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PSEG
Services Corporation

VIA BPU E-FILING SYSTEM & ELECTRONIC MAIL

June 1, 2020

In the Matter of Public Service Electric and Gas Company's 2020/2021
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, 2020. The Company is also requesting a decrease 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 decrease of approximately 1.02%.

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.

Very truly yours,

Katherine E. Smith

Katherine Smith

C Attached Service List (electronic)

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1. Motion, Supporting Testimony & Tariff Modifications

Motion – dated June 1, 2020

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 2020/2021 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.

2019/2020 ANNUAL BGSS COMMODITY CHARGE FILING

4) On May 31, 2019, the Company made its 2019/2020 Annual BGSS Commodity Charge filing for its Periodic Pricing Mechanism applicable to its residential gas customers pursuant to the BGSS Pricing Structure Order. The filing was also made in accordance with the above-referenced Minimum Filing Requirements.

5) In the 2019/2020 BGSS filing the Company requested a decrease in the then current BGSS Commodity Charge rate of $0.349059 cents per therm (including losses and SUT) to

$0.340221 cents per therm (including losses and SUT) effective October 1, 2019 to remain in effect through September 30, 2020. 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 two changes in its Balancing Charge, which recovers the cost of providing storage and peaking services. First, the Company requested a change in the balancing period from five billings months of November to March to the current eight billing months of October to May. Second, the Company requested a change in the Balancing Charge from $0.102825 per balancing therm (including losses and SUT) based on the five month balancing period to the current charge of $0.098620 per balancing use therm (including losses and SUT) based on the eight month balancing period. The modification of the balancing period was supported by testimony of Mr. Swetz and the change in the balancing charge was supported by testimony of 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 $0.003871 per therm (excl. losses & SUT) for the balancing portion and $0.006486 per therm (excl. losses & SUT) for the commodity portion using the applicable billing determinants for each.

8) The 2019/2020 filing by the Company also included the Company's estimated decrease in BGSS revenue of approximately $12 million (excluding losses and SUT) required for the period of October 1, 2019 through September 30, 2020.

9) Residential annual bills comparing the then current and proposed BGSS charge and the Balancing Charge, pursuant to the 2019/2020 filing were included in the form of public notice attached as Attachment C to that motion.

10) Notice setting forth the Company's May 31, 2019 request for the change in BGSS Commodity Charge and Balancing Charge, including the date, time, and place of the public hearings, was placed in newspapers having a circulation within PSE&G's gas service territory, and was served on the county executives and clerks of all municipalities within its gas service territory.

11) Public hearings were scheduled and conducted in New Brunswick, Hackensack, and Mt. Holly on August 22, 27, and 29, 2019, respectively. No member of the public appeared and/or spoke at the public hearings, and no members of the public submitted written comments to the Board on this matter.

12) PSE&G, Board Staff, and Rate Counsel agreed, on a provisional basis, to implement the BGSS-RSG Commodity Charge and Balancing Charge as of October 1, 2019, 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 11, 2019. The BGSS Commodity Charge was provisionally decreased from $0.349059 per therm (including losses and SUT) to $0.340221 per therm (including losses and SUT) for service rendered on and after October 1, 2019. The BGSS Balancing Charge period was provisionally modified to the eight (8) billing months of October to May and the Company's Balancing Charge was provisionally decreased from $0.102825 per therm (including losses and SUT) to $0.098620 per therm (including losses and SUT) for service rendered on and after October 1, 2019.

13) Subsequent to the Board's approval of the Provisional Stipulation, PSE&G made compliance filings in response to the Board's Orders in the Company's petitions in two (2) matters. First, on September 27, 2019, PSE&G made a compliance filing *In the Matter of the Petition of Public Service Electric and Gas Company for Approval of Gas Base Rate Adjustments Pursuant to its Gas System Modernization Program (April 2019 GSMP Rate Filing)* in BPU Docket No. GR19040522. In this matter, the BGSS-RSG Commodity Charge was decreased to $0.340185 per therm (including losses and SUT) effective October 1, 2019.

14) Second, on June 27, 2019, PSE&G made a compliance filing *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") (June 2019 GSMP Rate Filing)* in BPU Docket No. GR19060766. In this matter, the BGSS-RSG Commodity Charge was further decreased from the rate of $0.340185 per therm (including losses and SUT) to $0.340127 per therm (including losses and SUT) effective December 1, 2019.

15) On December 20, 2019, the Company filed a notice of a BGSS-RSG rate reduction of two (2) cents per therm (including losses and SUT) effective January 1, 2020, consistent with the Board's January 6, 2003 Order Approving BGSS Price Structure ("Price Structure Order") on page 4, Docket No. GX01050304, and paragraph 9 of the BGSS Pricing Proposal appended as Attachment A to, and approved in, the Price Structure Order ("December Notice"). This rate reduction further decreased the BGSS-RSG Commodity Charge from the rate of $0.340127 per therm (including losses and SUT) to $0.320127 per therm (including losses and SUT). As a result of the December Notice, 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 additional annual decrease of $20.80, or approximately 2.32% (based on rates in effect on January 1, 2020, and assuming the customer receives BGSS service from PSE&G).

16) PSE&G, Board Staff, and Rate Counsel subsequently completed their review of the Company's 2019/20 BGSS filing, and agreed that the Company's: (a) BGSS Commodity Service, tariff rate BGSS-RSG of $0.320127 per therm (including losses and SUT) would be deemed final; (b) the period over which the Company's Balancing Charge is calculated and charged shall be modified on a final basis to the eight (8) billing months of October to May; and (c) the Balancing Charge of $0.098620 per therm (including losses and SUT) would also be deemed final. The Board approved this stipulation for final rates on February 19, 2020.

2020/2021 ANNUAL BGSS COMMODITY CHARGE FILING

17) The Company is making this 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. This filing is also made in accordance with the above-referenced Minimum Filing Requirements.

18) In this Motion the Company is requesting to maintain the current Board approved BGSS rate of $0.320127 cents per therm (including losses and SUT) through September 30, 2021. 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.

19) The Company is also requesting a decrease in its Balancing Charge, which recovers the cost of providing storage and peaking services. The Company requests a change in the Balancing

Charge from \$0.098620 per balancing use therm (including losses and SUT) to \$0.085723 per balancing use therm (including losses and SUT). The decrease in the balancing charge is supported by Mr. Caffery (Attachment A).

20) 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 \$0.003201 per balancing use therm (excluding losses and SUT) for the balancing portion and \$0.005397 per therm (excluding losses and SUT) for the commodity portion using the applicable send out for each. The current charges are \$0.003871 cents per balancing therm for Balancing and \$0.006486 cents per therm for Commodity (excluding losses and SUT).

21) Natural gas prices during the most recent period have decreased from the levels experienced at this time last year. From a historic perspective, prices have fallen to the lowest levels in the past four years with, at the time of this BGSS Filing, with the NYMEX contract for June 2020 recently closing at \$1.722/Dth. NYMEX prices have traded between approximately \$2.20/Dth and \$1.60/Dth since the middle of January, 2020. However, the gas market of late has experienced considerable volatility related to the uncertainty around gas demand and production (related to the COVID emergency). The forward (May 7th) NYMEX strip used by the Company shows that prices are expected to increase quite significantly (over \$1.00/Dth) from current levels through the first quarter of 2021, followed by a more modest reduction for the balance of the BGSS period. This increase in forward prices largely has occurred due to recent production cut-backs as a result of current over-supply. In the past, however, producers have shown an inclination to increase production quickly in anticipation of higher market

prices, which results in a moderation of prices. Additionally, the forward NYMEX strip has varied in May and is presently several percentage points less than the May 7th forward strip. This, combined with the considerable uncertainty presently priced into the market, indicates that the significant level of price increase included in the May 7th NYMEX strip may be bullish, supporting the Company's proposal to maintain the current BGSS-RSG rate. Also, despite this increase in the forward prices, the NYMEX strip through September 2021 used for this year's BGSS Filing is approximately 7.4% below last year's (see the NYMEX forward strip included as Item 8).

22) The Company estimates that an increase in BGSS revenue of approximately $31 million (excluding losses and SUT) would be required for the period of October 1, 2020 and September 30, 2021. However, as stated in the testimony of Mr. Caffery, the Company is requesting to maintain the current Board approved rate of $0.320127 per therm (including losses and SUT) due to the significant volatility seen recently in natural gas prices.

23) 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 a decrease in the winter monthly bill of approximately 1.33% and on an annual basis the impact is a decrease of approximately 1.02%. 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, 2020 and February 1, 2021. The impact of such potential self-implementing increases on an

average residential bill (1,200 therms annually) would be an increase of approximately $8.21 per winter month on December 1, 2020 and an additional approximate increase of $8.21 per winter month on February 1, 2021.

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

25) 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 recent 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, 2020 approving:

(1) the Company's proposal to maintain its current Board approved BGSS-RSG Commodity Charge of $0.320127 per therm (including losses and SUT);

(2) a change in the Balancing Charge from $0.098620 per therm (including losses and SUT) to $0.085723 per balancing use therm (including losses and SUT) effective with the billing of month of October;

(3) 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

Katherine E. Smith

BY: ______________________________

Katherine E. Smith
Associate Counsel - Regulatory
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80 Park Plaza, T5G
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DATED: June 1, 2020
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, 2020

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 $0.320127 per therm (including losses and New Jersey Sales and Use Tax, SUT). This charge is requested to remain in effect from October 1, 2020 through September 30, 2021 or the effective date of the Company's next periodic BGSS Commodity Charge filing, subject to the potential self-implementing increases discussed in the Company's Motion. The Company is also requesting a decrease in its Balancing Charge, which recovers the cost of providing storage and peaking services. The decreased charge reflects significant reductions in the costs of such services as a result of recent settlements of Transco and Texas Eastern rate cases. As a result, the Company requests a change in the Balancing Charge from $0.098620 per balancing use therm (including losses and SUT) to $0.085723 per balancing use therm (including losses and SUT). The annual bill impact of the proposed Balancing Charge change is a decrease of approximately 1.02% on 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 7th NYMEX prices for the computations included in this filing, resulting in a projected under-recovery at the end of September 2021 of $31M (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 the recent volatility in the NYMEX over the last few weeks, fueled by the uncertainty in demand and production as a result of the COVID emergency, the Company is proposing to keep the current BGSS-RSG rate in effect for the upcoming BGSS period through September 2021.

The RSG customer class is expected to be over-recovered by $16.1 million by September 30, 2020. This period began with an over recovery of $0.8 million (there was $0.07 million of 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 $0.341808 per therm (including losses and SUT), would be required to reduce the projected under-collection of $31M to zero based on May 7th NYMEX prices. As noted above, however, the Company is requesting to maintain the current Board-approved rate of $0.320127 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 negative, therefore no interest has been included.

Natural gas prices during the most recent period have decreased from the levels experienced at this time last year. From a historic perspective, prices have fallen to the lowest levels in the past four years with, at the time of this BGSS Filing, with the NYMEX contract for June 2020 recently closing at $1.722/Dth. NYMEX prices have traded between approximately $2.20/Dth and $1.60/Dth since the middle of January 2020. However, as noted above, the gas market of late has experienced considerable volatility related to the uncertainty around gas demand and production (related to the COVID emergency). The forward (May 7th) NYMEX strip used by the Company shows that prices are expected to increase quite significantly (over $1.00/Dth) from current levels through the first quarter of 2021, followed by a more modest reduction for the balance of the BGSS period. This increase in forward prices largely has occurred due to recent production cut-backs as a result of current over-supply. In the past, however, producers have shown an inclination to increase production quickly in anticipation of higher market prices, which results in a moderation of prices. Additionally, the forward NYMEX strip has varied in May and is presently several percentage points less than the May 7th forward strip. This, combined with the considerable uncertainty presently priced into the market, indicates that the significant level of price increase included in the May 7th NYMEX strip may be bullish, supporting the Company's proposal to maintain the current BGSS-RSG rate. Also, despite this increase in the forward prices, the NYMEX strip through September 2021 used for this year's BGSS Filing is approximately 7.4% below last year's (see the NYMEX forward strip included as Item 8).

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 levels and also a reference to the possibility of self-implementing BGSS Commodity increases of up to 5% on December 1, 2020 and February 1, 2021, 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 $282 thousand that were credited to BGSS-RSG recovery costs from May 2019 through April 2020. The second schedule shows that the Company has included three projected refunds associated with the settlements of both the Transco and Texas Eastern rate cases. These amounts represent a refund of the costs paid by the Company above the settlement rates for the locked-in refund periods for each of the two pipelines. For Texas Eastern a refund of $19.2 million was received during May 2020. For Transco, a refund in the amount of $1.2 million related to the S-2 storage service is expected to be received in June 2020, while the bulk of the estimated Transco refund of $28.8 million is anticipated to be received in July 2020. These refunds represent significant reductions in the increased rate levels filed by both pipelines over the past two years and the successful settlement of these two major rate cases should provide cost stability for the Company in its pipeline transportation and storage costs.

5. <u>Cost of Gas Sendout by Component</u>

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

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

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

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

The schedules under this Item provide the derivation of the monthly over or under recoveries plus cumulative balances for the reconciliation and projected period. For the reconciliation period, one schedule also shows the calculation of the monthly actual or estimated accrued interest. The net interest calculated during the October 2019 to September 2020 period is negative and, therefore, has not 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 2021 based on the May 7, 2020 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 2020 and the projected period through September 2021 along with a comparison of these prices with the prices included in the current BGSS rate (from last year's BGSS filing) which indicates a decrease of approximately 7.4%. These estimates reflect the future NYMEX prices on May 7, 2020, when this analysis was done.

9. GCUA Recoveries and Balances

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

10. Historic Service Interruptions

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

11. Gas Price Hedging Activities

Included in this Item are the Company's last four quarterly hedging reports as filed with the Board. The reports provide gas purchase volume requirements and price-hedged volumes broken down into the Non-Discretionary Method and the Dollar Budget Method. 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 98% of its planned volume for the 2020 summer period, approximately 68% of its planned volume for the 2020-2021 winter period and approximately 38% of its planned volume for the 2021 summer period. Hedging for the winter 2021-2022 period has just begun in May 2020. The goal of the Company's hedging activities is to achieve a stable price through a disciplined hedging strategy that will, in the long run, result in a competitive price for the customer.

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

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

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

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

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

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

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

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

16. 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 such 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 a decrease 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 $0.098620 cents per balancing therm (including losses and SUT) to a Balancing Charge of $0.085723 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 $0.073905 cents per balancing therm (excluding losses and SUT), which is a decrease from the previous charge of $0.084350 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 $0.003201 cents per balancing therm (excluding losses & SUT) for the balancing portion and $0.005397 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 $0.003871 cents per balancing therm for Balancing and $0.006486 cents per therm for Commodity (excluding losses and SUT).

The revenue requirement on Production Plant is shown on page 3 and the requested charge is $0.001683 cents per therm (excluding losses & SUT), which is a decrease from the previous charge of $0.002421 cents per 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 $0.03566 per dth and the updated rate is $0.03592 per dth. This rate recovers the administrative cost associated with PSEG Energy Resources & Trade's provision of gas supply services to PSE&G.

CONCLUSION

The Company's filing should be approved as reasonable and fully supported. The Company stands ready to respond to any reasonable requests for additional data. The Company seeks a Board Order by October 1, 2020 or earlier, should the Board deem it appropriate, implementing the Company's proposal to maintain the current BGSS Commodity Charge of $0.320127 per therm (including losses and SUT) applicable to residential customers and reducing the Balancing Charge to $0.085723 per therm (including losses and SUT).

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, 2020

COMPUTATION OF
BGSS COMMODITY CHARGE FOR RSG
OCTOBER 2020 - SEPTEMBER 2021

($-000)

	$000	$/DTh
FIXED COSTS:		
FT DEMAND COST	$ 154,697	$1.0462
STORAGE DEMAND/CAPACITY COSTS	76,515	$0.5175
STORAGE INJ & W/D COSTS	4,849	$0.0328
PEAKING COSTS	9,510	$0.0643
	245,571	**$1.6608**
CONTRIBUTIONS	(28,891)	($0.1954)
PIPELINE REFUNDS	0	$0.0000
OFF-SYSTEM SALES MARGIN	(19,800)	($0.1339)
ELECTRIC CONTIBUTION - CSG	(10,938)	($0.0740)
NET TOTAL FIXED COST	**$ 185,942**	**$1.25750**
FIRM RSG SENDOUT (MDTh) 10/20 - 9/21	**147,867**	
TOTAL NON-GULF COAST COST ($/DTh)		**$1.25750**
Removal of Balancing Cost (incl. above)		(0.54819)
Inventory Carrying Charge Allocation		0.05397
Gas Supply A&G		0.03592
Total Adjustments		**($0.45830)**
ADJUSTED NON-GULF COAST COST ($/DTh)		**$0.79920**
(OVER)/UNDER RECOVERY @ 9/30/20 - INCL. INT.	**($16,127)**	**($0.10910)**
GULF COAST COST OF GAS ($/DTh)		
FT COMMODITY AND FUEL		0.00000
COST OF GAS		**2.45149**
TOTAL GULF COAST COST		**$2.45149**

SUMMARY OF CHARGE COMPONENTS

	(cents/therm) BGSS-RSG	(dollars/therm) BGSS-RSG
Estimated Non-Gulf Coast Cost of Gas	7.9920	$ 0.079920
Estimated Gulf Coast Cost of Gas	24.5149	$ 0.245149
Adjustment to Gulf Coast Cost of Gas	-	$ -
Prior Period (Over)/Under Recovery	(1.0910)	$ (0.010910)
Adjusted Cost of Gas	31.4159	$ 0.314159
COMMODITY CHARGE (after application of losses 2.0%)	**32.0570**	**$ 0.320570**
COMMODITY CHARGE (including SUT)	**34.1808**	**$ 0.341808**

3. Public Notice with Proposed Impact on Bills

Notice (including Typical Bills) – Attachment C

NOTICE TO PUBLIC SERVICE ELECTRIC AND GAS COMPANY GAS CUSTOMERS

IN THE MATTER OF PUBLIC SERVICE ELECTRIC AND GAS COMPANY'S 2020/2021 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, 2020, 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 decrease 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, 2020, or earlier should the Board deem it appropriate. The requested decrease in the Balancing Charge is from $0.098620 per therm (including SUT) to $0.085723 per therm (including SUT).

Based on rates effective June 1, 2020, the effect of the requested decrease 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 a decrease in their annual bill from $554.26 to $549.02, or $5.24 or approximately 0.95%. Moreover, under the Company's proposal, a typical residential heating customer using 172 therms per month during the winter months and 1,040 therms on an annual basis would see a decrease in their annual bill from $871.88 to $862.96, or $8.92 or approximately 1.02 %.

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, 2020, and/or February 1st of next year, 2021, 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 1st , 2020 and/or January 1st, 2021 of its intention to apply a December 1st or a February 1st self-implementing rate increase, respectively, and the approximate amount of the increases based upon then current market data. These increases, if implemented, would be in accordance with the Board-approved methodology.

Should it become necessary to apply the December 1st, 2020 self-implementing 5% increase, the bill impact would be an increase as illustrated in Table #2. Further, if a February 1st, 2021 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.

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

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

Date 1, 2020 Time 1	Date 2, 2020 Time 2	Date 3, 2020 Time 3

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

Customers may also file written comments with the Secretary of the Board of Public Utilities at 44 South Clinton Avenue, 9th Floor, Trenton, New Jersey, 08625-0350 ATTN: Secretary Aida Camacho-Welch or email aida.camacho@bpu.nj.gov, whether or not they attend the public hearings.

Written comments should reference the name of the petition and the above docket number in the subject line. Written comments will be provided the same weight as statements made at the hearings. Hearings will continue, if necessary, on such additional dates and at such locations as the Board may designate, to ensure that all interested persons are heard.

