STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

IN THE MATTER OF THE PROVISION OF BASIC GENERATION SERVICE FOR THE PERIOD BEGINNING JUNE 1, 2024	Docket No. ER23030124

ROCKLAND ELECTRIC COMPANY

PROPOSAL FOR BASIC GENERATION SERVICE REQUIREMENTS TO BE PROCURED EFFECTIVE JUNE 1, 2024

COMPANY SPECIFIC ADDENDUM COMPLIANCE FILING

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RECO's COMPANY SPECIFIC ADDENDUM

A. Introduction to RECO's Company Specific Filing

In its Decision and Order dated April 12, 2023 in Docket No. ER23030124, the New Jersey Board of Public Utilities ("Board" or "NJBPU") directed New Jersey's four investor owned electric distribution companies ("EDCs") to file proposals with the Board by no later than July 3, 2023 on the procurement of basic generation service ("BGS") for the period beginning June 1, 2024. This document constitutes the company-specific portion of the compliance filing for Rockland Electric Company ("RECO" or the "Company") mandated by the Board. RECO's filing also includes and incorporates by reference the Proposal for BGS Requirements to be Procured Effective June 1, 2024, filed by New Jersey's four EDCs on June 30, 2023 ("EDC Compliance Filing").

B. Use of Committed Supply

"Committed Supply" means any and all power supplies to which the EDCs have an existing physical or financial entitlement that may extend into or through the BGS bid period. This will include Non-Utility Generation ("NUG") contracts, including any restructured replacement power contracts; any wholesale purchases previously contracted for by the EDCs, and any generation assets, or options for/calls upon assets, still owned or under contract to the EDCs. RECO has no Committed Supply.

C. RECO Tranche Configuration

In its Decision and Order issued June 18, 2012 in Docket No. ER12020150, the Board lowered the threshold for the BGS-CIEP class to include all commercial and industrial customers with a peak load share of 500 kW and greater.[1] RECO continues to comply with this directive and will include these customers as one tranche (at 47.26 MW of BGS-CIEP eligible load per tranche) in the BGS-CIEP Auction.

As to the BGS-RSCP Auction, RECO currently has one 36-month tranche that terminates on May 31, 2024, one 36-month tranches that terminates on May 31, 2025, and two 36-month tranches that terminate on May 31, 2026. Accordingly, since the load requirements of RECO's Eastern Division are comprised of a total of four tranches, in the BGS-RSCP Auction for the period commencing June 1, 2024, RECO will include one 36-month tranche (for the period June 1, 2024 through May 31, 2027).

D. Contingency Plans

While not every contingency can be anticipated, the following three contingencies are of particular concern:

(a) The Auction Process fails to provide 100 percent of RECO's BGS Load (i.e., an insufficient number of bids to provide for a fully subscribed auction volume);

(b) A default by one of the winning bidders prior to June 1, 2024; and

(c) A default during the supply period.

The three contingencies are discussed further below:

(a) Insufficient Number of Bids

A viable Auction Process requires a sufficient degree of competition. To encourage a sufficient degree of competition, the volume of BGS power purchased at the

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[1] In accordance with the Board's December 8, 2005 Decision and Order (see footnote 13, at page 16), RECO will determine all eligibility criteria by measuring when a customer's billing demand exceeds the eligibility level during any two months of a calendar year.

Auction will be finally decided after the receipt of first round bids. Provided that there are sufficient bids at the starting price, the Auction will be held for 100 percent of the BGS Load[2] (i.e., both BGS-RSCP and BGS-CIEP).

It is possible, however, that the amount of initial bids will not result in a competitive auction for 100 percent of the BGS Load. Any determination to reduce the percentage of BGS Load included in the Auction Process will be made by the Auction Manager, in consultation with the EDCs and the NJBPU advisor. It is also possible that none of RECO's BGS Load tranches will be bid upon even at the starting price.

In the event that the Auction Volume is reduced to less than 100 percent of BGS Load, or there are unsubscribed tranches at the end of the Auction, each EDC will implement a contingency plan for the remaining tranches. Under RECO's contingency plan, RECO currently intends to purchase that percentage of BGS Load, not met through the Auction Process, in PJM administered markets.[3] This purchase is a strong feature of the Auction proposal because it provides bidders a strong incentive to participate in the Auction Process.

During the 2006 BGS Auction, RECO did not receive any bids on its BGS-CIEP tranche. As a result, RECO was forced to purchase its BGS-CIEP supply from the PJM markets. In the event that RECO is not able to auction its BGS-CIEP tranche successfully in the 2023 BGS Auction, RECO proposes to employ the following procedures:

- RECO will not submit any day-ahead energy bids, rather the BGS-CIEP load will be filled from the PJM real time market.

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[2] Excluding the three 36-month tranches that were auctioned off successfully in the previous two BGS-RSCP Auctions.

[3] While RECO's current intention is to purchase from PJM administered markets, RECO reserves the right to consider other alternatives. Although unlikely, in the event that purchases from New York Independent System Operator ("NYISO") administered markets provide a more cost-effective alternative to PJM, RECO reserves the right to make purchases from NYISO administered markets.

- RECO will prepare a BGS-CIEP load backcast for the previous day and submit this backcast to PJM.
- RECO will purchase capacity credits from eRPM in PJM or from bilateral purchases on a monthly and daily basis.
- RECO will purchase ancillary services on a daily basis from the real time PJM market.
- RECO will set its CIEP Standby Fee at the level determined by the Board.
- RECO will fulfill any Class I, Class II, and Solar requirements, for its unsubscribed BGS tranches, by securing the needed PJM Generation Attributes Tracking ("GATS") system generated renewable energy certificates ("RECs") through any available PJM market, or bilaterally. In the event RECs are not available on the market, RECO will make the necessary Alternative Compliance Payments.
- All costs and revenue (with the exception of retail margin revenue) will flow through the reconciliation account for BGS-CIEP. Costs will include the procurement of all necessary services, including energy, capacity, ancillary services, Class I, II and Solar RECs, and any other expenses related to the implementation of RECO's contingency plan.

(b) Defaults prior to June 1, 2024

If a winning bidder defaults prior to the commencement of the BGS service, then the open tranches may be offered to the other winning bidder(s) or these tranches will be bid out as quickly as possible. Additional costs will be assessed against the defaulting company's BGS credit security.

(c) Defaults during the Supply Period

If a default occurs during the supply period, then Tranches supplied by the defaulting party may be offered to other suppliers, bid out, or procured in PJM administered markets. If a default involves RECO's 36-month BGS-RSCP tranche, RECO only will seek replacement supply until May 31, 2025. For the remainder of the 36-month period, RECO will seek replacement supply through whatever process is implemented by the Board for the period commencing June 1, 2025.

Additional costs will be assessed against the defaulting company's BGS credit security.

E. Accounting and Cost Recovery

The accounting and cost recovery that RECO proposes with respect to BGS is summarized in this section.

(a) System Control Charge ("SCC")

If applicable to RECO, the SCC will be calculated initially, and then annually on a cents per kWh basis and the charge will be applied to all of the Company's electric distribution customers. This charge would be published in a separate SCC tariff leaf. This tariff leaf would be filed with the Board upon the Board's issuance of the appropriate order(s). If applicable to RECO, the SCC would be applied to all distribution customers' bills to provide recovery for appliance cycling load management costs. The charge would be set initially to recover estimated annual expenditures as approved by the Board. The SCC would be subject to deferred accounting with interest at the rate applicable to SBC deferrals.

(b) BGS-RSCP and BGS-CIEP Reconciliation Charges

In its Decision and Order in Docket No. ER12070643, the Board approved the Company's proposal to change the BGS-RSCP and BGS-CIEP reconciliation charges from a monthly to a quarterly mechanism. RECO will track and defer separately for the BGS-RSCP and BGS-CIEP classes of customers, on a monthly basis, any differences between BGS revenue and BGS costs.

BGS costs are comprised of the following:

1. Payments made for provisions of BGS-RSCP and BGS-CIEP service;

2. RECO’s pro-rata share of any procurement of capacity, energy, and ancillary services, pursuant to its FERC-approved Power Supply Agreement, and other costs incurred, including hedging and costs associated with the RECO Request for Proposal (“RFP”);

3. The cost of any procurement of capacity, energy, ancillary services, transmission, RPS compliance, and other costs incurred under the Contingency Plan less any payments recovered from defaulting suppliers;

4. Costs incurred by RECO to participate in the BGS Auction as well as any costs incurred to conduct the RECO RFP, including outside attorney and consultant expenses and other costs incurred by or allocated to RECO related to the conduct of the Auction; and

5. Any administrative costs associated with the provision of BGS-RSCP and BGS-CIEP service;

   Administrative costs are defined as commonly-incurred or directly-incurred. Commonly-incurred costs are costs shared among all of the EDCs. Directly-incurred costs are costs specifically incurred by each EDC, individually.

   a. 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 NJBPU, 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.

b. Directly-incurred costs include, but are not limited to, the following:
   - labor costs

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 their November 2021 Board Order, the Board authorized the EDCs to sublet the BGS Office in Newark. The EDCs subsequently did sublet the office, and the revenues related to the same serve to offset other commonly-incurred EDC costs.

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 (“EY”)[4] 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.

Reconciliation charges are necessary to reconcile the differences between monthly BGS supply costs and BGS revenues from customers for BGS service. Separate BGS-RSCP and BGS-CIEP Reconciliation Charges, applicable to all BGS-RSCP and BGS-CIEP customers, respectively, will be calculated and assessed quarterly

[4] The Energy Year is defined as the 12-month period commencing June 1.

on a cents per kWh basis to reconcile previous over- or under-collections. The BGS-RSCP and BGS-CIEP Reconciliation Charges will be published in separate BGS Reconciliation Charge tariff leaves on a quarterly basis. These tariff leaves will be filed with the Board fifteen days prior to the first day of the effective quarter.

The BGS-RSCP and BGS-CIEP Reconciliation Charges will be subject to deferred accounting with interest and will be determined individually as set forth below:

The BGS-RSCP and BGS-CIEP Reconciliation Charges[5] will be used to true up the differences between BGS costs and BGS revenues from customers. Differences in costs and cost recovery will be computed for each month in the quarter and assessed through the BGS-RSCP and BGS-CIEP Reconciliation Charges applied to customers' bills in the following quarter. Two of these differences are as follows:

1. The difference between BGS Costs and BGS revenues for each month in the quarter.
2. The difference between the total reconciliation charge revenue intended to be recovered in each quarter and the actual reconciliation charge revenues recovered in the quarter. This difference will be driven by differences between actual kWh in the quarter in which the reconciliation charge was assessed and the kWh used to calculate the charge.

The reconciliation charges to be applied in the following quarter are calculated individually for BGS-RSCP and BGS-CIEP service as the net of the two

[5] Included in the BGS-CIEP Reconciliation Charge will be recovery of the Per-Plug incentives provided under RECO's Electric Vehicle ("EV") Direct Current Fast Charging ("DCFC") 2-year program approved by the Board on November 17, 2023.

differences described above on a monthly basis for the current quarter (plus or minus any cumulative under or over recovery from the prior quarter) divided by the forecasted BGS kWh for the following quarter.

For any given quarter, the reconciliation charges shall not exceed a charge or credit of 2.0 cents per kWh, including sales and use tax. In the event the 2.0 cents per kWh limit is imposed, any remaining over- or under-collection balance shall be included in the subsequent quarter's reconciliation charges to the extent possible within the 2.0 cents per kWh limitation.

The following table summarizes RECO's current process.

Reconciliation for the Months of:	Quarter Rate is In Effect:
February – April	June 1 - August 31
May – July	September 1 - November 30
August – October	December 1 - February 28
November – January	March 1 - May 31

Interest will be applied based on two-year constant maturity treasuries as published in the Federal Reserve Statistical Release on the first day of each month or the closest day thereafter on which rates are published, plus 60-basis points. However, the interest rate shall not exceed the Company's overall rate of return as authorized by the Board. The interest rate will be determined for each month in the quarter based on the criteria above.

F. Description of BGS Tariff Changes

Draft tariff leaves indicating "X.XXX" for the rates that will change as a result of the BGS-RSCP and BGS-CIEP Auctions are included in Attachment A.

For the BGS rates applicable to BGS-RSCP eligible SC No. 2 demand billed customers, the Company has eliminated the differential for the first 5 kW and above 5 kW of demand.

Final tariff leaves including the actual BGS rates and tariff provisions to become effective on June 1, 2024 will be filed with the Board upon its issuance of an appropriate Board order approving the BGS Auction Process.

G. RECO RFP

Rockland's Central and Western divisions are physically connected to the New York Control Area administered by the New York Independent System Operator ("NYISO"). Therefore, RECO must purchase the energy and capacity needs of its Central and Western BGS customers from markets administered by the NYISO.

With regard to the purchase of energy, in the Board's November 18, 2020 Order in Docket No. ER20030190 (the "2020 Order"), the Board approved a Request for Proposal ("RFP") process for Rockland to solicit competitive bids from qualified bidders for fixed energy supply prices for BGS customers in Rockland's Central and Western Divisions, commencing June 1, 2021. On January 26, 2021, Rockland conducted its RFP for the period June 1, 2021 through May 31, 2024. As a result of awarding a three-year financial contract, RECO's energy purchases were hedged through May 31, 2024, and another procurement proposal must be made for the BGS year commencing June 1, 2024.

(a) Proposal

For the BGS year commencing June 1, 2024, RECO proposes the same procurement process that the Board approved in the 2020 Order. Rockland proposes to enter into a bi-lateral agreement or agreements to hedge the cost of energy purchases from the NYISO. The bi-lateral agreement or agreements will be a financial hedge, where no energy commodity is provided by the counterparty.

The Company proposes to conduct the bidding approximately two weeks before the BGS auction. The bids would be submitted by bidders the day before a Board agenda meeting, and the bid agreement would specify that the bidder will hold the bid open until the earlier of approval of the bid by the Board or midnight the day of the Board agenda meeting. Any bidder that has an ISDA[6] in place with the Company prior to bidding will be eligible to bid. Bidders will enter into binding bid agreements, but the Company will not require bid collateral, in order to encourage bidder participation. The Company reserves the right to reject any and all winning bids.

Rockland will seek bids on financial transactions for NYISO Zone G energy for the periods specified below. Each transaction will be a fixed-price transaction for approximately 13 MW "around-the-clock" of NYISO Zone G energy. Rockland is seeking to procure transactions to cover the period of June 1, 2024 to May 31, 2027 and will seek pricing for the following four periods:

1. Year 1: June 1, 2024 through May 31, 2025;
2. Year 2: June 1, 2025 through May 31, 2026;
3. Year 3: June 1, 2026 through May 31, 2027; and
4. Blended Price: June 1, 2024 through May 31, 2027.

[6] The ISDA Master Agreement, published by the International Swaps and Derivatives Association (ISDA), is a document that outlines the terms applied to a derivatives transaction between two parties.

Rockland will enter into a NYISO Zone G fixed-for-floating swap with a counterparty, whereby Rockland effectively pays the fixed price monthly for the term of the transaction.

Rockland will review the bids with Board Staff and its BGS auction consultant and select a winning bid that is the most competitive and that is consistent with market conditions. Rockland will submit this winning bid to the Board for approval. In the event that the bids that the Company receives do not reflect market conditions, the Board does not approve the winning bidder, or the bidder defaults on the bid agreement, the Company will report a failed procurement and will proceed to the default procurement process set out below.[7]

With regards to the procurement of capacity, on August 16, 2013, the FERC approved the creation of a new capacity market zone in the Lower Hudson Valley region encompassing NYISO Load Zones G, H, I, and J in FERC Docket No. ER13-1380. Lower Hudson Valley capacity is not actively traded, and the Company does not expect the above to change before the BGS Auction.[8] As a result of the capacity market changes at the NYISO noted above, RECO will purchase the capacity needs of its BGS customers in its Central and Western Divisions in the NYISO capacity market and blend its forecast of those prices into the BGS-RSCP price. This is the same proposal approved by the Board in its November 18, 2020 Order in Docket No. ER20030190. The impact of these capacity purchases is expected to be minimal because the

[7] If the Company uses an in-house auction facility, a technical failure of the auction facility will require that the Company proceed to the default procurement process.

[8] Such cleared products are necessary benchmarks that enable bidders to develop their bids for financial hedging contracts.

Company's Central and Western Divisions constitute only about ten percent of the Company's BGS load.

(b) Default Procurement

In the event of a default procurement, Rockland will purchase the energy needs of its BGS customers in the Central and Western Divisions in the NYISO Day-Ahead and Real Time Markets without a financial hedge. Currently, to determine rates for BGS service classifications, the Company calculates a load-weighted price to calculate BGS service classification rates. The load-weighted price combines, for the Central/Western division, the hedging contract fixed price and the Company's forecast of the NYISO capacity price, and for the Eastern division, three-year, tranche-weighted BGS auction prices. For this default proposal, the Company will use the BGS auction price as the input for the Central/Western portion of the load-weighted price.

H. BGS Rate Design Methodology

<u>RECO BGS Pricing Spreadsheet</u>

As described in the EDC Compliance Filing, the resulting charge for each BGS rate element (e.g., SC No. 1 summer charge, winter charge) for BGS supply service will be based on a factor applied to the tranche weighted average of the winning BGS-RSCP bid prices adjusted for the seasonal payment factors. These factors have been developed based on the ratios of the estimated underlying market costs of each rate element (for each service classification) to the overall all-in BGS cost. The tables included in Attachment B present all of the input data, intermediate calculations, and the final results in the calculation of these factors.

Table #1 (% Usage during PJM On-Peak Period) contains the percentage of on-peak load, by month, for each service classification. 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 year 2023 based on load profile information.

Table #2 (% Usage During RECO On-Peak Billing Period) contains percentages of on-peak load, by month, for RECO BGS-RSCP service classifications that are billed on a time of use basis (SC No. 1 Voluntary Time of Day ("SC No. 1 VTOD") and SC No. 3). These percentages are based on RECO's time periods used for customer billing.

Table #3 (Class Usage @ customer) contains monthly sales forecasted for the calendar year 2024 with a migration adjustment for retail access. The values in Table #3 will be updated in January 2024 to better reflect the amount by Service Classification that could be in effect starting on June 1, 2024.

Table #4 (Forward Prices – Energy Only @ bulk system) contains the forward prices for energy, by time period and month, for the BGS analysis period. These values are a weighted average forecast of PJM and NYISO energy prices as calculated in Table #18. The PJM values are the published energy on-peak forwards for the PJM West trading hub for the period of June 2024 to May 2025, and an estimate based on off/on peak LMP ratios for the off-peak periods of each month. The NYISO values are based on a combination of forward and historical prices. An adjustment to the PJM forward prices used to calculate the prices contained in Table #4 must be made to correct for the effects of the basis differential in the PJM system between the PJM West trading hub and the RECO zone where the BGS supply will be utilized. Table #18 contains an estimate of this basis differential, 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 RECO's PJM zone.

Table #5 (Losses) contains the factors utilized for average system losses, including PJM losses and unaccounted for supply (net of marginal losses) that are input by service classification and voltage level. Loss factors are those in RECO’s current, Board approved, Third Party Supplier Agreement. PJM losses are the average percentage PJM EHV losses plus Inadvertent Energy for the period of January 2020 to December 2022, which equals 0.6216%. Marginal losses are excluded from the loss factors based on historic de-rating factors for the period January 2020 to December 2022.

Table #6 (Summary of Average BGS Energy Only Unit Costs @ customer – PJM Time Periods) is the calculation of the energy only costs by service classification, 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 forward prices (from Table #4) adjusted for losses (from Table #5), 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 Capacity or Transmission costs, which will be considered in subsequent calculations.

Table #7 (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 #6, the monthly time period weights from Table #1 and the total sales to customers from Table #3.

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

Table #8 (Summary of Average BGS Energy Only Units Costs @ customer – RECO Time Periods) shows the result of this adjustment for SC No. 1 – VTOD and SC No. 3 rates billed on a time of use basis. These values are calculated by starting with the values in Table #6. Because RECO bills fewer peak hours than the peak hours defined by PJM, the prices in Table #6 would result in a revenue shortfall when applied to RECO's SC No. 1 – VTOD and SC No. 3 peak and off-peak kWh consumption. To correct for this difference, the shortfall for each is divided by the total kWh for the SC and the resulting per unit shortfall is added to both the on-peak and off-peak charges in Table #6 to arrive at the prices in Table #8. The next steps set up the values necessary for the inclusion of the costs of the Generation Capacity and Transmission.

The top portion of Table #9 (Generation & Transmission Obligations and Costs and Other Adjustments) 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 #9 will be updated in January 2024 to better reflect the aggregate amount by rate schedule that could be in effect on June 1, 2024. 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 and the average price of generation capacity for the three relevant RPM auctions. 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 2024/2025, 2025/2026, and 2026/2027 Base Residual Auction ("BRA") results under the Reliability Pricing Model ("RPM") applicable to load served in the RECO 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.

PJM has issued a schedule of upcoming BRAs and the recently conducted BRA's produced a preliminary price paid for capacity of $54.50 per MW-day for the 2024/2025 Delivery Year for the RECO Zone. Due to the postponements of the BRAs, contracts from the 2022 and 2023 BGS auctions contained supplements with Capacity Proxy Prices. With the prior postponements of the BRAs for the 2024/2025 Delivery Year and the 2025/2026 Delivery Year, the Capacity Proxy Prices of $87.98/MW-day was used in place of the 2024/2025 BRA value in the 2022 contracts, while a Capacity Proxy Price of $66.38/MW-day was used in place of the 2024/2025 BRA value and a Capacity Proxy Price of $44.63/MW-day was used in place of the 2025/2026 BRA value in the 2023 contracts.

Given the continued delay in the schedule of BRAs for the 2025/2026 Delivery Year and 2026/2027 Delivery Year, a Capacity Proxy Price of $47.46 per MW-Day has been used in place of the 2025/2026 BRA value and a Capacity Proxy Price of $49.05 per MW-Day have been used in place of the prices paid for 2025/2026 and 2026/2027 Delivery Years, respectfully.

For EY 2026, with Supplement A to the BGS-RSCP Supplier Master Agreement approved by the Board on November 17, 2023 and if 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 EY 2027, with Supplement B to the BGS-RSCP Supplier Master Agreement approved by the Board on November 17, 2023 and if 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 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 2026/2027 Delivery Year.

RECO will file new tariff sheets for EY 2026 and EY 2027, 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 SMA Supplements signed by BGS Suppliers in February 2022 and February 2023 are still in effect for a portion of the load for EY 2025 (the year beginning June 1, 2024). Payments to BGS-RSCP suppliers that executed the Supplement to the SMA approved by the Board on November 17, 2021 and November 9, 2022 will be adjusted for the price difference between the price paid by the BGS-RSCP Suppliers for Capacity in the Company's PJM Zone and the Capacity Proxy Price for the 2024/2025 Delivery Year. Upon the conclusion of the Third Incremental Auction, or the RPM's successor or otherwise, the price paid by the BGS-RSCP Suppliers for Capacity in the Company's PJM Zone will be known. At that time RECO 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 Suppliers in February 2022 and February 2023. The value of the recently concluded BRA was made available in early 2023 is used as an approximation for the Final PJM RPM Net Zonal Price for the 2024/2025 Delivery Year ($54.50 per MW-Day).

The cost of transmission service is equal to the rate in the PJM Open Access Transmission Tariff for network transmission service in the RECO zone. The generation capacity costs are based on an estimate of the relevant current wholesale market prices in the PJM (i.e., three-year average for the period 2024 to 2027 for RECO using a proxy price for 2027), and NYISO zones as calculated in Table #19. Also shown is the level of blocking in the BGS charges for SC No. 1, which will be utilized in the later calculations of the blocking of BGS charges for this service classification group.

An estimate of the cost of ancillary services and Renewable Portfolio Standard is included in Table #10 (Ancillary Services and Renewable Portfolio Standard). The Ancillary Services estimate is a weighted average of estimated Ancillary Services costs in RECO's PJM zone (i.e., $2 per MWH) and RECO's estimate of Ancillary Services costs in RECO's NYISO zone as calculated in Table #20. Additionally, Renewable Portfolio Standard costs estimated to be $20.88 per MWh are included in the calculation of the BGS-RSCP rates to reflect compliance costs.

Table #11 (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 MWh basis to those service classifications under which BGS service will be billed only on a per kWh basis.

Table #12 (Summary of BGS Unit Costs @ customer) is the result of the inclusion of the transmission, generation capacity, and Ancillary Services costs to the costs shown in Table #8. 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 and the bulk system meters.

Table #13 (Ratio of BGS Unit Costs @ customer to All-In Average Cost @ transmission nodes) indicates the ratio of the individual rate element costs from Table #12 to the overall all-in cost as measured at the bulk system plus constant, where applicable.

Table #14 (Summary of BGS Unit Costs Less Transmission @customer) provides the BGS unit costs as developed in Table 12, with the exception of transmission. The bottom portion of the table shows the total estimated costs for BGS less transmission costs and the average unit cost as measured at the customer meters and the bulk system.

Table #15 (Ratio of BGS Unit Costs Less Transmission @ customer to All-In Average Cost @ transmission nodes) indicates the ratio of the individual rate element costs from Table #14 to the overall all-in cost as measured at the bulk system. These ratios are used to establish the BGS prices to retail customers.

Table #16 (Summary of Total BGS Costs by Season) shows the summary of the total and percentage of costs by rate and by season. A calculation in the lower portion of this table shows the resulting average costs per MWh for the winter and summer costs and MWhs, while the ratio of these seasonal unit costs to the all-in cost (from Table #12) is shown in the lower right-hand portion of this table.

Table #17 (Summary of Total BGS Costs by Season Less Transmission) shows the summary of the total and percentage of costs by rate and by season. This is similar to the values indicated in Table #16, however this table excludes the cost for transmission. A calculation in the lower portion of this table shows the resulting average costs per MWh for the winter and summer costs and MWhs, while the ratio of these seasonal unit costs to the all-in cost (from Table #14) is shown in the lower right-hand portion of this table.

Tables #18 (Forward Energy Prices), #19 (Generation Capacity Prices), and #20 (Ancillary Services and Renewable Portfolio Standard Prices) show the calculation of weighted average prices for energy, generation capacity and Ancillary Services as more fully described under "Table #4", "Table #9" and "Table #10". An estimate of the effects of the cost of the Renewable Portfolio Standard is included in the development of the final BGS rates. The values of $2.00 per MWh and $20.88 per MWh are used, respectively for ancillary services and Renewable Portfolio Standard Prices. 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.

The second spreadsheet used in the calculation of the final BGS-RSCP rates is included as Attachment C. 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 (Weighted Average Price Calculation) contains the results of the BGS (i.e., current and prior two) auctions. 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 2022 and February 2023. 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 2024/2025 Delivery Year. The value of the recently concluded BRA in June of 2023 is used as an approximation of the price paid by BGS-RSCP Suppliers for Capacity in the Company's PJM Zone for 2024/2025. The table also includes the impacts of RECO's RFP for the Central and Western Divisions.[9] However, upon the conclusion of the RECO RFP, the RFP winning bid price will be applied to the results of the prior two BGS auctions. From these values, the weighted average total price (shown on line #20) is calculated. All of the formulas used in this table are shown in the right-hand column of this table, under the head of "Notes." To the extent the

[9] The prices shown for the tranche to be secured in the 2024 BGS Auction and RFP are for illustrative purposes only and will be replaced with actual data in determining RECO's final June 2024 BGS-RSCP rates.

seasonal factors for the 12-month BGS period beginning June 1, 2024 (as calculated in Table #16) produce a summer payment factor less than one and a winter payment factor greater than one, the Company reserves its right to set the seasonal factors to 1.0 for both the Summer and Winter periods in any updates to the Company's BGS Pricing Spreadsheet. Accordingly, the Company has set the seasonal factors to 1.0 for both the Summer and Winter periods.

Table B (Ratio of BGS Unit Costs Less Transmission @ Customer to All-In Average Cost @ transmission nodes) is a repeat of the values shown in Table #15 from Attachment B, the bid factors calculated based on current market conditions.

Table C (Determination of Preliminary Retail Rates to be Charged to BGS Customers) contains the preliminary customer BGS-RSCP rates as the product of the weighted average total price (from Table A) and the Bid Factors from Table B.

Table D (Calculation of Rate Adjustment Factors) 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 Rate Adjustment Factors is also performed in this table. These factors are equal to the seasonal dollar differences between the anticipated billed revenue and supplier payments, divided by the total anticipated seasonal billed BGS-RSCP portfolio related charges.

Table E (Final Retail 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 Rate Adjustment Factors that were developed in Table D. The resulting rates are then adjusted to include the New Jersey Sales and Use Tax at the rate of 6.625%.

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.

I. Capacity Charges

Capacity charges are the separate charges designed to recover the costs associated with generation capacity for BGS-RSCP customers. 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, 2024/2025, 2025/2026, and 2026/2027 BRA for RPM results applicable to load served in the RECO zone. PJM has now issued a calendar of upcoming BRAs and the recently concluded BRA produced a preliminary price paid for capacity of $54.50 per MW-day for the 2024/2025 Delivery Year for the RECO zone. Due to the postponement of the BRAs prior year BGS Auction contracts contained supplements with Capacity Proxy Prices.

With the prior postponement of the BRAs for the 2024/2025 and 2025/2026 Delivery Years, a Capacity Proxy Prices of $87.98 and $66.38 per MW-Day have been used in place of the 2024/2025 and 2025/2026 BRA values.

Given the continued delay in the schedule of BRAs for the 2025/2026 Delivery Year and 2026/2027 Delivery Year, a Capacity Proxy Price of $47.46 per MW-Day and a Capacity Proxy Price of $49.05 per MW-Day have has been used in place of the prices paid for capacity for 2025/2026 and 2026/2027 Delivery Year, respectfully.

For EY 2026, with Supplement A to the BGS-RSCP SMA approved by the Board on November 17, 2023 and if 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 capacity price difference between the Zonal Capacity Price, which is the price paid by BGS-RSCP Suppliers for capacity in the Company's RECO Zone, as may be determined under the RPM or its successor or otherwise, and the Capacity Proxy Price for the 2025/2026 Delivery Year.

For EY 2027, with Supplement B to the BGS-RSCP SMA approved by the Board on November 17, 2023 and if 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 capacity price difference between the Zonal Capacity Price charged to BGS-RSCP Suppliers for Capacity in the Company's RECO 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.

RECO will file new tariff sheets for EY 2026 and EY 2027, 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. However, the spreadsheets do not provide a value for this true-up as the actual value is not known at this time. Attachment D provides an illustrative example of the calculation.

The SMA Supplements to the SMAs signed by BGS-RSCP Suppliers in February 2022 and February 2023 are still in effect for a portion of the load for EY 2025 (the year beginning June 1, 2024). Payments to BGS-RSCP suppliers that executed the Supplements to the SMAs approved by the Board on November 17, 2021 and November 9, 2022 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 2024/2025 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 RECO 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 2022 and February 2023. The value of the recently concluded BRA was made available in early 2023 is used as an approximation for the price paid by BGS-RSCP Suppliers for Capacity in the Company's PJM Zone for the 2024/2025 Delivery Year ($54.50 per MW-Day)

J. Transmission Charges

The transmission charges applicable to RECO's BGS-RSCP and BGS-CIEP customers are based on the currently effective transmission rates applicable to the RECO zone, as stated in PJM's Open Access Transmission Tariff ("PJM Transmission Rates"). The PJM Transmission Rates will change from time to time as FERC approves changes in the PJM Open Access Transmission Tariff. Such changes in the PJM Transmission Rates, including but not limited to changes associated with the Seams Elimination Charge/Cost Adjustments/Assignments ("SECA"), Transmission Enhancement Charges ("TECs") and Reliability Must Run ("RMR") charges, will result in changes to RECO's transmission rates applicable to its BGS-RSCP and BGS-CIEP customers. RECO will review and verify the basis for any transmission cost adjustment, and file supporting documentation from the PJM Transmission Rates as well as any rate translation spreadsheets used.

K. DCFC Program

In the November 9, 2022 BGS Board Order (BPU Docket No. ER22030127), among other things, the Board directed the EDCs to work with interested parties to come to a consensus in an attempt to find a Direct Current Fast Charging ("DCFC") rate design solution to be included in each EDCs' 2024 BGS Auction proposal. To that end, RECO proposed to provide eligible customers with an incentive of up to 75% of the BGS-CIEP capacity charge of the customer bill, with an annual cap of $12,600 per DCFC Plug. Incentives would be administered annually and would be available to DCFC stations taking service under the BGS-CIEP tariff. RECO proposed to operate this program from the time of Board approval until year-end 2026. RECO would recover these incentives through the BGS-CIEP reconciliation charge. RECO could implement this program upon Board approval and will incur no incremental administrative expenses in doing so. On November 17, 2023 the Board approved this program, with the program beginning June 2024 and ending May 2026. The Company has included draft tariff language allowing for recovery of the DCFC Plug Incentives through the BGS-CIEP reconciliation charge.

L. Conclusion

In connection with this filing, the Company requests that the Board issue an order making the following findings and determinations:

1. The Company's proposed treatment of its Committed Supply is approved by the Board;

2. The Company's proposed accounting for BGS is approved by the Board for purposes of accounting and BGS cost recovery;
3. 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;
4. RECO's Contingency Plan is approved by the Board, and the costs incurred as a result of this Contingency Plan are presumptively prudent, subject to deferral, and approved for full and timely recovery;
5. The RECO-specific statewide Auction results are approved by the Board and produce BGS supply costs that are reasonable and prudent, subject to deferral, and approved for full and timely recovery;
6. The Company's proposal for its Central and Western Divisions is approved by the Board; and
7. The Company's Rate Design Methodology and Tariff Sheets are approved by the Board; and,

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GENERAL INFORMATION

No. 31 BASIC GENERATION SERVICE ("BGS")

(1) Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP)
Applicable to Service Classification Nos. 1, 2, 3, 4, and 6

Applicable to Service Classification Nos. 1, 2 (Non-Demand Billed), 3, 4, and 6
Charges per kilowatthour:

Service Classification	Summer Months*	Other Months
1 (Non-TOD) – First 600 kWh	X.XXX¢	X.XXX¢
1 (Non-TOD) – Over 600 kWh	X.XXX¢	X.XXX¢
1 (TOD) – Peak	XX.XXX¢	XX.XXX¢
1 (TOD) – Off-Peak	X.XXX¢	X.XXX¢
2 - (Non-Demand Billed) – All kWh	X.XXX¢	X.XXX¢
3 – Peak	XX.XXX¢	XX.XXX¢
3 – Off-Peak	X.XXX¢	X.XXX¢
4 – All kWh	X.XXX¢	X.XXX¢
6 – All kWh	X.XXX¢	X.XXX¢

Applicable to Service Classification No. 2 Demand Billed customers who do not take BGS-CIEP service in accordance with General Information Section No. 31(2):

	Summer Months*	Other Months
Demand Charges		
First 5 kW ($/kW)	X.XX	X.XX
Over 5 kW ($/kW)	X.XX	X.XX
Usage Charges		
All kWh (¢/kWh)	X.XXX¢	X.XXX¢

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

*Definition of Summer Billing Months - June through September

(Continued)

GENERAL INFORMATION

No. 31 BASIC GENERATION SERVICE ("BGS") (Continued)

(2) Basic Generation Service – Commercial and Industrial Energy Pricing (BGS-CIEP)

This service is applicable to all Service Classification No. 7 customers, and Service Classification No. 2 customers who maintain a billing demand of 500 kW or greater during any two months of a calendar year, taking BGS from the Company. Service Classification No. 2 metered customers who do not meet the above criteria may elect to take BGS-CIEP service on a voluntary basis. See General Information Section No. 31(1).

BGS Energy Charges:
Charges per kilowatthour:
BGS Energy Charges are hourly and are provided at the real time PJM Load Weighted Average Residual Metered Load Aggregate Locational Marginal Prices for the Rockland Electric Transmission Zone, plus Ancillary Services (including PJM Administrative Charges) at the rate of $0.00640 per kilowatthour, adjusted for losses and applicable taxes.

BGS Capacity Charges:

Charges per kilowatt of Capacity Obligation as determined in accordance with General Information Section No. 31(C):

Charge applicable in Summer* months..$ XX.XXXX
Charge applicable in other months...$ XX.XXXX

The above charges shall recover each customer's share of the overall summer peak load assigned to the Rockland Electric Transmission Zone by PJM as adjusted by PJM assigned capacity related factors.

In accordance with Rider SUT, the above charges include provision for the New Jersey Sales and Use Tax. When billed to customers exempt from this tax, as set forth in Rider SUT, such charges will be reduced by the relevant amount of such tax included therein.

* June through September

(Continued)

GENERAL INFORMATION

No. 31 BASIC GENERATION SERVICE ("BGS") (Continued)

(4) BGS Reconciliation Charges

Separate BGS-RSCP and BGS-CIEP reconciliation charges shall be computed quarterly and assessed on all BGS-RSCP and BGS-CIEP customers. The billing quarters shall be defined as the three-month periods beginning March, June, September, and December. The reconciliation charges shall recover the differences, including interest, between amounts paid to BGS suppliers and BGS revenue for the preceding quarter for the applicable BGS supply. The BGS Reconciliation Charges will also include refund of transmission charge retail rate revenue over collection for the period March 18, 2018 through April 30, 2019 resulting from the decrease in the PJM Open Access Transmission Tariff ("OATT") Schedule H-12 revenue requirement and the decrease in the Company's PJM OATT Schedule 1A scheduling, system control, and dispatch rate approved by FERC on November 15, 2018 in FERC Docket No. ER18-1585. The BGS-CIEP Reconciliation Charge will also include any Direct Current Fast Charging ("DCFC") Per-Plug program incentives paid out to participating customers. For any given quarter, the reconciliation charges shall not exceed a charge or a credit of 2.0 cents per kWh, including SUT. In the event the 2.0 cents per kWh limit is imposed, any remaining over- or under-collection balance shall be included in the subsequent quarter's reconciliation charges to the extent possible within the 2.0 cents per kWh limitation. Interest will be calculated as determined by the Board in its Order dated February 6, 2009 in Docket Number ER08050310.

These charges include all applicable taxes and are charged on a monthly basis for all usage billed in the month indicated.

BGS-RSCP Reconciliation Charge…………………….........…........... (X.XX) ¢/kWh

BGS-CIEP Reconciliation Charge …………………………................. (X.XX) ¢/kWh

In accordance with Rider SUT, the above charges include provision for the New Jersey Sales and Use Tax. When billed to customers exempt from this tax, as set forth in Rider SUT, such charges will be reduced by the relevant amount of such tax included therein.

The BGS Reconciliation Charges shall be filed with the Board not less than fifteen days prior to the date on which they are proposed to become effective.

Development of BGS Cost and Bid Factors for Rates Effective June 1, 2024

Table #1 **% Usage During PJM On-Peak Period**

Based on 2023 Load Profile Information
On-Peak periods defined as the 16 hr PJM Trading period, adj for NERC holidays

	Profile Meter Data	*Profile Meter Data*	*Profile Meter Data*	*--- Other Analysis ---*		*Profile Meter Data*
	SC1	**SC3**	**SC2 ND**	**SC4**	**SC6**	**SC2 Dem**
January	42.64%	46.20%	46.14%	53.47%	53.47%	50.46%
February	44.19%	48.36%	46.32%	54.83%	54.83%	51.94%
March	46.32%	50.40%	48.65%	56.56%	56.56%	54.30%
April	43.62%	47.58%	45.80%	53.89%	53.89%	51.66%
May	41.01%	48.45%	45.77%	52.40%	52.40%	50.84%
June	46.20%	54.13%	51.68%	56.24%	56.24%	56.23%
July	41.66%	48.82%	46.16%	49.03%	49.03%	49.79%
August	47.57%	55.88%	52.71%	56.32%	56.32%	56.65%
September	41.86%	50.59%	47.59%	53.03%	53.03%	52.30%
October	43.47%	48.83%	47.35%	51.82%	51.82%	51.21%
November	44.09%	47.67%	46.50%	53.07%	53.07%	51.22%
December	42.10%	46.83%	45.28%	52.59%	52.59%	49.59%

Table #2 **% Usage During RECO On-Peak Billing Period**

On-Peak periods as defined in specified rate schedule

	N/A		*N/A*	*N/A*	*N/A*	*N/A*	
(data rounded to nearest %)	**SC1**	**SC3**	**SC2 ND**	**SC4**	**SC6**	**SC2 Dem**	**SC1 TOD**
January	----	32.6%	----	----	----	----	23.2%
February	----	35.9%	----	----	----	----	24.4%
March	----	33.6%	----	----	----	----	23.4%
April	----	34.8%	----	----	----	----	22.7%
May	----	36.0%	----	----	----	----	26.5%
June	----	39.5%	----	----	----	----	30.5%
July	----	41.7%	----	----	----	----	31.4%
August	----	42.9%	----	----	----	----	31.8%
September	----	41.8%	----	----	----	----	29.4%
October	----	40.0%	----	----	----	----	24.1%
November	----	37.6%	----	----	----	----	26.0%
December	----	35.8%	----	----	----	----	24.6%

Table #3 **Class Usage @ customer**
Calendar month billed sales forecasted for 2024

in MWh	SC1	SC3	SC2 ND	SC4	SC6	SC2 Dem	Total
January	57,249	33	1,609	671	476	30,652	90,689
February	51,407	29	1,858	580	423	27,058	81,354
March	47,197	25	2,085	553	379	25,667	75,905
April	43,981	26	1,248	457	391	28,357	74,459
May	44,146	21	970	414	380	24,381	70,311
June	59,018	28	950	378	341	26,345	87,060
July	81,819	34	1,121	408	337	30,123	113,842
August	88,718	36	1,173	462	342	33,304	124,035
September	74,963	32	1,077	509	407	31,901	108,888
October	52,253	22	1,024	586	479	28,193	82,556
November	44,519	21	991	631	519	25,207	71,888
December	53,488	30	1,505	680	514	27,389	83,604
Total	698,755	337	15,611	6,326	4,987	338,577	1,064,592

Table #4 **Forwards Prices - Energy Only @ bulk system**
in $/MWh (See Table 18)

	On-Peak	Off-Peak
January	73.14	63.06
February	66.99	57.87
March	48.12	41.60
April	44.37	37.01
May	45.11	37.90
June	43.03	28.70
July	60.97	39.75
August	52.53	34.65
September	43.44	28.54
October	42.24	35.57
November	43.75	36.88
December	52.71	44.99

Table #5 **Losses**

	SC1	SC3	SC2 ND	SC4	SC6	SC2 Dem
Expansion Factor =	1.08662	1.08662	1.08662	1.08284	1.08284	1.08662
Expansion Factor (net Marginal Losses)	1.07646	1.07646	1.07646	1.07271	1.06603	1.07646

Table #6 **Summary of Average BGS Energy Only Unit Costs @ customer - PJM Time Periods**
based on Forwards prices corrected for basis differential & losses
in $/MWh

		SC1	SC3	SC2 ND	SC4	SC6	SC2 Dem
Summer - all hrs		$ 44.59	$ 45.86	$ 45.24	$ 45.34	$ 45.20	$ 45.85
	PJM on pk	$ 55.01	$ 54.67	$ 54.56	$ 53.68	$ 53.50	$ 54.32
	PJM off pk	$ 36.29	$ 36.17	$ 36.11	$ 35.68	$ 35.59	$ 36.02
Winter - all hrs		$ 52.60	$ 53.76	$ 53.93	$ 53.34	$ 52.65	$ 52.94
	PJM on pk	$ 57.35	$ 58.06	$ 58.40	$ 57.32	$ 56.62	$ 56.98
	PJM off pk	$ 48.96	$ 49.80	$ 50.04	$ 48.75	$ 48.09	$ 48.67
Annual		$ 49.11	$ 50.71	$ 51.53	$ 51.12	$ 50.52	$ 50.39
System Total		$ 49.57					

Table #7 **Summary of Average BGS Energy Only Costs @ customer - PJM Time Periods**
based on Forwards prices corrected for basis differential & losses
in $1000

		SC1	SC3	SC2 ND	SC4	SC6	SC2 Dem
Summer - all hrs		$ 13,578	$ 6	$ 195	$ 80	$ 64	$ 5,579
	PJM on pk	$ 7,423	$ 4	$ 117	$ 51	$ 41	$ 3,551
	PJM off pk	$ 6,155	$ 2	$ 79	$ 29	$ 24	$ 2,028
Winter - all hrs		$ 20,737	$ 11	$ 609	$ 244	$ 187	$ 11,482
	PJM on pk	$ 9,815	$ 6	$ 307	$ 140	$ 108	$ 6,349
	PJM off pk	$ 10,922	$ 5	$ 302	$ 103	$ 80	$ 5,133
Annual		$ 34,315	$ 17	$ 804	$ 323	$ 252	$ 17,061
System Total		$ 52,773					

Table #8 **Summary of Average BGS Energy Only Unit Costs @ customer - RECO Time Periods**
based on Forwards prices corrected for basis differential & losses - RECO billing time periods in $/MWh

		SC1	SC3	SC2 ND	SC4	SC6	SC2 Dem	SC1 TOD
Summer - all hrs		$ 44.59	$ 45.86	$ 45.24	$ 45.34	$ 45.20	$ 45.85	$ 44.59
	RECO On pk		$ 56.66					$ 57.51
	RECO Off pk		$ 38.16					$ 38.79
Winter - all hrs		$ 52.60	$ 53.76	$ 53.93	$ 53.34	$ 52.65	$ 52.94	$ 52.60
	RECO On pk		$ 59.08					$ 58.95
	RECO Off pk		$ 50.82					$ 50.56
Annual Average		$ 49.11	$ 50.71	$ 51.53	$ 51.12	$ 50.52	$ 50.39	$ 49.11
System Average		$ 49.57						

Table #9 **Generation & Transmission Obligations and Costs and Other Adjustments**
Obligations - annual average forecasted for 2023; costs are market estimates

in MW	SC1	SC3	SC2 ND	SC4	SC6	SC2 Dem	Total FP	
Gen Obl - MW	296.549	0.113	2.781	0.0	0.0	81.882	381.325	**TRUE**
Trans Obl - MW	285.911	0.106	2.744	0.0	0.0	80.269	369.030	**TRUE**

# 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*		$ 52,405 per MW-yr	143.58				
Generation Capacity cost	summer	$68.51	$/MW/day	Resulting avg gen cap cost =	summer >>	$ 25.01	per kW/yr
(see Table 19)	winter	$58.18	$/MW/day		winter >>	$ 21.24	per kW/yr

Current residential summer BGS charges
Current Tariff and % of total summer usage

	---------- SC1 ---------- Charges	% usage
Block 1 (0-600 kWh/month)	5.664 ¢/kWh	42.97%
Block 2 (>600 kWh/m)	11.841 ¢/kWh	57.03%
Calculated inversion =	6.177 ¢/kWh	

Table #10 **Ancillary Services**
forecasted overall annual average $22.91 /MWh

Table #11 **Summary of Obligation Costs Expressed as $/MWh @ customer (for non-demand rates only)**

	SC1	SC3	SC2 ND	SC4	SC6	SC1 TOD
Transmission Obl - all months	$ 21.44	$ 16.48	$ 9.21	$ -	$ -	$ 21.44
Generation Obl -						
per annual MWh	$ 9.55	$ 7.54	$ 4.01	$ -	$ -	$ 9.55
per summer MWh	$ 8.14	$ 7.27	$ 5.38	$ -	$ -	$ 8.14
per winter MWh	$ 10.63	$ 7.72	$ 3.48	$ -	$ -	$ 10.63

Table #12 **Summary of BGS Unit Costs @ customer**

NON-DEMAND RATES *(includes energy, G&T obligations, and Ancillary Services - adjusted to billing time periods in $/MWh)*

		SC1	SC3	SC2 ND	SC4	SC6	SC1 TOD
Summer - all hrs		$ 97.08	$ 92.52	$ 82.74	$ 68.25	$ 68.11	$ 97.08
	RECO On pk		$ 113.52				$ 128.25
	RECO Off pk		$ 77.56				$ 83.15
	Block 1	$ 61.85					
	Block 2	$ 123.62					
Winter - all hrs		$ 107.59	$ 100.87	$ 89.54	$ 76.25	$ 75.56	$ 107.59
	RECO On pk		$ 120.18				$ 147.03
	RECO Off pk		$ 90.22				$ 94.91
Annual -all hrs		$ 103.01	$ 97.65	$ 87.66	$ 74.03	$ 73.43	$ 103.01

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

	SC2 Dem
Summer - all hrs	$ 68.76
Winter - all hrs	$ 75.85
Annual - all hrs per MWh only	$ 73.30

PLUS:

Gen Cost (per kW of Billed Demand/Month)

	≤ 5 kW	> 5 kW
summer	$ 1.584	$ 1.584
winter	$ 1.487	$ 1.487

Trans cost
all months $ 4.37 per kW of T obl /month

Table #12 ***(Continued)***

Including T&G Obligation $		
Summer - all hrs	$	89.52
Winter - all hrs	$	97.22
Annual - including T&G Obl $	$	91.17

Gen Cost (per kW of Billed Demand/Month)

		≤ 5 kW		**> 5 kW**
summer	$	1.584	$	1.584
winter	$	1.487	$	1.487

ALL RATES

Grand Total Cost in $1000 = $ 105,081

All-In Average cost @ customer = $ 98.71 per MWh at customer (per customer metered MWh)

All-In Average costs @ transmission nodes = $ 91.70 per MWH at transmission nodes (per metered MWh at transmission node)

Table #13 **Ratio of BGS Unit Costs @ customer to All-In Average Cost @ transmission nodes**

NON-DEMAND RATES

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

		SC1	SC3	SC2 ND	SC4	SC6	SC1 TOD
Summer - all hrs		**1.059**		**0.902**	**0.744**	**0.743**	
	RECO On pk		**1.238**				**1.399**
	RECO Off pk		**0.846**				**0.907**
	Constant Blk 1 $	**(35.23)**					
	Constant Blk 2 $	**26.54**					
Winter - all hrs		**1.173**		**0.976**	**0.832**	**0.824**	
	RECO On pk		**1.311**				**1.6030**
	RECO Off pk		**0.984**				**1.0350**
Annual - all hrs		1.123	1.065	0.956	0.807	0.801	**1.1230**

Table #13 ***(Continued)***

DEMAND RATES

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

	SC2 Dem Multiplier		SC2 Dem Constant
Summer - all hrs	**0.976**	**$**	**(20.759)**
Winter - all hrs	**1.060**	**$**	**(21.375)**
Annual - including T&G Obl $	0.994		

PLUS:

Gen Cost (per kW of Billed Demand/Month)

		≤ 5 kW		> 5 kW
summer	$	1.58	$	1.58
winter	$	1.49	$	1.49

Trans cost
all months $ 4.367 per kW of T obl /month

Table #14 **Summary of BGS Unit Costs Less Transmission @ customer**

NON-DEMAND RATES

Includes energy, generation capacity obligation, and Ancillary Services - adjusted to billing time periods. Transmission billed at retail tariff level.
in $/MWh

		SC1	SC3	SC2 ND	SC4	SC6	SC1 TOD
Summer - all hrs		$ 75.64	$ 76.03	$ 73.53	$ 68.25	$ 68.11	$ 75.64
	RECO On pk		$ 97.04				$ 106.81
	RECO Off pk		$ 61.07				$ 61.70
	Block 1	$ 40.41					
	Block 2	$ 102.18					
Winter - all hrs		$ 86.14	$ 84.39	$ 80.33	$ 76.25	$ 75.56	$ 86.14
	RECO On pk		$ 103.70				$ 125.59
	RECO Off pk		$ 73.73				$ 73.47
Annual -all hrs		$ 81.57	$ 81.16	$ 78.45	$ 74.03	$ 73.43	$ 81.57

Table #14 (Continued)

DEMAND RATES

Includes energy and Ancillary Services, generation obligation charged separately - adjusted to billing time periods.
Transmission billed at retail tariff level. In $/MWh.

		SC2 Dem
Summer - all hrs	$	68.76
Winter - all hrs	$	75.85
Annual - all hrs per MWh only	$	73.30
Including Generation Obligation $		
Summer - all hrs	$	78.00
Winter - all hrs	$	84.29
Annual - including T&G Obl $	$	82.03

PLUS:

Gen Cost (per kW of Billed Demand/Month)

		< 5 kW		> 5 kW
summer	$	1.584	$	1.584
winter	$	1.487	$	1.487

ALL RATES

Grand Total Cost in $1000 = $ 86,855

All-In Average cost @ customer = $ 81.59 per MWh at customer (per customer metered MWh)

All-In Average costs @ tansmission nodes = $ 75.79 per MWh at tranmission node system (per metered MWh at transmission node)

Table #15 **Ratio of BGS Unit Costs Less Transmission @ customer to All-In Average Cost @ transmission nodes**

NON-DEMAND RATES
Includes energy, G&T obligations, and Ancillary Services - adjusted to billing time periods

			SC1	SC3	SC2 ND	SC4	SC6	SC1 TOD
Summer - all hrs			**0.998**		**0.970**	**0.900**	**0.899**	
	RECO On pk			**1.280**				**1.409**
	RECO Off pk			**0.806**				**0.814**
	Constant Blk 1	**$**	**(35.23)**					
	Constant Blk 2	**$**	**26.54**					
Winter - all hrs			**1.137**		**1.060**	**1.006**	**0.997**	
	RECO On pk			**1.368**				**1.657**
	RECO Off pk			**0.973**				**0.969**
Annual - all hrs			1.076	1.071	1.035	0.977	0.969	1.076

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

	SC2 Dem Multiplier	SC2 Dem Constant
Summer - all hrs	**1.029**	**(9.235)**
Winter - all hrs	**1.112**	**(8.446)**
Annual - including T&G Obl $	**1.082**	

PLUS:

Gen Cost (per kW of Billed Demand/Month)

	< 5 kW	> 5 kW
summer	$ 1.584	$ 1.584
winter	$ 1.487	$ 1.487

Table #16 **Summary of Total BGS Costs by Season**

	SC1	SC3	SC2 ND	SC4	SC6	SC2 Dem	SC1 TOD
Total Costs by Rate - in $1000							
Summer	$ 29,563	$ 12	$ 358	$ 120	$ 97	$ 10,453	$ 29,563
Winter	$ 42,415	$ 21	$ 1,011	$ 348	$ 269	$ 20,414	$ 42,415
Total	$ 71,978	$ 33	$ 1,368	$ 468	$ 366	$ 30,867	$ 71,978
% of Annual Total $ by Rate							
Summer	41%	37%	26%	26%	27%	34%	41%
Winter	59%	63%	74%	74%	73%	66%	59%

Total Costs - in $1000		
Summer	$	40,603
Winter	$	64,478
Total	$	105,081

% of Annual Total $		If total $ were split on a per MWh basis (on transmission node MWhs):	Ratio to All-In Cost	
Summer	39%	$ 86.95 per MWh @ transmission nodes	Summer	**0.9482**
Winter	61%	$ 94.97 per MWh @ transmission nodes	Winter	**1.0356**

Table #17 **Summary of Total BGS Costs by Season - Less Transmission**

	SC1	SC3	SC2 ND	SC4	SC6	SC2 Dem	SC1 TOD
Total Costs by Rate - in $1000							
Summer	$ 23,033	$ 10	$ 318	$ 120	$ 97	$ 9,051	$ 23,033
Winter	$ 33,961	$ 17	$ 907	$ 348	$ 269	$ 17,609	$ 33,961
Total	$ 56,995	$ 27	$ 1,225	$ 468	$ 366	$ 26,660	$ 56,995
% of Annual Total $ by Rate							
Summer	40%	36%	26%	26%	27%	34%	40%
Winter	60%	64%	74%	74%	73%	66%	60%

Total Costs - in $1000		
Summer	$	32,629
Winter	$	53,112
Total	$	85,742

% of Annual Total $		If total $ were split on a per MWh basis (on transmission node MWhs):	Ratio to All-In Cost	
Summer	38%	$ 69.87 per MWh @ transmission nodes	Summer	**0.9219**
Winter	62%	$ 78.23 per MWh @ transmission nodes	Winter	**1.0321**

Table #18 **Forward Energy Prices**

PJM Forward Prices - Energy Only @ bulk system *in $/MWh*	**On-Peak**	**Off/On Peak LMP ratio**	**Off-Peak**	**Zone to Western Hub Basis Differential** *in $/MWh* **On-Peak**	**Off-Peak**	**PJM Forward Prices (incl basis differential)** *in $/MWh* **On-Peak**	**Off-Peak**
January	74.45	0.8179	60.89	91%	94%	67.75	57.24
February	67.00	0.8179	54.80	91%	94%	60.97	51.51
March	50.40	0.8179	41.22	91%	94%	45.86	38.75
April	48.20	0.8179	39.42	91%	94%	43.86	37.05
May	49.30	0.8179	40.32	91%	94%	44.86	37.90
June	48.25	0.6246	30.14	88%	92%	42.46	27.73
July	68.35	0.6246	42.69	88%	92%	60.15	39.27
August	59.00	0.6246	36.85	88%	92%	51.92	33.90
September	49.10	0.6246	30.67	88%	92%	43.21	28.22
October	46.55	0.8179	38.07	91%	94%	42.36	35.79
November	47.75	0.8179	39.05	91%	94%	43.45	36.71
December	55.10	0.8179	45.07	91%	94%	50.14	42.37

NYISO Forward Prices - Energy Only @ bulk system
in $/MWh

	On-Peak	**Off-Peak**
January	121.65	115.45
February	121.20	115.20
March	68.50	67.30
April	48.95	36.60
May	47.35	37.90
June	48.20	37.40
July	68.40	44.10
August	58.00	41.45
September	45.50	31.45
October	41.15	33.55
November	46.50	38.40
December	75.90	68.60

Weighted Average Forward Prices - Energy Only @ bulk system (90.0% PJM - 10.0% NYISO)
in $/MWh

	On-Peak	**Off-Peak**
January	73.14	63.06
February	66.99	57.87
March	48.12	41.60
April	44.37	37.01
May	45.11	37.90
June	43.03	28.70
July	60.97	39.75
August	52.53	34.65
September	43.44	28.54
October	42.24	35.57
November	43.75	36.88
December	52.71	44.99

Table #19 **Generation Capacity Prices ($/MW/Day)**

	PJM Base Capacity	PJM 90.0%	NYISO 10.0%	Weighted Average
Summer	$50.34	$50.34	$232.16	$68.51
Winter	$50.34	$50.34	128.80	$58.18

Table #20 **Ancillary Services**

PJM Ancillary Services	NYISO Ancillary Services	Renewable Power Cost	PJM 90.0%	NYISO 10.0%	Weighted Average
$2.00	$2.32	$20.88	$22.88	$23.20	$22.91

Assumptions:

Gen Cost =		$68.51	per MW-day in summer
		$58.18	per MW-day in winter
Trans cost =	$	52,405	per MW-yr
Analysis time period =		4	summer months
		8	winter months
Ancillary Services =	$	22.91	/MWh

Energy Costs = Based on Jun 2024 to May 2025 Forwards @ PJM West as of November 01, 2023
Based on Jun 2024 to May 2025 Forwards @ NYISO Zone G and Lower Hudson Valley (LHV) as of June 13, 2023
Usage patterns = Forecasted 2023 energy use by class, PJM on/off % from 2022 class load profiles,
RECO billing on/off % from 6/22 to 5/23 actual data
Obligations = Class totals for 2023
Losses = Per RECO's Third Party Supplier Agreement adjusted for PJM 500kV losses and inadvertent energy.
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
RECO Billing time periods = as per specific rate schedule

Table A Weighted Average Price Calculation

Line #	Specific BGS-FP Auction >>		2022 Auction 36 Month	2023 Auction 36 Month	2024 Auction 36 Month	Total	Notes:
1	Tranches		1	2	1	4	From then-current auction
2(a)	Winning Bid Price (¢/kWh)*		8.206	9.648	9.648		
2(b)	Capacity Proxy Price True-up - in (¢/kWh)*		-4.460	-1.580	0.000		Entered After 2024 BGS Auction
3	BGS (¢/kWh)		3.746	8.068	9.648		= 2(a) + 2(b)
4	Weighted Avg BGS		0.937	4.034	2.412	7.383	= (1) / Total Tranches * (3)
5	Weighted Avg Total Price (¢/kWh)					**7.383**	
	Seasonal Payment Factors						
6		Summer	1.0000	1.0000	1.0000 **		From then-current Bid Factor Spreadsheet
7		Winter	1.0000	1.0000	1.0000 **		From then-current Bid Factor Spreadsheet
	Applicable Customer Usage @ transmission nodes				(Eastern Division)		
8		Summer MWh	420,320				From then-current Bid Factor Spreadsheet
9		Winter MWh	611,109				From then-current Bid Factor Spreadsheet
10			1,031,429				
	Total Cost						
11		Summer	3,936,295	16,955,702	10,138,114	31,030,111	= (1) / