IN THE MATTER OF THE PROVISION OF BASIC GENERATION SERVICE FOR BASIC GENERATION SERVICE REQUIREMENTS EFFECTIVE JUNE 1, 2025	: : : :	Docket No. ER24030191

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

PROPOSAL FOR

BASIC GENERATION SERVICE REQUIREMENTS

TO BE PROCURED EFFECTIVE JUNE 1, 2025

COMPANY SPECIFIC ADDENDUM

July 1, 2024

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I. USE OF COMMITTED SUPPLY AND CONTINGENCY PLANS

COMMITTED SUPPLY

"Committed Supply," means non-utility generation power supplies to which Public Service Electric and Gas ("PSE&G" or "Public Service" or "Company") has an existing physical or financial entitlement. In prior auctions, PSE&G provided renewable attributes from non-utility generation contracts on a pro-rata basis to BGS-RSCP Suppliers. Since PSE&G's last non-utility generation contract was terminated in 2014, no renewable attributes will be available going forward. PSE&G has no committed supply.

CONTINGENCY PLANS

While not every contingency can be anticipated, we can differentiate three time periods of concern:

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

(b) A default by one of the winning bidders prior to June 1, 2025;

(c) A default during the June 1, 2025 – May 31, 2026 supply period.

(a) Insufficient Number of Bids in Auction

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

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

In the event that the auction volume is reduced to less than 100 percent of BGS-RSCP or BGS- CIEP Load, PSE&G will implement a contingency plan for the remaining tranches. Under that plan, PSE&G, at its option, will purchase necessary services for the remaining tranches through PJM-administered markets until May 31, 2026. After May 31, 2026, any unfilled tranches may be included in a subsequent auction or treated as in Contingency Plans Part (c) below. This Contingency Plan will alert bidders that in order to secure BGS-RSCP or BGS-CIEP prices from New Jersey BGS customers for their supply, it will be necessary to bid in the auctions. Failure to bid will mean that the BGS market faced by suppliers will be a spot market with volatility and related risks.

Since the contingency plan calls for the purchase of BGS supply in PJM-administered markets, it is considered a strong feature of the auction proposal because it provides bidders a strong incentive to participate in the Auction Process. If bidders were to believe that a less than fully subscribed auction would lead to a negotiation or a secondary market in which PSE&G, on behalf of its customers, would seek to acquire fixed priced supplies, the incentive to participate in the auction and the incentive to offer the best prices in the auction would be diminished.

(b) Defaults prior to June 1st, 2025.

If a winning bidder defaults prior to the beginning of the BGS service, then, at the option of the EDC, the open tranches may be offered to the other winning bidders or these tranches may be bid out or procured in PJM-administered markets. Additional costs incurred by PSE&G in implementing this Contingency Plan will be assessed against the defaulting supplier's credit security.

(c) Defaults during the Supply Period

If a default occurs during the June 1, 2025 through May 31, 2028 period, at the option of PSE&G, the available tranches may be offered to other winning bidders, bid out, or procured in PJM administered markets. Additional costs incurred by PSE&G in implementing this Contingency Plan will be assessed against the defaulting supplier's credit security.

II. ACCOUNTING AND COST RECOVERY

The accounting and cost recovery that PSE&G proposes for its BGS service is summarized in this section. These provisions are intended to be applicable to PSE&G only. Each EDC will provide individual BGS cost recovery proposals.

BGS-RSCP and BGS-CIEP Reconciliation Charges

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

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

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

1. Payments made for the provision of BGS-RSCP or BGS-CIEP service;
2. Any administrative costs associated with the provision of BGS-RSCP and BGS- CIEP service;
   a. Administrative costs are defined as commonly-incurred or directly-incurred. *Commonly-incurred costs* are costs shared among all of the New Jersey Electric Distribution Companies (the "EDCs"). *Directly-incurred costs* are costs specifically incurred by each EDC, individually.

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

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

Directly-incurred costs (for PSE&G) include, but are not limited to, the following:

- GATS Administrative Fee
- Printing Costs of Environmental Label inserts

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

As noted, one element of commonly-incurred costs have been the costs associated with the rent and maintenance of office space in New Jersey for the Auction Manager to conduct the annual BGS Auction. As noted in the Joint EDC comments, in the November 2021 Order, the Board authorized PSE&G to sublet the BGS Office in Newark. PSE&G (on behalf of the EDCs) subsequently did sublet the office, and the revenues related to the same serve to offset other commonly-incurred EDC costs (including the aforementioned rent and maintenance expenses).

Additionally, in response to a recommendation included in the BGS Administrative

Expense audit (BPU Docket No. EA1701004), PSE&G has evaluated its administrative costs and identified additional directly incurred costs that are common across the EDCs and related to the provision of BGS service. The Company plans to ultimately account for such costs similar to other directly incurred BGS administrative costs (i.e. recoverable through the reconciliation charge(s)), at the conclusion of the Company's base rate case that is presently before the Board (BPU Docket No. ER23120924).

3. The cost of any procurement of necessary services including capacity, energy, ancillary services, transmission, RPS compliance, and other expenses related to the Contingency Plan less any payments recovered from defaulting suppliers.

Adjustment type (i.e., reconciliation) charges are necessary in order to balance out the difference between (1) the monthly amounts paid within the quarter to the BGS-RSCP and BGS-CIEP supplier(s) for BGS-RSCP and BGS-CIEP supply and (2) the total revenue from customers for BGS-RSCP and BGS-CIEP services within the quarter, respectively.

These reconciliation charges are calculated separately each quarter for BGS-RSCP and BGS- CIEP and applied for the upcoming quarter on a dollars per kWh basis and the respective rates are applied to all BGS-RSCP and BGS-CIEP kWh billed. These charges are combined with BGS-RSCP and hourly BGS-CIEP charges for billing although they are published in separate BGS-RSCP reconciliation charge and BGS-CIEP reconciliation charge tariff sheets that are revised quarterly to reflect actual revenues and costs. These tariff sheets are filed with the Board approximately 15 days prior to the first day of the effective quarter.

The BGS-RSCP reconciliation charge and BGS-CIEP reconciliation charge are subject to deferred accounting with interest at the NGC rate previously set by the Board and are determined individually as set forth below:

The reconciliation charges are used in both BGS-RSCP and BGS-CIEP to true up the differences between BGS payments to suppliers and BGS revenues from customers for the quarter. Differences in BGS costs and BGS revenues for a quarter are computed in the following month and applied to BGS rates for the upcoming quarter. Two of these differences are shown below:

1. The difference between BGS Costs (as defined above) paid to suppliers for each month in the quarter and each calendar month of BGS revenue in the quarter. This difference is calculated in each month after the quarter to become effective in the upcoming quarter.
2. The difference between the total adjustment charge revenue intended to be recovered in the quarter and the actual adjustment charge revenue recovered in the quarter. This difference is driven by differences between actual kWh in the quarter and the kWh used to calculate the charge.

The reconciliation charges to be applied in the upcoming quarter are calculated as the net of the two differences described above for the quarter (plus or minus any cumulative under or over recovery from the prior quarter) divided by the forecast of BGS kWh in upcoming quarter.

The following table summarizes PSE&G's proposed process:

Reconciliation for the Months of:	Quarterly Rate in Effect:
February – April	June – August 31
May – July	September – November 30
August – October	December – February 28
November – January	March – May 31

III. A. DESCRIPTION OF BGS TARIFF SHEETS AND OTHER TARIFF ITEMS

GENERAL

As described in the generic section of this filing, two different methods will continue to be utilized for the pricing of BGS default supply service to customers: Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP) for residential and small commercial customers and Basic Generation Service – Commercial and Industrial Energy Pricing (BGS-CIEP), a variable hourly energy pricing for large commercial and industrial customers.

The Company is not proposing any modification of the criteria for BGS-CIEP eligibility from the current peak load share of 500kW. Thus BGS-CIEP is proposed to continue to be the default service for all customers served under delivery rate schedules HTS-High Voltage, HTS-Subtransmission, and LPL-Primary and for LPL-Secondary customers with a peak load share (PLS) of 500 kW or higher.

As in prior years, all other non-residential customers also have the option of electing BGS-CIEP as their default supply service. All non-residential customers with BGS-CIEP as their optional default service will be notified of their option to switch to BGS-CIEP through PSE&G's website and tariffs. Annually, customers eligible for this option must notify PSE&G no later than the second business day of January of any given year to have BGS-CIEP as their default supply service option for the annual period beginning June 1st of that year. The BGS-RSCP default service will be available to residential and small and medium sized non-residential customers, specifically those served on Rate Schedules RS, RHS, RLM, WH, WHS, HS, BPL, BPL-POF, PSAL, GLP and LPL-Secondary (PLS less than 500 kW).

The following sections describe the tariff sheets that would implement Public Service's BGS service effective June 1, 2025.

BGS-RSCP

While Public Service is not proposing any change in the structure of the BGS-RSCP default supply service, the BGS Transmission Charges continue to be shown separately. The form of the BGS-RSCP tariff sheets is included in Attachment 1 and are indicated as Sheet Nos. 75, 76, and 79. Once the results of the BGS-RSCP Bid are finalized, the values on these tariff sheets will be updated reflecting the results of the bid.

As indicated on these form of tariff sheets, the BGS-RSCP default service is made up of several components: BGS Energy Charges, BGS Capacity Charges, BGS Transmission Charges, and the BGS Reconciliation Charges. These charges will apply for usage in the calendar months of June through September, or October through May, as applicable.

BGS Energy Charges

The values of the BGS Energy charges applicable to Rate Schedules RS, RHS, RLM, WH, WHS, HS, BPL, BPL-POF and PSAL include the costs related to energy, ancillary services and generation capacity costs. This overall approach is a continuation of the current approved methodology of recovering all electric supply service costs in the kilowatt-hour charges for these rate schedules.

Typically, the generation capacity costs used in the development of the BGS-RSCP rates are the relevant current wholesale market prices for capacity based on the average, 2025/2026, 2026/2027, and 2027/2028 Base Residual Auction (“BRA”) results under the Reliability Pricing Model (“RPM”) applicable to load served in the PSEG zone. This process has been impacted in recent years by delays in conducting the BRAs – resulting in the need for contract supplements with Capacity Proxy Prices for delivery years with delayed BRAs.

Due to the postponement of the BRAs, contracts from the 2023 and 2024 BGS auctions contained supplements with Capacity Proxy Prices. With the prior postponements of the BRAs for the 2025/2026 Delivery Year and the 2026/2027 Delivery Year, a Capacity Proxy Price of $44.63 per MW-Day was used in place of the 2025/2026 BRA value in the 2023 contracts, while a Capacity Proxy Price of $47.46 per MW-Day was used in place of the 2025/2026 BRA value and a Capacity Proxy Price of $49.05 per MW-Day was used in place of the 2026/2027 BRA value in the 2024 contracts.

At this time the results of the BRA's for the 2025/2026, 2026/2027 and 2027/2028 Delivery Year are not yet available but the BRA's are scheduled to be held in July 2024, December 2024, and June 2025, respectively. Given the continued delay in the schedule of these BRAs a Capacity Proxy price of $53.76 per MW-Day has been used for the 2025/2026 Delivery Year and a Capacity Proxy Price of $50.90 per MW-Day has been used in place of the prices paid for capacity for 2026/2027 and 2027/2028 Delivery Years, respectfully.

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

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

For Energy Year (EY) 2028, if Supplement C to the BGS-RSCP Supplier Master Agreement is approved by the BPU and the BRA for the 2027/2028 Delivery has not occurred at least 5 business days prior to the BGS-RSCP Auction, payments to BGS-RSCP Suppliers will be adjusted for the capacity price difference between the Zonal Capacity Price, which is the price paid by BGS-RSCP Suppliers for Capacity in the Company's PJM Zone, as may be determined under the Reliability Pricing Model or its successor or otherwise, and the Capacity Proxy Price for the 2027/2028 Delivery Year.

PSE&G will file new tariff sheets for EY 2026 reflecting the impact of this price adjustment, in a manner similar to Attachment 4, Page 1 ("Attach 4 P1")– Development of Capacity Proxy Price True Up - $/MWh. The rate design spreadsheets include the formulas that will be used to reflect the impact of payments made pursuant to the Supplements. Attachment 4, Pages 2 and 3 ("Attach 4 P2", "Attach 4 P3") are illustrative examples of how of how the Capacity Proxy Price True Up will be calculated for EY 2027 and EY 2028 respectively and prospectively.

The Supplements to the SMAs signed by BGS-RSCP Suppliers in February 2023 and February 2024 are still in effect for approximately two-thirds of the load for Energy Year 2026 (the year beginning June 1, 2025). Payments to BGS-RSCP Suppliers that executed the Supplements to the SMAs approved by the BPU on November 9, 2022 and November 27, 2023 will be adjusted for the price difference between the price paid by BGS-RSCP Suppliers for Capacity in the Company's PJM Zone and the Capacity Proxy Price for the 2025/2026 Delivery Year. Upon the conclusion of the Third Incremental RPM Auction, or the RPM's successor or otherwise, the price paid by BGS-RSCP Suppliers for Capacity in the Company's PJM Zone will be known. At that time, PSE&G will file new tariff sheets reflecting the impact of the Supplements. The rate design spreadsheets include the formulas that will be used to reflect the impact of payments made pursuant to the Supplements executed by BGS-RSCP Suppliers in

February 2023 and February 2024. The value of ($50.00 per MW-day) is used as an approximation for the price paid by BGS-RSCP Suppliers for Capacity in the Company's PJM Zone for the 2025/2026 Delivery Year.

The generation capacity and transmission related costs will continue to be recovered through separate charges for customers on Rates GLP and LPL-Secondary (less than 500 kW) based on the customer specific assigned generation capacity and transmission obligation values. The resulting BGS Energy Charges applicable to this latter set of customers thus do not include the costs related to generation capacity and transmission service.

In order to more accurately reflect the costs of providing energy and other electric services when relying on the day-ahead PJM verses the real-time markets, the Company will apply two ancillary services costs, one applied to BGS-RSCP service and the other applied to BGS-CIEP service. A $2.00 per MWh ancillary services rate is used in the calculation of the BGS-RSCP rates since it is more reflective of costs borne in the day-ahead market. Additionally, Renewable Portfolio Standard costs estimated to be $22.64 per MWh are included in the calculation of the BGS-RSCP rates to reflect compliance costs. A BGS-CIEP ancillary services cost of $6.00 per MWh is applied since it is more reflective of costs borne in the real-time market.

The specific values that will be utilized for the BGS Energy Charges will be calculated from the winning BGS-RSCP bid prices for the Public Service zone. It is the intent of the EDCs that the factors in the tables will be applied to the tranche-weighted average winning bid prices adjusted for seasonal payment factors resulting from the auctions for BGS-RSCP with terms covering the period from June 1, 2025 to May 31, 2026. For example, for Public Service, for the period beginning June 1, 2025 the weighting will be based on the load (i.e., successfully bid tranches) at the 36-month prices from the 2023, 2024, and 2025 BGS-RSCP auctions, and the seasonal payment factors calculated in Attachment 2.

The tables will be updated annually, prior to future BGS auctions and utilized to develop customer charges for a related annual period in a similar manner as discussed above. The updates will reflect then current factors such as updated futures prices, factors based on 12- month data, and any changes in the customer groups and loads eligible for the BGS-RSCP class.

BGS Capacity Charges

These charges are the separate charges previously mentioned that are designed to recover the costs associated with generation capacity for customers served on Rate Schedules GLP and LPL-Secondary (less than 500 kW). These charges are expressed on a per-kW of generation capacity obligation basis.

Typically, the generation capacity costs designed to be used in the development of the BGS-RSCP rates are the relevant current wholesale market prices for capacity based on the average, 2025/2026, 2026/2027, and 2027/2028 BRA for RPM results applicable to load served in the PSEG zone. This process has been impacted in recent years by delays in conducting the BRAs – resulting in the need for contract supplements with Capacity Proxy Prices for delivery years with delayed BRAs. Due to the postponement of the BRAs, contracts from the 2023 and 2024 BGS auctions contained supplements with Capacity Proxy Prices. With the prior postponements of the BRAs for the 2025/2026 Delivery Year and 2026/2027 Delivery Year, a Capacity Proxy Price of $44.63 per MW-Day was used in place of the 2026/2026 BRA value in the 2023 contracts, while a Capacity Proxy Price of $47.46 per MW-Day was used in place of the 2025/2026 BRA value and a Capacity Proxy Price of $49.05 per MW-Day was used in place of the 2026/2027 BRA value in the 2024 contracts.

At this time the results of the BRA's for the 2025/2026, 2026/2027 and 2027/2028 Delivery Year are not yet available but the BRA's are scheduled to be held in July 2024, December 2024, and June 2025, respectively. Given the continued delay in the schedule of these BRAs a Capacity Proxy Price of $53.76 per MW-Day has been used for the 2025/2026 Delivery Year and a Capacity Proxy Price of $50.90 per

MW-Day has been used in place of the prices paid for capacity for 2026/2027 and 2027/2028 Delivery Years, respectfully.

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

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

For Energy Year (EY) 2028, if Supplement C to the BGS-RSCP Supplier Master Agreement is approved by the BPU and the BRA for the 2027/2028 Delivery has not occurred at least 5 business days prior to the BGS-RSCP Auction, payments to BGS-RSCP Suppliers will be adjusted for the capacity price difference between the Zonal Capacity Price, which is the price paid by BGS-RSCP Suppliers for Capacity in the Company's PJM Zone, as may be determined under the Reliability Pricing Model or its successor or otherwise, and the Capacity Proxy Price for the 2027/2028 Delivery Year.

PSE&G will file new tariff sheets for EY 2026, EY 2027 and EY 2028, reflecting the impact of this price adjustment. The rate design spreadsheets include the formulas that will be used to reflect the impact of payments made pursuant to the Supplements.

The Supplements to the SMAs signed by BGS-RSCP Suppliers in February 2023 and February 2024 are still in effect for approximately two-thirds of the load for Energy Year 2026 (the year beginning June 1, 2025). Payments to BGS-RSCP Suppliers that executed the Supplements to the SMAs approved by the BPU on November 9, 2022 and November 27, 2023 will be adjusted for the price difference between the price paid by BGS-RSCP Suppliers for Capacity in the Company's PJM Zone and the Capacity Proxy Price for the 2025/2026 Delivery Year. Upon the conclusion of the Third Incremental RPM Auction, or the RPM's successor or otherwise, the price paid by BGS-RSCP Suppliers for Capacity in the Company's PJM Zone will be known. At that time, PSE&G will file new tariff sheets reflecting the impact of the Supplements. The rate design spreadsheets include the formulas that will be used to reflect the impact of payments made pursuant to the Supplements executed by BGS-RSCP Suppliers in February 2023 and February 2024. The value of ($50.00 per MW-Day) is used as an approximation for the price paid by BGS-RSCP Suppliers for Capacity in the Company's PJM Zone for the 2025/2026 Delivery Year.

BGS Transmission Charges

Similar to the BGS Capacity Charges, the BGS Transmission Charges recover the customer specific costs associated with network transmission service for customers on Rates GLP and LPL-Secondary (less than 500 kW). The charge is based on the annual transmission rate for network service for the PSE&G zone, as stated in PJM's Open Access Transmission Tariff (OATT), and as approved by the BPU for inclusion in the BGS Transmission Charge. The bids will exclude BGS Transmission Charges. PSE&G will file with the BPU to change the transmission cost components of the BGS charges to customers as FERC approves changes in the Network Integration Transmission Service rates for the PSE&G zone in the PJM OATT, or the FERC approves other network transmission-related charges in the PJM OATT at a minimum of twice per year for the rates to become effective January 1 and June 1 of each year. To the extent that there is a change to the payments required by PJM for transmission, either as a result of a change in the firm transmission rate or as a result of a cost reallocation, PSE&G will present an additional filing to the Board to change the transmission charge paid by BGS customers. PSE&G will review and verify the basis for any BGS transmission charge adjustment and will file supporting documentation from the OATT, as well as any rate translation spreadsheets used. For the BGS-RSCP energy only rates (Rate Schedules RS, RHS, RLM, WH, WHS, HS, BPL, BPL-POF and PSAL), upon BPU approval, changes in the OATT rate (per kW of transmission obligation) will be implemented by multiplying such change in the OATT rate by each rate class's ratio of the kW of transmission load of that class divided by the expected annual kWh of that class. The results, in dollars per kWh, will then be added to all BGS-RSCP Energy charges for each class.

In the event that PJM institutes a charge for transmission network service on an energy basis (per kWh), this charge will be added to the BGS-RSCP Energy charges for all kWhs for all rate schedules.

BGS Reconciliation Charge

The BGS Reconciliation Charge for the BGS-RSCP default service is explained in the prior Section II - Accounting and Cost Recovery and will be combined with the BGS-RSCP energy charge for billing on a monthly basis.

BGS-CIEP

The bid product in the 2024 BGS-CIEP auction will continue to be the Generation Capacity Cost, as it was in last year's BGS-CIEP auction. Public Service will continue the use of a value for the CIEP Standby Fee equal to 0.000150 dollars per kWh.

The form of tariff sheets for the Basic Generation Service – Commercial and Industrial Energy - Pricing (BGS-CIEP) are included in Attachment 1 and are indicated as Sheet Nos. 73, 82, and 83.

Similar to the BGS-RSCP, the charges for BGS-CIEP are comprised of several components: BGS Energy Charges, BGS Capacity Charges, BGS Transmission Charges, and the BGS Reconciliation Charges.

BGS Energy Charges

The primary component of this charge will be the actual PJM load-weighted average Residual Metered Load Aggregate Locational Marginal Price (LMP) of energy for the Public Service Transmission Zone. To this will be added an ancillary service cost (including PJM Administrative Costs) for the Public Service zone of $6.00 dollars per MWh that was estimated as being reflective of ancillary service costs in the PSEG zone for energy purchased in the real time market. This sum will then be adjusted for losses. Because the LMPs are calculated to include a marginal loss component for the transmission system, a loss correction is performed. This is done by removing the mean hourly marginal transmission loss factor for the PSE&G transmission zone (equal to 0.91210%) from the BPU-approved PSE&G delivery tariff loss factors. The result is reflective of losses from the customer meter to the transmission nodes (at which the LMPs are calculated).

BGS Capacity Charges

These charges will recover the costs associated with generation capacity. The BGS Capacity Charge component of the BGS-CIEP bid is set equal to the BGS-CIEP auction clearing price. These charges are expressed on a per-kW of generation capacity obligation basis.

Unlike prior years, there is no capacity price available for the2025/2026 Delivery Year at this time but the applicable BRA is scheduled to occur in July 2025. Therefore a Capacity Proxy Price of $53.76 per MW-Day has been used for the 2025/2026 Delivery Year. For Energy Year (EY) 2026, if Supplement A to the BGS-CIEP Supplier Master Agreement is approved by the BPU and the BRA for the 2025/2026

Delivery has not occurred at least 5 business days prior to the BGS-CIEP Auction, payments to BGS-CIEP Suppliers will be adjusted for the difference between the "Zonal Capacity Price", which is the price paid by BGS-CIEP Suppliers for Capacity in the Company's PJM Zone, as may be determined under the Reliability Pricing Model or its successor or otherwise, and the Capacity Proxy Price for the 2025/2026 Delivery Year.

PSE&G will file new tariff sheets for EY 2026 reflecting the impact of this price adjustment, in a manner similar to Attachment 4, Page 6 – Development of Capacity Proxy Price True Up - $/MW-day.

BGS Transmission Charges

BGS-CIEP Transmission Charges recover the customer specific costs associated with Transmission service for customers on BGS-CIEP. The charges are based on the annual transmission rate for network transmission service for the PSE&G zone, in PJM's Open Access Transmission Tariff (OATT), and as approved by the BPU for inclusion in the BGS-CIEP Transmission Charges. This charge is expressed as a monthly charge on a per-kW of transmission obligation basis. PSE&G will file with the BPU to change the transmission cost components of the BGS charges to customers as FERC approves changes in the Network Integration Transmission Service rates for the PSE&G zone in the PJM OATT, or the FERC approves other network transmission- related charges in the PJM OATT at a minimum of twice per year for the rates to become effective January 1 and June 1 or each year. To the extent that there is a change to the payments required by PJM for transmission, either as a result of a change in the firm transmission rate or as a result of a cost reallocation, PSE&G will present an additional filing to the Board to change the transmission charge paid by BGS customers. PSE&G will review and verify the basis for any BGS transmission charge adjustment and will file supporting documentation from the OATT, as well as any rate translation spreadsheets used.

BGS Reconciliation Charge

The BGS Reconciliation Charge for the BGS-CIEP default service is explained in the prior Section II -

Accounting and Cost Recovery and will be combined with the BGS-CIEP energy charge for billing on a monthly basis.

OTHER ITEMS

CIEP STANDBY FEE

PSE&G will continue to pay each BGS-CIEP supplier a CIEP Standby Fee, which is set at 0.000150 dollars per kWh times their pro-rata share of the total energy usage measured at the meters of all of PSE&G's customers whose default service option is limited to BGS-CIEP and those customers who have elected BGS-CIEP as their default supply.

A tariff sheet, included in Attachment 1 and indicated as Sheet No. 73, shows the CIEP Standby Fee as a Delivery Charge that is applicable to all customers having BGS-CIEP as their sole default supply service option and those customers who have elected BGS-CIEP as their default supply. This includes all customers served on Rate Schedules LPL-Secondary (peak load share of 500 kW or greater), LPL-Primary, HTS-Subtransmission, HTS-High Voltage, and all customers on Rate Schedules HS, GLP, and LPL-Secondary (less than 500 kW) that have elected the BGS-CIEP default supply option.

DESCRIPTION OF BGS PRICING SPREADSHEETS

As described in the generic write-up, the resulting charge for each BGS rate element (i.e. Rate RS summer charge, winter charge, etc.) for the non-hourly BGS supply service will generally be based on factors applied to the tranche-weighted average winning bid prices adjusted for seasonal payments. These factors have been developed based on the ratios of the estimated underlying market costs of each rate element (for each rate class) to the overall all-in BGS cost. The tables included in Attachments 2 and 3 present all of the input data, intermediate calculations, and the final results in the calculation of these factors.

The following is a description of the calculations shown in the spreadsheet titled "Development of BGS-RSCP Cost and Bid Factors for the 2025/2026 BGS Filing" and included as Attachment 2.

Table #1 (% Usage during PJM On-Peak Period) contains the percentage of on-peak load, inputted by month, for each rate schedule. The on-peak period as used in this table (referred to as PJM periods) is defined as the 16-hour period from 7 AM to 11 PM, Monday through Friday. All remaining weekday hours and all hours on weekends and holidays recognized by the National Electric Reliability Council (NERC) are considered the off-peak period. This is consistent with the time periods used in the forwards market for trading of bulk power. The values in this table for each month are the average on-peak percentages from the years 2021 and 2022 and 2023, as calculated from the same load research data used for retail settlement for current customers that have chosen to be supplied by a Third-Party Supplier (TPS). The average for a three-year period was used to reduce the variability of weather effects on the percentage from any single year.

Table #2 (% Usage During PSE&G On-Peak Billing Period) contains the percentage of on-peak load, by month, for each applicable rate schedule based on the definitions of time periods as contained in Public Service's delivery rate schedules. Since, excluding the hourly price BGS rates, only Rate Schedule RLM and LPL-Sec are billed on a time-of-day basis utilizing time periods, these are the only two columns in this table where data has been inputted. These are the percentage of actual on-peak kWh usage for the years, 2021, 2022, and 2023. As was done with Table #1, the three-year average was used to reduce the effects of weather in a particular year.

Table #3 (Class Usage @ customer) contains the total calendar month sales forecasted for the calendar year 2024 with a migration adjustment. The values in Table #3 will be updated in January 2025 to better reflect the amount by rate schedule that could be in effect starting on June 1, 2025. For Rate LPL-Secondary, these values have been reduced for the percentage of customers having a Peak Load Share of

500 kW or greater, and thus having BGS- CIEP as their default service. These monthly percentages were based on the 2023 monthly percentages of total actual sales for customers meeting this Peak Load Share threshold.

Table #4 (Forwards Prices – Energy Only @ Bulk System) contains the forward prices for energy, by time period and month for the BGS analysis period. These values are the most recent energy on-peak forwards values available for the PJM West trading hub for the period of June 2024 to May 2025 and the historical ratio of actual off-peak to on-peak PJM LMPs from June 2021 through September 2023 and March 2021 through February 2024, for summer and winter periods, respectively.

An adjustment of the forwards prices contained in Table #4 is then made to correct for the effects of transmission congestion in the PJM system between the PJM West trading hub and the Public Service zone where the BGS supply will be utilized.

Table #5 (Congestion Factors) contains an estimate of the average congestion factors, by month and time period, which when multiplied by the prices at the PJM West trading hub will result in costs for power delivered into the Public Service zone. These Hub-to-Zone differentials are based on the average percent differences from June 2021 through September 2023 and March 2021 through February 2024, for summer and winter periods, respectively.

Table #6 (Losses) The factors utilized for total average losses, including PJM losses, are inputted in the upper portion of Table #6 (Losses) by rate schedule. Delivery loss factors used are those in the Company's filed tariff. PJM losses are the average percentage PJM EHV losses plus inadvertent energy for the three-year period June 2013 through May 2016, a value equal to 0.456%.

The lower portion of this table shows the derivation of the effective losses from the customer meter to the transmission nodes at which the LMPs are calculated. The loss factors shown are the Delivery loss factors from the Company's filed tariff less the mean hourly marginal loss factors for the PSE&G transmission zone as calculated by PJM. The resulting loss factor is reflective of losses from the customer meter to the transmission nodes (at which the LMPs are calculated) and at which payments to the winning bidders are based. The marginal loss factors used above are actual marginal loss de-ration factors based May 2021 to April 2024 data adjusted for the portion of marginal losses attributed to PJM extra-high voltage.

Since the service for all of the rates indicated is at secondary voltages, the applicable loss factors are identical for all rates.

Table #7 (Summary of Average BGS Energy Only Unit Costs @ Customer – PJM Time Periods) is the calculation of the energy only costs by rate, time period and season. These values are the seasonal and time period average costs per MWh as measured at the customer billing meter (from Table #3), based on the forwards prices (from Table #4) corrected for congestion (from Table #5), losses (from Table #6), and monthly time period weights (from Table #1). These average costs do not include the costs associated with Ancillary Services, Renewable Portfolio Standard compliance, Generation Obligation or Transmission costs, which will be considered in subsequent calculations.

Table #8 (Summary of Average BGS Energy Only Costs @ Customer – PJM Time Periods) indicates the total value, in thousands of dollars, of the average BGS energy only costs. These are the results of the multiplication of the unit costs from Table #7, the monthly time period weights from Table #1 and the total sales to customers from Table #3.

Since the end result of these calculations are to be utilized in the development of retail BGS rates, the rates utilizing time-of-day pricing must be developed based upon the time periods as defined for billing.

Table #9 (Summary of Average BGS Energy Only Unit Costs @ Customer – PSE&G Time Periods) shows the result of the corrections for the two rates billed on a time-of-day basis, Rates RLM and LPL-Secondary (less than 500 kW). These values are calculated based on the assumption that the MWhs included in the PJM on-peak time period and not included in the PSE&G on-peak time periods are at the average of the on and off-peak PJM prices.

Table #10 (Generation & Transmission Obligations and Costs and Other Adjustments) The next steps set up the values necessary for the inclusion of the costs of the Generation Capacity and Transmission obligations. The top portion of Table #10 shows the total obligations with a migration adjustment, by rate schedule, that are currently being utilized in the year 2023. The values in the top portion of Table #10 will be updated in January 2025 to better reflect the aggregate amount by rate schedule that could be in effect on June 1, 2025. Similar to the methodology used in Table #3, the obligations for Rate LPL-Secondary have been reduced for the percentage of customers having a Peak Load Share of 500 kW or greater. The middle portion of this table shows the number of summer and winter days and months that are used in this analysis. The bottom portion of this table shows the annual cost for transmission service now to be zero and the average price of generation capacity, using the Capacity Proxy Price for Delivery Year 2025/2026, the Capacity Proxy Price for Delivery Year 2026/2027, and the Capacity Proxy Price for Delivery Year 2027/2028. The Capacity Proxy Prices will be replaced with the Zonal Capacity Prices, which are the prices paid by BGS-RSCP Suppliers for Capacity for the 2025/2026, 2026/2027 and the 2027/2028 delivery years, when available as may be determined through the Reliability Pricing Model or its successor or otherwise.

The BGS Transmission Charge will now be set through separate filings as discussed in the BGS Transmission Charge sections. This table also shows the level of blocking in current BGS charges for Rates RS and RHS, which will be utilized in the later calculations of the blocking of the new BGS charges for these rates. The Company has previously objected to the blocking of these charges since there is no compelling cost basis for any such blocking. The Company proposes to keep blocking in this year's filing but wishes to note that it does not believe that there is a cost basis for doing so.

Table #11 (Ancillary Services and Renewable Portfolio Standard) An estimate of the effects of the costs of ancillary services and Renewable Portfolio Standard is included in the development of the final BGS rates. The values of $2.00 per MWh and $22.64 per MWh are used, respectively. Since the actual costs are a complex combination of many factors, this Board-approved estimate of the overall annual average value, expressed on a dollar per MWh basis, is used as a reasonable and practical alternative.

Table #12 (Summary of Obligation Costs Expressed as $/MWh @ Customer – For Non- Demand Rates Only) shows the result of the allocation of both the transmission and generation costs on a per kWh basis to those rates whose BGS service will only be recovered through energy charges, Rates RS through BPL. The obligation costs for the rates not indicated in this table, Rates GLP and LPL-Sec, will be recovered directly through a distinct obligation charge based on a separate charge times each customer's assigned transmission and generation capacity obligation. The annual values are calculated as the total obligations (upper part of Table #10) times their costs (lower part of Table #10) divided by the appropriate total rate schedule MWh (from Table #3).

Table #13 (Summary of BGS Unit Costs @ Customer) is the result of the inclusion of the Transmission, Generation Capacity, Ancillary Services, and Renewable Portfolio Standard costs to the energy only costs shown in Table #9. The top portion of this table shows the total estimated all-in BGS costs for the non-demand rates (Rates RS, RHS, RLM, WH, WHS, HS, PSAL and BPL), whose BGS costs are proposed to be recovered on an energy only basis through kWh charges. The all-in costs for the residential non-time of day rates, Rates RS and RHS, are blocked in the summer based on the current level of BGS blocking inputted in Table #10 so as to maintain the same BGS rate differential that currently exists. The middle section shows the results for the demand rates (Rates GLP and LPL-Sec) whose BGS costs will be recovered through both energy charges on a per kWh basis and obligation charges on a per kW of obligation basis. The left-hand columns indicate the unit energy costs, while the right-hand columns indicate the obligation costs. The bottom portion of this table shows the total estimated costs for BGS, based on the assumptions utilized in the above tables, and the average per unit cost, as measured at the customer meters or the transmission nodes.

Table #14 (Ratio of BGS Unit Costs @ Customer to All-In Average Cost @ Transmission Nodes) indicates the ratio of the individual rate element costs from Table #13 to the overall all- in cost as measured at the transmission nodes, plus constants, where applicable. These bid factor ratios are a key element in the calculation of the actual BGS-RSCP charges and will be used in later tables to convert the winning bids into actual BGS rates charged to customers.

The top portion of this table indicates these ratios for the non-demand rates while the ratios for the demand rates are shown on the bottom portion of the table. Since the unit rates charged for generation and transmission obligation (as shown in the right-hand columns) for Rates GLP and LPL-Sec are not unitized but kept at the estimated market value, it is necessary to modify the energy ratios for these two rate classes to assure that the resulting overall revenue from charges to the customers equals the payment to suppliers. The first of the values indicated, the “multiplier” is utilized as a ratio, with the “constant” term an additive adjustment to the resulting value. For example, if the tranche weighted average winning bid prices adjusted for seasonal payment factors is $85.182 per MWh and the GLP multiplier for summer is 1.043 and the constant is ($6.021), the summer BGS rate charged customers would equal ($85.182 * 1.043) - $6.021 , or $82.82 per MWh.

Assumptions: This unnumbered table summarizes some of the most important assumptions utilized in the above calculations.

Table #15 (Summary of Total BGS Costs by Season) shows the calculation of the total BGS Costs, utilizing the total customer usage from Table #3 and the all-in unit costs from Table #13. The lower left portion of this table indicates the relative percentage of total costs by season for all rate schedules, while the center shows the calculation of the overall average all-in seasonal unit costs on a dollar per MWh basis. The ratio of these overall average seasonal costs to the overall total cost, shown in the lower right-hand portion of this table, are the seasonal payment ratios upon which payments to the winning bidders are based. Since the normal calculation would produce an atypical result of a summer payment ratio (factor) that is lower than the winter payment ratio (factor) for the 2025/2026 BGS Supply Period, a factor of 1.0 will be used for both the summer and winter payment factors.

Table #16 (Spreadsheet Error Checking) shows the reconciliation between the customer revenue calculation to the BGS supplier payments, utilizing an assumed winning bid price (as indicated) and the calculated summer-winter payment ratios, the customer usage from Table #3 and the all-in unit costs from Table #13.

Table #17 (Total Supplier Energy @ transmission nodes) shows the calculation of the total supplier energy by season, utilizing the total customer usage from Table #3 and the meter to transmission node loss factors from the lower portion of Table #6.

The second spreadsheet used in the calculation of the final BGS-RSCP rates is included as Attachment #3 and is titled “Calculation of June 2025 to May 2026 BGS-RSCP Rates”. The tables in this spreadsheet calculate the weighted average winning bid price and convert it into the final BGS-RSCP rates that are charged to customers. An explanation of each of the six tables, labeled as Table A through F, is as follows.

Table A (Auction Results) contains the results of the prior two BGS auctions as well as the results (shown with illustrative values) of the current auction. The Capacity Proxy Price True Up cost in $ per MWh will be used to reflect the impact of payments made pursuant to the Supplements executed by

BGS Suppliers in February 2023 and February 2024. Upon conclusion of the Third Incremental RPM Auction through the Reliability Pricing Model or its successor or otherwise, the price paid by BGS-RSCP Suppliers for Capacity in the Company's PJM Zone will be known. The Capacity Proxy Price True-Up will then be determined by the price difference between the price paid by BGS-RSCP Suppliers for Capacity in the Company's PJM Zone and the Capacity Proxy Price for the 2025/2026 Delivery Year. The value of ($50.00 per MW-Day) is used as an approximation for the price paid by BGS-RSCP Suppliers for Capacity in the Company's PJM Zone for the 2025/2026 Delivery Year.

Table B (Ratio of BGS Unit Costs @ Customer to All-In Average Cost @ transmission nodes) is a repeat of the values shown in Table #14 from Attachment 2, the bid factors calculated based on current market conditions.

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

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

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

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

B. PSE&G Direct Current Fast Charging ("DCFC") BGS Rate Program

Program Description

In the November 9, 2022 BGS Board Order (Docket No. ER22030127), the Board directed the EDCs to work with interested parties to come to a consensus for a Direct Current Fast Charging ("DCFC") rate solution and to include a DCFC rate design proposal in the EDCs' 2024 BGS Auction filing. Discussions with interested parties regarding DCFC rate design were conducted during the winter and spring of 2023. As a result, PSE&G proposed a two-year DCFC BGS Rate pilot program that implements a cents per kWh charge for both Capacity and Transmission costs (referred to as the "Average kWh DCFC Charge") for DCFC stations that are served on BGS-RSCP or BGS-CIEP and that elect to participate in program. On November 17, 2023, the BPU approved this program, effective for the billing periods beginning in June 2024.

Program Term

The second year of the DCFC BGS Rate pilot program will begin with rates effective for the billing periods beginning in June of 2025 and ending in May of 2026. The program will terminate automatically in June of 2026, unless renewed or otherwise modified by the Board.

Enrollment

To gauge interest in this program, in early December 2023, PSE&G sent an email to all DCFC customers and sites notifying them of this optional program and that it was to begin in June 2024. The email contained a brief description of the program and stated that eligible customers currently being served on BGS will also be sent a second email containing additional information and a non-binding application.

The second email explained that the enrollment would proceed in two stages: an initial non-binding application would have to be completed and submitted within two weeks, and a second stage would occur in March 2024 and would require the participants to make a binding agreement that would have to be signed and submitted before the end of March 2024. The application was designed to allow for a customer to place all its facilities on one application. In response, PSE&G received completed non-binding applications from 4 customers representing a total of 21 accounts and/or sites.

Once again, in March 2024, PSE&G repeated this process with a binding-application with a firm commitment date of March 31, 2024. Of the 4 customers representing 21 sites in the initial application process, 3 customers representing 15 accounts and/or sites committed to proceeding with this program.

Additional customer enrollment for the second year of the DCFC BGS Rate pilot, effective for the billing periods beginning in June 2025, will continue to be optional and is only applicable to DCFC charging stations that are individually metered (i.e., it is not applicable to DCFC charging stations that may be interconnected behind the meter of another load). BGS DCFC charging station customers that do not enroll in the DCFC BGS Rate will be served pursuant to the standard terms and conditions of the BGS-RSCP or BGS-CIEP tariff, as is applicable. Customers participating must enroll individual DCFC stations (i.e., each individually metered DCFC charging station) for the full two-year pilot program.

- Initial enrollment for the second year of the program must be in writing no later than December 20, 2024. Initial enrollments will be non-binding. PSE&G will publish instructions indicating the process by which EV installations may enroll in the program shortly following the Board Order approving the program in this matter, anticipated in November of 2024.
- Final enrollment must be in writing no later than March 31, 2025 in accordance with PSE&G's final enrollment instructions. Final enrollment will be a fully binding commitment for participation in the program's entire two-year term.

Following the 2025 BGS auction, PSE&G will provide to initial enrollees an updated rate estimate based on final auction results to inform final enrollment.

Program DCFC BGS Rates

The method for calculation the DCFC kWh Charge is shown in Attachment 5 will be used in the calculation of participating DCFC installations' capacity and transmission charges, only. All participants will continue to be billed for energy charges and all other rate components of BGS-RSCP or BGS-CIEP, as applicable, per the tariff. For the program that started in June 2024, the DCFC RSCP Rate is $0.072315 per kWh and the DCFC CIEP Rate is $0.090528 per kWh.

Capacity

The DCFC RSCP kWh rate for Capacity will be the BGS-RSCP Capacity price in $/kW-month converted to a $ per kWh charge using an average load factor based upon the latest available Capacity Obligation and historic twelve months' energy use for all PSE&G DCFC station customers. Similarly, the DCFC CIEP kWh rate for Capacity will be the BGS-CIEP Capacity price in $/kW-month converted to a $ per kWh charge using an average load factor based upon the latest available Capacity Obligation and historic twelve months' energy use for all PSE&G DCFC station customers.

Transmission

The DCFC Transmission price for both BGS-RSCP and BGS-CIEP is the same $/kW-month therefore the DCFC Transmission rate will be the Transmission price in $/kW-month converted to a $ per kWh charge using the average load factor based upon the latest available Transmission Obligation and historic twelve months' energy use for all PSE&G DCFC station customers.

The DCFC charges will be updated periodically during the BGS process with the latest data available, to reflect changes to capacity and transmission prices, changes in DCFC load factors as well as changes in participant load. Please see Attachment 5 for the calculation of the Average kWh DCFC charge.

Monthly Billing and Accounting

On a monthly basis, the Company will calculate each participating EV station's BGS-RSCP or BGS-CIEP capacity and transmission charges two ways:

1. The current BGS-RSCP method, or current BGS-CIEP method, as applicable to each participating EV installation, utilizing $ per MW-day charges to calculate Capacity and Transmission charges. This current method will continue to be printed on the bill.
2. The proposed Average kWh DCFC Charge methodology that utilizes average BGS-RSCP $/kWh or average BGS-CIEP $/kWh charges for Capacity and Transmission charges (described below), as applicable to each participating EV installation.

The result of subtracting the monthly calculated dollar amount of Item 1 from Item 2 listed above will be added to each DCFC customer's total monthly BGS supply bill for which the customer is responsible. This could result in a credit or charge. This dollar amount for all program participants will also be deferred and accumulated in the appropriate corresponding DCFC BGS-RSCP or DCFC BGS-CIEP reconciliation charges (applicable only to the enrolled EV installations, and collectively referred to as the "DCFC Reconciliation Charges").

The DCFC Reconciliation Charges will be forecasted to recover the over/under balances of the revenues and program implementation costs. The Company may modify the charges on a quarterly basis throughout the two-year term of the pilot as it deems appropriate based on actual and projected dollar differences between the two methods listed above. Interest will be calculated for the DCFC Reconciliation Charges similar to the manner in which interest is calculated for the BGS RSCP and BGS CIEP Reconciliation Charges.

Implementation Costs and Contingency Costs

The remaining actual implementation costs for this program will be recovered from program participants as a component of monthly bills. The remaining implementation costs will be spread over a forecasted amount of kWh over the second year of the program along with a contingency cost of $0.01 per kWh. A contingency fee of $0.01 per kWh will also be billed to participants for the purposes of mitigating the potential for a balance of unbilled DCFC Reconciliation Charges costs at program end. The forecasted kWh will be based upon the latest available historic twelve months' energy use for participating DCFC station customers.

The implementation costs will be deferred in a separate deferred account and collect interest in the same manner the current BGS reconciliation charges. Each month, the amount collected in the DCFC rates described above will be transferred from the DCFC Reconciliation Charge Balances to the Implementation Cost Deferred Balance. The remaining Implementation Cost Deferred balance will be allocated to DCFC RSCP and CIEP Reconciliation Charge balances by their corresponding proportion of kWh sales during the entire program.

Cost Recovery

At program end, if the program is not continued and there remains a balance of DCFC Reconciliation Charges or Implementation Cost Deferred Balance, PSE&G will petition to seek recovery of these charges.

C. PSE&G RESIDENTIAL TIME OF USE RATES ("TOU") PILOT PROGRAM

Program Description

As stated in PSE&G's electric distribution rate case filed on December 29, 2023, BPU Docket No. ER23120924, PSE&G is proposing a voluntary two year pilot program ("TOU Proposal") offering customers two new TOU Residential rates, a two period ("2P") and three period ("3P") rate structures, designed to be revenue neutral to the Residential RS rate and if successful, will provide for the closing of the RLM rate. As a result, new BGS TOU rates will be needed for the supply portion of the proposed electric distribution rates filed in that case. Together, these proposed rate structures will more closely align costs with cost causation, offer lower cost electricity to charge electric vehicles and may result in reducing future rates for all customers by encouraging the most efficient use of electricity at a fair and equitable cost.

The objective of the TOU rates is to create rates that would provide customers with time of use pricing options that give customers options to move some of their discretionary, relative to timing, usage to non-peak times, where lower pricing could be offered reflecting the lower costs to serve during off peak times. These time-dependent price options may be of interest to those customers for whom the off-peak pricing meets their usage patterns or for those customers willing to modify their usage pattern to take advantage of the lower non-peak rates. The development of the proposed two and three period rates are described in detail in the following Rate Design section.

Program Details

As previously stated, these TOU rates are proposed as part of the Company's current base rate case "TOU Proposal". The structure of these rates is based upon the Company's proposal being approved as requested. Any changes to the TOU Proposal would need to be reflected in the proposed BGS TOU rates. In the TOU Proposal, each residential customer that opts into one of the two new RS-TOU rates, at the end of the initial 12-month period, the Company will provide each customer with reporting showing his or her 12-month bill on the new RS-TOU rate and what this 12-month bill would have been on the RS Rate Schedule. The customer will be offered a one-time refund of the difference if the 12-month bill on the RS-TOU rate was higher compared to the RS Rate Schedule. The supply portion of the refund will be recording as a reduction to BGS revenue in the month it is granted to the customer (as utilized in the derivation of the BGS-RSCP reconciliation charge). This initial 12-month look back provision is incorporated to encourage customers to be more willing to try the RS-TOU rates knowing they will not be financially disadvantaged, and after the initial 12-month period, customers can choose to revert back to the RS Rate Schedule if they wish. The initial 12 month look back provision would only be available to customers who take service under either RS TOU rate during the first 24 months that the rate is available to customers. There will be a requirement for customer to stay on the new RS-TOU rate for a period of 12 months. After being on the rate for a minimum of 12 months, customers would also be able to choose to switch back to the RS Rate Schedule at any time.

Implementation Costs

All implementation costs related to the proposed TOU rates have been requested through the Company's TOU Proposal. It is not anticipated that any incremental cost will be incurred to implement the TOU Proposal BGS rates.

Rate Design

Since these are the initial rates, the rates are being designed to be revenue neutral to the RS rate class as well as using the RS rate class load profile. The revenue was allocated to Capacity and Energy components based upon the underlying cost components in the BGS model. Capacity costs were designed to collected on-peak period for both the 2P and 3P TOU rates. Energy Costs were designed to be collected over there corresponding time periods. RPS and Ancillary costs were design to be collected over all time periods.

Once there are customers receiving BGS under these new proposed rates, the actual load profiles of these rates will be used in rate design in future BGS years, similar to the existing rate classes being served. The detailed rate design for both the 2P and 3P TOU rates can be found in Attachment 6

IV. CONCLUSION

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

1. It is necessary and in the public interest for the electric public utilities to secure service for the BGS-RSCP and BGS-CIEP customers, as approved herein, for the period June 1, 2025 to May 31, 2028.
2. The Company's proposed accounting for BGS is approved for purposes of accounting and BGS cost recovery.
3. The proposed BGS Contingency Plan is approved, and there will exist a presumption of prudence with respect to the BGS Auction Plan method and the costs incurred for BGS service under the Auction Plan and the related Contingency Plan.
4. The Company's Rate Design Methodology and Tariff Sheets are approved.
5. The Company's continuation of the DCFC BGS Rate Program and cost recovery are approved.
6. The Company's PSE&G Residential Time of Use Rates ("TOU") Pilot Program and related supply rates.

V. ATTACHMENT 1 - TARIFF SHEETS

"Form Of" BGS-RSCP, BGS-CIEP and CIEP Standby Fee tariff sheets

(Pages 1 through 8)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 16 ELECTRIC **Original Sheet No. 73**

COMMERCIAL AND INDUSTRIAL ENERGY PRICING (CIEP) STANDBY FEE

APPLICABLE TO:

All kilowatt-hour usage under Rate Schedules LPL-Secondary (500 kilowatts or greater), LPL-Primary, HTS-Subtransmission, HTS-Transmission, HTS-High Voltage and all kilowatt-hour usage for customers under Rate Schedules HS, GLP and LPL-Secondary (less than 500 kilowatts) who have elected hourly energy pricing service from either BGS-CIEP or a Third Party Supplier.

	Charge (per kilowatt-hour)
Commercial and Industrial Energy Pricing (CIEP) Standby Fee	$ 0.000150
Charge including New Jersey Sales and Use Tax (SUT)	$ 0.000160

The above charges shall recover costs associated with the administration, maintenance and availability of the Basic Generation Service default electric supply service for applicable rate schedules. These charges shall be combined with the Distribution Kilowatt-hour Charges for billing.

Kilowatt threshold noted above is based upon the customer's Peak Load Share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM). See Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions of this Tariff.

Date of Issue: October 30, 2018 Effective: November 1, 2018
Issued by SCOTT S. JENNINGS, Vice President Finance – PSE&G
80 Park Plaza, Newark, New Jersey 07102
Filed pursuant to Order of Board of Public Utilities dated October 29, 2018
in Docket Nos. ER18010029, GR18010030, AX18010001 and ER18030231

PUBLIC SERVICE ELECTRIC AND GAS COMPANY **XXX Revised Sheet No. 75**
Superseding
B.P.U.N.J. No. 16 ELECTRIC **XXX Revised Sheet No. 75**

BASIC GENERATION SERVICE – RESIDENTIAL SMALL COMMERCIAL PRICING (BGS-RSCP) ELECTRIC SUPPLY CHARGES

APPLICABLE TO:

Default electric supply service for Rate Schedules RS, RHS, RLM, WH, WHS, HS, BPL, BPL-POF, PSAL, GLP and LPL-Secondary (less than 500 kilowatts).

BGS ENERGY & CAPACITY CHARGES:

Applicable to Rate Schedules RS, RHS, RLM, WH, WHS, HS, BPL, BPL-POF and PSAL

Charges per kilowatt-hour:

Rate Schedule	For usage in each of the months of October through May: Energy & Capacity Charges	For usage in each of the months of October through May: Charges Including SUT	For usage in each of the months of June through September: Energy & Capacity Charges	For usage in each of the months of June through September: Charges Including SUT
RS – first 600 kWh	$x.xxxxxx	$x.xxxxxx	$x.xxxxxx	$x.xxxxxx
RS – in excess of 600 kWh	x.xxxxxx	x.xxxxxx	x.xxxxxx	x.xxxxxx
RHS – first 600 kWh	x.xxxxxx	x.xxxxxx	x.xxxxxx	x.xxxxxx
RHS – in excess of 600 kWh	x.xxxxxx	x.xxxxxx	x.xxxxxx	x.xxxxxx
RLM On-Peak	x.xxxxxx	x.xxxxxx	x.xxxxxx	x.xxxxxx
RLM Off-Peak	x.xxxxxx	x.xxxxxx	x.xxxxxx	x.xxxxxx
WH	x.xxxxxx	x.xxxxxx	x.xxxxxx	x.xxxxxx
WHS	x.xxxxxx	x.xxxxxx	x.xxxxxx	x.xxxxxx
HS	x.xxxxxx	x.xxxxxx	x.xxxxxx	x.xxxxxx
BPL	x.xxxxxx	x.xxxxxx	x.xxxxxx	x.xxxxxx
BPL-POF	x.xxxxxx	x.xxxxxx	x.xxxxxx	x.xxxxxx
PSAL	x.xxxxxx	$x.xxxxxx	$x.xxxxxx	$x.xxxxxx

The above Basic Generation Service Energy Charges reflect costs for Energy, Generation Capacity, and Ancillary Services (including PJM Interconnection, L.L.C. (PJM) Administrative Charges).

Kilowatt threshold noted above is based upon the customer's Peak Load Share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM). See Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions of this Tariff.

BASIC GENERATION SERVICE – RESIDENTIAL SMALL COMMERCIAL PRICING (BGS-RSCP)
ELECTRIC SUPPLY CHARGES
(Continued)

BGS TRANSMISSION CHARGES:

Applicable to Rate Schedules RS, RHS, RLM, WH, WHS, HS, BPL, BPL-POF and PSAL

Charges per kilowatt-hour:

	For usage in all months	
Rate Schedule	Transmission Charges	Charges Including SUT
RS	$x.xxxxxx	$x.xxxxxx
RHS	x.xxxxxx	x.xxxxxx
RLM On-Peak	x.xxxxxx	x.xxxxxx
RLM Off-Peak	x.xxxxxx	x.xxxxxx
WH	x.xxxxxx	x.xxxxxx
WHS	x.xxxxxx	x.xxxxxx
HS	x.xxxxxx	x.xxxxxx
BPL	x.xxxxxx	x.xxxxxx
BPL-POF	x.xxxxxx	x.xxxxxx
PSAL	x.xxxxxx	x.xxxxxx

The above charges shall recover all costs related to the overall summer peak transmission load assigned to the Public Service Transmission Zone by the PJM Interconnection, L.L.C. (PJM) as adjusted by PJM assigned transmission capacity related factors and allocated to the above Rate Schedules. These charges will be changed from time to time on the effective date of such change to the PJM rate for charges for Network Integration Transmission Service, including the PJM Seams Elimination Cost Assignment Charges, the PJM Reliability Must Run Charge and PJM Transmission Enhancement Charges as approved by Federal Energy Regulatory Commission (FERC).

BGS ENERGY CHARGES:

Applicable to Rate Schedules GLP and LPL-Sec.

Charges per kilowatt-hour:

	For usage in each of the months of October through May		For usage in each of the months of June through September	
Rate Schedule	Charges	Charges Including SUT	Charges	Charges Including SUT
GLP	$x.xxxxxx	$x.xxxxxx	$x.xxxxxx	$x.xxxxxx
GLP Night Use	x.xxxxxx	x.xxxxxx	x.xxxxxx	x.xxxxxx
LPL-Sec. under 500 kW				
On-Peak	x.xxxxxx	x.xxxxxx	x.xxxxxx	x.xxxxxx
Off-Peak	x.xxxxxx	x.xxxxxx	x.xxxxxx	x.xxxxxx

The above Basic Generation Service Energy Charges reflect costs for Energy and Ancillary Services (including PJM Administrative Charges).

Kilowatt thresholds noted above are based upon the customer's Peak Load Share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM). See Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions of this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY **XXX Revised Sheet No. 79**
Superseding
B.P.U.N.J. No. 16 ELECTRIC **XXX Revised Sheet No. 79**

BASIC GENERATION SERVICE – RESIDENTIAL SMALL COMMERCIAL PRICING (BGS-RSCP)
ELECTRIC SUPPLY CHARGES
(Continued)

BGS CAPACITY CHARGES:

Applicable to Rate Schedules GLP and LPL-Sec.
Charges per kilowatt of Generation Obligation:

Charge applicable in the months of June through September ....$ x.xxxx
Charge including New Jersey Sales and Use Tax (SUT) ....$ x.xxxx

Charge applicable in the months of October through May...$ x.xxxx
Charge including New Jersey Sales and Use Tax (SUT) ....$ x.xxxx

The above charges shall recover each customer's share of the overall summer peak load assigned to the Public Service Transmission Zone by the PJM Interconnection, L.L.C. (PJM) as adjusted by PJM assigned capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions.

BGS TRANSMISSION CHARGES

Applicable to Rate Schedules GLP and LPL-Sec.
Charges per kilowatt of Transmission Obligation:

Currently effective Annual Transmission Rate for
Network Integration Transmission Service for the
Public Service Transmission Zone as derived from the
FERC Electric Tariff of the PJM Interconnection, LLC ....$ xxx,xxx.xx per MW per year
EL05-121 ....$ xx.xx per MW per month
FERC 680 & 715 Reallocation...$ x.xx per MW per month
PJM Seams Elimination Cost Assignment Charges...................................$ x.xx per MW per month
PJM Reliability Must Run Charge ....$ x.xx per MW per month
PJM Transmission Enhancements
Trans-Allegheny Interstate Line Company ....$ xx.xx per MW per month
Virginia Electric and Power Company..$ xx.xx per MW per month
Midcontinent Independent System Operator ....$ x.xx per MW per month
PPL Electric Utilities Corporation .... $ xxx.xx per MW per month
American Electric Power Service Corporation ....$ xx.xx per MW per month
Atlantic City Electric Company..$ x.xx per MW per month
Delmarva Power and Light Company ....$ x.xx per MW per month
Potomac Electric Power Company ....$ x.xx per MW per month
Baltimore Gas and Electric Company ....$ x.xx per MW per month
Jersey Central Power and Light...$ xx.xx per MW per month
Mid Atlantic Interstate Transmission ....$ x.xx per MW per month
PECO Energy Company ....$ xx.xx per MW per month
Silver Run Electric, Inc...$ xx.xx per MW per month
Northern Indiana Public Service Company ....$ x.xx per MW per month
Commonwealth Edison Company ....$ x.xx per MW per month
South First Energy Operating Company ....$ x.xx per MW per month
Duquesne Light Company ....$ x.xx per MW per month

Above rates converted to a charge per kW of Transmission
Obligation, applicable in all months ....$ xx.xxxx
Charge including New Jersey Sales and Use Tax (SUT)...$ xx.xxxx

The above charges shall recover each customer's share of the overall summer peak transmission load assigned to the Public Service Transmission Zone by the PJM Interconnection, L.L.C. (PJM) as adjusted by PJM assigned transmission capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions. These charges will be changed from time to time on the effective date of such change to the PJM rate for charges for Network Integration Transmission Service, including the PJM Seams Elimination Cost Assignment Charges, the PJM Reliability Must Run Charge and PJM Transmission Enhancement Charges as approved by Federal Energy Regulatory Commission (FERC).

BASIC GENERATION SERVICE – RESIDENTIAL SMALL COMMERCIAL PRICING (BGS-RSCP)
ELECTRIC SUPPLY CHARGES
(Continued)

DCFC RSCP RATE PROGRAM – CAPACITY AND TRANSMISSION CHARGE
Applicable to Rate Schedules GLP and LPL-Sec.
Charges per kilowatt-hour:

Charge	Charge Including SUT
$x.xxxxxx	$x.xxxxxx

The above charge is for customers who operate DCFC Stations to serve electric vehicles only and who elect to be included in the DCFC BGS Rate Program. BGS energy charges still apply.

The above charges shall recover each customer's share of the overall summer peak transmission load assigned to the Public Service Transmission Zone by the PJM Interconnection, L.L.C. (PJM) as adjusted by PJM assigned transmission capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions. These charges will be changed from time to time on the effective date of such change to the PJM rate for charges for Network Integration Transmission Service, including the PJM Seams Elimination Cost Assignment Charges, the PJM Reliability Must Run Charge and PJM Transmission Enhancement Charges as approved by Federal Energy Regulatory Commission (FERC).

PUBLIC SERVICE ELECTRIC AND GAS COMPANY **XXX Revised Sheet No. 82**
Superseding
B.P.U.N.J. No. 16 ELECTRIC **XXX Revised Sheet No. 82**

BASIC GENERATION SERVICE – COMMERCIAL AND INDUSTRIAL ENERGY PRICING (CIEP) ELECTRIC SUPPLY CHARGES

APPLICABLE TO:

Default electric supply service for Rate Schedules LPL-Secondary (500 kilowatts or greater), LPL-Primary, HTS-Subtransmission, HTS-Transmission, HTS-High Voltage and to customers served under Rate Schedules HS, GLP and LPL-Secondary (less than 500 kilowatts) who have elected BGS-CIEP as their default supply service.

BGS ENERGY CHARGES:

Charges per kilowatt-hour:

BGS Energy Charges are hourly and include PJM Locational Marginal Prices, and PJM Ancillary Services. The total BGS Energy Charges are based on the sum of the following:

- The real time PJM Load Weighted Average Residual Metered Load Aggregate Locational Marginal Prices for the Public Service Transmission Zone, adjusted for losses (tariff losses, as defined in Standard Terms and Conditions Section 4.3, adjusted to remove the mean hourly PJM marginal losses of 0.912100~~.86333~~%), and adjusted for SUT, plus
- Ancillary Services (including PJM Administrative Charges) at the rate of $0.006000 per kilowatt-hour, adjusted for losses (tariff losses, as defined in Standard Terms and Conditions Section 4.3, adjusted to remove the mean hourly PJM marginal losses of 0.912100~~.86333~~%), and adjusted for SUT, plus

BGS CAPACITY CHARGES:

Charges per kilowatt of Generation Obligation:

Charge applicable in the months of June through September .... $ xx.xxxx
Charge including New Jersey Sales and Use Tax (SUT) .... $ xx.xxxx

Charges applicable in the months of October through May .... $ xx.xxxx
Charges including New Jersey Sales and Use Tax (SUT)... $ xx.xxxx

The above charges shall recover each customer's share of the overall summer peak load assigned to the Public Service Transmission Zone by the PJM Interconnection, L.L.C. (PJM) as adjusted by PJM assigned capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY **XXX Revised Sheet No. 83**
Superseding
B.P.U.N.J. No. 16 ELECTRIC **XXX Revised Sheet No. 83**

BASIC GENERATION SERVICE – COMMERCIAL AND INDUSTRIAL ENERGY PRICING (CIEP)
ELECTRIC SUPPLY CHARGES
(Continued)

BGS TRANSMISSION CHARGES

Charges per kilowatt of Transmission Obligation:

Currently effective Annual Transmission Rate for Network Integration Transmission Service for the Public Service Transmission Zone as derived from the FERC Electric Tariff of the PJM Interconnection, LLC	$ xxx,xxx.xx per MW per year
EL05-121	$ xx.xx per MW per month
FERC 680 & 715 Reallocation	$ x.xx per MW per month
PJM Seams Elimination Cost Assignment Charges	$ x.xx per MW per month
PJM Reliability Must Run Charge	$ x.xx per MW per month
PJM Transmission Enhancements	
Trans-Allegheny Interstate Line Company	$ xx.xx per MW per month
Virginia Electric and Power Company	$ xx.xx per MW per month
Midcontinent Independent System Operator	$ x.xx per MW per month
PPL Electric Utilities Corporation	$ xxx.xx per MW per month
American Electric Power Service Corporation	$ xx.xx per MW per month
Atlantic City Electric Company	$ x.xx per MW per month
Delmarva Power and Light Company	$ x.xx per MW per month
Potomac Electric Power Company	$ x.xx per MW per month
Baltimore Gas and Electric Company	$ x.xx per MW per month
Jersey Central Power and Light	$ xx.xx per MW per month
Mid Atlantic Interstate Transmission	$ x.xx per MW per month
PECO Energy Company	$ xx.xx per MW per month
Silver Run Electric, Inc	$ xx.xx per MW per month
Northern Indiana Public Service Company	$ x.xx per MW per month
Commonwealth Edison Company	$ x.xx per MW per month
South First Energy Operating Company	$ x.xx per MW per month
Duquesne Light Company	$ x.xx per MW per month

Above rates converted to a charge per kW of Transmission Obligation, applicable in all months	$ xx.xxxx
Charge including New Jersey Sales and Use Tax (SUT)	$ xx.xxxx

DCFC CIEP RATE PROGRAM – CAPACITY AND TRANSMISSION CHARGE

Charges per kilowatt-hour:

Charge	Charge Including SUT
$x.xxxxxx	$x.xxxxxx

The above charge is for customers who operate DCFC Stations to serve electric vehicles only and who elect to be included in the DCFC BGS Rate Program. BGS energy charges still apply.

The above charges shall recover each customer's share of the overall summer peak transmission load assigned to the Public Service Transmission Zone by the PJM Interconnection, L.L.C. (PJM) as adjusted by PJM assigned transmission capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions. These charges will be changed from time to time on the effective date of such charge to the PJM rate for charges for Network Integration Transmission Service, including the PJM Seams Elimination Cost Assignment Charges, the PJM Reliability Must Run Charge and PJM Transmission Enhancement Charges as approved by Federal Energy Regulatory Commission (FERC).

Kilowatt threshold noted above is based upon the customer's Peak Load Share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM). See Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions of this Tariff.

Date of Issue: Effective:

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

VI. ATTACHMENT 2 - SPREADSHEETS FOR THE DEVELOPMENT OF BGS COST BID FACTORS

(Pages 1 through 7)

Public Service Electric and Gas Company Specific Addendum
Attachment 2

Development of BGS-RSCP Cost and Bid Factors for 2025/2026 BGS Filing
Adjusted to Billing Time Periods

Based on average of year 2021, 2022 & 2023 Load Profile Information

Table #1 **% Usage During PJM On-Peak Period** *On-Peak periods defined as the 16 hr PJM Trading period, adj for NERC holidays*

(data rounded to nearest .01%)	*Profile Meter Data* **RS**	*Profile Meter Data* **RHS**	*Profile Meter Data* **RLM**	*Profile Meter Data* **WH**	*Profile Meter Data* **WHS**	*Profile Meter Data* **HS**	*--- Other Analysis ---* **PSAL**	**BPL**	*Profile Meter Data* **GLP**	*Profile Meter Data* **LPL-S**
January	47.20%	45.87%	46.33%	47.20%	47.20%	46.87%	30.00%	30.00%	52.60%	50.90%
February	48.83%	46.50%	47.83%	48.83%	48.83%	47.13%	29.20%	29.20%	53.87%	52.63%
March	50.87%	49.30%	48.97%	50.87%	50.87%	50.30%	26.33%	26.33%	56.67%	54.73%
April	51.03%	50.40%	49.10%	51.03%	51.03%	51.40%	22.90%	22.90%	56.07%	54.17%
May	45.13%	45.47%	44.27%	45.13%	45.13%	50.47%	19.50%	19.50%	52.07%	49.77%
June	54.20%	55.17%	54.40%	54.20%	54.20%	62.00%	20.70%	20.70%	59.67%	56.70%
July	52.60%	53.30%	52.73%	52.60%	52.60%	60.00%	19.50%	19.50%	57.20%	54.10%
August	53.27%	54.00%	53.53%	53.27%	53.27%	61.00%	21.50%	21.50%	58.13%	54.77%
September	50.33%	51.60%	50.50%	50.33%	50.33%	58.33%	23.80%	23.80%	57.00%	54.63%
October	49.23%	49.43%	48.13%	49.23%	49.23%	53.80%	26.17%	26.17%	55.63%	53.63%
November	47.97%	47.17%	47.03%	47.97%	47.97%	48.63%	30.53%	30.53%	54.37%	52.53%
December	49.50%	48.00%	49.00%	49.50%	49.50%	48.43%	32.30%	32.30%	54.67%	52.83%

Based on average of year 2021, 2022 & 2023 Load Profile Information

Table #2 **% Usage During PSE&G On-Peak Billing Period** *On-Peak periods as defined in specified rate schedule (average of %s for 2021, 2022 & 2023)*

(data rounded to nearest .01%)	*N/A* **RS**	*N/A* **RHS**	*Profile Meter Data* **RLM**	*N/A* **WH**	*N/A* **WHS**	*N/A* **HS**	*N/A* **PSAL**	*N/A* **BPL**	*N/A* **GLP**	*Profile Meter Data* **LPL-S**
January	0%	0%	42%	0%	0%	0%	0%	0%	0%	46%
February	0%	0%	42%	0%	0%	0%	0%	0%	0%	46%
March	0%	0%	41%	0%	0%	0%	0%	0%	0%	46%
April	0%	0%	42%	0%	0%	0%	0%	0%	0%	47%
May	0%	0%	43%	0%	0%	0%	0%	0%	0%	48%
June	0%	0%	46%	0%	0%	0%	0%	0%	0%	49%
July	0%	0%	48%	0%	0%	0%	0%	0%	0%	49%
August	0%	0%	48%	0%	0%	0%	0%	0%	0%	48%
September	0%	0%	49%	0%	0%	0%	0%	0%	0%	49%
October	0%	0%	46%	0%	0%	0%	0%	0%	0%	49%
November	0%	0%	43%	0%	0%	0%	0%	0%	0%	48%
December	0%	0%	42%	0%	0%	0%	0%	0%	0%	47%

Public Service Electric and Gas Company Specific Addendum
Attachment 2

Table #3 **Class Usage @ customer**

Calendar month sales forecasted for 2025, less % for LPL-Sec > 500 kW Peak Load Share

in MWh	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL	GLP	< 500 kW LPL-S
January	1,121,492	12,422	14,247	55	1	1,657	14,910	31,151	531,647	445,035
February	943,089	9,973	12,197	53	1	1,361	11,882	29,306	498,617	407,025
March	914,188	7,639	11,831	59	1	1,113	11,649	27,223	533,581	427,818
April	752,016	3,826	9,990	51	1	620	9,193	23,864	458,953	370,143
May	874,037	3,246	12,272	54	0	386	8,838	19,584	482,213	426,819
June	1,222,208	3,601	17,689	41	1	424	7,865	19,801	530,906	421,693
July	1,647,699	4,970	23,582	34	1	583	7,759	18,302	628,844	485,005
August	1,590,636	4,648	20,856	37	1	527	8,575	17,475	599,871	499,467
September	1,154,055	3,562	15,521	42	0	410	9,258	21,614	529,601	428,544
October	828,787	4,116	11,069	25	0	440	10,722	23,241	475,303	406,504
November	850,672	7,473	10,275	53	0	683	11,426	25,784	460,827	394,535
December	1,064,630	10,017	12,591	52	1	1,048	10,253	23,848	500,710	421,744
Total	12,963,509	75,494	172,120	556	8	9,253	122,330	281,193	6,231,073	5,134,333

Table #4 **Forwards Prices - Energy Only @ bulk system**

in $/MWh, not including PJM losses

	On-Peak	Off/On Pk LMP ratio	Resulting Off-Peak
January	81.70	0.8220	67.158
February	70.35	0.8220	57.828
March	54.00	0.8220	44.388
April	49.65	0.8220	40.812
May	53.15	0.8220	43.690
June	52.70	0.6275	33.068
July	77.45	0.6275	48.598
August	69.25	0.6275	43.453
September	55.40	0.6275	34.762
October	49.80	0.8220	40.936
November	50.45	0.8220	41.470
December	58.35	0.8220	47.964

Table #5 **Zone to Western Hub Basis Differential**

On-Peak	Off-Peak	
83%	89%	*NYMEX Forwards (June 3, 2024) from NERA*
83%	89%	
83%	89%	*Congestion Factors & On/Off Peak Ratios*
83%	89%	*Summer Averages for June 2021 - Sept 2023*
83%	89%	*Winter Averages for Mar 2021 - Feb 2024*
82%	89%	
82%	89%	
82%	89%	
82%	89%	
83%	89%	
83%	89%	
83%	89%	

Table #6 **Losses**

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL	GLP	LPL-S
from meter to bulk system (includes Delivery & PJM EHV losses)										
Loss Factors =	6.2621%	6.2621%	6.2621%	6.2621%	6.2621%	6.2621%	6.2621%	6.2621%	6.2621%	6.2621%
Expansion Factor =	1.066804	1.066804	1.066804	1.066804	1.066804	1.066804	1.066804	1.066804	1.066804	1.066804
1 / Expansion Factor =	0.937379	0.937379	0.937379	0.937379	0.937379	0.937379	0.937379	0.937379	0.937379	0.937379
from meter to transmission node (includes Delivery less mean hourly PJM marginal losses)										
Loss Factors =	4.9659%	4.9659%	4.9659%	4.9659%	4.9659%	4.9659%	4.9659%	4.9659%	4.9659%	4.9659%
Expansion Factor =	1.052254	1.052254	1.052254	1.052254	1.052254	1.052254	1.052254	1.052254	1.052254	1.052254
1 / Expansion Factor =	0.950341	0.950341	0.950341	0.950341	0.950341	0.950341	0.950341	0.950341	0.950341	0.950341

Public Service Electric and Gas Company Specific Addendum
Attachment 2

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

		RS	RHS	RLM	WH	WHS	HS	PSAL	BPL	GLP	LPL-S
Summer - all hrs		$ 48.47	$ 48.61	$ 48.51	$ 46.72	$ 49.52	$ 49.86	$ 41.53	$ 41.30	$ 48.87	$ 48.26
	PJM on pk	$ 57.20	$ 57.16	$ 57.19	$ 55.16	$ 58.18	$ 57.15	$ 55.23	$ 54.92	$ 56.45	$ 56.35
	PJM off pk	$ 38.76	$ 38.77	$ 38.76	$ 37.37	$ 39.61	$ 38.77	$ 37.79	$ 37.57	$ 38.40	$ 38.37
Winter - all hrs		$ 49.30	$ 51.52	$ 49.15	$ 48.96	$ 52.07	$ 52.14	$ 48.30	$ 48.08	$ 49.07	$ 48.91
	PJM on pk	$ 52.31	$ 54.63	$ 52.25	$ 51.96	$ 55.03	$ 55.08	$ 53.33	$ 53.09	$ 51.65	$ 51.63
	PJM off pk	$ 46.45	$ 48.72	$ 46.34	$ 46.12	$ 49.17	$ 49.33	$ 46.39	$ 46.19	$ 45.98	$ 45.89
Annual		$ 48.94	$ 50.88	$ 48.86	$ 48.34	$ 51.11	$ 51.66	$ 46.45	$ 46.22	$ 48.99	$ 48.68
System Total		$ 48.87									

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

		RS	RHS	RLM	WH	WHS	HS	PSAL	BPL	GLP	LPL-S
Summer - all hrs		$ 272,158	$ 816	$ 3,766	$ 7	$ 0	$ 97	$ 1,390	$ 3,188	$ 111,864	$ 88,540
	PJM on pk	$ 169,165	$ 513	$ 2,348	$ 4	$ 0	$ 67	$ 397	$ 910	$ 74,917	$ 56,861
	PJM off pk	$ 102,993	$ 302	$ 1,418	$ 3	$ 0	$ 30	$ 993	$ 2,278	$ 36,946	$ 31,679
Winter - all hrs		$ 362,328	$ 3,025	$ 4,643	$ 20	$ 0	$ 381	$ 4,293	$ 9,809	$ 193,423	$ 161,393
	PJM on pk	$ 187,077	$ 1,523	$ 2,346	$ 10	$ 0	$ 197	$ 1,304	$ 2,973	$ 110,939	$ 89,632
	PJM off pk	$ 175,251	$ 1,502	$ 2,297	$ 10	$ 0	$ 185	$ 2,989	$ 6,835	$ 82,484	$ 71,761
Annual		$ 634,486	$ 3,841	$ 8,410	$ 27	$ 0	$ 478	$ 5,682	$ 12,996	$ 305,287	$ 249,933
System Total		$ 1,221,141									

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

		RS	RHS	RLM	WH	WHS	HS	PSAL	BPL	GLP	LPL-S
Summer - all hrs		$ 48.47	$ 48.61	$ 48.51	$ 46.72	$ 49.52	$ 49.86	$ 41.53	$ 41.30	$ 48.87	$ 48.26
	PSE&G On pk			$ 58.16							$ 57.49
	PSE&G Off pk			$ 39.65							$ 39.46
Winter - all hrs		$ 49.30	$ 51.52	$ 49.15	$ 48.96	$ 52.07	$ 52.14	$ 48.30	$ 48.08	$ 49.07	$ 48.91
	PSE&G On pk			$ 52.60							$ 51.96
	PSE&G Off pk			$ 46.59							$ 46.18
Annual Average		$ 48.94	$ 50.88	$ 48.86	$ 48.34	$ 51.11	$ 51.66	$ 46.45	$ 46.22	$ 48.99	$ 48.68
System Average		$ 48.87									

Public Service Electric and Gas Company Specific Addendum
Attachment 2

Table #10 **Generation & Transmission Obligations and Costs and Other Adjustments**

Obligations - Peak Load shares eff 6/1/24, scaling factors eff 6/1/24, Transmission Loads eff 1/1/24; costs are market estimates

in MW	**RS**	**RHS**	**RLM**	**WH**	**WHS**	**HS**	**PSAL**	**BPL**	**GLP**	**Adj for PLS > 500 kW LPL-S**
Gen Obl - MW	5,468.3	18.4	77.9	0.0	0.0	2.9	0.0	0.0	2,184.9	1,131.9
Trans Obl - MW	4,467.4	15.1	61.9	0.0	0.0	2.4	0.0	0.0	1,765.8	903.7

# of Months and Days used in this analysis

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

Transmission Cost year round = $0.00 per MW-yr

		Base Capacity	Capacity Proxy True Up	Total Capacity	
Generation Capacity cost	summer =	$ 51.85	$ -	$ 51.85	$/MW/day
	winter =	$ 51.85	$ -	$ 51.85	$/MW/day

	RS	**RHS**		
<u>% usage in Summer Blocks</u>				
Block 1 (0-600 kWh/m)	64.6%	66.1%		*(based on W/N actuals used in settlement and final rate design of 2018 Rate Case, rounded to .1%)*
Block 2 (>600 kWh/m)	35.4%	33.9%		
Required summer inversion =	0.8652	1.1569	¢/kWh	*(same as 2003/2004 BGS blocking inversion)*

Table #11 **Ancillary Services & Renewable Power Cost**

Ancillary Services	$ 2.00	
Renewable Power Cost	$ 22.64	
Total AncillaryServices & Renewable Power Costs	$ 24.64	per MWh @ bulk system

Table #12 **Summary of Obligation Costs Expressed as $/MWh @ customer (for non-demand rates only)**

	RS	**RHS**	**RLM**	**WH**	**WHS**	**HS**	**PSAL**	**BPL**
Transmission Obl - all months	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Generation Obl -								
per annual MWh	$ 7.98	$ 4.61	$ 19.06	$ -	$ -	$ 5.93	$ -	$ -
recovery per summer MWh	$ 6.16	$ 6.94	$ 13.27	$ -	$ -	$ 9.44	$ -	$ -
recovery per winter MWh	$ 9.38	$ 3.95	$ 24.40	$ -	$ -	$ 5.00	$ -	$ -
			For RLM, per on-peak kWh only					

Public Service Electric and Gas Company Specific Addendum
Attachment 2

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

NON-DEMAND RATES
includes energy, Generation obligations, Ancillary Services and Renewable Power Costs- adjusted to billing time periods
in $/MWh

		RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Summer - all hrs		$ 82.74	$ 79.51		$ 73.01	$ 75.80	$ 82.08	$ 67.82	$ 67.58
	PSE&G On pk			$ 103.51					
	PSE&G Off pk			$ 65.94					
	Block 1 (0-600 kWh/m)	$ 79.68	$ 75.59						
	Block 2 (>600 kWh/m)	$ 88.33	$ 87.16						
Winter - all hrs		$ 83.57	$ 82.42		$ 75.25	$ 78.35	$ 84.35	$ 74.59	$ 74.37
	PSE&G On pk			$ 97.94					
	PSE&G Off pk			$ 72.88					
Annual -all hrs		$ 83.21	$ 81.77	$ 83.71	$ 74.63	$ 77.40	$ 83.88	$ 72.74	$ 72.50

DEMAND RATES
includes energy and Ancillary Services, G&T obligations charged separately - adjusted to billing time periods
in $/MWh

		GLP	LPL-S
Summer - all hrs		$ 75.15	$ 74.54
	PSE&G On pk		$ 83.77
	PSE&G Off pk		$ 65.75
Winter - all hrs		$ 75.36	$ 75.20
	PSE&G On pk		$ 78.25
	PSE&G Off pk		$ 72.47
Annual - all hrs per MWh only		$ 75.28	$ 74.96
Including Generation Obligation $			
Summer - all hrs		$ 81.17	$ 78.44
	PSE&G On pk		$ 91.74
	PSE&G Off pk		$ 65.75
Winter - all hrs		$ 82.35	$ 79.53
	PSE&G On pk		$ 87.41
	PSE&G Off pk		$ 72.47
Annual - including Gen Obl $		$ 81.92	$ 79.14

Note: Obligation $ included in On pk costs

PLUS:		GLP	LPL-S	
Gen Cost				
	summer	$ 1.5814	$ 1.5814	per kW of G obl /month
	winter	$ 1.5749	$ 1.5749	per kW of G obl /month
	annual	$ 1.5771	$ 1.5771	per kW of G obl /month
Trans cost				
	all months	$ -	$ -	per kW of T obl /month

ALL RATES

Grand Total Cost in $1000 =	$ 2,046,164	
All-In Average cost @ customer =	$ 81.88	per MWh at customer (per customer metered MWh)
All-In Average costs @ transmission nodes =	$ 77.81	per MWh at transmission nodes (per metered MWh at transmission node)

Public Service Electric and Gas Company Specific Addendum
Attachment 2

Table #14 **Ratio of BGS Unit Costs @ customer to All-In Average Cost @ transmission nodes -** *rounded to 3 decimal places, unit obligation $ rounded to 4 decimal places*

NON-DEMAND RATES
includes energy, Generation obligations, Ancillary Services and Renewable Power Costs- adjusted to billing time periods

		RS	RHS	RLM	WH	WHS	HS	PSAL	BPL	
Summer - all hrs					**0.938**	**0.974**	**1.055**	0.872	0.869	
	PSE&G On pk			**1.330**				Use weighted average		
	PSE&G Off pk			**0.847**				for all streetlighting =		**0.870**
	All usage Multiplier	**1.063**	**1.022**							
	Constant (in $/MWh)	**$ (3.063)**	**$ (3.922)**	for Block 1 (0-600 kWh/m) usage						
	Constant (in $/MWh)	**$ 5.589**	**$ 7.647**	for Block 2 (>600 kWh/m) usage						
Winter - all hrs		**1.074**	**1.059**		**0.967**	**1.007**	**1.084**	0.959	0.956	
	PSE&G On pk			**1.259**				Use weighted average		
	PSE&G Off pk			**0.937**				for all streetlighting =		**0.957**
Annual - all hrs		1.069	1.051	1.076	0.959	0.995	1.078	0.935	0.932	

DEMAND RATES
includes energy and Ancillary Services, G&T obligations charged separately - adjusted to billing time periods

		GLP Multiplier	GLP Constant (in $/MWh)	LPL-S Multiplier	LPL-S Constant (in $/MWh)
Summer - all hrs		**1.043**	**(6.021)**		
	PSE&G On pk			**1.179**	**(7.973)**
	PSE&G Off pk			**0.845**	**-**
Winter - all hrs		**1.058**	**(6.993)**		
	PSE&G On pk			**1.123**	**(9.163)**
	PSE&G Off pk			**0.931**	**-**
Annual - including Gen Obl $		1.053		1.017	

PLUS:

Gen Cost				
summer	$ 1.5814	$ 1.5814	per kW of G obl /month
winter	$ 1.5749	$ 1.5749	per kW of G obl /month
annual	$ 1.5771	$ 1.5771	per kW of G obl /month
Trans cost			
all months	$ -	$ -	per kW of T obl /month

Assumptions:

Gen Cost =	$ 51.85	/MW day	summer
	$ 51.85	/MW day	winter
Trans cost =	$ -	per MW-yr	
Analysis time period =	4	summer months	
	8	winter months	
Ancillary Services & RPS =	$ 24.64	per MWh	

Energy Costs = based on Forwards @ PJM West - corrected for congestion
Usage patterns = forecasted 2024 energy use by class, PJM and PSE&G on/off % from 2021, 2022 & 2023 class load profiles

Obligations = class totals in effect as of filing date
Losses = Delivery losses from tariff, PJM losses based on 3 year average %
PJM Time Periods = PJM trading time periods - 7 AM to 11 PM weekdays, local time, x NERC holidays - New Year's, Memorial, 4th of July, Labor Day, Thanksgiving & Christmas
PSE&G Billing time periods = as per specific rate schedule
NJ SUT (Sales & Use Tax) = SUT excluded from all rates

Public Service Electric and Gas Company Specific Addendum
Attachment 2

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

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL	GLP	LPL-S
Total Costs by Rate - in $1000										
Summer	$ 464,566	$ 1,334	$ 6,515	$ 11	$ 0	$ 160	$ 2,269	$ 5,217	$ 185,859	$ 143,928
Winter	$ 614,169	$ 4,839	$ 7,893	$ 30	$ 0	$ 617	$ 6,629	$ 15,171	$ 324,568	$ 262,388
Total	$ 1,078,735	$ 6,173	$ 14,408	$ 41	$ 1	$ 776	$ 8,898	$ 20,388	$ 510,427	$ 406,316
% of Annual Total $ by Rate										
Summer	43%	22%	45%	27%	37%	21%	26%	26%	36%	35%
Winter	57%	78%	55%	73%	63%	79%	74%	74%	64%	65%

Total Costs - in $1000	
Summer	$ 809,859
Winter	$ 1,236,304
Total	$ 2,046,164

rounded to 4 decimal places

% of Annual Total $		If total $ were split on a per MWh basis (on transmission node MWhs):			
Summer	40%	$ 77.38 per MWh @ trans nodes	Ratio to All-In Cost >>>	Summer	1.0000
Winter	60%	$ 78.10 per MWh @ trans nodes		Winter	1.0000

Table #16 **Spreadsheet Error Checking -** *Reconciliation of Customer Revenue and Supplier Payments, based on above data only*

Assumed Winning Bid Price = $ 77.81 *(bid includes payments for all losses)*
Payment Ratio - Summer = 1.0000
Payment Ratio - Winter = 1.0000

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL	GLP	LPL-S
Total Rate Revenue - in $1000										
Summer	$ 464,415	$ 1,334	$ 6,513	$ 11	$ 0	$ 160	$ 2,265	$ 5,226	$ 185,830	$ 143,931
Winter	$ 614,162	$ 4,838	$ 7,896	$ 30	$ 0	$ 617	$ 6,618	$ 15,191	$ 324,483	$ 262,305
Total	$ 1,078,578	$ 6,173	$ 14,409	$ 41	$ 1	$ 776	$ 8,883	$ 20,417	$ 510,313	$ 406,236

Total Summer	$ 809,686
Total Winter	$ 1,236,141
Grand Total	$ 2,045,827

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL	GLP	LPL-S
Total Supplier Payment - in $1000										
Summer	$ 459,722	$ 1,374	$ 6,358	$ 13	$ 0	$ 159	$ 2,739	$ 6,320	$ 187,441	$ 150,226
Winter	$ 601,727	$ 4,807	$ 7,735	$ 33	$ 0	$ 598	$ 7,277	$ 16,704	$ 322,758	$ 270,172
Total	$ 1,061,449	$ 6,181	$ 14,093	$ 46	$ 1	$ 758	$ 10,016	$ 23,024	$ 510,199	$ 420,398

Total Summer	$ 814,352
Total Winter	$ 1,231,812
Grand Total	$ 2,046,164

Difference (in $1000) = $ (336)
Note: Minor differences in totals are due to rounding of Bid Factors and Payment Factors

Table #17 **Total Supplier Energy** *@ transmission nodes*

in MWh	
Summer	10,465,410
Winter	15,830,280
Total	26,295,690

VII. ATTACHMENT 3 - SPREADSHEETS FOR THE CALCULATION OF BGS RATES

(Pages 1 through 6)

Public Service Electric and Gas Company Specific Addendum
Attachment 3

Calculation of June 2025 to May 2026 BGS-RSCP Rates

Illustrative Only

NJ Sales & Use Tax (SUT) excluded

Table A **Auction Results**

line #	**Specific BGS-FP Auction >>**	*remaining portion of 36 month bid - 2023 auction*	*remaining portion of 36 month bid - 2024 auction*	*2025 auction*	*Notes:*
1	**Winning Bid - in $/MWh**	$ 93.11	$ 80.88	$ 81.19	Illustrative Only
1A	Capacity Proxy Price True-Up - in $/MWh	$ 0.66	$ 0.31	$ (0.46)	entered after 2024 auction
1B	[redacted]				
1C	**Total - in $/MWh**	$ 93.77	$ 81.19	$ 80.73	= line 1 + line 1A - line 1B
	(includes all payments, including impact of PJM marginal losses)				
2	**# of Tranches for Bid**	28	29	28	from then current Bid
3	**Total # of Tranches**	85	85	85	from then current Bid
	Payment Factors				
4	Summer	1.0000	1.0000	1.0000	
5	Winter	1.0000	1.0000	1.0000	
	Applicable Customer Usage @ transmission nodes - *in MWh*				
6	Summer MWh	10,465,410			from Table #17 of the current Bid Factor Spreadsheet
7	Winter MWh	15,830,280			
	Total Payment to Suppliers *- in $1000*				
8	Summer	$ 323,265	$ 289,893	$ 278,311	= ((1C * (2)/(3) * (4) * (6)) /1000
9	Winter	$ 488,981	$ 438,501	$ 420,981	= ((1C * (2)/(3) * (5) * (7)) /1000
10	Total	$ 812,246	$ 728,394	$ 699,292	Note: $ reflect total payment
	Average Payment to Suppliers *- in $/MWh*				
11	Summer	$ 85.182			= sum(line 8) / (6) - rounded to 3 decimal places
12	Winter	$ 85.182			= sum(line 9) / (7) - rounded to 3 decimal places
13	Total weighted average	**$ 85.182**	<<< used in calculation of Customer Rates		= sum(line 10) / [(6) + (7)] rounded to 3 decimal places
	Reconciliation of amounts *- in $1000*				
14	Weighted Average * Total MWh =	$ 2,239,919			= (13) * [(6)+(7)] / 1000
15	Total Payment to Suppliers =	$ 2,239,932			= sum (line 10)
16	Difference =	$ (12)			= line (14) - line (15)

Public Service Electric and Gas Company Specific Addendum
Attachment 3

Calculation of June 2025 to May 2026 BGS-RSCP Rates

Illustrative Only

NJ Sales & Use Tax (SUT) excluded

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

from Table #14 of the bid factor spreadsheet ---
rounded to 3 decimal places, unit obligation $ rounded to 4 decimal places

NON-DEMAND RATES

includes energy, G&T obligations, and Ancillary Services - adjusted to billing time periods

		RS	RHS	RLM	WH	WHS	HS	PSAL	BPL	
Summer - all hrs					**0.938**	**0.974**	**1.055**	0.872	0.869	
	PSE&G On pk			**1.330**				Use weighted average		
	PSE&G Off pk			**0.847**				for all streetlighting =		**0.870**
	All usage Multiplier	**1.063**	**1.022**							
	Constant (in $/MWh)	$ **(3.063)**	$ **(3.922)**	for Block 1 (0-600 kWh/m) usage						
	Constant (in $/MWh)	$ **5.589**	$ **7.647**	for Block 2 (>600 kWh/m) usage						
Winter - all hrs		**1.074**	**1.059**		**0.967**	**1.007**	**1.084**	0.959	0.956	
	PSE&G On pk			**1.259**				Use weighted average		
	PSE&G Off pk			**0.937**				for all streetlighting =		**0.957**
Annual - all hrs		1.069	1.051	1.076	0.959	0.995	1.078	0.935	0.932	

DEMAND RATES

includes energy and Ancillary Services, G&T obligations charged separately - adjusted to billing time periods

		GLP Multiplier	GLP Constant (in $/MWh)	LPL-S Multiplier	LPL-S Constant (in $/MWh)
Summer - all hrs		**1.043**	**(6.021)**		
	PSE&G On pk			**1.179**	**(7.973)**
	PSE&G Off pk			**0.845**	**-**
Winter - all hrs		**1.058**	**(6.993)**		
	PSE&G On pk			**1.123**	**(9.163)**
	PSE&G Off pk			**0.931**	**-**
Annual - including T&G Obl $		1.053		1.017	

PLUS:	GLP	LPL-S	
Gen Cost			
summer	$ 1.5771	$ 1.5771	per kW of G obl /month
winter	$ 1.5771	$ 1.5771	per kW of G obl /month
Trans cost			
all months	$ -	$ -	per kW of T obl /month

Public Service Electric and Gas Company Specific Addendum
Attachment 3

Calculation of June 2025 to May 2026 BGS-RSCP Rates

Illustrative Only

NJ Sales & Use Tax (SUT) excluded

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

NON-DEMAND RATES --

includes energy, G&T obligations, and Ancillary Services - adjusted to billing time periods

		RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Summer - all hrs					***7.9901***	***8.2967***	***8.9867***	***7.4108***	***7.4108***
	PSE&G On pk			***11.3292***					
	PSE&G Off pk			***7.2149***					
for Block 1 (0-600 kWh/m) usage		***8.7485***	***8.3134***						
for Block 2 (>600 kWh/m) usage		***9.6137***	***9.4703***						
Winter - all hrs		***9.1485***	***9.0208***		***8.2371***	***8.5778***	***9.2337***	***8.1519***	***8.1519***
	PSE&G On pk			***10.7244***					
	PSE&G Off pk			***7.9816***					

DEMAND RATES --

includes energy and Ancillary Services, G&T obligations charged separately - adjusted to billing time periods

		GLP	LPL-S
Summer - all hrs		***8.2824***	
	PSE&G On pk		***9.2457***
	PSE&G Off pk		***7.1979***
Winter - all hrs		***8.3130***	
	PSE&G On pk		***8.6496***
	PSE&G Off pk		***7.9304***

PLUS:		**GLP**		**LPL-S**	
Gen Cost					
summer	**$**	**1.5771**	**$**	**1.5771**	per kW of G obl /month
winter	**$**	**1.5771**	**$**	**1.5771**	per kW of G obl /month
Trans cost					
all months	**$**	**-**	**$**	**-**	per kW of T obl /month

Public Service Electric and Gas Company Specific Addendum
Attachment 3

Calculation of June 2025 to May 2026 BGS-RSCP Rates

Illustrative Only

NJ Sales & Use Tax (SUT) excluded

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

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Total Preliminary Rate Revenue - in $1000								
Summer	$ 508,390	$ 1,461	$ 7,130	$ 12	$ 0	$ 175	$ 2,479	$ 5,721
Winter	$ 672,315	$ 5,296	$ 8,644	$ 33	$ 0	$ 675	$ 7,245	$ 16,630
Total	$ 1,180,705	$ 6,757	$ 15,774	$ 45	$ 1	$ 850	$ 9,724	$ 22,351

	GLP Energy $	GLP Obligation $	LPL-S Energy $	LPL-S Obligation $
Summer	$ 189,602	$ 13,783	$ 150,399	$ 7,140
Winter	$ 327,686	$ 27,566	$ 272,883	$ 14,281
Total	$ 517,289	$ 41,350	$ 423,282	$ 21,421

	Energy $	Obligation $	Total $
Total Summer	$ 865,369	$ 20,924	$ 886,293
Total Winter	$ 1,311,408	$ 41,847	$ 1,353,255
Grand Total	$ 2,176,777	$ 62,771	**$ 2,239,548**

Total Supplier Payment - in $1000	
Summer	$ 891,469
Winter	$ 1,348,462
Total	$ 2,239,932
Differences - in $1000	
Summer	$ 5,176
Winter	$ (4,793)
Total	$ 384

kWh Rate Adjustment Factors	*rounded to 5 decimal places*
1.00598	
0.99635	

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

Calculation of June 2025 to May 2026 BGS-RSCP Rates

Illustrative Only

NJ Sales & Use Tax (SUT) excluded

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

NON-DEMAND RATES ---

includes energy, G&T obligations, and Ancillary Services - adjusted to billing time periods & adjustment to energy price

		RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Summer - all hrs					***8.0379***	***8.3463***	***9.0404***	***7.4551***	***7.4551***
	PSE&G On pk			***11.3969***					
	PSE&G Off pk			***7.2580***					
for Block 1 (0-600 kWh/m) usage		***8.8008***	***8.3631***						
for Block 2 (>600 kWh/m) usage		***9.6712***	***9.5269***						
Winter - all hrs		***9.1151***	***8.9879***		***8.2070***	***8.5465***	***9.2000***	***8.1221***	***8.1221***
	PSE&G On pk			***10.6853***					
	PSE&G Off pk			***7.9525***					

DEMAND RATES ---

includes energy and Ancillary Services, G&T obligations charged separately - adjusted to billing time periods & adjustment to energy price

		GLP	LPL-S
Summer - all hrs		***8.3319***	
	PSE&G On pk		***9.3010***
	PSE&G Off pk		***7.2409***
Winter - all hrs		***8.2827***	
	PSE&G On pk		***8.6180***
	PSE&G Off pk		***7.9015***

PLUS:		GLP	LPL-S
Gen Cost			
	summer	**$1.5771**	**$1.5771**
	winter	**$1.5771**	**$1.5771**
Trans cost			
	all months	**$0.0000**	**$0.0000**

Calculation of June 2025 to May 2026 BGS-RSCP Rates

Illustrative Only

NJ Sales & Use Tax (SUT) excluded

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

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL	GLP	LPL-S
Total Rate Revenue - in $1000										
Summer	$ 511,429	$ 1,470	$ 7,173	$ 12	$ 0	$ 176	$ 2,494	$ 5,755	$ 204,519	$ 158,439
Winter	$ 669,861	$ 5,277	$ 8,612	$ 33	$ 0	$ 672	$ 7,218	$ 16,569	$ 354,058	$ 286,168
Total	$ 1,181,290	$ 6,747	$ 15,785	$ 45	$ 1	$ 848	$ 9,713	$ 22,324	$ 558,577	$ 444,607

Total Summer	$ 891,467	
Total Winter	$ 1,348,470	
Grand Total	$ 2,239,936	
Total Supplier Payment - in $1000		
Summer	$ 891,469	
Winter	$ 1,348,462	
Total	$ 2,239,932	
Differences - in $1000		% difference
Summer	$ (3)	-0.0003%
Winter	$ 7	0.0005%
Total	$ 5	0.0002%

VIII. ATTACHMENT 4 – DEVELOPMENT OF CAPACITY PROXY PRICE TRUE UP - $/MWh

(Pages 1 through 6)

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

2025/2026 Delivery Year - Illustrative Data

		Capacity Proxy Price True-Up Development for Winning Suppliers from 2023 BGS-RSCP Auction 2025/26 Delivery Year	Capacity Proxy Price True-Up Development for Winning Suppliers from 2024 BGS-RSCP Auction 2025/26 Delivery Year	Capacity Proxy Price True-Up Development for Winning Suppliers from 2025 BGS-RSCP Auction (if needed) 2025/26 Delivery Year	*Notes:*
1	**Zonal Capacity Price ($/MW-day)**	$50.00	$50.00	$50.00	as may be determined by the RPM or its successor or otherwise
2	**Capacity Proxy Price ($/MW-day)**	$44.63	$47.46	$53.76	per Board Orders dated 11/09/2022 and 11/17/2023 and XX/XX/2024
3	**Capacity Proxy Price True-Up - $/MW-day**	$5.37	$2.54	-$3.76	= line 1 - line 2
4	**BGS-RSCP Gen Obl - MW**	8,884.3	8,884.3	8,884.3	
5	**Days in Year**	365	365	365	
6	**Capacity Proxy Price True-Up Annual Cost**	$17,413,672	$8,236,635	-$12,192,813	= line 3 * line 4 * line 5
7	**Eligible Tranches**	28	29	28	from Table A
8	**Total Tranches**	85	85	85	from Table A
9	**% of tranches eligible for payment**	32.94%	34.12%	32.94%	= line 7 / line 8
10	**Capacity Proxy Price True-Up Cost**	$5,736,268	$2,810,146	-$4,016,456	= line 6 * line 9
11	**Total Applicable Customer Usage @ bulk system - in MWh**	26,295,690	26,295,690	26,295,690	
12	**Eligible Customer Usage @ bulk system - *in MWh***	8,662,110	8,971,471	8,662,110	= line 9 * line 11
13	**Capacity Proxy Price True-Up - $/MWh**	**$0.66**	**$0.31**	**-$0.46**	**= line 10/ line 12 - rounded to 2 decimal places**

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

2026/2027 Delivery Year - Illustrative Data

		Capacity Proxy Price True-Up Development for Winning Suppliers from 2024 BGS-RSCP Auction (if needed)	Capacity Proxy Price True-Up Development for Winning Suppliers from 2025 BGS-RSCP Auction (if needed)	
		2026/27 Delivery Year	2026/27 Delivery Year	*Notes:*
1	**Zonal Capacity Price ($/MW-day)**	$50.00	$50.00	as may be determined by the RPM or its successor or otherwise
2	**Capacity Proxy Price ($/MW-day)**	$49.05	$50.90	per Board Orders dated 11/17/2023 and XX/XX/2024
3	**Capacity Proxy Price True-Up - $/MW-day**	$0.95	-$0.90	= line 1 - line 2
4	**BGS-RSCP Gen Obl - MW**	8,884.3	8,884.3	
5	**Days in Year**	365	365	
6	**Capacity Proxy Price True-Up Annual Cost**	$3,080,631	-$2,918,493	= line 3 * line 4 * line 5
7	**Eligible Tranches**	29	28	from Table A
8	**Total Tranches**	85	85	from Table A
9	**% of tranches eligible for payment**	34.12%	32.94%	= line 7 / line 8
10	**Capacity Proxy Price True-Up Cost**	$1,051,039	-$961,386	= line 6 * line 9
11	**Total Applicable Customer Usage @ bulk system - in MWh**	26,295,690	26,295,690	
12	**Eligible Customer Usage @ bulk system *- in MWh***	8,971,471	8,662,110	= line 9 * line 11
13	**Capacity Proxy Price True-Up - $/MWh**	**$0.12**	**-$0.11**	**= line 10/ line 12 - rounded to 2 decimal places**

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

2027/2028 Delivery Year - Illustrative Data

		Capacity Proxy Price True-Up Development for Winning Suppliers from 2025 BGS-RSCP Auction (if needed) 2027/28 Delivery Year	*Notes:*
1	**Zonal Capacity Price ($/MW-day)**	$50.00	as may be determined by the RPM or its successor or otherwise
2	**Capacity Proxy Price ($/MW-day)**	$50.90	per Board Order dated XX/XX/2024
3	**Capacity Proxy Price True-Up - $/MW-day**	-$0.90	= line 1 - line 2
4	**BGS-RSCP Gen Obl - MW**	8,884.3	
5	**Days in Year**	366	
6	**Capacity Proxy Price True-Up Annual Cost**	-$2,926,488	= line 3 * line 4 * line 5
7	**Eligible Tranches**	28	from Table A
8	**Total Tranches**	85	from Table A
9	**% of tranches eligible for payment**	32.94%	= line 7 / line 8
10	**Capacity Proxy Price True-Up Cost**	-$964,020	= line 6 * line 9
11	**Total Applicable Customer Usage @ bulk system - in MWh**	26,295,690	
12	**Eligible Customer Usage @ bulk system - *in MWh***	8,662,110	= line 9 * line 11
13	**Capacity Proxy Price True-Up - $/MWh**	**-$0.11**	**= line 10/ line 12 - rounded to 2 decimal places**

Public Service Electric and Gas Company Specific Addendum
Attachment 4 P5

Table A With Additional Line Item

Calculation of June 2026 to May 2027 BGS-RSCP Rates

Illustrative Purposes Only

Table A	**Auction Results**				
line #	**Specific BGS-RSCP Auction >>**	*remaining portion of 36 month bid - 2024 auction*	*remaining portion of 36 month bid - 2025 auction*	*36 month bid - 2026 auction*	*Notes:*
1	**Winning Bid - in $/MWh**	$ 80.88	$ 81.19	$ 81.08	Winning Bids
1A	**26/27 Capacity Proxy Price True-up - in $/MWh**	$ 0.12	$ (0.11)		entered after 2026 BGS Auction
1B	**Total - in $/MWh**	$ 81.00	$ 81.08	$ 81.08	= line 1 + line 1A
2	**# of Tranches for Bid**	29	28	28	from then current Bid
3	**Total # of Tranches**	85	85	85	from then current Bid
	Payment Factors				
4	Summer	1.0000	1.0000	1.0000	from then current Bid Factor Spreadsheet
5	Winter	1.0000	1.0000	1.0000	from then current Bid Factor Spreadsheet
	Applicable Customer Usage @ bulk system - in MWh				
6	Summer MWh	10,465,410			from current Bid Factor Spreadsheet
7	Winter MWh	15,830,280			
	Total Payment to Suppliers - *in $1000*				
8	Summer	$ 289,215	$ 279,518	$ 279,518	= (1B * (2)/(3) * (4) * (6)) / 1000
9	Winter	$ 437,474	$ 422,806	$ 422,806	= (1B * (2)/(3) * (5) * (7)) / 1000
10	Total	$ 726,689	$ 702,324	$ 702,324	
	Average Payment to Suppliers - *in $/MWh*				
11	Summer	$ 81.05			= sum(line 8) / (6) - rounded to 2 decimal places
12	Winter	$ 81.05			= sum(line 9) / (7) - rounded to 2 decimal places
13	Total weighted average	**$ 81.05**	<<< used in calculation of Customer Rates		= sum(line 10) / [(6) + (7)] rounded to 2 decimal places

Public Service Electric and Gas Company Specific Addendum
Attachment 4 P5

Table A With Additional Line Item

Calculation of June 2027 to May 2028 BGS-RSCP Rates

Illustrative Purposes Only

Table A	**Auction Results**				
line #	**Specific BGS-RSCP Auction >>**	*remaining portion of 36 month bid - 2025 auction*	*remaining portion of 36 month bid - 2026 auction*	*36 month bid - 2027 auction*	*Notes:*
1	**Winning Bid - in $/MWh**	$ 81.19	$ 81.08	$ 81.08	Winning Bids
1A	**27/28 Capacity Proxy Price True-up - in $/MWh**	$ (0.11)			entered after 2027 BGS Auction
1B	**Total - in $/MWh**	$ 81.08	$ 81.08	$ 81.08	= line 1 + line 1A
2	**# of Tranches for Bid**	28	28	29	from then current Bid
3	**Total # of Tranches**	85	85	85	from then current Bid
	Payment Factors				
4	Summer	1.0000	1.0000	1.0000	from then current Bid Factor Spreadsheet
5	Winter	1.0000	1.0000	1.0000	from then current Bid Factor Spreadsheet
	Applicable Customer Usage @ bulk system - in MWh				
6	Summer MWh	10,465,410			from current Bid Factor Spreadsheet
7	Winter MWh	15,830,280			
	Total Payment to Suppliers - *in $1000*				
8	Summer	$ 279,518	$ 279,518	$ 289,500	= (1B * (2)/(3) * (4) * (6)) / 1000
9	Winter	$ 422,806	$ 422,806	$ 437,907	= (1B * (2)/(3) * (5) * (7)) / 1000
10	Total	$ 702,324	$ 702,324	$ 727,407	
	Average Payment to Suppliers - *in $/MWh*				
11	Summer	$ 81.08			= sum(line 8) / (6) - rounded to 2 decimal places
12	Winter	$ 81.08			= sum(line 9) / (7) - rounded to 2 decimal places
13	Total weighted average	**$ 81.08**	<<< used in calculation of Customer Rates		= sum(line 10) / [(6) + (7)] rounded to 2 decimal places

Public Service Electric and Gas Company Specific Addendum
Attachment 4 P2

Development of Capacity Proxy Price True-Up - $/MW-day

2025/2026 Delivery Year - Illustrative Data

		Capacity Proxy Price True-Up Development for Winning Suppliers from 2025 BGS-CIEP Auction (if needed)		
		2025/26 Delivery Year		*Notes:*
1	**Zonal Capacity Price ($/MW-day)**	$50.00		as may be determined by the RPM or its successor or otherwise
2	**Capacity Proxy Price ($/MW-day)**	$53.76		per Board Order dated XX/XX/2024
3	**Capacity Proxy Price True-Up - $/MW-day**	**-$3.76**		= line 1 - line 2
4	**Winning Bid - in $/MW-day**	$378.21		illustrative winning bid in 2025 BGS - CIEP Auction
5	**Payment to Suppliers - in $/MW-day**	**$374.45**	<<< used in calculation of Customer Rates	= line 3 + line 4

IX. ATTACHMENT 5 – DEVELOPMENT OF AVERAGE kWh DCFC CHARGE - $/kWh

DEVELOPMENT OF AVERAGE kWh DCFC CHARGE - $/kWh

3/18/2024

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

DCFC Capacity & Transmission Average Rate Estimate

line #			Capacity		Transmission	Notes
			RSCP	CIEP		
1		Rates $/kW-mo[1]	**1.5312**	**11.5118**	**13.7104**	= PSEG Electric Tariff No. 16
2		Load Factors[2]	80%	80%	81%	= DCFC Customer Data
3	$/kWh	Avg Capacity Cost	0.002621	0.019702	0.023170	= 12 x (Line 1 / 8760 /Line 2)
4		Avg Trans Cost	0.023170	0.023170		= line 3 Transmission
5		Cap & Trans Cost	0.025791	0.042872		= line 3 + line 4
6		Implementation	0.032031	0.032031		= *see footnote 4*
7		Contingency[3]	0.010000	0.010000		
8		Subtotal w/out SUT	0.067822	0.084903		= line 5 + line 6 + line 7
9		**Total w/ SUT**	**0.072315**	**0.090528**		

[1]Rates effective 03/01/24 and proposed transmission rate

[2]Load factors based upon 2023 DCFC population actuals

[3]Added contingency to account for lower 1st year Capacity and Transmission obligations

[4]Implementation Cost Calculation

400	Cost $k
6,244	2022 BGS usage - MWh
2	Years of pilot
0.032031	$/kWh

X. ATTACHMENT 6 – DEVELOPMENT OF TWO PERIOD KWH RATES - $/kWh

(Pages 1 and 2)

Attachment 6

3 pd rate

Page 1 of 2

			$/kWh		$k						
Total	**Notes**		summer	winter	summer	winter	Total				
		Days			122	243	365		$/MWh RS Cost from BGS model		
$113,328	*Capacity*	*on-peak*	*0.03582*	0.05932	37,879	75,448	113,328	Capacity	9.6%	$ 7.98	
		mid-peak						Total		$ 83.21	
		off-peak								Input energy only	
										S	W
1,067,962	Energy	on peak	0.10963	0.08478	473,550	594,412	1,067,962	Energy	90.4%	0.06821	0.04679
		mid peak	0.08738	0.07868			1.0875	- Taget to Zero		0.04903	0.04153
		off-peak	0.06888	0.07022			Change this cell in goal seek			0.03308	0.03424
1,181,290	Total Generation	on peak	0.1455	0.1441	511,429	669,861	1,181,290				
		mid peak	0.0874	0.0787							
		off-peak	0.0689	0.0702							
							Load Shape				
			Summer	Winter			Summer	Winter	Total		
	MWh	on peak	1,057,503	1,271,793	2,329,297		18.83%	17.31%	17.97%		
		mid peak	3,547,057	4,484,730	8,031,788		63.18%	61.03%	61.96%		
		off-peak	1,010,037	1,592,388	2,602,425		17.99%	21.67%	20.08%		
		All	5,614,598	7,348,911	12,963,509		100.00%	100.00%	100.00%		

Rate Summary

1.06625 SUT Factor

kWh Rates		**w/o SUT**		**w/ SUT**	
Rate	Period	Summer	Winter	Summer	Winter
3P	on peak	0.145454	0.144107	0.1550904	0.1536543
	mid peak	0.087382	0.078680	0.0931708	0.0838928
	off-peak	0.068877	0.070222	0.0734396	0.0748746
2P	on peak	0.145454	0.144107	0.1550904	0.1536543
	off peak	0.082991	0.076681	0.0884891	0.0817611

Attachment 6

2 pd rate

			$/kWh		$k								
Total	**Notes**		**summer**	winter	summer	winter	Total						
		Days											
$113,328	*Capacity*	*on-peak*	0.03582	0.05932	37,879	75,448	113,328						
		mid-peak											
		off-peak								Input energy only			
										S	W		
1,067,962	Energy	on peak	0.10963	0.08478	115,939	107,826	223,765			0.06821	0.04679	1.091	Factor
		mid peak								0.04500	0.03958	-	zero target
		off-peak	0.08299	0.07668	378,198	466,000	844,197						
							1,067,962						
1,181,290	Total Generation	on peak	0.1455	0.1441									
		mid peak											
		off-peak	0.0830	0.0767									
								Load Shape					
								Summer	Winter	Total			
	MWh	on peak	1,057,503	1,271,793	2,329,297			18.83%	17.31%	17.97%			
		mid peak											
		off-peak	4,557,094	6,077,118	10,634,212			81.17%	82.69%	82.03%			
		All	5,614,598	7,348,911	12,963,509			100%	100%	100%			

Ancillary Services	$ 2.00	per MWh @ bulk system
Renewable Power Cost	$ 22.64	per MWh @ bulk system
	24.64	
	0.02464	
	0.0262861	
1.066804	Expansion factor customer to bulk system	