7,226	7,165	14,174	30,351	41,154	49,293	
Natural Gas Receipt	13,878	15,595	15,087	19,883	19,958	19,689	15,513	14,477	21,345	15,018	12,129	15,977	198,550
Total Inventory Available	78,588	85,927	81,676	68,697	49,194	34,473	22,740	21,642	35,519	45,369	53,283	65,270	
Gas Demand (MDTh)													
Firm Sendout	8,257	19,338	32,862	39,461	34,411	27,246	15,575	7,468	5,168	4,215	3,990	4,212	202,203
Ending Inventory MDTh	70,332	66,589	48,814	29,236	14,783	7,226	7,165	14,174	30,351	41,154	49,293	61,058	

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	61,058	70,330	65,891	47,272	27,448	12,568	4,635	5,254	13,093	30,576	42,381	51,230	
Natural Gas Receipt	17,664	15,275	14,476	19,914	19,878	19,616	16,324	15,421	22,639	15,955	12,758	16,744	206,666
Total Inventory Available	78,721	85,605	80,368	67,186	47,326	32,184	20,959	20,675	35,732	46,531	55,140	67,974	
Gas Demand (MDTh)													
Firm Sendout	8,392	19,713	33,095	39,738	34,759	27,549	15,705	7,582	5,156	4,150	3,910	4,138	203,887
Ending Inventory MDTh	70,330	65,891	47,272	27,448	12,568	4,635	5,254	13,093	30,576	42,381	51,230	63,836	

15. Actual Peak Day Supply and Demand

Actual Peak Day Supply and Demand - Item 15

	DATE	NEWARK AVG. TEMP (F)	LOAD (000 DTh) TOTAL	FIRM	INTERR.	SUPPLY SOURCES (000 DTh) NATURAL GAS HLF TRANSP.	STORAGE / LNG	LPA
2020 / 2021 WINTER								
	29-Jan-21	20.3	2504	2146	358	1489	1008	7
	28-Jan-21	24.0	2308	1956	352	1405	895	8
	31-Jan-21	24.4	2274	1932	342	1646	628	0
	30-Jan-21	25.5	2151	1845	306	1532	618	0
	16-Dec-20	27.2	2178	1796	382	1270	907	1
2019 / 2020 WINTER								
	19-Dec-19	23.7	2389	1983	406	1768	620	1
	20-Jan-20	25.6	2311	1909	402	1530	780	1
	18-Dec-19	24.8	2251	1852	399	1499	751	0
	17-Jan-20	24.5	2243	1847	396	1523	721	0
	14-Feb-20	22.1	2164	1878	286	1484	677	4
2018 / 2019 WINTER								
	21-Jan-19	13.0	2782	2591	191	1636	1146	0
	31-Jan-19	13.1	2761	2510	251	1686	1075	0
	30-Jan-19	12.5	2624	2406	218	1581	1043	0
	1-Feb-19	18.0	2605	2295	310	1612	993	0

16. Capacity Contract Changes

Including Gas Sales Forecast Support

SCHEDULE F

May-21

PEAK DAY GAS REQUIREMENTS AND SUPPLY
(MDTh)

	SUPPLY		2021-2022	2022-2023	2023-2024	2024-2025	2025-2026
	Transco FT		432.4	432.4	432.4	432.4	432.4
	Transco FT (DTI)		32.2	32.2	32.2	32.2	32.2
	Transco FT (Cove Point)		20.0	20.0	20.0	20.0	20.0
	Transco FT (Gateway)		54.0	54.0	54.0	54.0	54.0
	Texas Eastern FT		246.6	246.6	246.6	246.6	246.6
	Tennessee FT		36.4	36.4	36.4	36.4	36.4
	FT from Lebanon:						
	Texas Eastern		180.7	180.7	180.7	180.7	180.7
	DTI/Transco		49.7	49.7	49.7	49.7	49.7
	Columbia		12.5	12.5	12.5	12.5	12.5
	Subtotal		242.9	242.9	242.9	242.9	242.9
	Transco/Tetco FT (Leidy)		330.2	330.2	330.2	330.2	330.2
	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		1,428.5	1,428.5	1,428.5	1,428.5	1,428.5
	Refinery Gas		0.0	0.0	0.0	0.0	0.0
	Total Firm FT Supply		1,428.5	1,428.5	1,428.5	1,428.5	1,428.5
	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		82.0	82.0	82.0	82.0	82.0
	LPA		199.7	199.7	199.7	199.7	199.7
	Total Peaking Supply		570.3	570.3	570.3	570.3	570.3
	PSEG Firm Supply Subtotal		2,893.1	2,893.1	2,893.1	2,893.1	2,893.1
	FTS DCQ 1./		310.3	309.4	310.1	311.0	311.5
[a]	Total PSEG Gas Supply		3,203.3	3,202.4	3,203.2	3,204.1	3,204.5
	Peak Day Sendout Forecast 2./		3,031.0	3,067.0	3,094.0	3,123.0	3,149.0
[b]	Total Peak Day Capacity Requirements	3./	3,173.2	3,217.1	3,242.2	3,272.2	3,298.4
[a]-[b]	Surplus / (Deficiency)	3./	30.1	(14.7)	(39.1)	(68.1)	(93.9)

1./ Forecasted FT-S DCQ (January)
2./ Based on Corporate Energy Forecast, Gas -2021
3./ 3% Loss of Load Probability

Item 16

Natural Gas Sales Forecast - 2021

Public Service Electric & Gas Company

Finance Department

Electric and Gas Sales and Revenue Forecasting Group

April 2021

Contents

Introduction

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

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

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

The purpose of this document is to describe the current forecast methodology, forecast assumptions, and the 2021 gas sales forecast. The first section describes the econometric sales models. A discussion of the forecast assumptions used to develop the sales forecast follows. Section III describes the maximum daily send-out projection. An appendix contains more detailed information on the billing period to calendar month conversion, and forecast tables.

I Model Specification and Estimation

Residential Model

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

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

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

where:

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

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

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

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

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

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

$$\text{THERM/CUST}_t = f(\overline{\text{MONTH}}\text{x}\text{HDD}_t \times \text{PRICEGAS}_{a-1}, \overline{\text{MONTH}}\text{x}\text{HDD}_t \times \text{INCOME}_{a-1}, \overline{\text{MONTH}}\text{x}\text{HDD}_t) \qquad [2]$$

where:

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

The models were estimated using monthly data from January 2006 to December 2019 period (excluding data from 2009 due to distortions resulting from the implementation of a new billing system.)The results of the OLS estimation procedure are summarized in Table 1 and Figures 1 and 2.

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

Figure 1
RSG Space Heating Model
Actual vs. Fitted Values

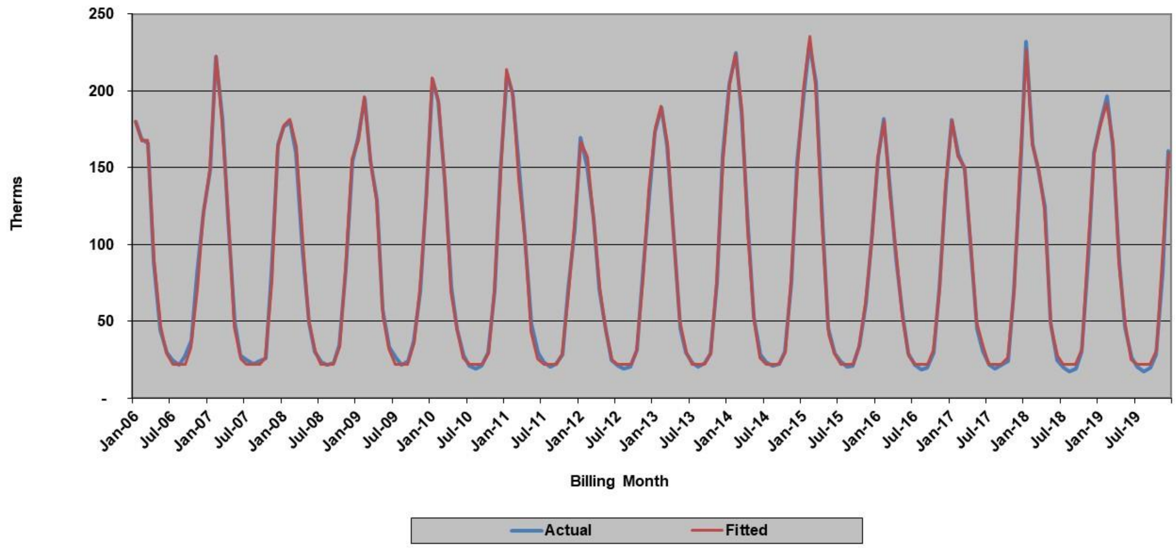
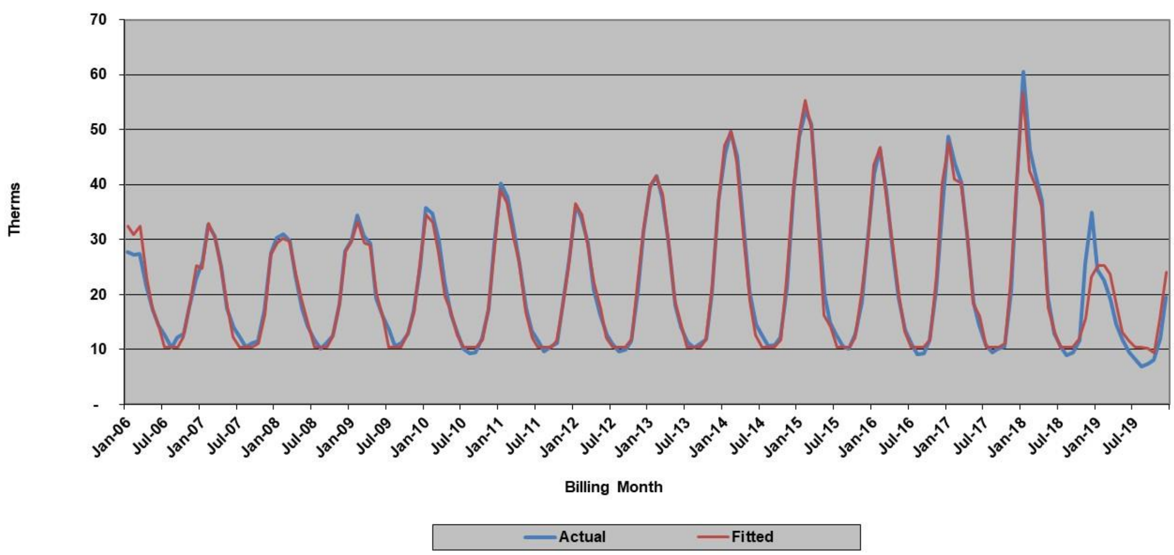


Figure 2
RSG Non-Space Heating Model
Actual vs. Fitted Values



The price elasticity estimates were estimated to be -0.0142 and -0.42 for space heating and non-space heating customers, respectively and consistent with lower gas prices and the lack of a surge in consumption in response to them. The non-space heating elasticity is the result of a similar therm impact of price but, measured over a much smaller base usage. Income was found to have an effect on gas consumption by space heating customers in the fall. This is consistent with income changes resulting affecting when space heating equipment is turned on. The economic downturn appeared to result in a delay in turning on this equipment in the fall reducing use.