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	$27.23	$26.99	($0.24)	(0.88%)
340	50	45.83	45.37	(0.46)	(1.00)
610	100	84.07	83.00	(1.07)	(1.27)
1,040	172	138.39	136.55	(1.84)	(1.33)
1,200	201	159.49	157.35	(2.14)	(1.34)
1,816	300	234.94	231.73	(3.21)	(1.37)

(1) Based upon Delivery Rates and Basic Gas Supply Service (BGSS-RSG) in effect June 1, 2020, 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, 2020 Monthly Winter Change Would Be:	February 1, 2021 Monthly Winter Change Would Be:	Total If both 5% Self-Implementing Increases Are Put Into Effect
170	25	$1.02	$1.03	$2.05
340	50	2.04	2.04	4.08
610	100	4.09	4.08	8.17
1,040	172	7.03	7.02	14.05
1,200	201	8.21	8.21	16.42
1,816	300	12.25	12.26	24.51

(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 2019 - April 2020
(000)

MONTH	SUPPLIER	AMOUNT	TOTAL
May 2019	Texas Eastern	$ 119	$ 119
June 2019	Transcontinental	$ 4	$ 4
July 2019	Texas Eastern	$ 14	
	Dominion Energy	$ 40	$ 54
August 2019	Texas Eastern	$ 72	$ 72
September 2019		$ -	$ -
October 2019	Texas Eastern	$ 3	
	Transcontinental	$ 11	$ 14
November 2019	Algonquin	$ 1	
	Tennessee	$ 3	
	Transco	$ 4	$ 8
December 2019	Texas Eastern	$ 10	
	Transco	$ 1	$ 11
January 2020		$ -	$ -
February 2020		$ -	$ -
March 2020		$ -	$ -
April 2020		$ -	$ -
Total		$ 282	$ 282

Item 4

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

DOCKET	SUPPLIER	STATUS
RP19-343	Texas Eastern	A settlement of this rate case was approved by FERC providing for refunds during the month of May. We have estimated the RSG portion of the refund to be $19 million.
RP19-343	Texas Eastern	A settlement of this rate case provides for a refund for the Transco S-2 storage service, which Transco then passes through to its S-2 customers. We have estimated the receipt of this refund in June and the RSG portion of the refund to be $1.2 million
RP18-1126	Transco	A settlement of this rate case was approved by FERC providing for refunds during the month of July. We have estimated the RSG portion of the refund to be $29 million.

5. Cost of Gas Sendout by Component

ACTUAL COST OF BGSS-RSG GAS SENDOUT BY COMPONENT

	Oct-19	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	Total
Beginning Inventory Cost $000	$215,573	$233,443	$221,184	$192,526	$157,873	$124,093	$105,524	
Fixed Pipeline Charge $000	$22,918	$24,212	$23,730	$24,552	$23,679	$24,309	$21,277	
Gas Purchases and Hedges $000	$20,110	$42,242	$41,607	$32,964	$25,457	$20,781	$16,641	
Receipt Value $000	$43,028	$66,454	$65,338	$57,516	$49,136	$45,090	$37,918	$364,480
Total Inventory Value $000	$258,601	$299,898	$286,521	$250,042	$207,009	$169,184	$143,442	
Total $/dth	$4.14	$4.03	$3.87	$3.84	$3.91	$4.15	$4.05	
Beginning Inventory Volume MDth	51,421	56,244	54,873	49,710	41,128	31,750	25,487	
Receipt Volume MDth	10,972	18,119	19,088	15,392	11,796	9,032	9,906	94,305
Total Inventory Volume MDth	62,393	74,363	73,961	65,102	52,924	40,783	35,393	
RSG Sendout MDth	5,992	19,546	24,277	24,022	21,222	15,385	11,416	121,860
Total RSG Sendout Cost $000	$24,834	$78,825	$94,050	$92,263	$83,007	$63,824	$46,268	$483,071
Ending Inventory Rebalance								
Volume	(157)	55	27	47	48	90	330	
Amount	($324)	$111	$55	$94	$92	$164	$560	

FORECASTED COST OF BGSS-RSG GAS SENDOUT BY COMPONENT

	May-20	Jun-20	Jul-20	Aug-20	Sep-20	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 Oct - Sept
Beginning Inventory Cost $000	$97,735	$98,942	$121,747	$149,541	$177,686	$205,112	$218,349	$217,820	$183,641	$125,802	$83,665	$59,310	$59,920	$81,963	$116,970	$147,200	$176,446	
Receipt Value $000	$39,271	$40,555	$39,998	$39,573	$39,801	$40,281	$61,385	$58,623	$61,533	$61,699	$56,097	$47,815	$43,913	$52,008	$42,366	$40,834	$43,282	$609,836
Total Inventory Value $000	$137,006	$139,497	$161,745	$189,114	$217,487	$245,393	$279,734	$276,443	$245,173	$187,501	$139,761	$107,125	$103,833	$133,971	$159,336	$188,034	$219,728	
Total $/dth	$3.99	$4.05	$4.07	$4.07	$4.08	$4.09	$4.02	$4.05	$4.09	$4.13	$4.14	$4.16	$4.20	$4.14	$4.21	$4.27	$4.29	
Beginning Inventory Volume MDth	24,307	24,770	30,078	36,770	43,655	50,313	53,393	54,170	45,342	30,735	20,238	14,316	14,414	19,494	28,231	34,925	41,297	
Receipt Volume MDth	9,992	9,693	9,693	9,693	9,693	9,693	16,175	14,086	14,556	14,621	13,498	11,452	10,282	12,841	9,573	9,084	9,879	145,740
Total Inventory Volume MDth	34,299	34,463	39,771	46,463	53,348	60,006	69,568	68,256	59,899	45,356	33,736	25,769	24,695	32,335	37,804	44,009	51,175	
RSG Sendout MDth	9,529	4,385	3,001	2,808	3,036	6,613	15,398	22,914	29,164	25,118	19,420	11,355	5,202	4,103	2,879	2,712	2,990	147,867
Total RSG Sendout Cost $000	$38,064	$17,750	$12,204	$11,428	$12,376	$27,044	$61,915	$92,802	$119,371	$103,836	$80,451	$47,205	$21,871	$17,001	$12,136	$11,588	$12,838	$608,058

6. BGSS Contribution and Credit Offsets

Actual BGSS Contribution and Credit Offsets

($000)

			Oct-19	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	Total
(1)	**BGSS-I Contribution**		$31	$78	$408	$300	($125)	$361	$255	$1,307
(2)	**Cogeneration Contribution**		$113	$573	$1,034	($107)	$741	($496)	($236)	$1,622
(3)	**TSG-F Contribution**		$137	$398	$327	$382	$255	$266	($114)	$1,650
(4)	**"Contribution"**	Sum of (1) through (4)	$282	$1,049	$1,768	$574	$871	$130	($95)	$4,580
(5)	**Off-System Contribution**		$524	$2,269	$3,597	$3,475	$2,284	$787	$713	$13,649
(6)	**Electric Contribution**		$1,486	$1,407	$1,160	$906	$605	$502	$336	$6,402
(7)	**FT-S Balancing Credit**		$563	$2,722	$3,867	$4,170	$3,801	$2,680	$1,992	$19,795
(8)	**Pipeline Refunds**		$14	$8	$11	$0	$0	$0	$0	$34

Forecasted BGSS Contribution and Credit Offsets

		May-20	Jun-20	Jul-20	Aug-20	Sep-20	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 Oct - Sept
(1)	**BGSS-RSG Sendout, Mdth**	5,309	4,385	3,001	2,808	3,036	6,613	15,398	22,914	29,164	25,118	19,420	11,355	5,202	4,103	2,879	2,712	2,990	147,867
(2)	**BGSS-F Sendout, Mdth**	1,345	901	926	1,017	1,119	2,393	4,668	7,977	9,826	8,431	7,060	3,903	2,003	1,251	1,196	1,191	1,201	51,099
(3)	**Total Firm Sendout, Mdth**	6,654	5,286	3,926	3,825	4,155	9,006	20,066	30,891	38,989	33,549	26,480	15,258	7,204	5,355	4,075	3,903	4,191	198,966
(4)	**Annual % BGSS-RSG of Firm Sendout**	74.3%	74.3%	74.3%	74.3%	74.3%	74.3%	74.3%	74.3%	74.3%	74.3%	74.3%	74.3%	74.3%	74.3%	74.3%	74.3%	74.3%	74.3%
(5)	**BGSS-I Contribution**	$145.4	$16.7	$17.5	$22.9	$27.7	$31.7	$75.8	$408.4	$298.0	($124.2)	$365.6	$254.2	$160.7	$18.1	$18.9	$24.2	$28.3	$1,559.7
(6)	**Cogeneration Contribution, $000**	$70.0	$418.5	($17.5)	$497.1	$581.6	$253.8	$670.1	$748.3	($76.6)	($14.3)	($24.8)	($195.2)	$77.3	$453.1	($18.9)	$525.0	$595.7	$2,993.4
(7)	**TSG-F Contribution**	$32.5	$115.3	$178.2	($43.6)	($34.1)	$138.5	$385.6	$327.4	$379.1	$253.2	$269.4	($113.7)	$35.9	$124.9	$192.7	($46.0)	($34.9)	$1,912.1
(8)	**CSG**	$294.5	$294.5	$294.5	$294.5	$294.5	$294.5	$294.5	$294.5	$294.5	$294.5	$294.5	$294.5	$294.5	$294.5	$294.5	$294.5	$294.5	$3,533.8
(9)	**"Contribution"**	$542.4	$845.0	$472.7	$770.9	$869.7	$718.5	$1,425.9	$1,778.6	$894.9	$409.2	$904.7	$239.8	$568.5	$890.5	$487.2	$797.7	$883.6	$9,999.0
(10)	**Off-System Contribution, $000**	$750.3	$750.3	$750.3	$750.3	$750.3	$750.3	$2,017.8	$3,497.2	$3,989.0	$3,989.0	$1,052.1	$750.8	$750.8	$750.8	$750.8	$750.8	$750.8	$19,800.1
(11)	**Electric Contribution, $000**	$1,165.4	$971.8	$901.3	$733.9	$774.9	$807.6	$741.9	$814.7	$773.1	$852.5	$1,016.7	$1,383.6	$1,165.4	$971.8	$901.3	$733.9	$774.9	$10,937.5
(12)	**Pipeline Refund, $000**	$19,231.5	$1,184.0	$28,809.1	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
(13)	**FT-S Balancing Use, Mdth**	596.1	0.0	0.0	0.0	0.0	1,255.5	3,752.2	6,420.1	6,978.9	6,350.0	5,656.9	3,237.7	745.6	0.0	0.0	0.0	0.0	
(14)	**Balancing Charge, $/dth**	$0.8435	$0.0000	$0.0000	$0.0000	$0.0000	$0.7391	$0.7391	$0.7391	$0.7391	$0.7391	$0.7391	$0.7391	$0.7391	$0.0000	$0.0000	$0.0000	$0.0000	
(15)	**FT-S Balancing Credit, $000**	$596.1	$0.0	$0.0	$0.0	$0.0	$689.6	$2,060.9	$3,526.2	$3,833.1	$3,487.7	$3,107.0	$1,778.3	$409.5	$0.0	$0.0	$0.0	$0.0	$18,892.3
(16)	**BGSS-RSG Balancing Use, Mdth**	3,264	0	0	0	0	3,360	12,249	19,660	25,910	22,179	16,166	8,207	1,948	0	0	0	0	
(17)	**Balancing Charge, $/dth**	$0.8435	$0.0000	$0.0000	$0.0000	$0.0000	$0.7391	$0.7391	$0.7391	$0.7391	$0.7391	$0.7391	$0.7391	$0.7391	$0.0000	$0.0000	$0.0000	$0.0000	
(18)	**BGSS-RSG Balancing Rev., $000**	$2,753.1	$0.0	$0.0	$0.0	$0.0	$2,483.0	$9,052.9	$14,530.0	$19,149.1	$16,391.7	$11,947.8	$6,065.3	$1,440.0	$0.0	$0.0	$0.0	$0.0	$81,059.7

BGSS-RSG MARGIN FROM GAS TRANSPORTATION FOR ELECTRIC GENERATION

	Oct-19	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	Total
BGSS Asset Charge ($000)	$1,205	$1,129	$1,048	$952	$693	$488	$494	$6,008
CSG Transportation Revenues ($000)	($281)	($278)	($112)	$45	$88	($14)	$158	($394)
Total BGSS-RSG Margin ($000)	$923	$851	$936	$997	$781	$473	$652	$5,614

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 2019 - SEPTEMBER 2020

(000)

		TOTAL RECOVERY	LESS: TOTAL EXPENSE	MONTHLY OVER/(UNDER RECOVERY
Balance September 30, 2019				**$763**
Interest Adjustment				**71**
October 1, 2019 Adjusted Balance				**$834**
October 2019		$ 19,804	$ 23,823	(4,019)
November		72,399	78,655	(6,257)
December		99,222	93,072	6,150
January 2020		94,616	94,352	264
February		73,463	82,598	(9,135)
March		51,737	62,170	(10,433)
April		50,505	49,009	1,496
May	**(Est.)**	29,833	15,778	14,055
June	**(Est.)**	12,462	13,999	(1,537)
July	**(Est.)**	8,527	(18,730)	27,257
August	**(Est.)**	7,979	9,173	(1,194)
September	**(Est.)**	8,627	9,981	(1,354)
Total				**$16,127**

INTEREST
COMPUTED AT 6.99% ROR FOR October 2019 - SEPTEMBER 2020

(000)

		OVER/(UNDER) RECOVERIES			
		Monthly	Cumulative	Average Balance	INTEREST
Balance September 30, 2019			**$763**		
Interest Adjustment			**71**		
October 1, 2019 Adjusted Balance			**$834**		
October 2019		$ (4,019)	(3,185)	$ (1,175)	$ (7)
November		(6,257)	(9,442)	$ (6,313)	$ (37)
December		6,150	(3,291)	(6,366)	$ (37)
January 2020		264	(3,028)	(3,159)	$ (18)
February		(9,135)	(12,162)	(7,595)	$ (44)
March		(10,433)	(22,595)	(17,379)	$ (101)
April		1,496	(21,100)	(21,847)	$ (127)
May	**(Est.)**	14,055	(7,045)	(14,072)	$ (82)
June	**(Est.)**	(1,537)	(8,582)	(7,813)	$ (46)
July	**(Est.)**	27,257	18,675	5,047	$ 29
August	**(Est.)**	(1,194)	17,481	18,078	$ 105
September	**(Est.)**	(1,354)	16,127	16,804	$ 98
Total					**$ (267)**

BGSS-RSG 2020-2021
NYMEX====>>> May 7, 2020

NO CHANGE IN RATES

		BGSS-RSG MDTh	COST	REFUNDS	CONTRIB	OFF-SYS Margin	Electric Contribution	FT Balancing Credit	ADJ COST	RSG Bal. Revenue	BGSS RECOVERY	EXCESS COST	OVER/(UNDER) RECOVERY Month	Cumulative	RSG Rate $/dth
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)=(2).+.(7)	(9)	(10)=(1)*(14)+(9)	(11)=(10)-(8)	(12)=-(11)	(13)	(14)
Apr-20	Act													**($21,100)**	$2.8418
May-20	Est.	9,529	$38,064	($19,231)	($542)	($750)	($1,165)	($596)	$15,778	$2,753	$29,833	($14,055)	$14,055	($7,045)	$2.8418
Jun-20	Est.	4,385	$17,750	($1,184)	($845)	($750)	($972)	$0	$13,999	$0	$12,462	$1,537	($1,537)	($8,582)	$2.8418
Jul-20	Est.	3,001	$12,204	($28,809)	($473)	($750)	($901)	$0	($18,730)	$0	$8,527	($27,257)	$27,257	$18,675	$2.8418
Aug-20	Est.	2,808	$11,428	$0	($771)	($750)	($734)	$0	$9,173	$0	$7,979	$1,194	($1,194)	$17,481	$2.8418
Sep-20	**Est.**	**3,036**	**$12,376**	**$0**	**($870)**	**($750)**	**($775)**	**$0**	**$9,981**	**$0**	**$8,627**	**$1,354**	**($1,354)**	**$16,127**	$2.8418
Oct-20	Est.	6,613	$27,044	$0	($718)	($750)	($808)	($690)	$24,078	$2,483	$21,276	$2,802	($2,802)	$13,325	$2.8418
Nov-20	Est.	15,398	$61,915	$0	($1,426)	($2,018)	($742)	($2,061)	$55,668	$9,053	$52,810	$2,858	($2,858)	$10,467	$2.8418
Dec-20	Est.	22,914	$92,802	$0	($1,779)	($3,497)	($815)	($3,526)	$83,185	$14,530	$79,646	$3,540	($3,540)	$6,928	$2.8418
Jan-21	Est.	29,164	$119,371	$0	($895)	($3,989)	($773)	($3,833)	$109,881	$19,149	$102,026	$7,855	($7,855)	($927)	$2.8418
Feb-21	Est.	25,118	$103,836	$0	($409)	($3,989)	($853)	($3,488)	$95,098	$16,392	$87,772	$7,326	($7,326)	($8,253)	$2.8418
Mar-21	Est.	19,420	$80,451	$0	($905)	($1,052)	($1,017)	($3,107)	$74,371	$11,948	$67,134	$7,236	($7,236)	($15,490)	$2.8418
Apr-21	Est.	11,355	$47,205	$0	($240)	($751)	($1,384)	($1,778)	$43,052	$6,065	$38,334	$4,718	($4,718)	($20,207)	$2.8418
May-21	Est.	5,202	$21,871	$0	($568)	($751)	($1,165)	($410)	$18,976	$1,440	$16,222	$2,754	($2,754)	($22,962)	$2.8418
Jun-21	Est.	4,103	$17,001	$0	($891)	($751)	($972)	$0	$14,388	$0	$11,661	$2,727	($2,727)	($25,689)	$2.8418
Jul-21	Est.	2,879	$12,136	$0	($487)	($751)	($901)	$0	$9,997	$0	$8,183	$1,814	($1,814)	($27,503)	$2.8418
Aug-21	Est.	2,712	$11,588	$0	($798)	($751)	($734)	$0	$9,306	$0	$7,708	$1,598	($1,598)	($29,102)	$2.8418
Sep-21	**Est.**	**2,990**	**$12,838**	**$0**	**($884)**	**($751)**	**($775)**	**$0**	$10,429	**$0**	$8,497	$1,932	($1,932)	($31,033)	$2.8418
Oct-20 to Sept-21		**147,867**	**$608,058**	**$0**	**($9,999)**	**($19,800)**	**($10,938)**	**($18,892)**	**$548,429**	**$81,060**	**$501,269**	**$47,161**			

BGSS-RSG 2020-2021 NYMEX====>>> May 7, 2020												ZERO BALANCE		
	BGSS-RSG				OFF-SYS	Electric	FT Balancing		RSG Bal.	BGSS	EXCESS	OVER/(UNDER) RECOVERY		RSG Rate
	MDTh	COST	REFUNDS	CONTRIB	Margin	Contribution	Credit	ADJ COST	Revenue	RECOVERY	COST	Month	Cumulative	$/dth
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)=(2).+.(7)	(9)	(10)=(1)*(14)+(9)	(11)=(10)-(8)	(12)=-(11)	(13)	(14)
Apr-20 Act.													**($21,100)**	$2.8418
May-20 Est.	9,529	$38,064	($19,231)	($542)	($750)	($1,165)	($596)	$15,778	$2,753	$29,833	($14,055)	$14,055	($7,045)	$2.8418
Jun-20 Est.	4,385	$17,750	($1,184)	($845)	($750)	($972)	$0	$13,999	$0	$12,462	$1,537	($1,537)	($8,582)	$2.8418
Jul-20 Est.	3,001	$12,204	($28,809)	($473)	($750)	($901)	$0	($18,730)	$0	$8,527	($27,257)	$27,257	$18,675	$2.8418
Aug-20 Est.	2,808	$11,428	$0	($771)	($750)	($734)	$0	$9,173	$0	$7,979	$1,194	($1,194)	$17,481	$2.8418
Sep-20 Est.	**3,036**	**$12,376**	**$0**	**($870)**	**($750)**	**($775)**	**$0**	**$9,981**	**$0**	**$8,627**	**$1,354**	**($1,354)**	**$16,127**	$2.8418
Oct-20 Est.	6,613	$27,044	$0	($718)	($750)	($808)	($690)	$24,078	$2,483	$22,664	$1,414	($1,414)	$14,713	$3.0517
Nov-20 Est.	15,398	$61,915	$0	($1,426)	($2,018)	($742)	($2,061)	$55,668	$9,053	$56,042	($374)	$374	$15,087	$3.0517
Dec-20 Est.	22,914	$92,802	$0	($1,779)	($3,497)	($815)	($3,526)	$83,185	$14,530	$84,455	($1,269)	$1,269	$16,356	$3.0517
Jan-21 Est.	29,164	$119,371	$0	($895)	($3,989)	($773)	($3,833)	$109,881	$19,149	$108,147	$1,734	($1,734)	$14,622	$3.0517
Feb-21 Est.	25,118	$103,836	$0	($409)	($3,989)	($853)	($3,488)	$95,098	$16,392	$93,043	$2,055	($2,055)	$12,567	$3.0517
Mar-21 Est.	19,420	$80,451	$0	($905)	($1,052)	($1,017)	($3,107)	$74,371	$11,948	$71,210	$3,161	($3,161)	$9,407	$3.0517
Apr-21 Est.	11,355	$47,205	$0	($240)	($751)	($1,384)	($1,778)	$43,052	$6,065	$40,717	$2,335	($2,335)	$7,072	$3.0517
May-21 Est.	5,202	$21,871	$0	($568)	($751)	($1,165)	($410)	$18,976	$1,440	$17,314	$1,663	($1,663)	$5,409	$3.0517
Jun-21 Est.	4,103	$17,001	$0	($891)	($751)	($972)	$0	$14,388	$0	$12,522	$1,866	($1,866)	$3,543	$3.0517
Jul-21 Est.	2,879	$12,136	$0	($487)	($751)	($901)	$0	$9,997	$0	$8,787	$1,210	($1,210)	$2,333	$3.0517
Aug-21 Est.	2,712	$11,588	$0	($798)	($751)	($734)	$0	$9,306	$0	$8,277	$1,029	($1,029)	$1,304	$3.0517
Sep-21 Est.	**2,990**	**$12,838**	**$0**	**($884)**	**($751)**	**($775)**	**$0**	**$10,429**	**$0**	**$9,125**	**$1,304**	**($1,304)**	**$0**	$3.0517
Oct-20 to Sept-21	**147,867**	**$608,058**	**$0**	**($9,999)**	**($19,800)**	**($10,938)**	**($18,892)**	**$548,429**	**$81,060**	**$532,302**	**$16,127**			

BGSS
FOR PERIOD OCT 2019 TO SEP 2020

	Oct-19	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20
Beginning Balance	834,062	(3,185,127)	(9,441,795)	(3,291,543)	(3,027,753)	(12,162,386)	(22,595,376)
FUEL REVENUES							
Fuel Revenues	19,522,514	71,349,756	97,453,649	94,041,535	72,592,087	51,607,175	50,600,268
Interruptible Contribution	281,577	1,049,036	1,768,269	574,386	871,398	130,196	(95,169)
Total Fuel Revenues	19,804,091	72,398,792	99,221,918	94,615,921	73,463,486	51,737,372	50,505,099
FUEL EXPENSE							
Gas Purchases	23,837,490	78,663,251	93,082,735	94,352,309	82,598,374	62,170,496	49,009,477
Refunds	(14,209)	(7,792)	(11,068)	(178)	(255)	(135)	(29)
Total Fuel Expense	23,823,280	78,655,459	93,071,667	94,352,130	82,598,119	62,170,361	49,009,448
OVER / (UNDER) RECOVERY	(4,019,189)	(6,256,667)	6,150,251	263,791	(9,134,633)	(10,432,990)	1,495,651
Cumulative Recovery	(3,185,127)	(9,441,795)	(3,291,543)	(3,027,753)	(12,162,386)	(22,595,376)	(21,099,725)

BGSS
CALCULATION OF FUEL REVENUES
FOR PERIOD OCT 2019 TO SEP 2020

	Oct-19	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20
RSG Fuel Revenues	$16,677,840	$54,575,994	$72,594,060	$69,114,450	$49,249,282	$34,590,055	$40,593,696
RSGM Fuel Revenues	$336,510	$1,143,329	$1,552,231	$1,428,611	$1,022,820	$760,945	$839,976
Subtotal	$17,014,350	$55,719,323	$74,146,291	$70,543,061	$50,272,102	$35,351,000	$41,433,673
FT Balancing Revenues	1,546,801	9,616,023	21,831,661	23,034,606	22,978,319	16,768,595	12,460,997
FT Balancing Revenues (Unbilled Calc)	961,363	6,975,773	8,451,470	8,915,337	8,257,004	7,744,584	4,450,182
FT Balancing Revenues (Prior Unbilled Calc)	0	-961,363	-6,975,773	-8,451,470	-8,915,337	-8,257,004	-7,744,584
Total BGSSR Fuel Recovery	$19,522,514	$71,349,756	$97,453,649	$94,041,535	$72,592,087	$51,607,175	$50,600,268
Bill Credits							
Billed Revenues					$ (8,875,637.89)	$ (12,586,710.73)	$ (4,048,415.84)
Current Unbilled Usage					81,943,249	59,363,570	0
Prior Unbilled Usage					0	81,943,249	59,363,570
Net Unbilled Usage					81,943,249	-22,579,679	-59,363,570
Rate					($0.070340)	($0.070340)	($0.070340)
Subtotal Unbilled Revenues					($5,763,888)	$1,588,255	$4,175,634
Total Bill Credits					($14,639,526)	($10,998,456)	$127,218

	Oct-19	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20
<u>Interruptible Contributions:</u>							
ISG (BGSS-I):							
ISG (BGSS-I) Sales Therms	162,323	673,692	1,876,730	1,908,955	384,169	1,267,486	1,151,675
ISG BGSS-I) Gross Revenues	$ 72,868	$ 321,433	$ 857,128	$ 787,334	$ 181,096	$ 665,251	$ 426,394
ISG (BGSS-I) Cost	$ 28,406	$ 201,546	$ 347,493	$ 379,482	$ 237,633	$ 250,167	$ 122,206
PSEG Power's share of Contribution	$ 13,148	$ 41,671	$ 102,039	$ 107,896	$ 68,582	$ 54,285	$ 49,619
ISG Interuptible Contribution to BGSSR	$ 31,314	$ 78,216	$ 407,596	$ 299,956	$ (125,119)	$ 360,799	$ 254,569
CIG:							
CIG SBC Rate adjustment (line 84)							
CIG Sales Therms	2,075,625	4,166,620	2,927,748	1,865,964	1,376,167	1,782,904	(124,707)
CIG Gross Revenues	$ 885,977	$ 1,694,085	$ 1,655,058	$ 582,146	$ 685,225	$ 600,675	$ (23,023)
CIG SBC/GPRC Revenues	$ 107,773	$ 216,343	$ 152,017	$ 96,886	$ 71,455	$ 92,574	$ (6,475)
CIG Cost	$ 415,079	$ 738,626	$ 669,412	$ 500,151	$ 587,004	$ 506,714	$ 137,690
CIG TAC revenues	$ (22,761)	$ (40,624)	$ (32,106)	$ (20,462)	$ (54,965)	$ (23,570)	$ 1,649
PSEG Power's share of Contribution	$ 135,119	$ 87,872	$ 118,890	$ 82,696	$ 96,161	$ 49,444	$ 39,559
CIG Interuptible Contribution to BGSSR	$ 250,768	$ 691,867	$ 746,844	$ (77,125)	$ (14,430)	$ (24,486)	$ (195,446)
TSG-F:							
TSG-F SBC Rate adjustment (line 84)							
TSG-F Sales Therms	2,264,884	1,188,988	2,606,947	3,390,398	2,123,710	2,062,878	1,904,197
TSG-F Gross Revenues	$ 294,623	$ 489,098	$ 515,500	$ 610,779	$ 413,513	$ 435,361	$ (8,610)
TSG-F SBC/GPRC Revenues	$ 117,600	$ 61,736	$ 135,360	$ 176,040	$ 110,269	$ 107,111	$ 98,872
TSG-F TAC Revenues	$ (46,579)	$ (37,271)	$ (53,613)	$ (69,726)	$ (64,102)	$ (50,121)	$ (46,265)
TSG-F MAC Revenues	$ (14,355)	$ (7,536)	$ (16,523)	$ (21,488)	$ (13,460)	$ (13,075)	$ (12,069)
TSG-F PSEG Power's share of Contribution	$ 101,120	$ 73,992	$ 123,471	$ 144,435	$ 125,682	$ 125,620	$ 64,699
TSG-F Interuptible Contribution to BGSSR	$ 136,837	$ 398,177	$ 326,805	$ 381,519	$ 255,123	$ 265,825	$ (113,846)
CSG NON-Power:							
CSG Non-Power Therms	16,101,190	2,393,519	3,212,245	(7,952,250)	2,258,461	4,310,031	1,465,613
CSG Non-Power Revenues	$ (27,015)	$ 23,257	$ 438,285	$ 262,098	$ 891,834	$ (238,158)	$ 162,831
CSG Non Power SBC Revenues	$ 132,397	$ 249,385	$ 249,385	$ 249,385	$ 249,385	$ 249,385	$ 249,385
CSG TAC Revenues Power and NON-Power	$ (104,453)	$ (130,486)	$ (93,678)	$ 15,207	$ (133,274)	$ (39,073)	$ (63,444)
CSG Non-Power ER&T's share of Contribution	$ 82,383	$ 23,581	$ (4,447)	$ 27,471	$ 19,900	$ 23,473	$ 17,335
CSG Non-Power Contribution to BGSSR	$ (137,342)	$ (119,223)	$ 287,025	$ (29,964)	$ 755,824	$ (471,942)	$ (40,445)
Total Interruptible Contributions	$ 281,577	$ 1,049,036	$ 1,768,269	$ 574,386	$ 871,398	$ 130,196	$ (95,169)
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	$ 23,542,399	$ 78,697,844	$ 93,263,248	$ 94,096,059	$ 84,781,759	$ 62,982,495	$ 46,977,205
Prior Month Actual - Gas Purchases (1) See below row 105	$ 12,256,696	$ 23,500,015	$ 78,506,263	$ 93,519,320	$ 91,912,419	$ 83,969,625	$ 65,014,738
Prior Month Estimate - Gas Purchases See below row 115	$ 11,975,815	$ 23,542,399	$ 78,697,844	$ 93,263,248	$ 94,096,059	$ 84,781,759	$ 62,982,495
Gas Purchases	$ 23,823,280	$ 78,655,459	$ 93,071,667	$ 94,352,130	$ 82,598,119	$ 62,170,361	$ 49,009,448
Gas Refunds	-	-	-	-	-	-	
ISG (BGSS-I) Cost Est. (2)	$ 29,107	$ 202,584	$ 345,075	$ 374,049	$ 232,714	$ 229,410	$ 137,166
PSEG Power's share of Contribution CMnth Est. (2)	$ 12,457	$ 42,790	$ 102,605	$ 107,066	$ 65,273	$ 51,565	$ 48,047
ISG (BGSS-I) Cost Pr Mnth Act. (2)	$ 25,174	$ 28,069	$ 205,002	$ 350,508	$ 378,968	$ 253,471	$ 214,450
PSEG Power's share of Contribution Pr Mnth Act. (2)	$ 9,762	$ 11,338	$ 42,224	$ 103,435	$ 110,375	$ 67,993	$ 53,138
ISG (BGSS-I) Cost PrMnth Est.	$ 25,875	$ 29,107	$ 202,584	$ 345,075	$ 374,049	$ 232,714	$ 229,410
PSEG Power's share of Contribution PrMnth Est.	$ 9,071	$ 12,457	$ 42,790	$ 102,605	$ 107,066	$ 65,273	$ 51,565
CIG Cost (3) - CMnth Est. (3)	$ 426,530	$ 752,706	$ 648,295	$ 488,173	$ 522,965	$ 483,023	$ 169,189
PSEG Power's share of Contribution - CMnth Est. (3)	$ 123,485	$ 97,477	$ 120,467	$ 82,450	$ 84,443	$ 52,075	$ 33,770
CIG Cost (3) - PrMnth Act. (3)	$ 532,362	$ 412,451	$ 773,823	$ 660,272	$ 552,212	$ 546,656	$ 451,525

	Oct-19	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20
PSEG Power's share of Contribution - PrMnth Act. (3)	$ 132,987	$ 113,879	$ 95,901	$ 120,712	$ 94,168	$ 81,812	$ 57,864
CIG Cost - PrMnth Est.	$ 543,813	$ 426,530	$ 752,706	$ 648,295	$ 488,173	$ 522,965	$ 483,023
PSEG Power's share of Contribution - PrMnth Est.	$ 121,354	$ 123,485	$ 97,477	$ 120,467	$ 82,450	$ 84,443	$ 52,075
TSG-F PSEG Power's share of Contribution CMth Est. (4)	$ 92,174	$ 83,933	$ 111,597	$ 139,711	$ 119,613	$ 120,412	$ 69,126
TSG-F PSEG Power's share of Contribution PrMth Actual (4)	$ 86,142	$ 82,233	$ 95,807	$ 116,321	$ 145,780	$ 124,821	$ 115,984
TSG-F PSEG Power's share of Contribution PrMth Est.	$ 77,196	$ 92,174	$ 83,933	$ 111,597	$ 139,711	$ 119,613	$ 120,412
CSC Non-Power Cost & PSEG Power's share of Contribution CMth Est. (6)	$ 63,972	$ 40,725	$ 17,992	$ 27,075	$ 18,786	$ 22,691	$ 18,307
CSC Non-Power Cost & PSEG Power's share of Contribution PMth Act. (6)	$ 67,863	$ 46,828	$ 18,286	$ 18,388	$ 28,188	$ 19,568	$ 21,720
CSC Non-Power Cost & PSEG Power's share of Contribution PMth Est.	$ 49,452	$ 63,972	$ 40,725	$ 17,992	$ 27,075	$ 18,786	$ 22,691
BGSS-RSG Prior Month Actual	$ 12,956,980	$ 24,065,752	$ 79,623,213	$ 94,754,247	$ 93,048,142	$ 84,919,557	$ 65,791,714
BGSS-RSG Cogen Contracts Prior Month Actual (6)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BGSS-RSG TSG Cashouts Prior Mnth Actuals	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Subtotal	$ 13,160,219	$ 24,328,555	$ 79,826,233	$ 94,754,247	$ 93,048,142	$ 85,023,629	$ 65,765,035
Total BGSS-RSG Actual Bill	**$ 13,160,219**	**$ 24,328,555**	**$ 79,826,233**	**$ 94,754,247**	**$ 93,048,142**	**$ 84,875,225**	**$ 65,765,035**
Difference	-	-	-	-	-	-	
BGSS-RSG Current Month Estimate	$ 24,489,793	$ 80,164,169	$ 94,759,592	$ 95,382,343	$ 85,833,735	$ 63,855,282	$ 47,290,779
BGSS-RSG Cogen Contracts Prior Month Estimate (6)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Subtotal	$ 24,489,793	$ 80,164,169	$ 94,759,592	$ 95,382,343	$ 85,833,735	$ 63,855,282	$ 47,290,779
Total BGSS-RSG Estimate Bill	**$ 24,489,793**	**$ 80,164,169**	**$ 94,759,592**	**$ 95,382,343**	**$ 85,833,735**	**$ 63,855,282**	**$ 47,290,779**
Difference	-	-	-	-	-	-	
<u>Gas Purchases Details:</u>							
Current Month Estimate							
BGSS-RSG GAS COMMODITY VOLUMES MDTh	5,978,273	19,730,631	24,339,240	24,672,567	21,624,899	14,899,666	11,421,418
BGSS-RSG GAS COMMODITY COST	$ 24,807,790	$ 79,188,561	$ 94,136,937	$ 94,689,526	$ 84,362,085	$ 61,906,432	$ 46,272,181
BGSS-RSG Balancing	$ 825,484	$ 3,253,666	$ 4,072,919	$ 4,095,287	$ 3,591,242	$ 2,440,760	$ 1,826,311
BGSS-RSG Off System Sales	$ (534,722)	$ (2,247,487)	$ (3,622,422)	$ (3,502,304)	$ (2,331,234)	$ (819,496)	$ (700,078)
Electric Reservation Charge	$ (1,200,339)	$ (1,126,127)	$ (1,044,284)	$ (951,905)	$ (693,754)	$ (488,487)	$ (495,806)
Other	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CSG Revenues	**$ (355,814)**	**$ (370,768)**	**$ (279,902)**	**$ (234,546)**	**$ (146,580)**	**$ (56,714)**	**$ 74,597**
Credit for Pipeline Refunds	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total	$ 23,542,399	$ 78,697,844	$ 93,263,248	$ 94,096,059	$ 84,781,759	$ 62,982,495	$ 46,977,205
Prior Actual							
BGSS-RSG GAS COMMODITY VOLUMES MDTh	3,178,350	5,999,257	19,564,580	24,291,332	24,032,113	21,296,161	15,390,667
BGSS-RSG GAS COMMODITY COST	$ 13,628,441	$ 24,681,782	$ 78,839,003	$ 94,103,977	$ 92,310,494	$ 83,374,974	$ 63,828,545
BGSS-RSG Balancing	$ 318,502	$ 848,592	$ 3,233,091	$ 4,054,876	$ 4,007,902	$ 3,542,368	$ 2,478,251
BGSS-RSG Off System Sales	$ (513,622)	$ (556,346)	$ (2,221,911)	$ (3,595,468)	$ (3,454,583)	$ (2,298,997)	$ (832,037)
Electric Reservation Charge	$ (959,177)	$ (1,203,419)	$ (1,129,833)	$ (1,043,887)	$ (951,140)	$ (692,916)	$ (486,671)
CSG Revenues	**$ (203,239)**	**$ (262,803)**	**$ (203,020)**	**$ -**	**$ -**	**$ (104,072)**	**$ 26,679**
Credit for Pipeline Refunds	$ (14,209)	$ (7,792)	$ (11,068)	$ (178)	$ (255)	$ (135)	$ (29)
Residential Share of Property Taxes Paid	$ -	$ -	$ -	$ -	$ -	$ 148,403	$ -
Other	$ -	$ -	$ -	$ -	$ -	$ 1	$ -
Total	$ 12,256,696	$ 23,500,015	$ 78,506,263	$ 93,519,320	$ 91,912,419	$ 83,969,625	$ 65,014,738
Prior Estimate							
BGSS-RSG GAS COMMODITY VOLUMES MDTh	3,201,096	5,978,273	19,730,631	24,339,240	24,672,567	21,624,899	14,899,666
BGSS-RSG GAS COMMODITY COST	$ 13,411,918	$ 24,807,790	$ 79,188,561	$ 94,136,937	$ 94,689,526	$ 84,362,085	$ 61,906,432
BGSS-RSG Balancing	$ 320,782	$ 825,484	$ 3,253,666	$ 4,072,919	$ 4,095,287	$ 3,591,242	$ 2,440,760
BGSS-RSG Off System Sales	$ (524,293)	$ (534,722)	$ (2,247,487)	$ (3,622,422)	$ (3,502,304)	$ (2,331,234)	$ (819,496)
Electric Reservation Charge	$ (954,989)	$ (1,200,339)	$ (1,126,127)	$ (1,044,284)	$ (951,905)	$ (693,754)	$ (488,487)
Other	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Prior CSG Revenues	$ (277,603)	$ (355,814)	$ (370,768)	$ (279,902)	$ (234,546)	$ (146,580)	$ (56,714)

		Oct-19	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20
Credit for Pipeline Refunds		$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Total	$ 11,975,815	$ 23,542,399	$ 78,697,844	$ 93,263,248	$ 94,096,059	$ 84,781,759	$ 62,982,495
Net								
BGSS-RSG GAS COMMODITY VOLUMES MDTh		5,955,527	19,751,615	24,173,189	24,624,659	20,984,445	14,570,928	11,912,419
BGSS-RSG GAS COMMODITY COST		$ 25,024,313	$ 79,062,553	$ 93,787,379	$ 94,656,565	$ 81,983,054	$ 60,919,321	$ 48,194,293
BGSS-RSG Balancing		$ 823,205	$ 3,276,773	$ 4,052,345	$ 4,077,244	$ 3,503,857	$ 2,391,885	$ 1,863,802
BGSS-RSG Off System Sales		$ (524,051)	$ (2,269,111)	$ (3,596,845)	$ (3,475,350)	$ (2,283,513)	$ (787,259)	$ (712,619)
Electric Reservation Charge		$ (1,204,527)	$ (1,129,207)	$ (1,047,990)	$ (951,507)	$ (692,989)	$ (487,648)	$ (493,990)
Other		$ -	$ -	$ -	$ -	$ -	$ 148,404	$ -
CSG Revenues		$ (281,450)	$ (277,757)	$ (112,154)	$ 45,356	$ 87,965	$ (14,206)	$ 157,990
Credit for Pipeline Refunds		$ (14,209)	$ (7,792)	$ (11,068)	$ (178)	$ (255)	$ (135)	$ (29)
	Total	$ 23,823,280	$ 78,655,459	$ 93,071,667	$ 94,352,130	$ 82,598,119	$ 62,170,361	$ 49,009,448
BGSS-RSG GAS COMMODITY VOLUMES MDTh		5,955,527	19,751,615	24,173,189	24,624,659	20,984,445	14,570,928	11,912,419
NET SALES VOLUMES RESIDENTIAL		5,340,026	17,470,102	23,258,273	23,459,294	21,695,101	15,473,583	12,317,224
	Diff	615,501	2,281,513	914,916	1,165,365	(710,656)	(902,655)	(404,805)

INTEREST CALCULATION
FOR PERIOD OCT 2019 TO SEP 2020

	Oct-19	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20
CUMULATIVE OVER/(UNDER) RECOVERY PRIOR MONTH	$834,062	($3,185,127)	($9,441,795)	($3,291,543)	($3,027,753)	($12,162,386)	($22,595,376)
CUMULATIVE OVER/(UNDER) RECOVERY CURRENT MONTH	($3,185,127)	($9,441,795)	($3,291,543)	($3,027,753)	($12,162,386)	($22,595,376)	($21,099,725)
AVERAGE BALANCE	($1,175,533)	($6,313,461)	($6,366,669)	($3,159,648)	($7,595,069)	($17,378,881)	($21,847,550)
MONTHLY INTEREST (Income)/Expense allowed rate of return of 6.99%	($6,847)	($36,776)	($37,086)	($18,405)	($44,241)	($101,232)	($127,262)
INTEREST ACCUMULATED, (Income)/Expense	($6,847)	($43,623)	($80,709)	($99,114)	($143,355)	($244,587)	($371,849)

8. Wholesale Gas Pricing Assumptions

Item 8

A Comparison of the Forecasted Cost of Gas as represented by the NYMEX
June 2020 Filing versus June 2019 Filing

($/Mbtu)

		June '20 Filing Nymex - 5/7/2020	June '19 Filing Nymex - 5/09/19	Difference	Percentage Difference
2020	**May**	$1.794	$2.566	($0.772)	-30.1%
	June	$1.894	$2.595	($0.701)	-27.0%
	July	$2.127	$2.631	($0.504)	-19.2%
	August	$2.202	$2.652	($0.450)	-17.0%
	September	$2.256	$2.650	($0.394)	-14.9%
	October	$2.342	$2.681	($0.339)	-12.6%
	November	$2.572	$2.755	($0.183)	-6.6%
	December	$2.893	$2.919	($0.026)	-0.9%
2021	**January**	$3.031	$3.007	$0.024	0.8%
	February	$2.991	$2.963	$0.028	0.9%
	March	$2.854	$2.838	$0.016	0.6%
	April	$2.559	$2.590	($0.031)	-1.2%
	May	$2.526	$2.554	($0.028)	-1.1%
	June	$2.564	$2.586	($0.022)	-0.9%
	July	$2.610	$2.619	($0.009)	-0.3%
	August	$2.617	$2.627	($0.010)	-0.4%
	September	$2.597	$2.611	($0.014)	-0.5%
	Average	$2.496	$2.697	($0.201)	-7.4%

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 2019-2020.

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: 18

- No events

Rate Schedule TSG-NF (Third Party Suppliers):
Number of Customers: 146

- 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:

May 5, 2020

January 13, 2020

November 13, 2019

July 10, 2019

Matthew M. Weissman
Managing Counsel – State Regulatory

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PSEG Services Corporation

VIA ELECTRONIC MAIL

May 5, 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 – FIRST 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 March 31, 2020.

As shown on the attached schedules, hedging for the 2019/2020 winter season is at 96% of plan and 98% of the plan has been completed for 2020 summer. Hedging for the 2020/2021 winter season is at 63% and 33% of the plan has been completed for 2021 summer. All of these periods are based on a plan of approximately 70bcf with an even split between winter and summer.

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

Very truly yours,

Matthew Weissman

Matthew M. Weissman

Attachment

C Stefanie A. Brand
Kevin Moss

PSE&G Residential Hedging Report November 2019 - October 2020 As of 3/31/2020	Bcf Target*	Bcf Hedged	% Hedged Target		% Hedged Actual	Current Price/ MMBtu
WINTER - Nov 19-Mar 20 Hedge Volume						
(230,000/ day) (152 days)						
Non-Discretionary Volume	17.500	**17.480**	94%	100%	100%	**$2.45**
Dollar Budget Method	17.500	**15.975**	$2.175M/mo.		91%	**$2.42**
Total Winter Hedge Volume	35.000	**33.455**			96%	**$2.44**
			Actual Nymex Settles			**$2.18**
SUMMER - Apr 20-Oct 20 Hedge Volume						
(160,000/ day) (214 days)						
Non-Discretionary Volume	17.500	**17.120**	94%	100%	98%	**$1.89**
Dollar Budget Method	17.500	**17.334**	$1.95M/mo.		99%	**$1.91**
Total Summer Hedge Volume	35.000	**34.454**			98%	**$1.90**
			3/27/20 Nymex Settles			**$1.85**
Total Non-Discretionary Method	35.000	**34.600**				**$2.17**
Total Dollar Budget Method	35.000	**33.309**				**$2.15**
					Difference	**($0.02)**
					Percent	**-0.9%**

PSE&G Residential Hedging Report November 2020 - October 2021 As of 3/31/2020	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	**11.325**	56%	61%	65%	**$2.25**
Dollar Budget Method	17.500	**10.781**	$2.228M/mo.		62%	**$2.24**
Total Winter Hedge Volume	35.000	**22.106**			63%	**$2.24**
			3/27/20 Nymex Settles			**$2.56**
SUMMER - Apr 21-Oct 21 Hedge Volume (160,000/ day) (214 days)						
Non-Discretionary Volume	17.500	**5.350**	28%	31%	33%	**$1.81**
Dollar Budget Method	17.500	**6.078**	$1.856M/mo.		35%	**$1.82**
Total Summer Hedge Volume	35.000	**11.428**			33%	**$1.82**
			3/27/20 Nymex Settles			**$2.35**
Total Non-Discretionary Method	35.000	**16.675**				**$2.11**
Total Dollar Budget Method	35.000	**16.859**				**$2.09**
					Difference	**($0.02)**
					Percent	**-0.7%**

Matthew M. Weissman
General State Regulatory Counsel

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VIA ELECTRONIC MAIL

January 13, 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 – FOURTH QUARTER 2019

Dear Director Peterson:

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

As shown on the attached schedules, hedging for the 2019/2020 winter season is at 96% of plan and 82% of the plan has been completed for 2020 summer. Hedging for the 2020/2021 winter season is at 46% and 18% of the plan has been completed for 2021 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 in deciding when to implement hedges, and keep the Board appraised of any changes it anticipates in the program.

Very truly yours,

Matthew Weissman

Matthew M. Weissman

Attachment

C Stefanie A. Brand
Kevin Moss

PSE&G Residential Hedging Report November 2019 - October 2020 As of Dec 31, 2019	Bcf Target*	Bcf Hedged	% Hedged Target		% Hedged Actual	Current Price/ MMBtu
WINTER - Nov 19-Mar 20 Hedge Volume						
(230,000/ day) (152 days)						
Non-Discretionary Volume	17.500	**17.480**	94%	100%	100%	**$2.45**
Dollar Budget Method	17.500	**15.975**	$2.175M/mo.		91%	**$2.42**
Total Winter Hedge Volume	35.000	**33.455**			96%	**$2.44**
			Actual & 12/31/19 Nymex Settles			**$2.31**
SUMMER - Apr 20-Oct 20 Hedge Volume						
(160,000/ day) (214 days)						
Non-Discretionary Volume	17.500	**13.910**	78%	83%	79%	**$1.96**
Dollar Budget Method	17.500	**14.830**	$1.95M/mo.		85%	**$1.95**
Total Summer Hedge Volume	35.000	**28.740**			82%	**$1.95**
			12/31/2019 Nymex Settles			**$2.27**
Total Non-Discretionary Method	35.000	**31.390**				**$2.23**
Total Dollar Budget Method	35.000	**30.805**				**$2.19**
					Difference	**($0.04)**
					Percent	**-1.7%**

PSE&G Residential Hedging Report November 2020 - October 2021 As of Dec 31, 2019	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	**8.305**	39%	44%	47%	**$2.29**
Dollar Budget Method	17.500	**7.626**	$2.228M/mo.		44%	**$2.30**
Total Winter Hedge Volume	35.000	**15.931**			46%	**$2.30**
			12/31/2019 Nymex Settles			**$2.60**
SUMMER - Apr 21-Oct 21 Hedge Volume (160,000/ day) (214 days)						
Non-Discretionary Volume	17.500	**3.210**	11%	17%	18%	**$1.83**
Dollar Budget Method	17.500	**3.017**	$1.856M/mo.		17%	**$1.83**
Total Summer Hedge Volume	35.000	**6.227**			18%	**$1.83**
			12/31/2019 Nymex Settles			**$2.31**
Total Non-Discretionary Method	35.000	**11.515**				**$2.16**
Total Dollar Budget Method	35.000	**10.643**				**$2.17**
					Difference	**$0.01**
					Percent	**0.4%**

Matthew M. Weissman
General State Regulatory Counsel

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November 13, 2019

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

VIA ELECTRONIC MAIL

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

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

Dear Director Peterson:

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

As shown on the attached schedules, hedging for the 2019/2020 winter season is at 91% of plan and 67% of the plan has been completed for 2020 summer. Hedging for the 2020/2021 winter season is at 26% and we have not begun to hedge for the 2021 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
Kevin Moss

PSE&G Residential Hedging Report November 2019 - October 2020 As of Sept. 30, 2019	Bcf Target*	Bcf Hedged	% Hedged Target		% Hedged Actual	Current Price/ MMBtu
WINTER - Nov 19-Mar 20 Hedge Volume						
(230,000/ day) (151 days)						
Non-Discretionary Volume	17.500	**16.720**	89%	94%	96%	**$2.47**
Dollar Budget Method	17.500	**14.972**	$2.175M/mo.		86%	**$2.44**
Total Winter Hedge Volume	35.000	**31.692**			91%	**$2.46**
			09/30/19 Actual Nymex settles			**$2.57**
SUMMER - Apr 20-Oct 20 Hedge Volume						
(160,000/ day) (214 days)						
Non-Discretionary Volume	17.500	**11.770**	61%	67%	67%	**$1.99**
Dollar Budget Method	17.500	**11.642**	$1.95M/mo.		67%	**$1.98**
Total Summer Hedge Volume	35.000	**23.412**			67%	**$1.99**
			09/30/19 Actual Nymex settles			**$2.34**
Total Non-Discretionary Method	35.000	**28.490**				**$2.27**
Total Dollar Budget Method	35.000	**26.614**				**$2.24**
					Difference	**($0.03)**
					Percent	**-1.2%**

PSE&G Residential Hedging Report November 2020 - October 2021 As of Sept. 30, 2019	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	**4.530**	22%	28%	26%	**$2.35**
Dollar Budget Method	17.500	**4.651**	$2.228M/mo.		27%	**$2.35**
Total Winter Hedge Volume	35.000	**9.181**			26%	**$2.35**
			09/30/19 Actual Nymex settles			**$2.62**
SUMMER - Apr 21-Oct 21 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!**
			Current Nymex prices			
Total Non-Discretionary Method	35.000	**4.530**				**$2.35**
Total Dollar Budget Method	35.000	**4.651**				**$2.35**
					Difference	**$0.00**
					Percent	**0.2%**

Matthew M. Weissman
General State Regulatory Counsel

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

July 10, 2019

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

VIA ELECTRONIC MAIL

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

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

Dear Director Peterson:

Enclosed please find Public Service Electric and Gas Company's ("Public Service" or the "Company") quarterly status report which is filed pursuant to the Board's March 30, 2001 Decision and Order in the above-referenced matter. This quarterly report identifies the Company's outstanding hedging positions as of June 28, 2019.

As shown on the attached schedules, hedging for the 2019/2020 winter season is at 76% of plan and 49% of the plan has been completed for 2020 summer. Hedging for the 2020/2021 winter season is at 12% and we have not begun to hedge for the 2021 summer. All of these periods are based on a plan of approximately 70bcf with an even split between winter and summer.

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

Very truly yours,

Matthew Weissman

Matthew M. Weissman

Attachment

C Stefanie A. Brand
Kevin Moss

PSE&G Residential Hedging Report November 2019 - October 2020 As of June 28, 2019	Bcf Target*	Bcf Hedged	% Hedged Target		% Hedged Actual	Current Price/ MMBtu
WINTER - Nov 19-Mar 20 Hedge Volume (230,000/ day) (151 days)						
Non-Discretionary Volume	17.500	**14.440**	72%	78%	83%	**$2.50**
Dollar Budget Method	17.500	**12.084**	$2.175M/mo.		69%	**$2.50**
Total Winter Hedge Volume	35.000	**26.524**			76%	**$2.50**
			6/28/19 Nymex Settle prices			**$2.60**
SUMMER - Apr 20-Oct 20 Hedge Volume (160,000/ day) (214 days)						
Non-Discretionary Volume	17.500	**8.560**	44%	50%	49%	**$2.03**
Dollar Budget Method	17.500	**8.603**	$1.95M/mo.		49%	**$2.01**
Total Summer Hedge Volume	35.000	**17.163**			49%	**$2.02**
			6/28/19 Nymex Settle prices			**$2.45**
Total Non-Discretionary Method	35.000	**23.000**				**$2.32**
Total Dollar Budget Method	35.000	**20.687**				**$2.30**
					Difference	**($0.03)**
					Percent	**-1.2%**

PSE&G Residential Hedging Report November 2020 - October 2021 As of June 28, 2019	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	**2.265**	6%	11%	13%	**$2.42**
Dollar Budget Method	17.500	**1.827**	$2.228M/mo.		10%	**$2.43**
Total Winter Hedge Volume	35.000	**4.092**			12%	**$2.42**
			6/28/19 Nymex Settle prices			**$2.73**
SUMMER - Apr 21-Oct 21 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!**
			Current Nymex prices			
Total Non-Discretionary Method	35.000	**2.265**				**$2.42**
Total Dollar Budget Method	35.000	**1.827**				**$2.43**
					Difference	**$0.01**
					Percent	**0.3%**

12. Storage Gas Volumes, Prices and Utilization

Ending Storage Inventory by Contract

Mdth

Storage Contract	Oct-19	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20
DTI GSS	**16,208.5**	**15,598.5**	**14,385.1**	**12,966.5**	**10,811.5**	**8,058.5**	**7,332.7**
ARLINGTON	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
TR GSS	**15,724.9**	**14,791.8**	**12,802.0**	**10,115.9**	**7,548.8**	**5,276.5**	**5,264.1**
TR S-2	**6,133.4**	**5,594.6**	**4,286.9**	**2,648.4**	**1,454.6**	**1,126.0**	**1,195.4**
TR LSS	**4,950.4**	**4,717.3**	**3,864.1**	**2,621.4**	**1,863.5**	**1,536.0**	**1,780.1**
TENN FS-MA	**4,389.7**	**4,016.6**	**3,708.7**	**3,357.1**	**3,304.8**	**3,404.6**	**2,853.3**
DTI GSS-TE	**14,097.5**	**13,588.4**	**12,604.3**	**10,543.1**	**8,617.4**	**7,473.9**	**5,022.6**
TE SS-1 / SS	**3,681.5**	**3,571.6**	**3,036.8**	**2,376.2**	**1,661.8**	**1,402.3**	**1,105.5**
TE SS1	**1,448.0**	**1,394.0**	**1,191.3**	**987.3**	**754.9**	**664.0**	**544.5**
TR ESS	**1,186.5**	**1,186.5**	**1,186.5**	**1,186.5**	**822.9**	**822.9**	**822.9**
GULF SOUTH	**753.7**	**984.7**	**1,000.0**	**941.9**	**402.8**	**68.1**	**456.0**
TR LNG	**1,333.8**	**1,333.8**	**1,333.8**	**1,333.8**	**1,333.8**	**1,333.8**	**1,333.8**
TR LNG New	**15.5**	**15.5**	**15.5**	**15.5**	**15.5**	**15.5**	**15.5**
Total	**69,923.3**	**66,793.4**	**59,415.1**	**49,093.7**	**38,592.3**	**31,182.1**	**27,726.5**
Ending Inventory Cost ($/Dth)	**$4.15**	**$4.03**	**$3.87**	**$3.84**	**$3.91**	**$4.14**	**$4.02**

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-17	46	$528	91	$836	78	$781	62	$531
Feb-17	46	$528	91	$836	78	$781	62	$531
Mar-17	46	$528	85	$780	70	$694	62	$531
Apr-17	46	$528	92	$835	70	$694	55	$476
May-17	46	$528	92	$835	76	$748	49	$422
Jun-17	46	$528	92	$835	76	$748	49	$422
Jul-17	46	$528	92	$835	76	$748	49	$422
Aug-17	46	$528	92	$835	76	$748	49	$422
Sep-17	46	$528	92	$835	76	$748	60	$550
Oct-17	46	$528	92	$835	76	$748	60	$549
Nov-17	46	$528	92	$835	76	$748	60	$549
Dec-17	46	$521	91	$828	73	$725	60	$544
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

LPG INVENTORY VOLUMES AND COST BY LOCATION
(000)

	Camden		Central		Harrison		Linden	
Month	**Dth**	**Dollars**	**Dth**	**Dollars**	**Dth**	**Dollars**	**Dth**	**Dollars**
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
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 est	45	$493	55	$523	55	$631	64	$592
May-20 est	45	$493	55	$523	55	$631	64	$592
Jun-20 est	45	$493	55	$523	55	$631	64	$592
Jul-20 est	45	$493	55	$523	55	$631	64	$592
Aug-20 est	45	$493	55	$523	55	$631	64	$592
Sep-20 est	45	$493	55	$523	55	$631	64	$592
Oct-20 est	45	$493	55	$523	55	$631	64	$592
Nov-20 est	45	$493	55	$523	55	$631	64	$592
Dec-20 est	45	$493	55	$523	55	$631	64	$592

LNG INVENTORY VOLUMES AND COST
(000)

Month	Dth	Dollars	Month	Dth	Dollars
Jan-17	355	$328	Jan-19	282	$152
Feb-17	177	$163	Feb-19	262	$141
Mar-17	179	$168	Mar-19	237	$128
Apr-17	160	$150	Apr-19	228	$123
May-17	200	$195	May-19	221	$119
Jun-17	190	$187	Jun-19	263	$115
Jul-17	184	$180	Jul-19	257	$168
Aug-17	177	$174	Aug-19	250	$164
Sep-17	171	$167	Sep-19	244	$159
Oct-17	151	$148	Oct-19	234	$153
Nov-17	203	$213	Nov-19	267	$199
Dec-17	165	$174	Dec-19	303	$242
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 est	220	$176
May-18	181	$190	May-20 est	220	$176
Jun-18	174	$182	Jun-20 est	220	$176
Jul-18	167	$175	Jul-20 est	220	$176
Aug-18	161	$169	Aug-20 est	220	$176
Sep-18	155	$162	Sep-20 est	220	$176
Oct-18	144	$151	Oct-20 est	220	$176
Nov-18	135	$142	Nov-20 est	220	$176
Dec-18	154	$162	Dec-20 est	220	$176

13. Affiliate Gas Supply Transactions

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 2017 - September 2018)

	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Total
Gas Supplies (MDTh)													
Beginning Inventory	69,032	76,094	71,634	61,028	49,251	39,341	24,392	22,908	31,692	39,547	48,502	57,467	
Natural Gas Receipt	13,910	16,355	24,624	28,007	15,893	14,558	16,202	14,556	12,456	12,824	12,832	12,977	195,194
	-------------	-------------	-------------	-------------	-------------	-------------	-------------	-------------	-------------	-------------	-------------	-------------	
Total Inventory Available	82,942	92,449	96,258	89,036	65,144	53,899	40,594	37,464	44,148	52,371	61,335	70,444	
Gas Demand (MDTh)													
Firm Sendout	6,848	20,815	35,229	39,785	25,803	29,507	17,686	5,771	4,602	3,869	3,868	4,205	197,988
	-------------	-------------	-------------	-------------	-------------	-------------	-------------	-------------	-------------	-------------	-------------	-------------	
Ending Inventory MDTh	76,094	71,634	61,028	49,251	39,341	24,392	22,908	31,692	39,547	48,502	57,467	66,239	

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

	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Total
Gas Supplies (MDTh)													
Beginning Inventory	66,239	74,400	71,559	65,575	47,973	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	33,646	35,716	43,364	52,182	60,601	
Natural Gas Receipt	14,427	23,028	25,783	20,785	15,935	12,091	13,271	13,567	12,934	12,744	12,244	12,244	189,053
	-------------	-------------	-------------	-------------	-------------	-------------	-------------	-------------	-------------	-------------	-------------	-------------	
Total Inventory Available	84,375	99,525	100,418	88,410	71,907	55,330	48,006	47,213	48,650	56,108	64,426	72,845	
Gas Demand (MDTh)													
Firm Sendout	7,878	24,890	32,793	32,438	28,668	20,595	14,360	11,497	5,286	3,926	3,825	4,155	190,312
	-------------	-------------	-------------	-------------	-------------	-------------	-------------	-------------	-------------	-------------	-------------	-------------	
Ending Inventory MDTh	76,497	74,635	67,625	55,972	43,239	34,735	33,646	35,716	43,364	52,182	60,601	68,690	

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	68,690	71,931	72,956	61,066	41,548	27,535	19,468	19,413	26,242	37,479	46,728	55,660	
Natural Gas Receipt	12,247	21,090	19,001	19,471	19,536	18,413	15,203	14,033	16,592	13,324	12,835	13,630	195,375
Total Inventory Available	80,937	93,022	91,957	80,537	61,084	45,948	34,671	33,446	42,833	50,803	59,563	69,290	
Gas Demand (MDTh)													
Firm Sendout	9,006	20,066	30,891	38,989	33,549	26,480	15,258	7,204	5,355	4,075	3,903	4,191	198,966
Ending Inventory MDTh	71,931	72,956	61,066	41,548	27,535	19,468	19,413	26,242	37,479	46,728	55,660	65,099	

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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	**65,099**	70,938	66,232	48,853	29,197	15,026	6,926	8,530	17,334	30,518	41,433	52,103	
Natural Gas Receipt	15,037	16,070	13,619	19,613	19,703	18,594	17,039	15,899	18,565	15,033	14,565	15,349	199,086
Total Inventory Available	80,136	87,007	79,850	68,466	48,901	33,620	23,964	24,429	35,899	45,552	55,998	67,452	
Gas Demand (MDTh)													
Firm Sendout	9,198	20,776	30,997	39,268	33,874	26,695	15,435	7,095	5,381	4,119	3,895	4,171	200,903
Ending Inventory MDTh	70,938	66,232	48,853	29,197	15,026	6,926	8,530	17,334	30,518	41,433	52,103	63,282	

15. Actual Peak Day Supply and Demand

Actual Peak Day Supply and Demand - Item 15

		NEWARK AVG.	LOAD (000 DTh)			SUPPLY SOURCES (000 DTh)		
						NATURAL GAS		LPA / REFINERY
	DATE	TEMP (F)	TOTAL	FIRM	INTERR.	HLF TRANSP.	STORAGE / LNG	
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
	20-Jan-19	18.0	2357	2107	250	1754	603	0
2017 / 2018 WINTER								
	6-Jan-18	8.8	2604	2556	48	1656	922	26
	31-Dec-17	11.1	2596	2424	173	1791	805	0
	5-Jan-18	11.9	2527	2499	28	1734	779	14
	1-Jan-18	15.7	2505	2350	155	1851	654	0

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

Including Gas Sales Forecast Support

May-20

PEAK DAY GAS REQUIREMENTS AND SUPPLY
(MDTh)

	SUPPLY		2020-2021	2021-2022	2022-2023	2023-2024	2024-2025
	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		49.6	49.6	49.6	49.6	49.6
	Columbia		12.5	12.5	12.5	12.5	12.5
	Subtotal		242.8	242.8	242.8	242.8	242.8
	Transco/Tetco FT (Leidy)		330.5	330.5	330.5	330.5	330.5
	Columbia (Hanover)		18.8	18.8	18.8	18.8	18.8
	Algonquin		15.0	15.0	15.0	15.0	15.0
	Total Firm FT Supply		1,428.7	1,428.7	1,428.7	1,428.7	1,428.7
	Storage		896.6	896.6	896.6	896.6	896.6
	Transco Peaking		13.2	13.2	13.2	13.2	13.2
	Transco LGA		275.4	275.4	275.4	275.4	275.4
	PSEG Burlington LNG		67.0	67.0	67.0	67.0	67.0
	LPA		196.3	196.3	196.3	196.3	196.3
	Total Peaking Supply		551.9	551.9	551.9	551.9	551.9
	PSEG Firm Supply Subtotal		2,877.2	2,877.2	2,877.2	2,877.2	2,877.2
	FTS DCQ 1./		299.8	300.8	304.9	305.9	306.0
[a]	Total PSEG Gas Supply		3,177.0	3,178.0	3,182.1	3,183.1	3,183.3
	Peak Day Sendout Forecast 2./		2,981.0	2,997.0	3,037.0	3,060.0	3,088.0
[b]	Total Peak Day Capacity Requirements	3./	3,142.0	3,158.8	3,201.0	3,225.2	3,254.8
[a]-[b]	Surplus / (Deficiency)	3./	35.0	19.2	(18.9)	(42.2)	(71.5)

1./ Forecasted FT-S DCQ (January)
2./ Based on Corporate Energy Forecast, Gas -2020
3./ 3% Loss of Load Probability

Item 16

Natural Gas Sales Forecast - 2020

Public Service Electric & Gas Company

Finance Department

Electric and Gas Sales and Revenue Forecasting Group

May 2020

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 2020 gas sales forecast. The first section describes the econometric sales models. A discussion of the forecast assumptions used to develop the sales forecast follows. Section III describes the maximum daily send-out projection. An appendix contains more detailed information on the billing period to calendar month conversion, and forecast tables.

I Model Specification and Estimation

Residential Model

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

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

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

where:

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

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

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

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

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

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

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

where:

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

The models were estimated using monthly data from 2006 to June 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

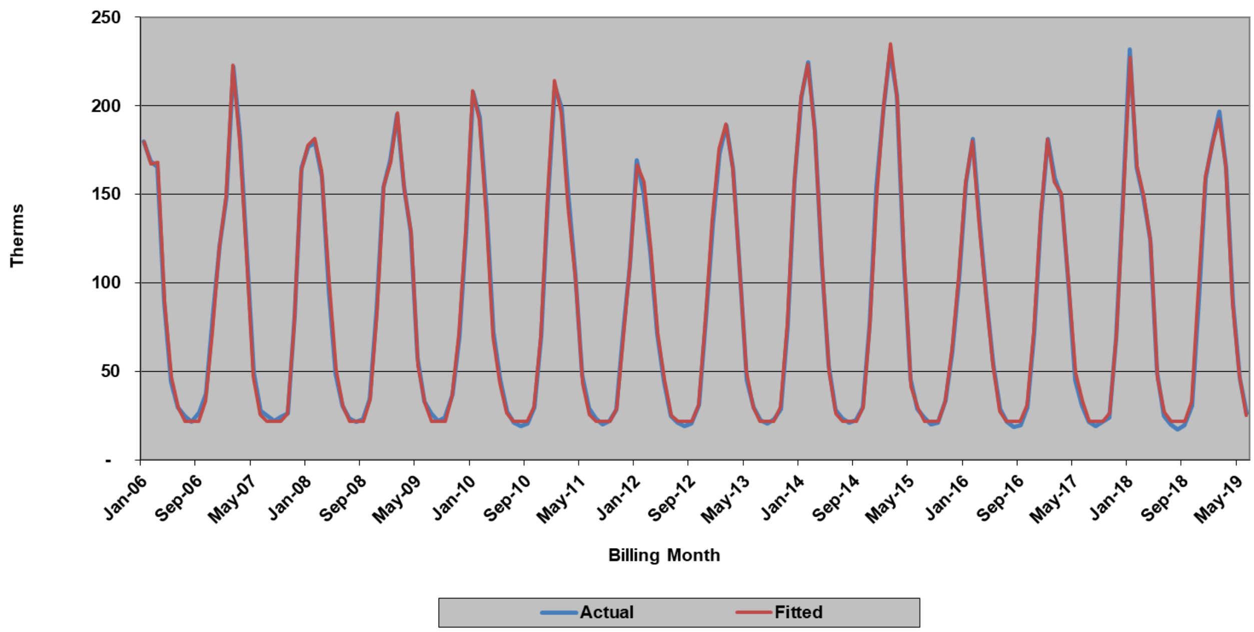
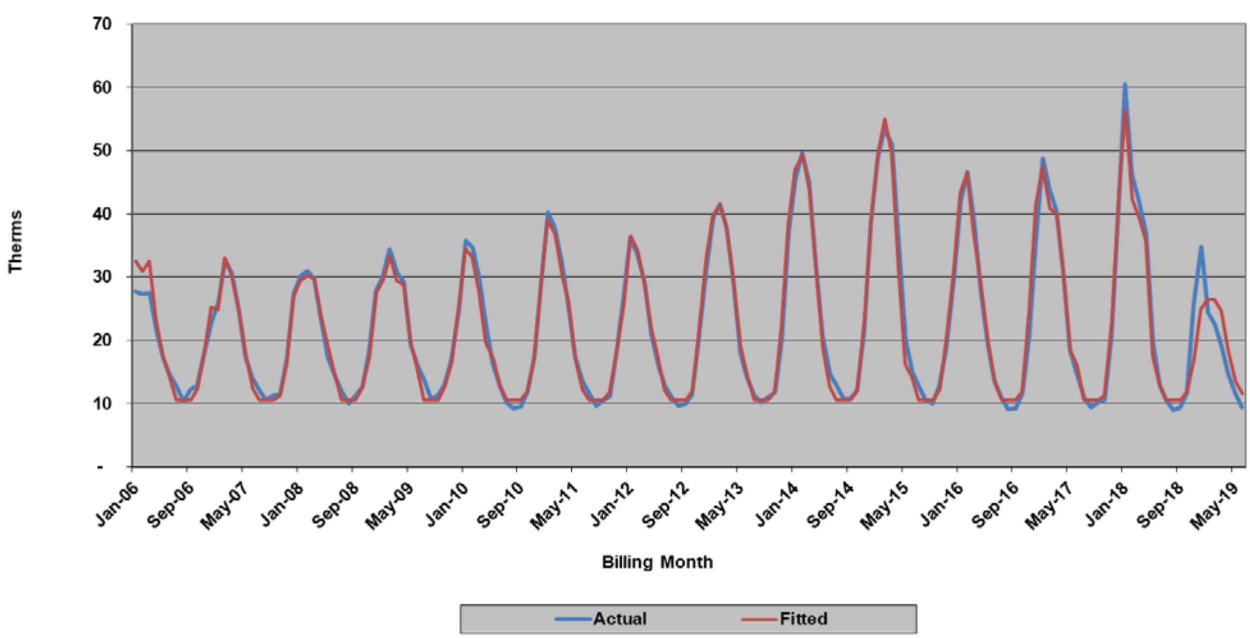


Figure 2
RSG Non-Space Heating Model
Actual vs. Fitted Values



The price elasticity estimates were estimated to be -0.0152 and -0.23 for space heating and non-space heating customers, respectively and consistent with lower gas prices and the lack of a surge in consumption in response to them. The non-space heating elasticity is the result of a similar therm impact of price but, measured over a much smaller base usage. Income was found to have an effect on gas consumption by space heating customers in the fall. This is consistent with income changes resulting affecting when space heating equipment is turned on. The economic downturn appeared to result in a delay in turning on this equipment in the fall reducing use.

Table 1

Estimated Coefficients of the Residential Models

(standard errors in parentheses)

	JAN	FEB	MAR	APR	MAY	JUNE	OCT	NOV	DEC	R2	DW	n
HEATING												
HDD	0.20521	0.20454	0.20253	0.19727	0.14541	0.16118			0.14414	0.999	1.325	150
	(0.007)	(0.007)	(0.007)	(0.010)	(0.007)	(0.021)			(0.023)			
		FEB -MAR	**APR-MAY**									
PRICE x HDD		-0.00506	-0.00724									
		(0.002)	(0.004)									
WAGE x HDD							0.00133	0.00204	0.00036			
							(0.00012)	(0.00003)	(0.00033)			
I-POWER	-0.00730											
	(0.00126)											
RSG-TRAN	-0.00089											
	(0.00172)											
	JAN	**FEB**	**MAR**	**APR**	**MAY**	**JUNE**	**OCT**	**NOV**	**DEC**	**R2**	**DW**	**n**
NON-HEATING												
HDD	0.05833	0.05585	0.05522	0.05578	0.03841	0.07661	0.01398	0.05829	0.06120	0.974	0.989	150
	(0.002)	(0.002)	(0.003)	(0.004)	(0.003)	(0.016)	(0.007)	(0.006)	(0.003)			
PRICE x HDD	-0.01960	-0.01800	-0.01664	-0.01531				-0.02253	-0.02129			
	(0.002)	(0.002)	(0.002)	(0.003)				(0.002)	(0.003)			
RSG-TRAN	-0.02373											
	(0.00125)											

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

Commercial

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

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

where:

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

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

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

Substituting [4] into [3] yields:

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

LVG model was estimated for customers in the commercial sector using monthly billing data from 2005 to June 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 2011 to June 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,
$\overline{\text{MONTH}}$	= 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 -0.25 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

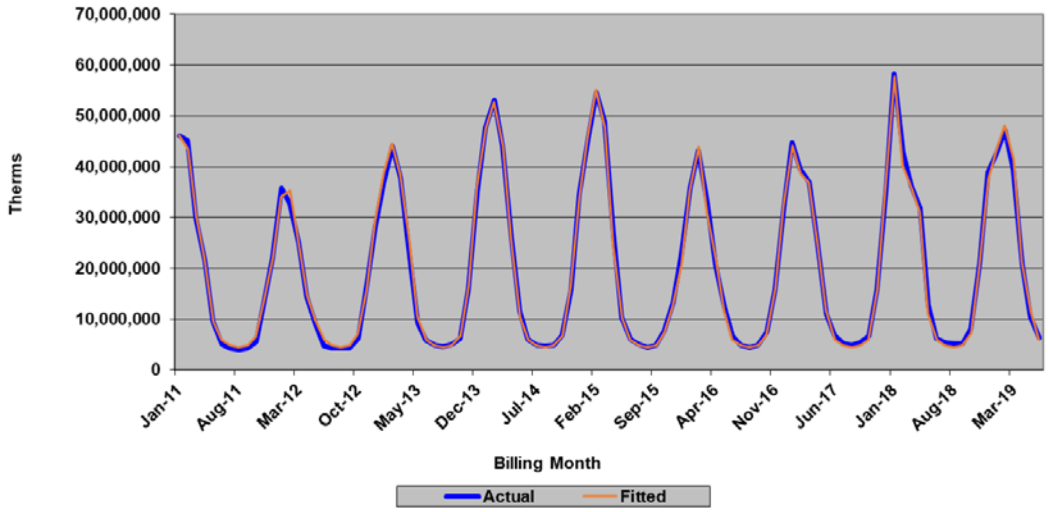


Figure 4

GSG Commercial Non-Space Heating Model

Actual vs. Fitted Values

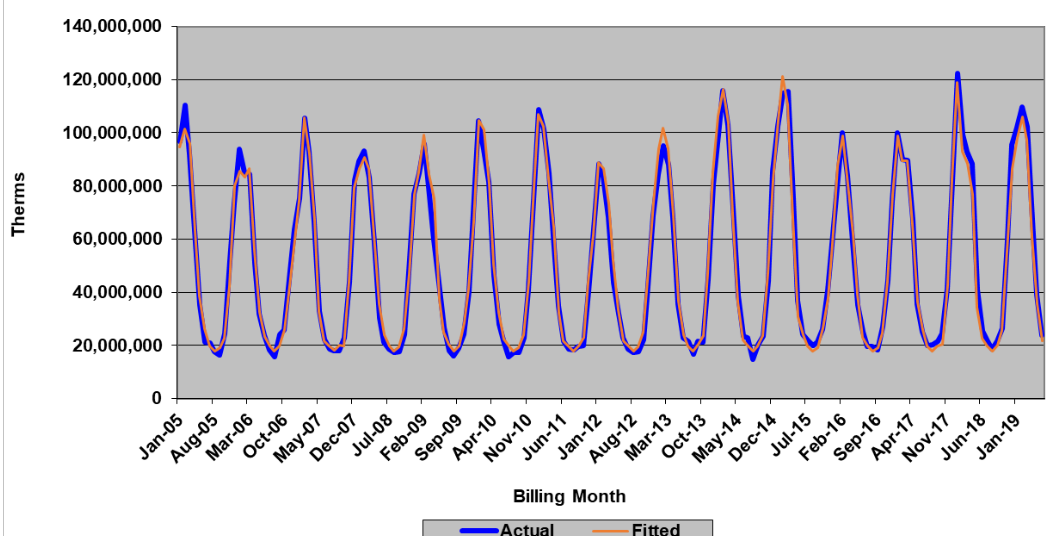


Figure 5
LVG Commercial Model
Actual vs. Fitted Values

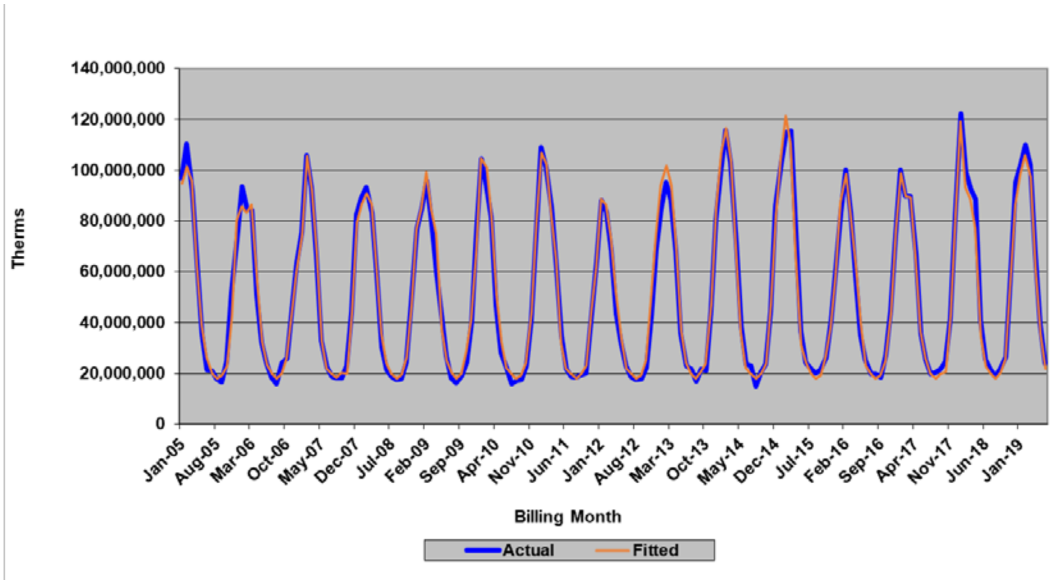


Table 2

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

	JAN	FEB	MAR	APR	MAY	JUN	SEP	OCT	NOV	DEC	R2	DW	n
HEATING													
PRICE x HDD	-13885	-11112	-12199	-13024	-29054				-19793	-12144	0.997	1.509	102
	(2,569)	(2,825)	(3,377)	(5,238)	(17,217)				(7,123)	(4,104)			
CUST x HDD	22.74	18.08	19.18	20.20	9.48			5.96	16.00	18.11			
	(1.33)	(1.37)	(1.18)	(1.78)	(4.25)			(5.21)	(2.81)	(1.23)			
NON-HEATING													
HDD	3831	3959	3974	4027	3961	4231		874	2550	3626	0.985	1.475	102
	(76)	(78)	(93)	(149)	(371)	(1,798)		(786)	(200)	(107)			

Table 3

Estimated Coefficients of the LVG Commercial Gas Sales Models

(standard errors in parentheses)

HDD x PRICE	HDD x CUST	R2	DW	n
-7829.99	27.74	0.988	1.305	162
(1,819)	(1.3)			

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:

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

where:

EMP = Manufacturing employment.

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

$$\text{THERMS}_t = f(\text{HDD}_t \times \text{PRICEGAS}_{a-1}, \text{HDD}_t \times \text{EMP}_{a-1}, \text{HDD}_t) \qquad [8]$$

where:

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

The results of the OLS estimation procedure, summarized in Figures 6-8, show that the industrial models for customers in the two space heating segments fit the historical data well. GSG Heating model is estimated for using monthly billing data from 2011 to June 2019 period while Non-Heating model is estimated for using monthly billing data from 2013 to June 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 2005 to June 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 -0.06 Small response of the industrial sector to gas prices is attributed to the fact that gas, since it is not used for process heat, is a relatively small proportion of the total costs of production.

Figure 6

GSG Industrial Space Heating Model

Actual vs. Fitted Values

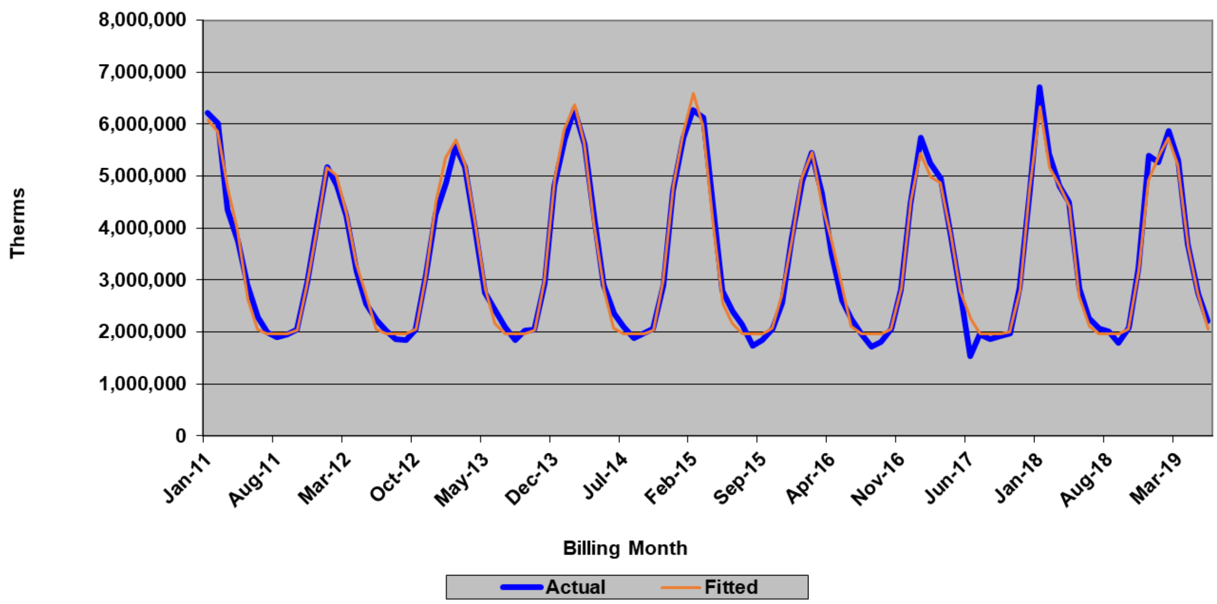


Figure 7

GSG Industrial Non-Space Heating Model

Actual vs. Fitted Values

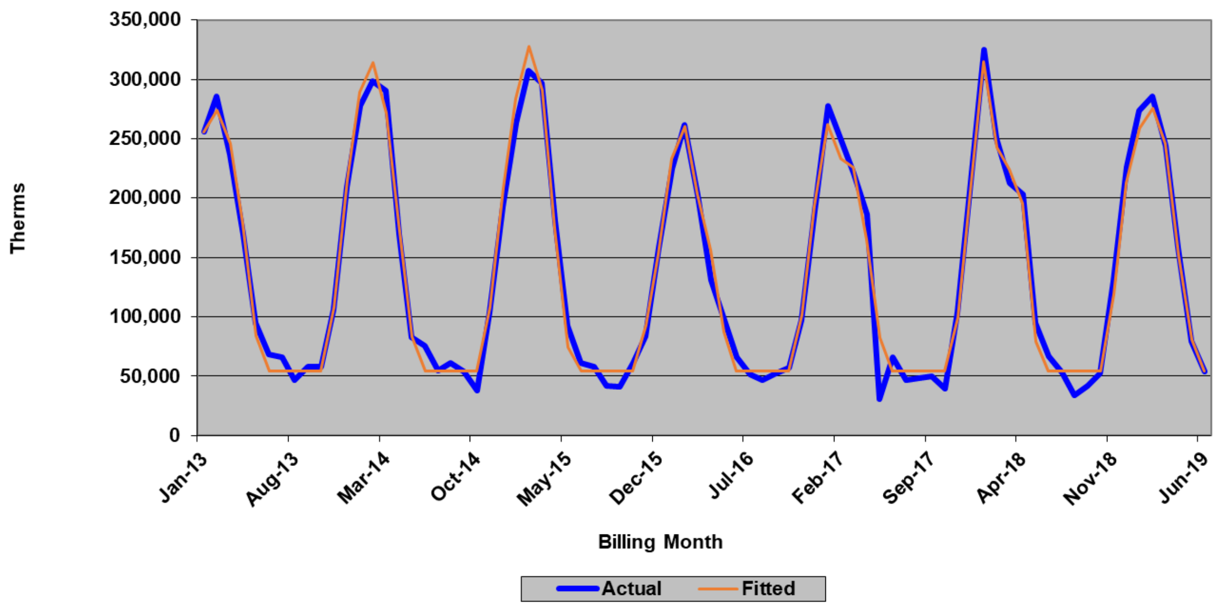


Figure 8

LVG Industrial Heating Model

Actual vs. Fitted Values

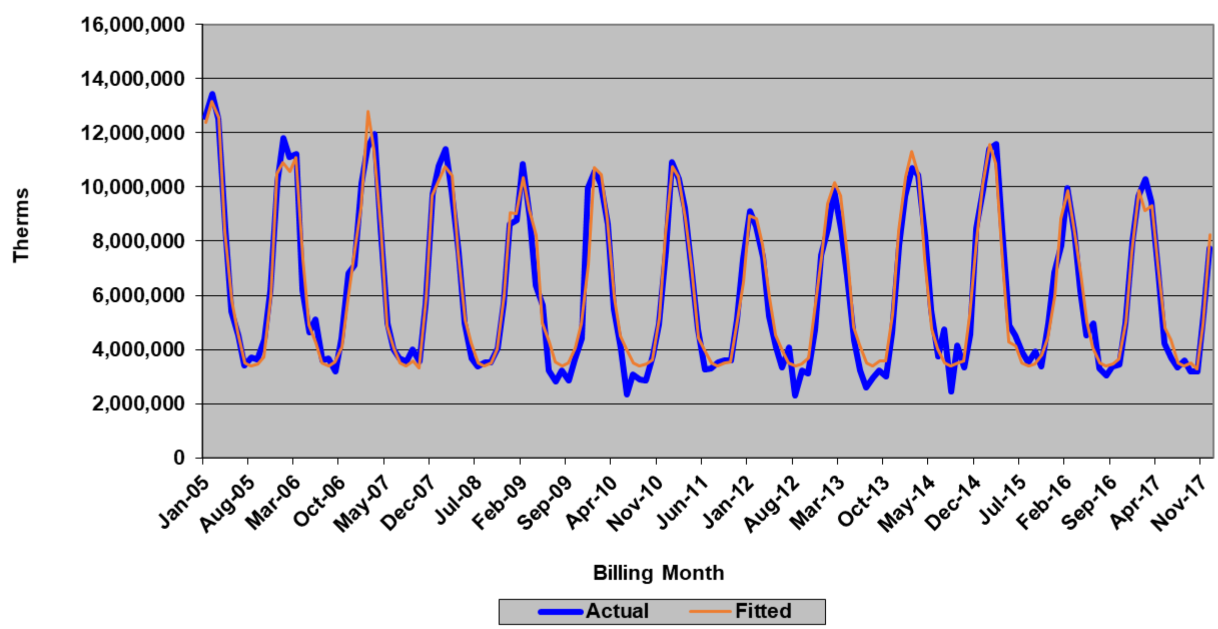


Table 4

Estimated Coefficients of the GSG Industrial Gas Sales Models

(standard errors in parentheses)

	JAN	FEB	MAR	APR	MAY	JUN	OCT	NOV	DEC	R2	DW	n
HEATING												
HDD	2588.67	1758.19	2212.78	1738.67	960.37		446.00	1165.94	2178.48	0.992	2.274	102
	(200.87)	(166.05)	(173.61)	(52.79)	(131.43)		(278.38)	(70.91)	(215.78)			
NON-HEATING												
HDD	228.74	233.63	234.77	232.64	136.33			136.30	196.12	0.982	1.993	78
	(5.70)	(5.68)	(6.65)	(10.72)	(26.79)			(15.35)	(7.82)			

Table 5

Estimated Coefficients of the LVG Industrial Gas Sales Models

(standard errors in parentheses)

HDD x PRICE	HDD x EMP	R2	DW	n
-1410.69	35.04	0.955	1.691	162
(620.33)	(3.88)			

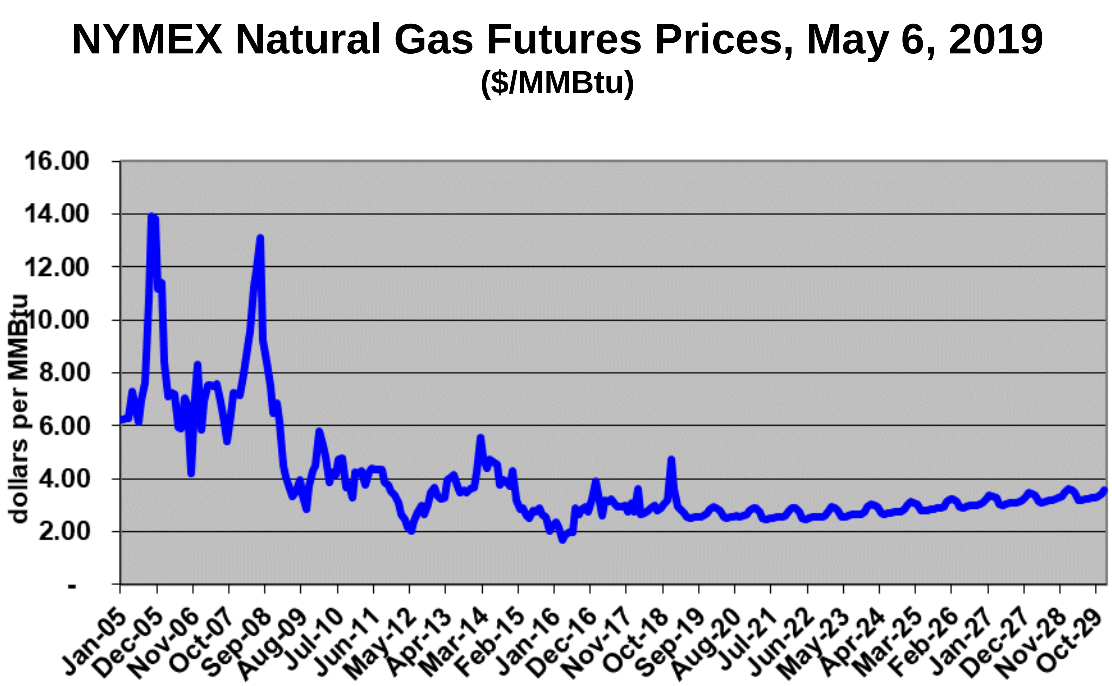
II Forecast Assumptions

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)

	RSG		Commercial			Industrial		
			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

BILLING MONTH ASUMPTIONS
(in therms)

	EMP	EE	CEF
2010	14,596,330	1,014,482	-
2011	16,831,360	1,685,403	-
2012	12,618,148	1,899,385	-
2013	16,790,499	1,912,354	-
2014	22,116,578	1,912,354	-
2015	24,589,911	1,912,354	-
2016	27,228,971	1,912,354	-
2017	29,995,086	1,912,354	-
2018	32,761,200	2,164,784	-
2019	35,527,315	2,316,230	-
2020	38,293,430	3,296,785	1,643,215
2021	41,059,544	3,451,491	7,756,646
2022	43,825,659	3,204,025	13,882,594
2023	46,591,774	2,977,359	20,909,994
2024	49,357,888	2,897,351	29,568,465
2025	52,124,003	2,897,351	39,760,945
2026	54,890,117	2,897,351	50,011,617
2027	57,656,232	2,897,351	60,262,289
2028	60,422,347	2,897,351	70,512,961
2029	63,188,461	2,795,374	80,763,633
2030	63,188,461	2,241,955	91,014,305

Economic Projections

Economic and demographic forecast assumptions for the nation and New Jersey are from Moody's Economy March 2019 forecast. This forecast assumes that, nationally, the economy continues to recover at a slow but steady rate. This national forecast is expected to be reflected in New Jersey's economic outlook that is also expected to be at a slow pace. The forecast is summarized in Table 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, 2017.

Table 8

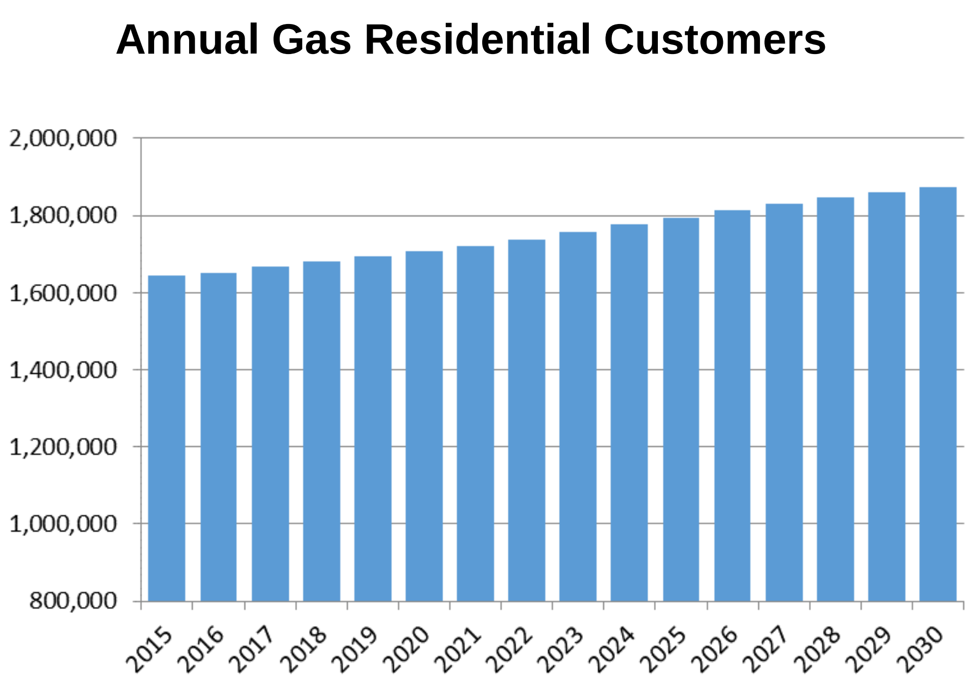
National and New Jersey Economic Forecast Assumptions

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
United States													
Gross Domestic Product, (Bil. USD, SAAR)	18,219	18,707	19,486	20,501	21,446	22,198	23,144	24,238	25,245	26,279	27,272	28,283	29,365
Industrial Production: Total, (Index 2012=100, SA)	104	102	104	108	110	112	113	115	116	118	119	121	122
Income: Personal - Total, (Bil. Ch. 2009 USD, SAAR)	15,243	15,470	15,867	16,244	16,655	17,023	17,300	17,688	18,068	18,435	18,823	19,223	19,657
Employment: Total Nonagricultural, (Mil. #, SA)	142	144	147	149	151	153	153	154	155	156	156	157	158
Household Survey: Unemployment Rate, (%, SA)	5.3	4.9	4.3	3.9	3.8	3.7	4.5	4.8	4.8	4.8	4.8	4.8	4.7
CPI: Urban Consumer - All Items, (Index 1982-84=100, SA)	237	240	245	251	255	261	267	273	279	285	292	298	305
Interest Rates: 3-Month Treasury Bills EBY, (% p.a., NSA)	0.1	0.3	0.9	2.0	2.6	3.0	3.1	2.7	2.8	3.0	3.3	3.4	3.4
Terms Conventional Mortgages: All Loans Fixed Effective Rate, (%, NSA)	4.1	3.9	4.1	4.7	5.0	5.2	5.6	6.0	6.0	6.0	6.1	6.3	6.3
New Jersey													
Real Personal Income, (Mil. 09$, SAAR)	494,898	501,737	515,554	523,498	532,526	536,235	542,204	552,986	563,055	572,737	583,273	594,271	606,014
Employment: Total Nonagricultural, (Ths., SA)	4,012	4,073	4,129	4,190	4,241	4,256	4,251	4,276	4,298	4,317	4,334	4,351	4,368
Employment: Total Manufacturing, (Ths., SA)	239	242	245	252	255	251	245	242	238	234	231	227	223
Employment: Total Non-Manufacturing, (Ths., SA)	3,773	3,831	3,884	3,938	3,986	4,005	4,006	4,034	4,060	4,082	4,103	4,124	4,144
Labor: Unemployment Rate, (%, SA)	5.8	5.0	4.6	4.3	4.1	4.4	5.4	5.7	5.7	5.7	5.6	5.6	5.5
Population: Total, (Ths.)	8,871	8,876	8,891	8,908	8,912	8,911	8,908	8,908	8,908	8,911	8,913	8,915	8,920
Households: Total, (Ths.)	3,315	3,334	3,350	3,366	3,386	3,401	3,415	3,431	3,446	3,461	3,474	3,487	3,498
Housing Starts: Single-family, (#, SAAR)	10,702	10,718	11,597	11,460	10,907	11,767	15,222	17,581	17,749	17,146	16,545	15,434	14,098

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 Newark Airport as the measuring base. Gas supplies are designed to meet the estimated maximum daily as well as maximum hourly demand. The maximum daily sendout forecast process consists of:

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

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

Daily Firm Sendout Model Estimation

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

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

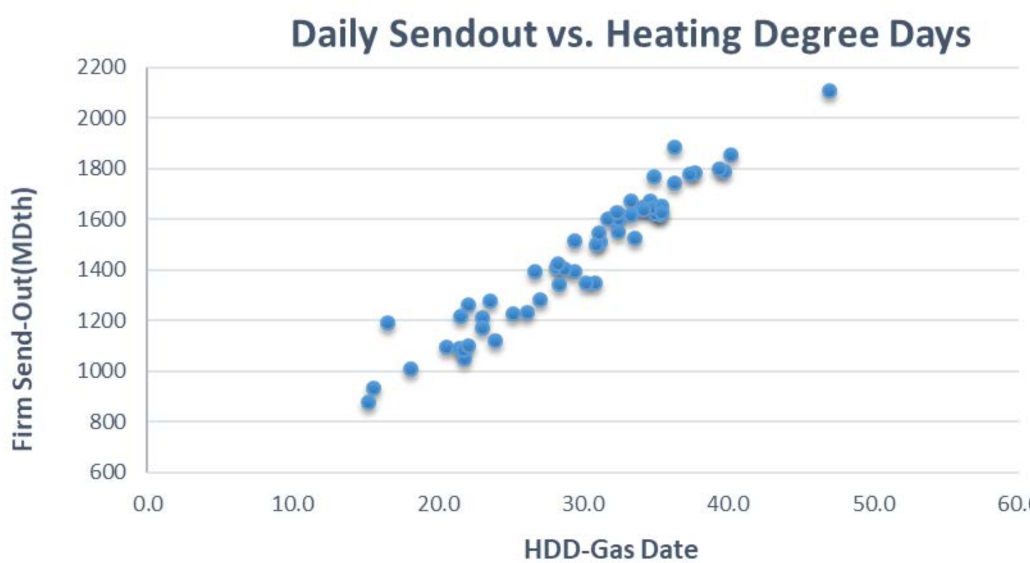
The second issue, of extrapolation, is addressed in a similar way. The relationship between sendout and weather is fairly linear. In reality, it is probably not perfectly linear. This is not an issue when estimating a model and using the results to interpolate values with the range of the estimation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

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

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

Figure 11

January & February 2019



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

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

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

Where:

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

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

Table 8

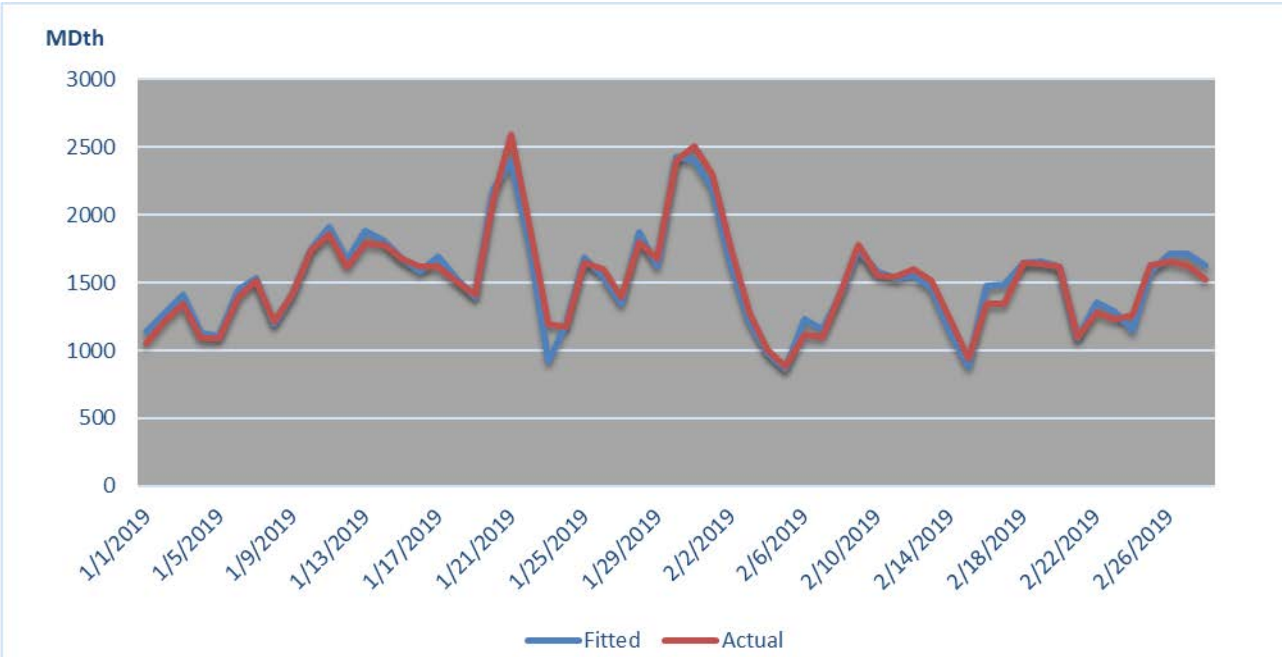
Estimated Coefficients of the Daily Sendout Model

(standard errors in parentheses)

Intercept	HDD	HOLIDAY	WEEKDAY	R2	DW	n
226.8	40.6	1.1	1.3	0.95400	1.226	59
(40.2)	(1.6)	(1.2)	(1.0)			

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 Monday. The model predicts that the maximum peak daily sendout would be 2,590 MDth.

A. Calendar-Month Sales Calculation

Introduction

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

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

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

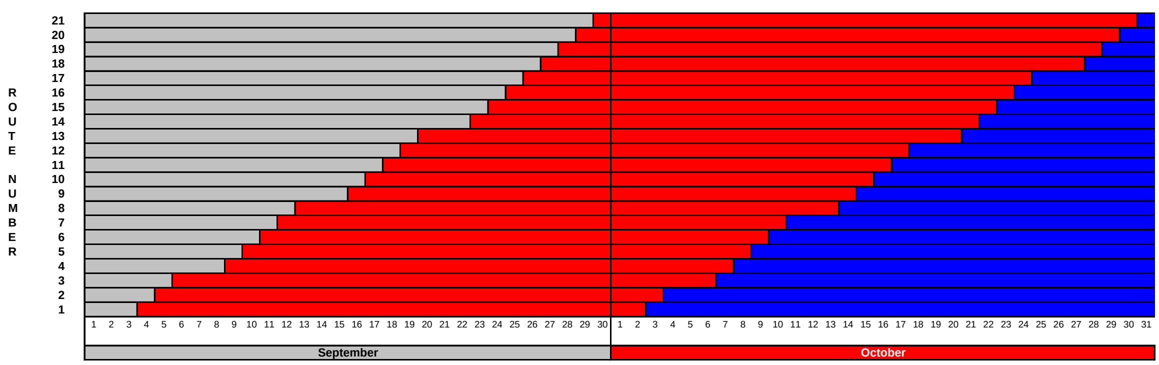
The Unbilled and Calendar-Month Estimation

A Simple Example

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

Figure 1

Hypothetical October 2008 Billing-Month



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

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

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

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

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

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

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

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

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

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

This is the familiar:

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

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

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

---

[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.

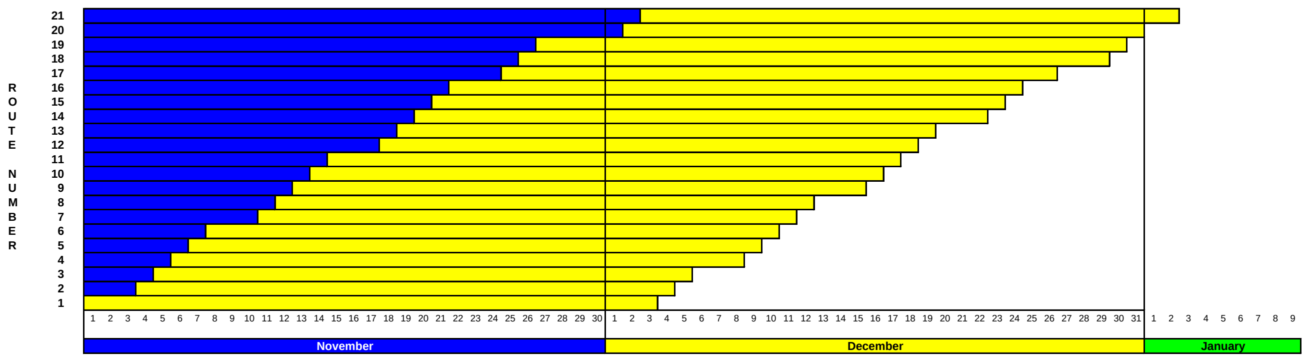
A More General Example

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:

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

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

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

December unbilled less the equivalent November unbilled or:

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

or, in words:

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

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

The PSE&G Gas Calendar-Month Estimation

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

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

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

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

Table 1

Unbilled Weather and Base Coefficients, 2008-2009

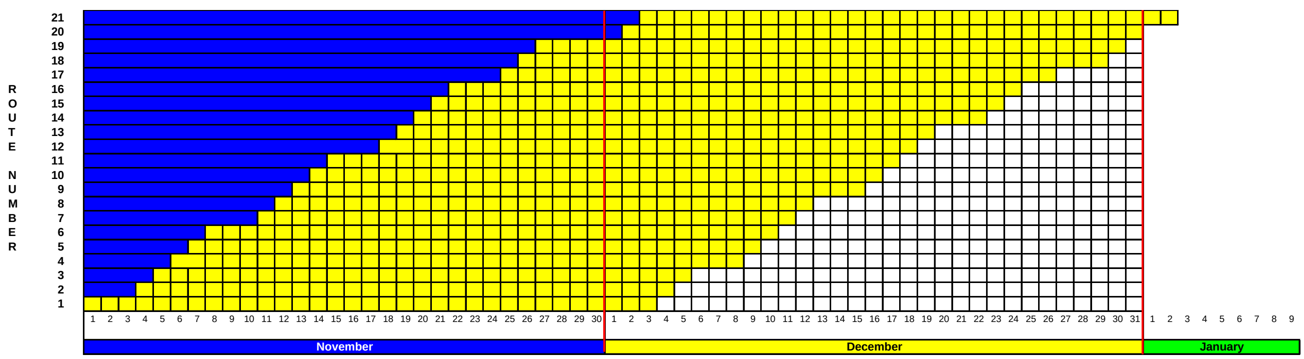
	RSG				GSG-Commercial				GSG-Industrial				LVG - Non Vehicle			
Billing	Heating		Non-heating		Heating		Non-heating		Heating		Non-heating		Commercial		Industrial	
Month	Base	HDD	Base	HDD	Base	HDD	Base	HDD	Base	HDD	Base	HDD	Base	HDD	Base	HDD
Jan-08	1,477,624	246,082	218,393	4,689	56,941	45,607	168,133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

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

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

Figure 3

PSE&G December 2008 Billing-Month



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

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

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

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

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

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

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

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

Table 2

Billed and Unbilled Days and Weather 2008-2009

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

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

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

Where:

UnbilledDays = the number of route days in the unbilled period as defined by [9],

Unbilled HDD = the number of HDD in the unbilled period as defined by [9],

BASECoef = the Base coefficient,

HDDCoef = the HDD coefficient.

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

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

B. Summary Tables

Delivered Gas Sales As Billed
2017-2027
(MDth)

Class	Rate	Category	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Residential	RSG	Heating	130,512	147,879	142,604	144,782	146,653	148,260	150,800	152,878	155,415	157,746	160,076
		Non-Heating	8,860	9,314	4,825	4,770	4,749	4,755	4,777	4,782	4,769	4,738	4,708
	Total		139,371	157,193	147,430	149,552	151,401	153,015	155,578	157,660	160,184	162,484	164,784
Commercial	GSG	Heating	22,541	25,864	23,151	23,619	23,924	23,752	24,244	24,142	24,004	23,802	23,555
		Non-Heating	3,939	4,315	4,120	4,151	4,154	4,148	4,148	4,148	4,150	4,148	4,147
		Total	26,480	30,179	27,272	27,770	28,077	27,901	28,393	28,290	28,153	27,949	27,702
	LVG		61,091	70,527	66,840	67,743	68,091	68,027	68,465	68,451	68,558	68,524	68,485
	TSG	Firm	941	1,193	1,152	1,152	1,145	1,118	1,083	1,021	939	857	775
		Non-Firm	10,062	14,028	15,072	15,072	15,067	15,043	15,013	14,943	14,850	14,756	14,663
		Total	11,003	15,221	16,224	16,224	16,213	16,161	16,096	15,964	15,789	15,613	15,437
	CIG		3,595	5,471	4,504	4,504	4,504	4,504	4,504	4,504	4,504	4,504	4,504
	CSG		16,341	21,300	12,816	12,816	12,816	12,816	12,816	12,816	12,816	12,816	12,816
	Total		118,510	142,697	127,656	129,058	129,701	129,409	130,274	130,025	129,821	129,407	128,944
Industrial	GSG	Heating	871	1,019	935	946	948	946	947	946	947	948	948
		Non-Heating	153	169	161	162	162	162	162	162	162	162	162
		Total	1,025	1,188	1,096	1,108	1,110	1,108	1,109	1,108	1,109	1,109	1,110
	LVG		7,043	8,383	8,234	8,254	8,198	8,141	8,150	8,097	8,059	8,008	7,963
	TSG	Firm	1,511	1,528	1,397	1,397	1,397	1,397	1,397	1,397	1,397	1,397	1,397
		Non-Firm	17,374	6,115	6,077	6,077	6,077	6,077	6,077	6,077	6,077	6,077	6,077
		Total	18,886	7,643	7,474	7,474	7,474	7,474	7,474	7,474	7,474	7,474	7,474
	CIG		564	1,020	771	771	771	771	771	771	771	771	771
	CSG		83,737	106,647	129,704	129,704	129,704	129,704	129,704	129,704	129,704	129,704	129,704
	Contract		8,822	-	-	-	-	-	-	-	-	-	-
	Total		120,075	124,880	147,280	147,312	147,258	147,198	147,209	147,154	147,117	147,067	147,023
Lighting	SLG		66	76	66	66	66	66	66	66	66	66	66
Total			378,023	424,847	422,431	425,988	428,425	429,688	433,126	434,904	437,188	439,024	440,816

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	137,731	139,836	141,639	143,189	145,639	147,645	150,092	152,339	154,583
		Non-Heating	8,362	8,844	4,585	4,532	4,512	4,518	4,540	4,544	4,532	4,502	4,474
	Total		132,437	150,315	142,316	144,369	146,151	147,707	150,179	152,190	154,624	156,841	159,058
Commercial	GSG	Heating	17,387	19,929	18,910	18,489	18,731	18,600	18,991	18,918	18,816	18,664	18,478
		Non-Heating	2,965	3,158	3,057	3,079	3,081	3,077	3,077	3,077	3,078	3,077	3,076
		Total	20,352	23,087	21,967	21,568	21,812	21,677	22,068	21,995	21,895	21,741	21,554
	LVG		24,578	26,300	26,638	25,180	25,318	25,293	25,470	25,476	25,523	25,520	25,514
	TSG	Firm	-	-	-	-	-	-	-	-	-	-	-
		Non-Firm	942	807	812	812	812	812	812	812	812	812	812
		Total	942	807	812	812	812	812	812	812	812	812	812
	CIG		3,595	5,471	4,504	4,504	4,504	4,504	4,504	4,504	4,504	4,504	4,504
	CSG		-	-	-	-	-	-	-	-	-	-	-
	Total		49,467	55,664	53,921	52,064	52,445	52,286	52,854	52,787	52,733	52,576	52,383
Industrial	GSG	Heating	689	799	767	776	778	776	777	776	777	777	778
		Non-Heating	113	127	126	127	127	127	127	127	127	127	127
		Total	802	927	893	903	905	903	904	903	904	904	904
	LVG		1,864	2,108	2,160	2,162	2,144	2,126	2,128	2,113	2,101	2,085	2,071
	TSG	Firm	-	-	-	-	-	-	-	-	-	-	-
		Non-Firm	108	109	63	63	63	63	63	63	63	63	63
		Total	108	109	63	63	63	63	63	63	63	63	63
	CIG		564	1,020	771	771	771	771	771	771	771	771	771
	CSG		-	-	-	-	-	-	-	-	-	-	-
	Contract		1,301	-	-	-	-	-	-	-	-	-	-
	Total		4,638	4,164	3,887	3,899	3,883	3,863	3,866	3,850	3,839	3,823	3,810
Lighting	SLG		26	26	26	25	25	25	25	25	25	25	25
Total			186,568	210,170	200,150	200,357	202,504	203,881	206,924	208,852	211,222	213,266	215,276

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%	82%	78%	78%	78%	78%	78%	78%	78%	78%
		Non-Heating	75%	73%	74%	74%	74%	74%	74%	74%	74%	74%	74%
		Total	77%	76%	81%	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%	5%	5%	5%	5%	5%	5%	5%	5%	6%
		Total	9%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%
	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%	42%	40%	40%	40%	41%	41%	41%	41%	41%
Industrial	GSG	Heating	79%	78%	82%	82%	82%	82%	82%	82%	82%	82%	82%
		Non-Heating	74%	75%	78%	78%	78%	78%	78%	78%	78%	78%	78%
		Total	78%	78%	81%	81%	81%	81%	81%	81%	81%	81%	81%
	LVG		26%	25%	26%	26%	26%	26%	26%	26%	26%	26%	26%
	TSG	Firm	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
		Non-Firm	1%	2%	1%	1%	1%	1%	1%	1%	1%	1%	1%
		Total	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
	CIG		100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
	CSG		0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	Contract		15%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	Total		4%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%
Lighting	SLG		39%	35%	39%	39%	39%	39%	39%	39%	39%	39%	39%
Total			49%	49%	47%	47%	47%	47%	48%	48%	48%	49%	49%

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	143,157	145,334	146,357	148,191	150,591	153,611	155,202	157,517	159,750
		Non-Heating	8,866	9,044	4,717	4,782	4,731	4,751	4,768	4,802	4,756	4,723	4,690
	Total		140,667	153,243	147,874	150,116	151,089	152,942	155,358	158,413	159,959	162,240	164,441
Commercial	GSG	Heating	22,771	25,196	24,369	23,708	23,865	23,718	24,216	24,249	23,940	23,733	23,473
		Non-Heating	4,040	4,256	4,147	4,163	4,143	4,144	4,140	4,159	4,142	4,139	4,136
		Total	26,811	29,453	28,516	27,870	28,008	27,862	28,356	28,409	28,081	27,872	27,609
	LVG		61,513	68,128	67,469	67,964	67,924	67,951	68,345	68,688	68,414	68,373	68,297
	TSG	Firm	951	1,197	1,122	1,152	1,145	1,118	1,083	1,021	939	857	775
		Non-Firm	9,668	10,972	15,072	15,072	15,067	15,043	15,013	14,943	14,850	14,756	14,663
		Total	10,618	12,169	16,195	16,224	16,213	16,161	16,096	15,964	15,789	15,613	15,437
	CIG		3,408	3,568	4,520	4,504	4,504	4,504	4,504	4,504	4,504	4,504	4,504
	CSG		8,734	18,277	13,267	12,816	12,816	12,816	12,816	12,816	12,816	12,816	12,816
	Total		111,084	131,594	129,966	129,379	129,464	129,294	130,117	130,380	129,604	129,178	128,664
Industrial	GSG	Heating	875	993	947	950	945	944	944	950	945	945	945
		Non-Heating	155	166	162	162	162	161	161	162	161	161	161
		Total	1,030	1,159	1,109	1,112	1,107	1,106	1,106	1,112	1,106	1,106	1,106
	LVG		7,093	8,258	8,331	8,271	8,175	8,130	8,137	8,114	8,042	7,991	7,943
	TSG	Firm	1,574	1,453	1,507	1,397	1,397	1,397	1,397	1,397	1,397	1,397	1,397
		Non-Firm	15,878	5,486	6,077	6,077	6,077	6,077	6,077	6,077	6,077	6,077	6,077
		Total	17,451	6,939	7,584	7,474	7,474	7,474	7,474	7,474	7,474	7,474	7,474
	CIG		557	657	801	771	771	771	771	771	771	771	771
	CSG		72,331	86,007	130,376	129,704	129,704	129,704	129,704	129,704	129,704	129,704	129,704
	Contract		6,389	-	-	-	-	-	-	-	-	-	-
	Total		104,851	103,020	148,202	147,332	147,231	147,185	147,192	147,176	147,097	147,047	146,999
Lighting	SLG		66	72	67	66	66	66	66	66	66	66	66
Total			356,668	387,928	426,110	426,892	427,850	429,487	432,733	436,034	436,726	438,531	440,169

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	138,272	140,367	141,355	143,123	145,437	148,350	149,888	152,119	154,270
		Non-Heating	8,365	8,561	4,481	4,543	4,496	4,514	4,530	4,563	4,520	4,488	4,457
	Total		133,680	146,164	142,753	144,911	145,850	147,637	149,968	152,913	154,407	156,607	158,728
Commercial	GSG	Heating	17,569	19,242	19,102	18,558	18,685	18,573	18,969	19,002	18,766	18,611	18,414
		Non-Heating	2,976	3,083	3,079	3,088	3,073	3,074	3,071	3,085	3,072	3,070	3,068
		Total	20,545	22,325	22,181	21,646	21,758	21,647	22,040	22,087	21,839	21,681	21,482
	LVG		24,708	25,405	26,659	25,263	25,255	25,265	25,424	25,565	25,468	25,462	25,443
	TSG	Firm	-	-	-	-	-	-	-	-	-	-	-
		Non-Firm	892	699	812	812	812	812	812	812	812	812	812
		Total	892	699	812	812	812	812	812	812	812	812	812
	CIG		3,408	3,568	4,520	4,504	4,504	4,504	4,504	4,504	4,504	4,504	4,504
	CSG		-	-	-	-	-	-	-	-	-	-	-
	Total		49,553	51,997	54,172	52,225	52,328	52,228	52,780	52,968	52,623	52,459	52,241
Industrial	GSG	Heating	692	785	777	779	775	775	775	779	775	775	775
		Non-Heating	115	124	127	127	127	127	127	127	127	127	126
		Total	806	909	904	906	902	901	901	906	901	902	901
	LVG		1,877	2,082	2,200	2,167	2,137	2,122	2,124	2,119	2,095	2,080	2,065
	TSG	Firm	-	-	-	-	-	-	-	-	-	-	-
		Non-Firm	59	82	63	63	63	63	63	63	63	63	63
		Total	59	82	63	63	63	63	63	63	63	63	63
	CIG		557	657	801	771	771	771	771	771	771	771	771
	CSG		-	-	-	-	-	-	-	-	-	-	-
	Contract		805	-	-	-	-	-	-	-	-	-	-
	Total		4,104	3,731	3,968	3,907	3,873	3,858	3,860	3,859	3,831	3,815	3,801
Lighting	SLG		26	26	26	25	25	25	25	25	25	25	25
Total			187,362	201,918	200,919	201,068	202,077	203,747	206,633	209,766	210,887	212,907	214,794

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%	78%	78%	78%	78%	78%	78%	78%	78%	78%
		Non-Heating	74%	72%	74%	74%	74%	74%	74%	74%	74%	74%	74%
		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%	5%	5%	5%	5%	5%	5%	5%	5%	6%
		Total	8%	6%	5%	5%	5%	5%	5%	5%	5%	5%	5%
	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%	40%	42%	40%	40%	40%	41%	41%	41%	41%	41%
Industrial	GSG	Heating	79%	79%	82%	82%	82%	82%	82%	82%	82%	82%	82%
		Non-Heating	74%	75%	79%	78%	78%	78%	78%	78%	78%	78%	78%
		Total	78%	78%	81%	81%	81%	81%	81%	81%	81%	81%	81%
	LVG		26%	25%	26%	26%	26%	26%	26%	26%	26%	26%	26%
	TSG	Firm	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
		Non-Firm	0%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
		Total	0%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
	CIG		100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
	CSG		0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	Contract		13%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	Total		4%	4%	3%	3%	3%	3%	3%	3%	3%	3%	3%
Lighting	SLG		39%	37%	38%	39%	39%	39%	39%	39%	39%	39%	39%
Total			53%	52%	47%	47%	47%	47%	48%	48%	48%	49%	49%

17. FERC Pipeline Activities

Item 17

FERC Pipeline Activities

Pipeline	Docket No.	Description
Transco	RP18-1126	On August 31, 2018 Transco filed a general Section 4 rate increase case seeking a $2.5 billion annual cost of service. The Company protested the application, and was instrumental in forming and leading a large group of firm customers that jointly sought to decrease the magnitude of the proposed rate increase. The group retained an expert witness and a group counsel to assist in the pursuit of cost of service issues. In addition, the Company teamed with another local distribution company to jointly retain the services of an expert witness on cost allocation and rate design issues. FERC approved an uncontested settlement on February 13, 2020 for rates to be effective June 1, 2020, with refunds for the locked-in rate period to be received in July 2020.
Texas Eastern	RP19-343	On November 30, 2018, Texas Eastern filed a general Section 4 rate increase seeking a $1.9 billion annual cost of service. The Company protested the application, and was the largest member in a group of firm customers jointly seeking to decrease the magnitude of the proposed rate increase. The group retained an expert witness and a group counsel that assisted in the pursuit of cost of service issues. The Company also identified and advanced certain cost

		allocation and rate design proposals that were incorporated into the final resolution of the case. FERC approved an uncontested Settlement on February 25, 2020 for rates effective April 1, 2020, with refunds for the locked-in rate period to be received in May 2020.
Texas Eastern	CP18-26	On December 7, 2017, Texas Eastern applied for approval of the Lambertville East Expansion Project, which includes an incremental firm daily quantity of 30,000 dekatherms/day to the Company at its Hillsborough and Jamesburg stations. Acting to meet increasing market demand from its firm customers, the Company worked with the pipeline as an anchor shipper for the project, which received its FERC certificate on November 26, 2018, and had an in-service date of December 1, 2019.
Transco	CP18-18	On November 15, 2017, Transco applied for approval of the Gateway Expansion Project, which is designed to provide an incremental firm daily quantity of 54,000 dekatherms/day to the Company at its Ridgefield and Paterson stations. Acting to meet increasing market demands from its firm customers, the Company worked with the pipeline as an anchor shipper for the project, which received its FERC certification on December 12, 2018, and was completed ahead of schedule with an in-service date of January 1, 2020.
Algonquin	RP19-57	FERC Order 859 adopted procedures for determining which jurisdictional natural gas pipelines may be collecting unjust and unreasonable rates in light of the income tax reductions provided by the Tax Cuts and

		Jobs Act. As a result of this order, Algonquin and its customers engaged in informal settlement discussions instead of a formal rate case proceeding. On June 21, 2019 Algonquin initiated settlement discussions with a $675 million annual cost of service. All parties have agreed to a settlement in principle for rates to be effective June 1, 2020. Parties are negotiating the actual settlement language, which is expected to be filed at FERC in the near future.
National Fuel	RP19-1426	On July 31, 2019, National Fuel Gas Supply filed a general Section 4 rate increase seeking a $295 million annual cost of service. PSEG is not a direct customer of National Fuel, but is indirectly affected because Transco's LSS service uses National Fuel's SS-1 service. Since this rate proceeding would have an impact on the Company's annual cost responsibility, we protested the application, and we were an active participant in all settlement discussions. FERC approved an uncontested Settlement on April 20, 2020 for rates to be effective February 1, 2020.
Columbia	TBD	Columbia anticipates filing a General Section 4 rate case on July 31, 2020 with rates to be effective on February 1, 2021. In preparation for this filing, Columbia is currently engaging with customers on potential changes. This filing will include an update to Columbia's modernization programs. The Company is an active participant in this matter and is 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 issues.
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.
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 of an approximate $58 million 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 to assign cost responsibility to those entities that caused the under-recoveries.

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 decreased from the levels experienced at this time last year. From a historical perspective, prices have fallen to the lowest levels in the past four years at the time of this BGSS Filing, with the NYMEX contract for June 2020 recently closing at $1.722/Dth. NYMEX prices have traded in a relatively tight range between approximately $2.20/Dth and $1.60/Dth since the middle of January, 2020. The forward NYMEX strip used by the Company shows that prices are expected to increase quite significantly (over $1.00/Dth) from current levels through the first quarter of 2021, followed by a more modest reduction for the balance of the BGSS period. Despite this increase in the forward prices, the NYMEX strip through September 2021 used for this year's BGSS Filing is approximately 7.4% below last year's (see the NYMEX forward strip included as Item 8).

The Company's gas procurement objectives are to provide a reliable natural gas supply to its firm gas customers, 365 days a year, at the lowest possible price. The Company is proud of its achievements in this area both with respect to the reliability of its natural gas service as well as its repeatedly having the lowest natural gas prices to residential gas customers in the state of NJ.

The achievement of this objective is met by the Company 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 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 updated Natural Gas Sales Forecast for 2020. 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 2020/2021 winter period and then experience a shortfall in peak day supply commencing in 2021/2022 which will increase throughout the five year forecast period.

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

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

The Company has also entered into a transportation service agreement with Transco to obtain incremental firm transportation capacity to further help meet its projected peak day shortfall. The agreement with Transco provides for 54,000 Dth/d of incremental firm capacity. This capacity was placed in-service on January 1, 2020 and has eliminated the projected shortfall in peak day supply for the 2020/2021 winter.

Also, the Company increased the capacity under a transportation service agreement with Columbia by 6,250 Dth/d effective December 1, 2019 to further meet projected peak day supply shortfalls.

The Company recently participated in an open season for Transco's Regional Energy Access Project which provides for an expansion of the Transco system between the Marcellus supply region in northeast Pennsylvania and central and southern New Jersey. The Company has entered into a precedent agreement with Transco providing for 60,000 Dth/d of new transportation capacity to help meet the projected shortfall in peak day supply for the 2023/2024 winter, and to meet increased gas requirements in the Mount Laurel and Camden areas of its distribution system.

Finally, the Company is a shipper in the PennEast project which will provide increased capacity from the Marcellus shale region, as well as provide a new independent source of pipeline supply, and thereby increase the reliability of the Company's portfolio of firm pipeline transportation capacity. PennEast received its FERC Certificate on January 19, 2018, and is currently seeking the required state and local permits to provide for construction to commence. 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. 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:

Counterparty	Rate Schedule	Contract Number	Top Gas Quantity	Daily Contract 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	797625		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	FT	200316		41,813
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 98 % of its planned volume for the 2020 summer period, approximately 68 % of its planned volume for the 2020-2021 winter period and approximately 38 % of its planned volume for the 2021 summer period. Hedging for the winter 2021-2022 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 2019-2020 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 2020. For the upcoming BGSS period that is covered by this filing, the Company has a total of approximately $ 20 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, 2020 total $ 7 million, approximately 35% of last year's 12-month total.

For the prior period, 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/day 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

2013 - 2020

Year	BGSS-RSG OSS Revenue (1)	BGSS-RSG OSS Cost (2)	BGSS-RSG OSS Margins (3)
2013	$240,938,997	$120,566,928	$120,372,069
2014	$327,717,529	$143,452,710	$184,264,819
2015	$197,662,767	$61,941,827	$135,720,940
2016	$145,423,895	$86,729,138	$58,694,758
2017	$156,240,095	$96,425,765	$59,814,330
2018	$194,555,168	$124,011,106	$70,544,017
2019	$79,655,383	$59,067,798	$20,587,585
2020*	$41,431,877	$34,146,182	$7,285,695

*Note: Through April 2020

Item 18

<u>Attachment D</u>

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	875.3	0.0	0.0%
Storage	896.6	514.2	57.3%
Balancing FT	397.4	397.4	100.0%
Peaking	551.9	551.9	100.0%
	2,721.2	1,463.5	

	Total Cost	Percent Allocated to Balancing Use	Allocated Cost
Fixed Cost Allocation:			
Base FT	$150,260.6	0.0%	$0.0
Storage	$102,956.4	57.3%	$59,044.3
Balancing FT	$57,895.2	100.0%	$57,895.2
Peaking	$11,775.3	100.0%	$11,775.3
	$322,887.4		
Variable Cost Allocation:			
Base FT	$0.0	0.0%	$0.0
Storage	$6,524.7	57.3%	$3,741.8
Balancing FT	$0.0	100.0%	$0.0
Peaking	$1,021.2	100.0%	$1,021.2
	$7,545.9		

Total Annual Allocated Costs ($000)	**$ 133,477.8**
Balancing Use Billing Determinants - Oct - May (MDth)	180,608
Balancing Charge - Annual Allocated Cost ($/Dth)	$ 0.73905
Storage Inventory Carrying Charge ($/Dth) (page 2)	$ 0.03201
Revenue Requirement on Gas Production Plant Charge ($/Dth) (page 3)	$ 0.01683
Total Balancing Charge (excl. losses) ($/Dth)	$ 0.78789
Total Balancing Charge (incl. losses @ 2%) ($/Dth)	$ 0.80397
Total Balancing Charge (incl. SUT) ($/Dth)	**$ 0.85723**
Total Balancing Charge (incl. SUT) ($/Therm)	**$ 0.085723**

Storage Inventory Carrying Charge

	12 Months Oct 2020- Sept 2021 (000)
RSG Inventory Cost	$ 139,888
BGSS-F Inventory Cost	$ 28,507
BGSS-F Fixed Cost Deferred	$ 12,335
LNG + LPA	$ 2,416
Total Inventory Cost	**$ 183,146**
Total Annual Storage Carrying Cost @ 9.02%	**$ 16,520**

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

Rate per Dth	MDth	Cost	**$/Dth**
Balancing	180,608	$ 5,782	**$ 0.03201**
Commodity	198,966	$ 10,738	**$ 0.05397**

Revenue Requirement on Gas Production Plants

			12 Months Oct 20 - Sep 21
2020	October	$	211,848
	November	$	211,848
	December	$	211,848
2021	January	$	211,848
	February	$	460,424
	March	$	460,424
	April	$	211,848
	May	$	211,848
	June	$	211,848
	July	$	211,848
	August	$	211,848
	September	$	211,848
Total		**$**	**3,039,328**
Balancing Use Billing Determinants (MDth)			**180,608**
Revenue Requirement on Gas Production Plant Charge ($/Dth)		**$**	**0.01683**

Gas Supply A&G

	12 Months Oct 20 - Sep 21
Direct Labor & Overhead	$ 7,146,870
Firm Sendout - Dth (000)	198,966
Gas Supply A&G Rate	$ 0.03592

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	$ 0.060450
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	0.294231
Commodity Charge after application of losses: (Loss Factor = 2.0%)	$ 0.300236
Commodity Charge including New Jersey Sales and Use Tax (SUT)	$ 0.320127

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	
$0.360706	$0.384603	per therm

Balancing Charge:

Charge	Charge Including SUT	
$0.080397 ~~0.092492~~	$0.085723 ~~$0.098620~~	per Balancing Use Therm

Societal Benefits Charge:

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

Margin Adjustment Charge:

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

Green Programs Recovery Charge:

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

Weather Normalization Charge:

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

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

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:

$15.19 in each month [$16.20 including New Jersey Sales and Use Tax (SUT)].

Distribution Charges:

Pre-July 14, 1997 *		All Others		
Charge	Charge Including SUT	Charge	Charge Including SUT	
$0.288299	$0.307399	$0.288299	$0.307399	per therm

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

Balancing Charge:

Charge	Charge Including SUT	
$0.080397	$0.085723	
~~0.092492~~	~~$0.098620~~	per Balancing Use Therm

Societal Benefits Charge:

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

Margin Adjustment Charge:

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

Green Programs Recovery Charge:

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

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:

$134.85 in each month [$143.78 including New Jersey Sales and Use Tax (SUT)].

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

Charge	Charge Including SUT	
$ 3.9473	$ 4.2088	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
$ 0.042298	$ 0.045100	$0.041894	$ 0.044669

Balancing Charge:

Charge	Charge Including SUT	
$0.080397 ~~0.092492~~	$0.085723 ~~$0.098620~~	per Balancing Use Therm

Societal Benefits Charge:

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

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:
$722.23 in each month [$770.08 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	
$0.080397 ~~0.092492~~	$0.085723 ~~0.098620~~	per Balancing Use Therm

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

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

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	$ 0.060450
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	0.294231
Commodity Charge after application of losses: (Loss Factor = 2.0%)	$ 0.300236
Commodity Charge including New Jersey Sales and Use Tax (SUT)	$ 0.320127

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

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	
$0.360706	$0.384603	per therm

Balancing Charge:

Charge	Charge Including SUT	
$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:

$15.19 in each month [$16.20 including New Jersey Sales and Use Tax (SUT)].

Distribution Charges:

Pre-July 14, 1997 *		All Others		
Charge	Charge Including SUT	Charge	Charge Including SUT	
$0.288299	$0.307399	$0.288299	$0.307399	per therm

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

Balancing Charge:

Charge	Charge Including SUT	
$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.

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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:

$134.85 in each month [$143.78 including New Jersey Sales and Use Tax (SUT)].

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

Charge	Charge Including SUT	
$ 3.9473	$ 4.2088	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
$ 0.042298	$ 0.045100	$0.041894	$ 0.044669

Balancing Charge:

Charge	Charge Including SUT	
$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:
$722.23 in each month [$770.08 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:
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Charge	Charge Including SUT	
$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. 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.

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