Table 1

Estimated Coefficients of the Residential Models

(standard errors in parentheses)

	JAN	FEB	MAR	APR	MAY	JUNE	OCT	NOV	DEC	R2
HEATING										
HDD	0.20345	0.20335	0.20206	0.19631	0.14524	0.16500			0.12416	0.999
	(0.007)	(0.007)	(0.007)	(0.010)	(0.007)	(0.020)			(0.017)	
		FEB -MAR	**APR-MAY**							
PRICE x HDD		-0.00457	-0.00665							
		(0.002)	(0.004)							
WAGE x HDD							0.00123	0.00198	0.00064	
							(0.00012)	(0.00003)	(0.00023)	
I-POWER	-0.00659									
	(0.00126)									
RSG-TRAN	-0.00147									
	(0.00158)									
	JAN	**FEB**	**MAR**	**APR**	**MAY**	**JUNE**	**OCT**	**NOV**	**DEC**	**R2**
NON-HEATING										
HDD	0.05905	0.05667	0.05612	0.05658	0.03936	0.08050	0.01401	0.05460	0.05860	0.974
	(0.002)	(0.002)	(0.003)	(0.004)	(0.004)	(0.017)	(0.007)	(0.006)	(0.003)	
PRICE x HDD	-0.01961	-0.01809	-0.01678	-0.01533				-0.01967	-0.01908	
	(0.002)	(0.002)	(0.002)	(0.003)				(0.002)	(0.003)	
RSG-TRAN	-0.02486									
	(0.00122)									

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

Commercial

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

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

where:

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

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

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

Substituting [4] into [3] yields:

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

LVG model was estimated for customers in the commercial sector using monthly billing data from January 2005 to December 2019 period (again, excluding 2009).The firm delivery customers in this class whose usage does not exceed 300 Dth are served under rate GSG. These customers are further disaggregated into those with gas space heat and those that heat with other fuels. These two groups of customers are modeled separately. Time period for GSG models set from January 2007 to December 2019 period in order to get better estimation results. The larger commercial customers are served under rate LVG. These are also modeled separately.

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

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

where:

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

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

The estimated coefficients of the three commercial models indicate that while the small commercial space heating are sensitive to price, with an estimated elasticity of -0.1429 the non-space heating customers are not, and the large commercial LVG customers are sensitive to price, with an estimated elasticity of -0.043. In addition, while the coefficients on households, the economic indicator in the models, are highly statistically significant, this does not imply large sales increases given the anticipated slow growth in the number of households.

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

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

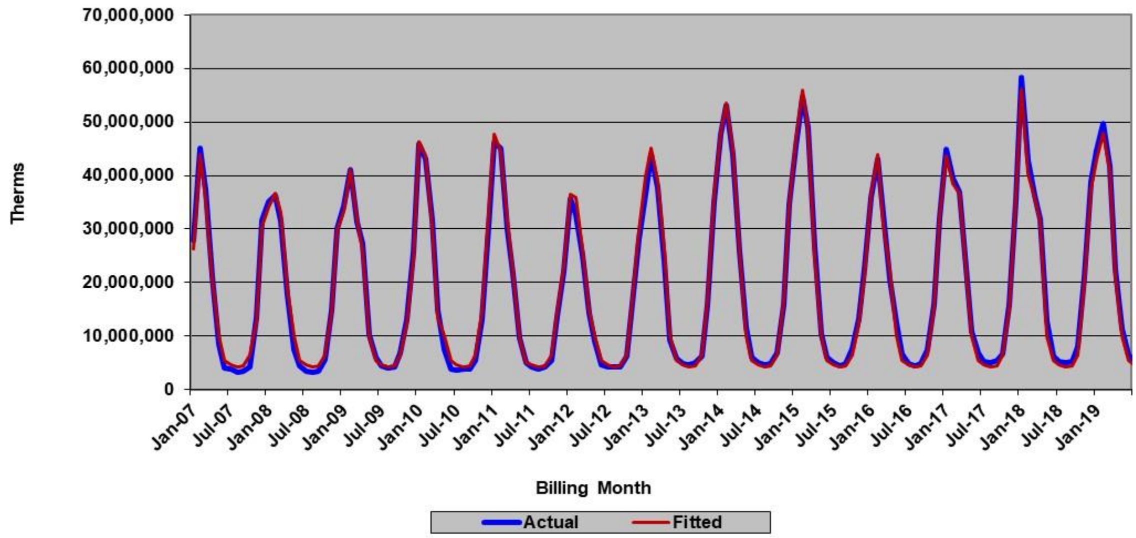


Figure 4
GSG Commercial Non-Space Heating Model
Actual vs. Fitted Values

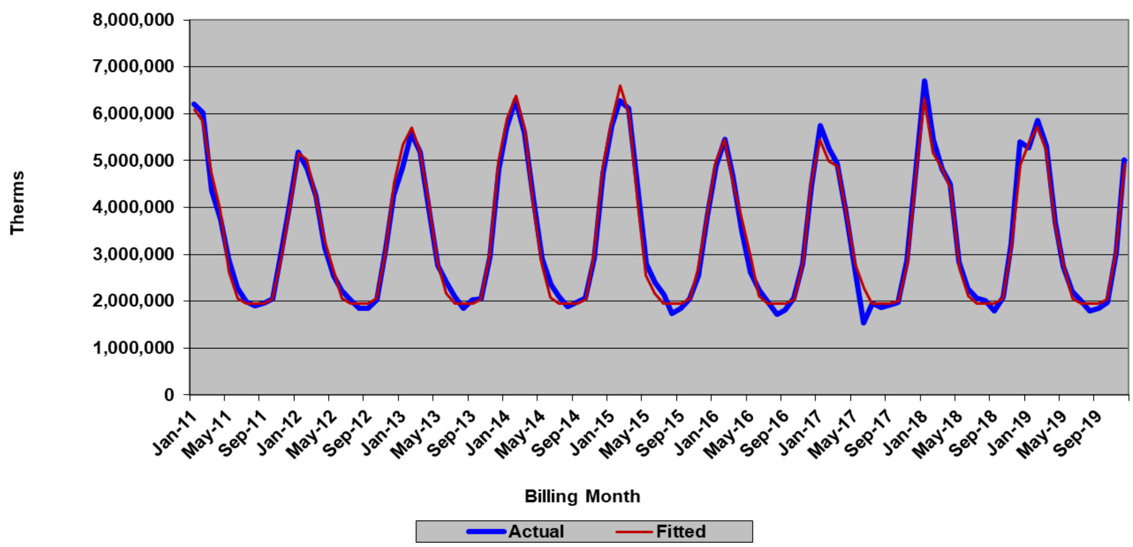


Figure 5
LVG Commercial Model
Actual vs. Fitted Values

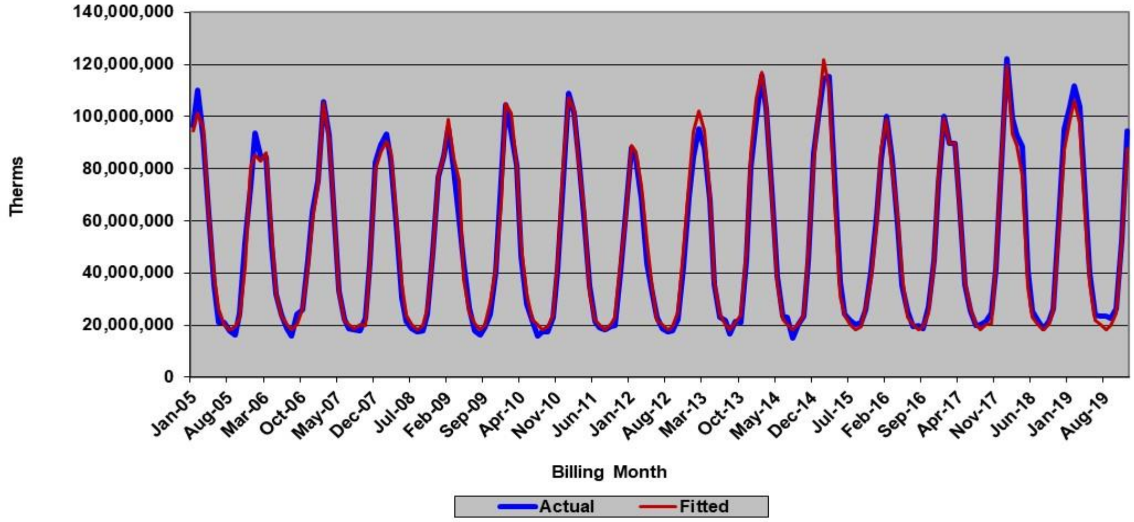


Table 2

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

	JAN	FEB	MAR	APR	MAY	JUN	SEP	OCT	NOV	DEC	R2
HEATING											
PRICE x HDD	-7124	-8367	-7646	-14046					-10844	-8416	0.995
	(1,695)	(1,340)	(1,580)	(2,470)					(3,228)	(1,598)	
CUST x HDD	18.58	17.57	18.02	20.81					14.19	17.16	
	(1)	(1)	(1)	(1)					(2)	(1)	
NON-HEATING											
HDD	3840	3968	3985	4044	4003	4428		878	2569	3654	0.986
	(74)	(75)	(90)	(144)	(358)	(1,735)		(725)	(182)	(97)	

Table 3

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

HDD x PRICE	HDD x CUST	R2
-8954.0	28.8	0.988
(1,888)	(1)	

Industrial

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

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

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 model is estimated for using monthly billing data from January 2011 to December 2019 period while Non-Heating model is estimated for using monthly billing data from January 2013 to December 2019 in order to get better estimation results. 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 2005 to December 2019 period (excluding 2009).

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 -0.07 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

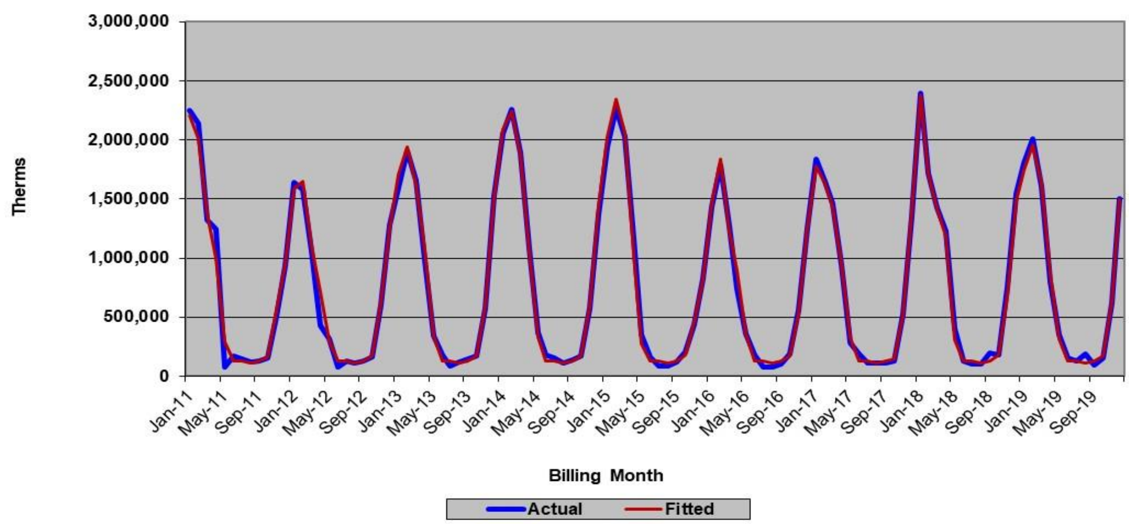


Figure 7

GSG Industrial Non-Space Heating Model

Actual vs. Fitted Values

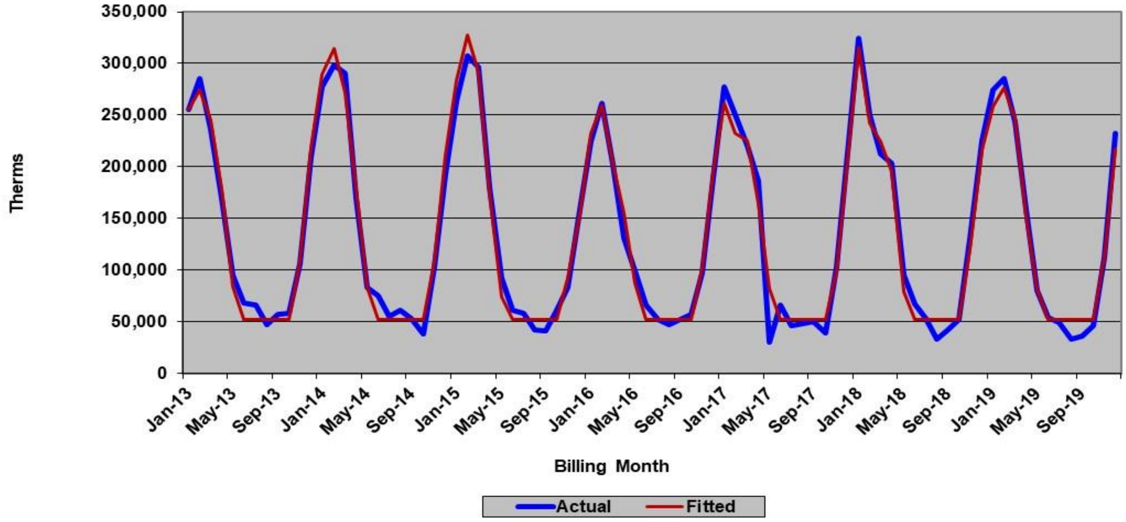


Figure 8

LVG Industrial Heating Model

Actual vs. Fitted Values

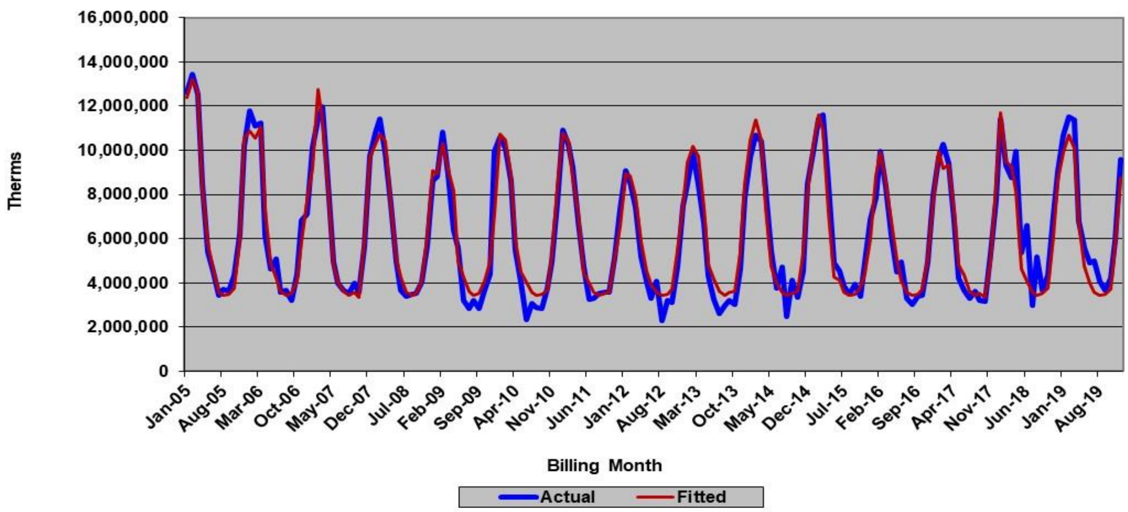


Table 4

Estimated Coefficients of the GSG Industrial Gas Sales Models

(standard errors in parentheses)

	JAN	FEB	MAR	APR	MAY	JUN	OCT	NOV	DEC	R2
HEATING										
HDD	2588 (196)	1758 (162)	2213 (170)	1741 (51)	967 (127)		440 (258)	1167 (65)	2186 (201)	0.993
NON-HEATING										
HDD	230 (6)	235 (6)	237 (7)	235 (11)	143 (27)			140 (14)	202 (7)	0.981

Table 5

Estimated Coefficients of the LVG Industrial Gas Sales Models

(standard errors in parentheses)

HDD x PRICE	HDD x EMP	R2
-1561.12 (671)	35.92 (5)	0.946

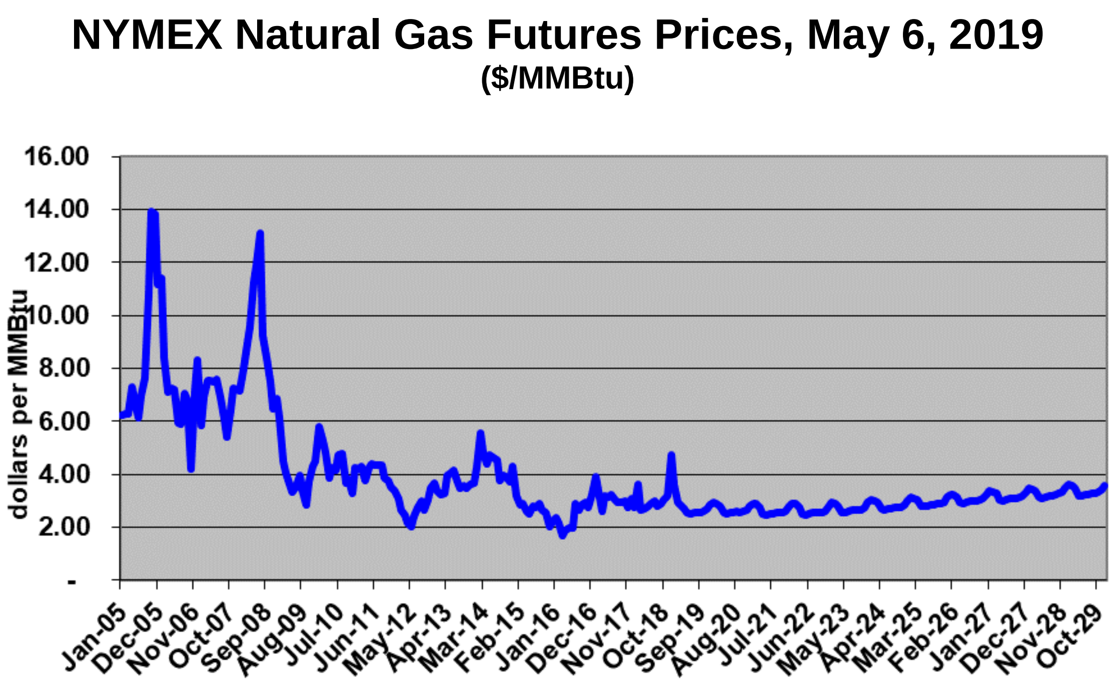
II Forecast Assumptions

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

Natural Gas Prices

The main driver of retail natural gas prices is the wholesale cost of gas which changes monthly. While these costs are passed through to commercial and industrial customers on monthly basis, the gas cost under- or over-collection of the residential customers is addressed in October where the rate is adjusted to collect or return the imbalance over the following twelve months. For the purpose of the forecast, the wholesale natural gas price was assumed to follow the NYMEX future prices as of May 06, 2019. As figure 9 shows, the wholesale price of gas is projected to stay relatively stable during the 2019-2029 periods.

Figure 9



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

Table 6
Historic and Projected Retail Gas Prices
(dollars per therm)

			Commercial			Industrial		
	RSG		GSG		LVG	GSG		LVG
Year	Heating	Non-Heating	Heating	Non-Heating		Heating	Non-Heating	
2006	1.39	1.58	1.41	1.30	1.23	1.43	1.33	1.22
2007	1.35	1.54	1.31	1.27	1.17	1.32	1.24	1.13
2008	1.40	1.57	1.42	1.42	1.29	1.41	1.40	1.25
2009	1.40	1.56	1.09	1.05	0.94	1.09	1.06	0.92
2010	1.24	1.43	1.10	1.07	0.97	1.11	1.06	0.92
2011	1.09	1.26	1.06	1.04	0.92	1.05	1.05	0.87
2012	1.00	1.18	0.95	0.93	0.80	0.95	0.98	0.75
2013	0.94	1.09	1.00	0.99	0.84	1.00	1.01	0.80
2014	0.80	0.94	1.06	1.04	0.91	1.10	1.08	0.90
2015	0.64	0.80	0.86	0.85	0.74	0.86	0.88	0.74
2016	0.71	0.87	0.83	0.83	0.69	0.83	0.86	0.70
2017	0.77	0.91	0.95	0.95	0.79	0.95	0.98	0.80
2018	0.74	0.88	0.93	0.92	0.79	0.94	0.96	0.77
2019	0.79	0.90	0.94	0.92	0.78	0.94	0.96	0.75
2020	0.79	0.91	0.92	0.91	0.75	0.92	0.94	0.73
2021	0.76	0.88	0.92	0.91	0.76	0.92	0.94	0.73
2022	0.74	0.86	0.83	0.82	0.67	0.83	0.85	0.64
2023	0.72	0.84	0.81	0.80	0.65	0.81	0.83	0.62
2024	0.71	0.83	0.80	0.79	0.63	0.80	0.82	0.61
2025	0.71	0.83	0.80	0.79	0.63	0.79	0.82	0.60
2026	0.71	0.83	0.80	0.79	0.63	0.79	0.82	0.60
2027	0.71	0.83	0.80	0.79	0.63	0.79	0.82	0.60
2028	0.71	0.83	0.80	0.79	0.63	0.79	0.82	0.60
2029	0.71	0.83	0.80	0.79	0.63	0.79	0.82	0.60
2030	0.71	0.83	0.80	0.79	0.63	0.79	0.82	0.60
2031	0.71	0.83	0.80	0.79	0.63	0.79	0.82	0.60
2032	0.71	0.83	0.80	0.79	0.63	0.79	0.82	0.60
2033	0.71	0.83	0.80	0.79	0.63	0.79	0.82	0.60
2034	0.71	0.83	0.80	0.79	0.63	0.79	0.82	0.60
2035	0.71	0.83	0.80	0.79	0.63	0.79	0.82	0.60

Energy Efficiency

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.

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

	BILLING MONTH ASUMPTIONS		
	EMP	EE	CEF
2010	14,596,330	1,014,483	-
2011	16,831,360	3,286,510	-
2012	12,618,148	4,213,546	-
2013	16,790,499	5,039,977	-
2014	22,116,578	6,586,486	-
2015	24,589,911	6,989,516	-
2016	27,228,971	7,495,738	-
2017	30,109,455	8,348,880	-
2018	33,743,658	9,541,067	-
2019	37,356,813	9,791,476	-
2020	40,969,968	10,870,995	-
2021	40,969,968	11,229,066	6,784,016
2022	40,969,968	11,689,030	17,622,437
2023	40,969,968	11,698,164	29,976,349
2024	40,969,968	11,618,156	42,206,408
2025	40,969,968	11,618,156	59,455,919
2026	40,969,968	11,618,156	76,249,006
2027	40,969,968	11,618,156	92,318,583
2028	40,969,968	11,618,156	108,388,159
2029	40,969,968	11,516,179	124,457,735
2030	40,969,968	10,962,760	139,251,837

Economic Projections

Economic and demographic forecast assumptions for the nation and New Jersey are from Moody's Economy August 2020 forecast. This forecast captures impact of COVID-19 on economy which assumes that, nationally, the economy will recover at a slow rate after pandemic. This national forecast is expected to be reflected in New Jersey's economic outlook that is also expected to be at a slow pace. In addition, an adjustment was made to the sales forecast in 2021, to capture perceived impacts of pandemic due to the most recent impacts of the government mandated economic restrictions that were not captured in the economic forecast.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, 2019.

Table 8

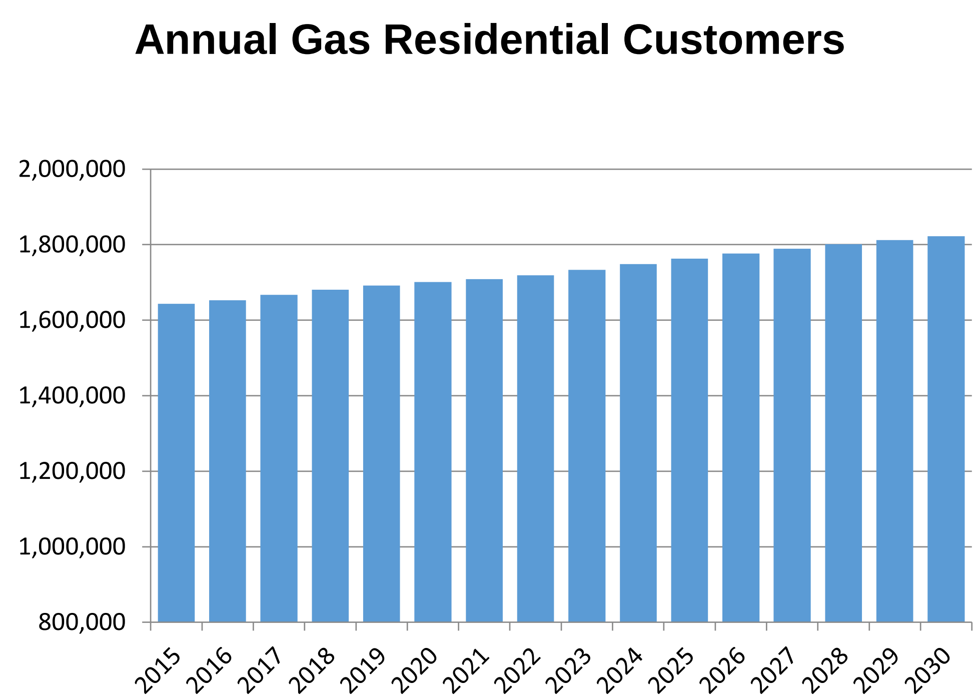
National and New Jersey Economic Forecast Assumptions

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
United States														
Gross Domestic Product, (Bil. USD, SAAR)	19,543	20,612	21,433	20,529	21,291	22,862	24,270	25,425	26,477	27,505	28,601	29,779	30,993	32,253
Industrial Production: Total, (Index 2012=100, SA)	104	109	109	101	104	108	110	111	112	114	115	117	119	120
Income: Personal - Total, (Bil. Ch. 2009 USD, SAAR)	15,992	16,493	16,889	17,703	16,903	17,375	17,967	18,473	18,905	19,351	19,840	20,361	20,873	21,385
Employment: Total Nonagricultural, (Mil. #, SA)	147	149	151	141	141	146	151	153	154	154	155	156	157	158
Household Survey: Unemployment Rate, (%, SA)	4.3	3.9	3.7	9.0	8.8	6.6	4.8	4.5	4.6	4.8	4.9	4.9	4.8	4.7
CPI: Urban Consumer - All Items, (Index 1982-84=100, SA)	245	251	256	259	263	271	278	286	293	300	307	314	322	329
Interest Rates: 3-Month Treasury Bills EBY, (% p.a., NSA)	0.9	2.0	2.1	0.4	0.3	0.3	0.6	1.5	2.4	2.6	2.6	2.6	2.5	2.5
Terms Conventional Mortgages: All Loans Fixed Effective Rate, (%, NSA)	4.1	4.7	4.4	3.8	3.6	4.2	4.9	5.4	5.7	5.9	6.0	6.0	5.9	5.9
New Jersey														
Real Personal Income, (Mil. 09$, SAAR)	544,481	561,605	573,976	587,526	560,211	573,182	590,677	605,594	618,360	631,922	646,663	662,538	678,036	693,160
Employment: Total Nonagricultural, (Ths., SA)	4,120	4,158	4,199	3,848	3,889	3,998	4,100	4,146	4,161	4,174	4,184	4,197	4,213	4,230
Employment: Total Manufacturing, (Ths., SA)	247	250	252	237	229	232	234	232	228	225	221	218	214	211
Employment: Total Non-Manufacturing, (Ths., SA)	3,874	3,908	3,947	3,611	3,661	3,767	3,867	3,914	3,933	3,949	3,963	3,980	3,999	4,019
Labor: Unemployment Rate, (%, SA)	4.6	4.1	3.5	10.1	9.0	6.7	4.9	4.6	4.7	4.9	4.9	4.9	4.8	4.8
Population: Total, (Ths.)	8,886	8,885	8,880	8,892	8,928	8,968	9,003	9,035	9,067	9,099	9,128	9,152	9,171	9,186
Households: Total, (Ths.)	3,343	3,353	3,363	3,375	3,378	3,390	3,409	3,431	3,453	3,473	3,491	3,508	3,525	3,540
Housing Starts: Single-family, (#, SAAR)	11,568	12,255	12,243	11,207	15,058	20,508	20,996	20,342	19,703	18,386	16,965	15,344	14,397	13,902

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 and with seven weather stations in NJ as the measuring base. Gas supplies are designed to meet the estimated maximum daily as well as maximum hourly demand. The maximum daily sendout forecast process consists of:

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

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

Daily Firm Sendout Model Estimation

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

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

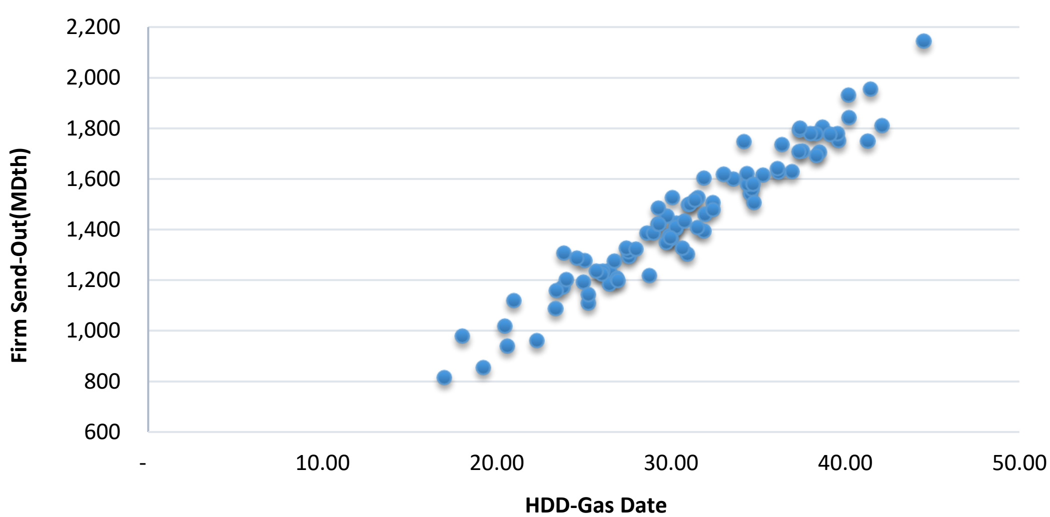
The second issue, of extrapolation, is addressed in a similar way. The relationship between sendout and weather is fairly linear. In reality, it is probably not perfectly linear. This is not an issue when estimating a model and using the results to interpolate values with the range of the estimation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

To address both of these forecasting issues, the data used in estimating the relationship between daily sendout and weather was limited to December 2020, January and February 2021 during the most recent year available. 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

December 2020 - January & February 2021
Daily Firm Sendout vs Heating Degree Days



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:

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

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.

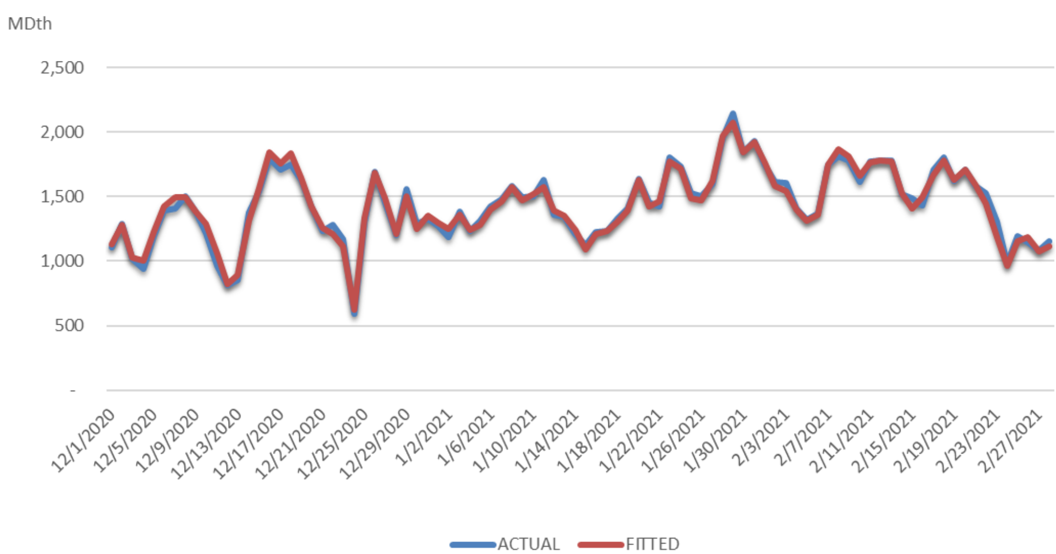
Table 8

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

		HDD						
Intercept	**HDD**	**LAG**	**HOLIDAY**	**WEEKDAY**	**WIND-SPEED**	**SKY COND**	**SNOW**	**R2**
-34.5	35.8	7.8	0.47	0.53	13.3	9.3	-11.1	0.9792
(30.2)	(1.0)	(0.9)	(0.5)	(0.4)	(1.5)	(3.3)	(17.6)	

Figure 12

Daily Sendout Model
Actual vs. Fitted Values



The estimated coefficients of the model suggest that the estimated maximum daily peak would occur on a Friday. The model predicts that the maximum peak daily sendout would be 2074 MDth.

A. Calendar-Month Sales Calculation

Introduction

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

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

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

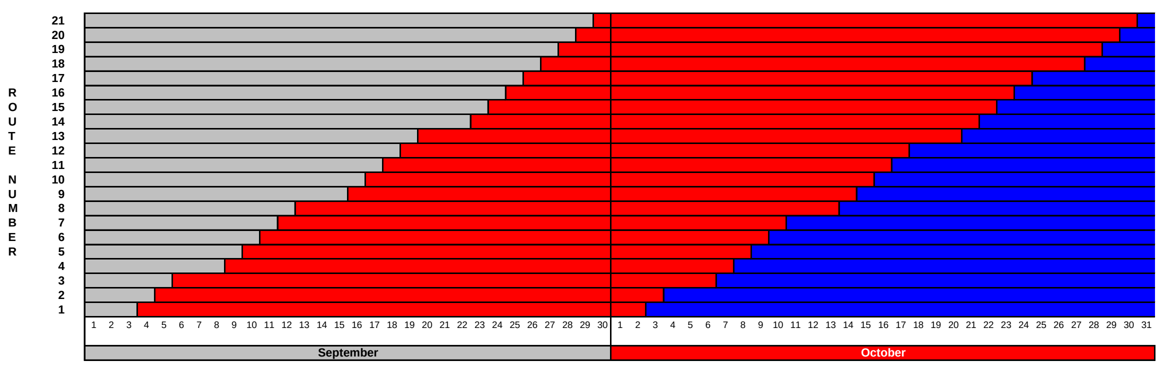
The Unbilled and Calendar-Month Estimation

A Simple Example

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

Figure 1

Hypothetical October 2008 Billing-Month



From the red portion of the diagram, it can be seen that the October billing-month consists of September sales that are billed in October that, to facilitate discussion, will be referred to as $\boxed{\text{SEP B> OCT}}$ and October sales that are billed in October i.e., $\boxed{\text{OCT B> OCT}}$. 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 $\boxed{\text{OCT B> OCT}}$ sales and the October unbilled sales, $\boxed{\text{OCT B> NOV}}$, 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.

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

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

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

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

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

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

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

This is the familiar:

$$\text{October Calendar} = \text{October Billed} + \text{October Unbilled} - \text{September Unbilled}^{3} \qquad [5]$$

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.

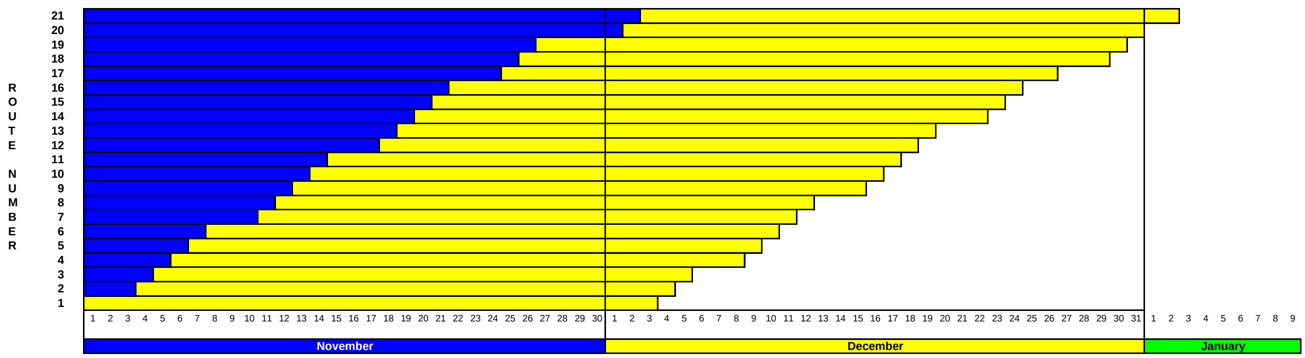
A More General Example

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:

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

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:

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

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

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

December unbilled less the equivalent November unbilled or:

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

or, in words:

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

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

The PSE&G Gas Calendar-Month Estimation

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

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

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

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

Table 1

Unbilled Weather and Base Coefficients, 2008-2009

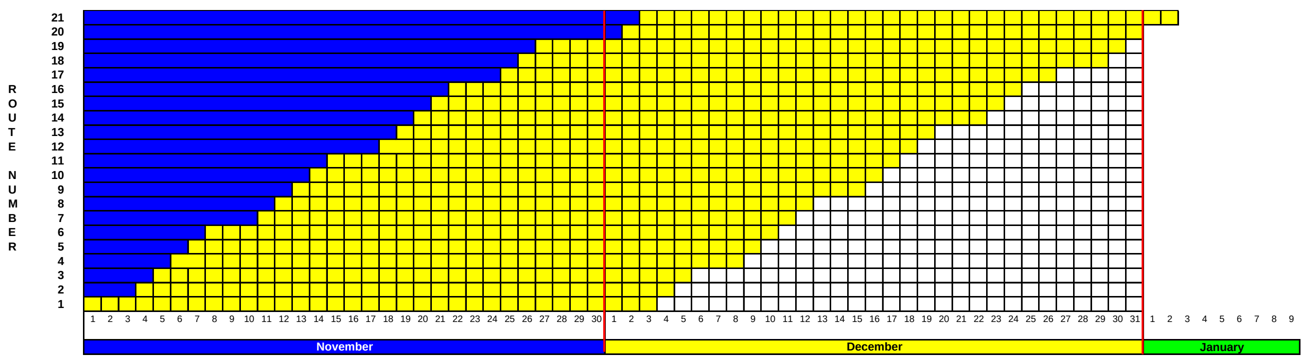
	RSG				GSG-Commercial				GSG-Industrial				LVG - Non Vehicle			
Billing	Heating		Non-heating		Heating		Non-heating		Heating		Non-heating		Commercial		Industrial	
Month	Base	HDD	Base	HDD	Base	HDD	Base	HDD	Base	HDD	Base	HDD	Base	HDD	Base	HDD
Jan-08	1,477,624	246,082	218,393	4,689	56,941	45,607	168,133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

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

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

Figure 3

PSE&G December 2008 Billing-Month



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

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

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

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

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

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

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

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

Table 2

Billed and Unbilled Days and Weather
2008-2009

	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
2017-2027
(MDth)

Class	Rate	Category	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Residential	RSG	Heating	130,512	147,879	146,246	147,875	151,624	150,066	152,275	154,763	157,422	159,943	162,525
		Non-Heating	8,860	9,314	4,016	3,342	4,025	4,040	4,088	4,115	4,128	4,123	4,118
	Total		139,371	157,193	150,262	151,217	155,649	154,106	156,363	158,878	161,550	164,066	166,643
Commercial	GSG	Heating	22,541	25,864	24,501	24,517	22,930	23,463	23,839	23,606	23,339	23,055	22,741
		Non-Heating	3,939	4,315	4,077	4,080	4,082	4,077	4,077	4,076	4,078	4,076	4,075
		Total	26,480	30,179	28,577	28,597	27,012	27,540	27,916	27,682	27,418	27,131	26,817
	LVG		61,091	70,527	68,443	68,682	62,254	66,937	67,420	67,448	67,576	67,578	67,589
	TSG	Firm	941	1,193	1,060	966	963	918	844	744	603	461	322
		Non-Firm	10,062	14,028	14,595	9,972	9,969	9,923	9,847	9,735	9,564	9,386	9,213
		Total	11,003	15,221	15,655	10,939	10,932	10,841	10,691	10,480	10,167	9,846	9,536
	CIG		3,595	5,471	4,746	1,853	1,853	1,853	1,853	1,853	1,853	1,853	1,853
	CSG		16,341	21,300	8,119	5,275	5,275	5,275	5,275	5,275	5,275	5,275	5,275
	Total		118,510	142,697	125,540	115,346	107,325	112,446	113,155	112,738	112,289	111,684	111,069
Industrial	GSG	Heating	871	1,019	940	935	937	934	935	935	936	936	936
		Non-Heating	153	169	160	160	160	160	160	160	160	160	160
		Total	1,025	1,188	1,100	1,095	1,097	1,094	1,095	1,094	1,096	1,096	1,096
	LVG		7,043	8,383	8,339	8,153	7,869	7,978	7,987	7,935	7,898	7,848	7,804
	TSG	Firm	1,511	1,528	1,444	1,408	1,408	1,408	1,408	1,408	1,408	1,408	1,408
		Non-Firm	17,374	6,115	6,373	5,828	5,828	5,828	5,828	5,828	5,828	5,828	5,828
		Total	18,886	7,643	7,816	7,235	7,235	7,235	7,235	7,235	7,235	7,235	7,235
	CIG		564	1,020	695	611	611	611	611	611	611	611	611
	CSG		83,737	106,647	122,752	81,353	81,353	81,353	81,353	81,353	81,353	81,353	81,353
	Contract		8,822	-	-	-	-	-	-	-	-	-	-
	Total		120,075	124,880	140,702	98,447	98,165	98,271	98,282	98,228	98,193	98,143	98,099
Lighting	SLG		66	76	62	62	62	62	62	62	62	62	62
Total			378,023	424,847	416,566	365,072	361,201	364,885	367,861	369,906	372,094	373,955	375,873

Supplied Gas Sales As Billed
2017-2027
(MDth)

Class	Rate	Category	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Residential	RSG	Heating	124,075	141,470	141,490	143,331	146,962	145,453	147,595	150,009	152,587	155,033	157,537
		Non-Heating	8,362	8,844	3,814	3,176	3,827	3,841	3,887	3,913	3,925	3,921	3,916
	Total		132,437	150,315	145,305	146,507	150,788	149,294	151,482	153,921	156,512	158,953	161,453
Commercial	GSG	Heating	17,387	19,929	19,320	19,287	18,040	18,463	18,767	18,590	18,388	18,171	17,932
		Non-Heating	2,965	3,158	3,044	3,057	3,058	3,054	3,054	3,054	3,055	3,054	3,053
		Total	20,352	23,087	22,364	22,344	21,098	21,518	21,821	21,644	21,444	21,225	20,985
	LVG		24,578	26,300	27,067	25,582	23,192	24,937	25,136	25,166	25,230	25,243	25,260
	TSG	Firm	-	-	-	-	-	-	-	-	-	-	-
		Non-Firm	942	807	840	991	991	991	991	991	991	991	991
		Total	942	807	840	991	991	991	991	991	991	991	991
	CIG		3,595	5,471	4,746	1,853	1,853	1,853	1,853	1,853	1,853	1,853	1,853
	CSG		-	-	-	-	-	-	-	-	-	-	-
	Total		49,467	55,664	55,017	50,769	47,134	49,298	49,801	49,653	49,517	49,312	49,088
Industrial	GSG	Heating	689	799	774	768	770	768	769	768	769	769	769
		Non-Heating	113	127	126	130	130	130	130	130	130	130	130
		Total	802	927	901	898	900	897	898	897	898	899	899
	LVG		1,864	2,108	2,426	2,255	2,171	2,203	2,211	2,197	2,185	2,169	2,154
	TSG	Firm	-	-	-	-	-	-	-	-	-	-	-
		Non-Firm	108	109	67	17	17	17	17	17	17	17	17
		Total	108	109	67	17	17	17	17	17	17	17	17
	CIG		564	1,020	695	760	760	760	760	760	760	760	760
	CSG		-	-	-	-	-	-	-	-	-	-	-
	Contract		1,301	-	-	-	-	-	-	-	-	-	-
	Total		4,638	4,164	4,089	3,930	3,847	3,877	3,886	3,871	3,860	3,844	3,830
Lighting	SLG		26	26	24	24	24	24	24	24	24	24	24
Total			186,568	210,170	204,435	201,230	201,794	202,493	205,193	207,470	209,914	212,134	214,395

Supplied Share of Delivered Gas Sales As Billed
2017-2027
(percent)

Class	Rate	Category	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Residential	RSG	Heating	95%	96%	97%	97%	97%	97%	97%	97%	97%	97%	97%
		Non-Heating	94%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%
	Total		95%	96%	97%	97%	97%	97%	97%	97%	97%	97%	97%
Commercial	GSG	Heating	77%	77%	79%	79%	79%	79%	79%	79%	79%	79%	79%
		Non-Heating	75%	73%	75%	75%	75%	75%	75%	75%	75%	75%	75%
		Total	77%	76%	78%	78%	78%	78%	78%	78%	78%	78%	78%
	LVG		40%	37%	40%	37%	37%	37%	37%	37%	37%	37%	37%
	TSG	Firm	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
		Non-Firm	9%	6%	6%	10%	10%	10%	10%	10%	10%	11%	11%
		Total	9%	5%	5%	9%	9%	9%	9%	9%	10%	10%	10%
	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		42%	39%	44%	44%	44%	44%	44%	44%	44%	44%	44%
Industrial	GSG	Heating	79%	78%	82%	82%	82%	82%	82%	82%	82%	82%	82%
		Non-Heating	74%	75%	79%	81%	81%	81%	81%	81%	81%	81%	81%
		Total	78%	78%	82%	82%	82%	82%	82%	82%	82%	82%	82%
	LVG		26%	25%	29%	28%	28%	28%	28%	28%	28%	28%	28%
	TSG	Firm	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
		Non-Firm	1%	2%	1%	0%	0%	0%	0%	0%	0%	0%	0%
		Total	1%	1%	1%	0%	0%	0%	0%	0%	0%	0%	0%
	CIG		100%	100%	100%	124%	124%	124%	124%	124%	124%	124%	124%
	CSG		0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	Contract		15%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	Total		4%	3%	3%	4%	4%	4%	4%	4%	4%	4%	4%
Lighting	SLG		39%	35%	39%	39%	39%	39%	39%	39%	39%	39%	39%
Total			49%	49%	49%	55%	56%	55%	56%	56%	56%	57%	57%

Delivered Gas Sales Calendar-Year
2017-2027
(MDth)

Class	Rate	Category	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Residential	RSG	Heating	131,801	144,199	146,339	149,551	150,954	149,974	152,120	155,610	157,233	159,738	162,218
		Non-Heating	8,866	9,044	4,065	2,986	4,072	4,039	4,085	4,130	4,122	4,115	4,109
	Total		140,667	153,243	150,404	152,537	155,026	154,013	156,205	159,740	161,355	163,853	166,327
Commercial	GSG	Heating	22,771	25,196	24,676	24,762	22,762	23,465	23,812	23,706	23,276	22,994	22,667
		Non-Heating	4,040	4,256	4,086	4,099	4,072	4,073	4,069	4,087	4,071	4,069	4,066
		Total	26,811	29,453	28,762	28,861	26,834	27,538	27,881	27,793	27,347	27,062	26,732
	LVG		61,513	68,128	67,729	69,318	61,751	67,095	67,312	67,682	67,442	67,443	67,418
	TSG	Firm	951	1,197	924	966	963	918	844	744	603	461	322
		Non-Firm	9,668	10,972	12,155	9,972	9,969	9,923	9,847	9,735	9,564	9,386	9,213
		Total	10,618	12,169	13,079	10,939	10,932	10,841	10,691	10,480	10,167	9,846	9,536
	CIG		3,408	3,568	3,373	1,853	1,853	1,853	1,853	1,853	1,853	1,853	1,853
	CSG		8,734	18,502	6,131	5,275	5,275	5,275	5,275	5,275	5,275	5,275	5,275
	Total		111,084	131,819	119,074	116,246	106,645	112,601	113,012	113,083	112,084	111,479	110,814
Industrial	GSG	Heating	875	993	943	945	934	933	933	938	933	933	933
		Non-Heating	155	166	161	161	160	160	160	160	160	160	159
		Total	1,030	1,159	1,104	1,106	1,093	1,092	1,092	1,099	1,093	1,093	1,093
	LVG		7,093	8,258	8,373	8,227	7,834	7,976	7,977	7,953	7,881	7,831	7,783
	TSG	Firm	1,574	1,453	1,499	1,408	1,408	1,408	1,408	1,408	1,408	1,408	1,408
		Non-Firm	15,878	5,486	6,373	5,828	5,828	5,828	5,828	5,828	5,828	5,828	5,828
		Total	17,451	6,939	7,872	7,235	7,235	7,235	7,235	7,235	7,235	7,235	7,235
	CIG		557	657	594	611	611	611	611	611	611	611	611
	CSG		72,331	86,007	99,401	81,353	81,353	81,353	81,353	81,353	81,353	81,353	81,353
	Contract		6,389	-	-	-	-	-	-	-	-	-	-
	Total		104,851	103,020	117,344	98,532	98,127	98,268	98,269	98,251	98,173	98,123	98,075
Lighting	SLG		66	72	62	62	62	62	62	62	62	62	62
Total			356,668	388,153	386,884	367,377	359,860	364,944	367,548	371,136	371,674	373,517	375,278

Supplied Gas Sales Calendar-Year
2017-2027
(MDth)

Class	Rate	Category	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Residential	RSG	Heating	125,315	137,603	141,644	144,967	146,311	145,363	147,444	150,831	152,404	154,833	157,240
		Non-Heating	8,365	8,561	3,859	2,837	3,871	3,840	3,884	3,927	3,919	3,913	3,907
	Total		133,680	146,164	145,502	147,804	150,182	149,203	151,329	154,758	156,323	158,747	161,147
Commercial	GSG	Heating	17,569	19,242	19,479	19,493	17,906	18,465	18,745	18,670	18,337	18,122	17,872
		Non-Heating	2,976	3,083	3,053	3,071	3,051	3,051	3,048	3,062	3,050	3,048	3,046
		Total	20,545	22,325	22,531	22,564	20,957	21,516	21,793	21,732	21,387	21,170	20,918
	LVG		24,708	25,405	26,878	25,928	22,995	24,998	25,094	25,258	25,178	25,190	25,193
	TSG	Firm	-	-	-	-	-	-	-	-	-	-	-
		Non-Firm	892	699	803	991	991	991	991	991	991	991	991
		Total	892	699	803	991	991	991	991	991	991	991	991
	CIG		3,408	3,568	3,373	1,853	1,853	1,853	1,853	1,853	1,853	1,853	1,853
	CSG		-	-	-	-	-	-	-	-	-	-	-
	Total		49,553	51,997	53,586	51,335	46,795	49,358	49,731	49,834	49,408	49,204	48,954
Industrial	GSG	Heating	692	785	778	776	767	766	766	771	767	767	767
		Non-Heating	115	124	127	131	129	129	129	130	129	129	129
		Total	806	909	905	906	897	896	896	901	896	896	896
	LVG		1,877	2,082	2,428	2,323	2,158	2,202	2,207	2,203	2,178	2,162	2,147
	TSG	Firm	-	-	-	-	-	-	-	-	-	-	-
		Non-Firm	59	82	67	17	17	17	17	17	17	17	17
		Total	59	82	67	17	17	17	17	17	17	17	17
	CIG		557	657	594	760	760	760	760	760	760	760	760
	CSG		-	-	-	-	-	-	-	-	-	-	-
	Contract		805	-	-	-	-	-	-	-	-	-	-
	Total		4,104	3,731	3,994	4,006	3,832	3,875	3,880	3,881	3,851	3,835	3,820
Lighting	SLG		26	26	24	24	24	24	24	24	24	24	24
Total			187,362	201,918	203,107	203,169	200,834	202,460	204,963	208,498	209,607	211,810	213,944

Supplied Share of Delivered Gas Sales Calendar Year 2017-2027 (percent)

Class	Rate	Category	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Residential	RSG	Heating	95%	95%	97%	97%	97%	97%	97%	97%	97%	97%	97%
		Non-Heating	94%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%
	Total		95%	95%	97%	97%	97%	97%	97%	97%	97%	97%	97%
Commercial	GSG	Heating	77%	76%	79%	79%	79%	79%	79%	79%	79%	79%	79%
		Non-Heating	74%	72%	75%	75%	75%	75%	75%	75%	75%	75%	75%
		Total	77%	76%	78%	78%	78%	78%	78%	78%	78%	78%	78%
	LVG		40%	37%	40%	37%	37%	37%	37%	37%	37%	37%	37%
	TSG	Firm	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
		Non-Firm	9%	6%	7%	10%	10%	10%	10%	10%	10%	11%	11%
		Total	8%	6%	6%	9%	9%	9%	9%	9%	10%	10%	10%
	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%	39%	45%	44%	44%	44%	44%	44%	44%	44%	44%
Industrial	GSG	Heating	79%	79%	83%	82%	82%	82%	82%	82%	82%	82%	82%
		Non-Heating	74%	75%	79%	81%	81%	81%	81%	81%	81%	81%	81%
		Total	78%	78%	82%	82%	82%	82%	82%	82%	82%	82%	82%
	LVG		26%	25%	29%	28%	28%	28%	28%	28%	28%	28%	28%
	TSG	Firm	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
		Non-Firm	0%	1%	1%	0%	0%	0%	0%	0%	0%	0%	0%
		Total	0%	1%	1%	0%	0%	0%	0%	0%	0%	0%	0%
	CIG		100%	100%	100%	124%	124%	124%	124%	124%	124%	124%	124%
	CSG		0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	Contract		13%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	Total		4%	4%	3%	4%	4%	4%	4%	4%	4%	4%	4%
Lighting	SLG		39%	37%	39%	39%	39%	39%	39%	39%	39%	39%	39%
Total			53%	52%	52%	55%	56%	55%	56%	56%	56%	57%	57%

17. FERC Pipeline Activities

Item 17

FERC Pipeline Activities

Pipeline	Docket No.	Description
Columbia	RP20-1060	On July 31, 2020 Columbia filed a General Section 4 rate case seeking a $2.9 billion cost of service. Among other things this filing also includes a $3 billion update to their modernization program. The Company protested the application and is an active participant in this case as well as a member of a group of firm customers jointly seeking to decrease the magnitude of the potential rate increase. The group has retained expert witnesses to assist them in their pursuit of cost of service and operational issues. Settlement discussions are currently being pursued. For this BGSS Filing, the Company has projected a settlement of the case with a rate reduction below the level of the rates currently being paid subject to refund to become effective July 1, 2021 and refunds for the locked-in rate period to be received by October 1, 2021.
Transco	RP20-614	On February 28, 2020, Transco filed proposed tariff records that would change the way it calculates prices used for cashing out monthly imbalances. Transco's goal is to reduce the incentive for the pipeline's shippers to intentionally create large imbalances subject to cashout for the purpose of taking advantage of differences between spot market prices and Transco's cashout

		prices. The Company provided comments to this filing, and is an active intervenor in this matter. As a part of a large customer group, the Company is working to achieve a cashout mechanism that would maintain the operational integrity of the pipeline while retaining operational flexibility for the Company. All parties have agreed to a settlement in principle and are currently negotiating the actual settlement language, which is expected to be filed at FERC in the near future.
Transco	RP20-618	On February 28, 2020, Transco filed proposed tariff records that would change its cashout reconciliation mechanism from the current refund/carry-forward process to an annual refund/surcharge process, which would include the recovery from previous years of under-recoveries. The Company protested this filing, and is an active intervenor in this matter. As a part of a large customer group, PSEG is seeking a resolution that is fair to all parties involved. All parties have agreed to a settlement in principle and are negotiating the actual settlement language, which is expected to be filed at FERC in the near future.
Transco	RP21-24	On October 1, 2020 Transco made an updated filing to adjust the cashout surcharge effective November 1, 2020 as a part of their RP20-614 and RP20-618 cashout filings.
Transco	CP21-94	On March 26, 2021, Transco applied for approval of the Regional Energy Access Project, which is designed to provide an

		incremental firm daily quantity of 60,000 dekatherms/day to the Company. Acting to meet increasing market demands from its firm customers, the Company has filed comments in support for the project, which has a target in-service date of December 2023.
Transco	RP20-948	On June 8, 2020, Transco filed revised tariff records, to revise their rates for service under Rate Schedules LNG and LG-A in accordance with their rate case Stipulation and Agreement in Docket Nos. RP18-1126. Transco updated balances for gas plant in service and accumulated reserve for depreciation, as well as revising the injection fuel retention from 33.32% to a fixed rate of 25.00%. PSEG is the largest LNG customer and actively negotiated certain elements of the filing. FERC approved this filing and the tariff records are accepted effective May 1, 2020 and June 1, 2020, as proposed.
Transco	RP20-1111	On August 20, 2020, Transco submitted a filing to revise their procedures for allocating available firm capacity by proposing to expand the possible factors upon which the net present value calculations could be based. The Company protested this filing to the extent that this new aggregation language will permit the pipeline to combine non-contiguous and operationally unrelated parcels of capacity into one open season package and could motivate customers to purchase undesired capacity in order to have a better opportunity to obtain the capacity that the customer actually does want. Many other companies intervened in this matter,

		but ultimately FERC accepted Transco's filing.
Transco	RP21-686	On March 31, 2021, Transco filed revised tariff records that proposed to revise the tariff provisions that set forth the reservation charge credits due customers under storage Rate Schedules GSS, S-2, LG-A, and LNG when Transco orders the interruption or reduction of firm contract storage service Although the Company did not protest this filing the Company was actively monitoring this filing. FERC accepted the tariff records subject to certain conditions, effective May 1, 2021.
Transco	TBD	Transco is currently working with its customers on a potential Emissions Reduction Program. The Emissions Reduction Program is designed to strengthen the safety, reliability, and efficiency of the Transco system, while also minimizing environmental impact by reducing emissions. To-date, no FERC filing has been made, but both customers and Transco are working together on how this type of program could be implemented.
Dominion	RP21-144	On October 30, 2020, Dominion filed revised tariff records to establish gas quality provisions specific to renewable natural gas in its tariff. On November 30, 2020, the Commission issued an order accepting and suspending tariff records subject to the outcome of a technical conference. The Company, as well and many other customers, were an active participant in this technical conference that resulted in FERC's rejection of the renewable natural gas tariff records.
Tennessee	RP21-552	On March 1, 2021 Tennessee filed to adjust

		their fuel and loss percentages and their electric power cost rates that resulted in a small cost increase to the Company. This filing impacted other companies in a more substantial way and a settlement conference has been scheduled on May 13, 2021 to review this filling. The Company will continue to be an active participant in this filing in order to reach a favorable outcome for all participants.
Texas Eastern	RP21-234 & RP20-1194	On November 20, 2020, Texas Eastern filed a tariff record to comply with the Stipulation and Agreement approved by the Commission in Docket No. RP20-1194 The Stipulation and Agreement requires Texas Eastern to separately calculate the rate component and reflect the allocated cost for each transportation path when dealing with imbalance resolutions in its annual applicable shrinkage adjustment filings. As per FERC's approval these updated tariff records became effective December 1, 2020.

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

Gas Procurement Objectives

Current & Forecasted Gas Service Requirements

Projected Sources of Capacity

Affiliate Relationship / Asset Management

Hedging Plan & Strategy

Capacity Releases / Off-System Sales

Item 18

Gas Supply Plan

1. Gas Procurement Objectives

As discussed in the body of the testimony of David F. Caffery herein, natural gas prices during the most recent period have increased significantly from the levels experienced at this time last year. Nymex prompt month daily prices have traded between approximately $2.50/Dth and $3.25/Dth since the middle of January 2021, with current prices about $3.00/Dth. This compares with a Nymex price of $1.72/Dth at this time last year following the onset of the Covid crisis. The forward (May 6th) Nymex strip used by the Company in this filing (see Item 8) shows that prices are 15.5% higher than last year's Nymex strip. Based upon the forward strip, prices are expected to remain essentially flat through the rest of 2021, followed by a modest increase during the winter months and then a reduction for the balance of the BGSS period. This relative stability in forward prices largely has occurred due to a recent supply/demand balance in the market with demand recovering from last year's Covid related declines and production increasing close to pre-Covid levels to meet demand increases. Despite these higher price levels, historically producers have shown an inclination to increase production quickly in anticipation of higher market prices, which subsequently results in a moderation of prices. This, combined with the uncertainty presently priced into the market, indicates that the current level of the Nymex strip near or above $3.00/Dth may be overly bullish, supporting the Company's proposal to maintain the current BGSS-RSG rate.

The natural gas market has undergone significant changes since last year's BGSS Filing. US dry gas production levels hit a peak of 93.5 Bcf/d during 2019 only to decline dramatically during the summer of 2020 to a level of 85 Bcf/d due to the demand destruction resulting from the Covid restrictions. Over the course of the past 9 months, production volumes have increased to a level of approximately 91 Bcf/d to meet rising demand levels as Covid related restrictions have been gradually lifted. Feedgas volumes for the country's six LNG export facilities have recently averaged a record 11.5 Bcf/d, representing 12% of US dry gas production during the same timeframe. Additional pipeline takeaway capacity placed into service during 2017 and 2018, primarily from the Marcellus/Utica region, has continued to motivate producers to maintain high production levels. US natural gas storage levels are currently 5% below the 5-year average and 391 Bcf, or 16%, below this time last year. The current storage levels are typical of what would be representative of this time of year as illustrated by the comparison to the 5-year average.

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 and storage 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 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 low 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 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 RSG customers. Through the active and effective management of these resources, the Company consistently provides the reliable, low cost supply desired by its firm 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 2021 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 periodically reviews its pipeline transportation, storage and peaking capacity supplies to ensure that the optimal mix of capacity assets are maintained to meet its forecasted peak day and seasonal requirements at the lowest possible cost. Several changes in the Company's pipeline capacity portfolio have been made which are reflected in the instant BGSS Filing.

As mentioned in last year's BGSS Filing, the Company has taken certain steps to ensure that it continues to meet its projected peak day capacity requirements to serve its firm customers. As illustrated on Item 16, based on the Company's latest forecast, it is projected that the Company will have a slight surplus in peak day supply for the upcoming 2021/2022 and then experience a shortfall in peak day supply commencing in 2022/2023 which will increase throughout the five year forecast period.

In 2020 the Company participated in an open season for Transco's Regional Energy Access Project which provides for an expansion of the Transco system between the Marcellus supply region in northeast Pennsylvania and central and southern New Jersey. The Company has entered into a precedent agreement with Transco providing for 60,000 Dth/d of new firm transportation capacity to help meet the projected shortfall in peak day supply for the 2023/2024 winter and beyond, and to meet increased gas requirements in the Mount Laurel and Camden areas of its distribution system. Transco filed its certificate application for REA at FERC on March 26, 2021. Transco anticipates placing the REA project into service effective December 1, 2023.

Finally, the Company is a shipper in the PennEast project which will provide increased capacity from the Marcellus shale region, as well as provide a new independent source of pipeline supply, and thereby increase the reliability of the Company's portfolio of firm pipeline transportation capacity. PennEast received its FERC Certificate on January 19, 2018, and is currently seeking the required state and local permits to provide for construction to commence. On February 12, 2020, PennEast filed an Amendment to its FERC Certificate requesting a phasing of the project with Phase I providing for facility construction and transportation service within Pennsylvania and Phase II providing for facilities and service in New Jersey. In addition, PennEast filed for certiorari with the US Supreme Court for a review of the

Third Circuit Court of Appeals decision denying PennEast's right to exercise eminent domain over NJ State lands. The Supreme Court heard oral argument of the case in April, 2021. Given this timeline, the Company does not envision PennEast providing Phase II service before late 2022 to NJ shippers. As such, costs associated with the PennEast capacity are not included in the instant BGSS Filing.

As agreed to in the Stipulation between the Parties in the June 2018 BGSS Filing, in addition to the description of the contract changes above, the following table represents a listing of all contracts that have been extended pursuant to their evergreen provisions during the last BGSS Filing period:

			Top	Daily
Counterparty	Rate	Contract	Gas	Contract
	Schedule	Number	Quantity	Quantity
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
Algonquin	AFT - 1	511103		12,500
Transco	FT	1006312		72,450
Transco	FT	1044211		50,000
Transco	FT	9009846		73,500
Transco	FT	9146335		9,400
Transco	FT	9146336		9,850
Transco	FT	1002228		6,440
Transco	FT	1003688		425,930
Transco	FT	1003835		198,950
Transco	FT	1005002		13,248
Transco	FT	1033145		48,240
Transco	FT	1041156		50,000
Transco	S - 2	1000823	6,158,589	68,514
Transco	FT	9066768		43,300
Dominion	GSSTE	600043	14,249,916	162,995
Gulf South	FSS	661	1,000,000	100,000

4. Affiliate Relationships/Asset Management

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

5. Hedging Plan and Strategy

The Company has included as Item 11 in the instant BGSS Filing its PSE&G Quarterly Gas Hedging Reports, which have been filed with the NJBPU over the past year. As discussed in the testimony of David F. Caffery herein, the Company to date has hedged approximately 96 % of its planned volume for the 2021 summer period, approximately 59 % of its planned volume for the 2021-2022 winter period and approximately 37 % of its planned volume for the 2022 summer period. Hedging for the winter 2022-2023 period has just begun.

In addition to its transportation and peaking assets, PSEG ERT maintains approximately 70 Bcf of storage assets under contract with various pipeline suppliers. These storage assets are used to supplement flowing gas supplies when customer demand on the Company's distribution system increases during the winter period. The Company typically injects gas into its storages during the April through October timeframe, targeting a level of approximately 97% full by October 31st. Item 12 included herein provides the list of storage services under contract as well as the monthly ending storage inventory by contract for the past winter period. This illustrates the manner in which each storage service was utilized over the 2020-2021 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 2021. For the upcoming BGSS period that is covered by this filing, the Company has a total of approximately $ 29 million in credits attributed to capacity release and off-system sales. As can be seen on the attached schedule, off-system sales margins for the 4 months ending April 2021 total $ 18.6 million, approaching the annual totals for 2019 and 2020. The Company's 2021 off-system sales year to date benefitted from a much colder February than normal during which the Company was able to maximize its off-system sales volumes and margins.

Despite the favorable results so far this year, the Company has continued to experience significantly decreased margins in off-system sales and capacity release transactions. A number of significant pipeline expansions from the Marcellus and Utica supply regions, representing over 9 Bcf/d of new capacity, were placed into service during 2017/2018, providing additional outlets for these shale gas supplies. The increased ability of these pipelines to move additional volumes to market has resulted in a large decrease in the basis differentials between the Marcellus and Utica supply region and the Transco Z6 market, where the Company makes the majority of its off-system sales. The Company anticipates this extensive pipeline capacity buildout will continue to put significant downward pressure on capacity release and off-system sales margins throughout the upcoming BGSS period.

Off System Sales -- Revenues, Costs and Margins

2014 - 2021

Year	BGSS-RSG OSS Revenue (1)	BGSS-RSG OSS Cost (2)	BGSS-RSG OSS Margins (3)
2014	$327,717,529	$143,452,710	$184,264,819
2015	$197,662,767	$61,941,827	$135,720,940
2016	$145,423,895	$86,729,138	$58,694,758
2017	$156,240,095	$96,425,765	$59,814,330
2018	$194,555,168	$124,011,106	$70,544,017
2019	$79,655,383	$59,067,798	$20,587,585
2020	$95,986,987	$75,386,530	$20,600,457
2021*	$58,349,818	$39,757,528	$18,592,289

*Note: Through April 2021 Estimate

Item 18

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	882.3	0.0	0.0%
Storage	896.6	505.9	56.4%
Balancing FT	402.3	402.3	100.0%
Peaking	551.9	551.9	100.0%
	2,733.0	1,460.1	

	Total Cost	Percent Allocated to Balancing Use	Allocated Cost
Fixed Cost Allocation:			
Base FT	$154,057.7	0.0%	$0.0
Storage	$103,787.5	56.4%	$58,564.2
Balancing FT	$60,388.8	100.0%	$60,388.8
Peaking	$20,338.7	100.0%	$20,338.7
	$338,572.8		
Variable Cost Allocation:			
Base FT	$0.0	0.0%	$0.0
Storage	$8,002.7	56.4%	$4,515.7
Balancing FT	$0.0	100.0%	$0.0
Peaking	$1,068.0	100.0%	$1,068.0
	$9,070.7		
Total Annual Allocated Costs ($000)			**$ 144,875.4**

Balancing Use Billing Determinants - Oct - May (MDth)	180,658
Balancing Charge - Annual Allocated Cost ($/Dth)	$ 0.80193
Storage Inventory Carrying Charge ($/Dth) (page 2)	$ 0.02778
Revenue Requirement on Gas Production Plant Charge ($/Dth) (page 3)	$ 0.02945
Total Balancing Charge (excl. losses) ($/Dth)	$ 0.85916
Total Balancing Charge (incl. losses @ 2%) ($/Dth)	$ 0.87669
Total Balancing Charge (incl. SUT) ($/Dth)	**$ 0.93477**
Total Balancing Charge (incl. SUT) ($/Therm)	**$ 0.093477**

Storage Inventory Carrying Charge

	12 Months Oct 2021- Sept 2022 (000)
RSG Inventory Cost	$ 116,102
BGSS-F Inventory Cost	$ 26,752
BGSS-F Fixed Cost Deferred	$ 13,762
LNG + LPA	$ 2,364
Total Inventory Cost	**$ 158,979**
Total Annual Storage Carrying Cost @ 9.02%	**$ 14,340**

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

Rate per Dth	MDth	Cost	**$/Dth**
Balancing	180,658	$ 5,019	**$ 0.02778**
Commodity	202,203	$ 9,321	**$ 0.04610**

Revenue Requirement on Gas Production Plants

		12 Months Oct 21 - Sep 22
2020	October	$ 687,365.95
	November	$ 687,365.95
	December	$ 199,865.95
2021	January	$ 199,865.95
	February	$ 423,534.14
	March	$ 423,534.14
	April	$ 199,865.95
	May	$ 199,865.95
	June	$ 199,865.95
	July	$ 199,865.95
	August	$ 949,865.95
	September	$ 949,865.95
Total		**$ 5,320,728**
Balancing Use Billing Determinants (MDth)		**180,658**
Revenue Requirement on Gas Production Plant Charge ($/Dth)		**$ 0.02945**

Gas Supply A&G

	12 Months Oct 21 - Sep 22
Direct Labor & Overhead	$ 8,025,435
Firm Sendout - Dth (000)	202,203.1
Gas Supply A&G Rate	$ 0.03969

Attachment B

Redlined Tariff Sheets

PUBLIC SERVICE ELECTRIC AND GAS COMPANY **XXX Revised Sheet No. 54**
Superseding
B.P.U.N.J. No. 16 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	$ 0.060276
Estimated Gulf Coast Cost of Gas	0.235911
Adjustment to Gulf Coast Cost of Gas	0.000000
Prior period (over) or under recovery	(0.002130)
Adjusted Cost of Gas	0.294057
Commodity Charge after application of losses: (Loss Factor = 2.0%)	$ 0.300058
Commodity Charge including New Jersey Sales and Use Tax (SUT)	$ 0.319937

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. 65**
Superseding
B.P.U.N.J. No. 16 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:

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

Distribution Charges:

Charge	Charge Including SUT	
$0.391767	$0.417722	per therm

Balancing Charge:

Charge	Charge Including SUT	
$0.087669	$0.093477	
~~$0.080397~~	~~$0.085723~~	per Balancing Use Therm

Societal Benefits Charge:

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

Margin Adjustment Charge:

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

Green Programs Recovery Charge:

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

Weather Normalization Charge:

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

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

PUBLIC SERVICE ELECTRIC AND GAS COMPANY **XXX Revised Sheet No. 72**
Superseding
B.P.U.N.J. No. 16 GAS **XXX Revised Sheet No. 72**

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:

$16.65 in each month [$17.75 including New Jersey Sales and Use Tax (SUT)].

Distribution Charges:

Pre-July 14, 1997 *		All Others		
Charge	Charge Including SUT	Charge	Charge Including SUT	
$0.304859	$0.325056	$0.304859	$0.325056	per therm

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

Balancing Charge:

Charge	Charge Including SUT	
$0.087669	$0.093477	
~~$0.080397~~	~~$0.085723~~	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. 16 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:

$147.80 in each month [$157.59 including New Jersey Sales and Use Tax (SUT)].

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

Charge	Charge Including SUT	
$ 4.0632	$ 4.3324	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
$ 0.043725	$ 0.046622	$ 0.043078	$ 0.045932

Balancing Charge:

Charge	Charge Including SUT	
$0.087669	$0.093477	
~~$0.080397~~	~~$0.085723~~	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. 16 GAS **XXX Revised Sheet No. 112A**

RATE SCHEDULE CSG
CONTRACT SERVICE
(Continued)

ECONOMICALLY VIABLE BYPASS
DELIVERY CHARGES:

Service Charge:
$ 791.61 in each month [$844.05 including New Jersey Sales and Use Tax (SUT)]

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

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

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

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

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

Charge	Charge Including SUT	
$0.087669 ~~$0.080397~~	$0.093477 ~~$0.085723~~	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.

Attachment B

Proposed Tariff Sheets

PUBLIC SERVICE ELECTRIC AND GAS COMPANY **XXX Revised Sheet No. 54**
Superseding
B.P.U.N.J. No. 16 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	$ 0.060276
Estimated Gulf Coast Cost of Gas	0.235911
Adjustment to Gulf Coast Cost of Gas	0.000000
Prior period (over) or under recovery	(0.002130)
Adjusted Cost of Gas	0.294057
Commodity Charge after application of losses: (Loss Factor = 2.0%)	$ 0.300058
Commodity Charge including New Jersey Sales and Use Tax (SUT)	$ 0.319937

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. 65**
Superseding
B.P.U.N.J. No. 16 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:

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

Distribution Charges:

Charge	Charge Including SUT	
$0.391767	$0.417722	per therm

Balancing Charge:

Charge	Charge Including SUT	
$0.087669	$0.093477	per Balancing Use Therm

Societal Benefits Charge:

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

Margin Adjustment Charge:

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

Green Programs Recovery Charge:

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

Weather Normalization Charge:

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

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

RATE SCHEDULE 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:

$16.65 in each month [$17.75 including New Jersey Sales and Use Tax (SUT)].

Distribution Charges:

Pre-July 14, 1997 *		All Others		
Charge	Charge Including SUT	Charge	Charge Including SUT	
$0.304859	$0.325056	$0.304859	$0.325056	per therm

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

Balancing Charge:

Charge	Charge Including SUT	
$0.087669	$0.093477	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. 16 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:

$147.80 in each month [$157.59 including New Jersey Sales and Use Tax (SUT)].

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

Charge	Charge Including SUT	
$ 4.0632	$ 4.3324	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
$ 0.043725	$ 0.046622	$ 0.043078	$ 0.045932

Balancing Charge:

Charge	Charge Including SUT	
$0.087669	$0.093477	per Balancing Use Therm

Societal Benefits Charge:

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

RATE SCHEDULE CSG
CONTRACT SERVICE
(Continued)

ECONOMICALLY VIABLE BYPASS
DELIVERY CHARGES:

Service Charge:
$ 791.61 in each month [$844.05 including New Jersey Sales and Use Tax (SUT)]

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

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

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

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

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

Charge	Charge Including SUT	
$0.087669	$0.093477	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.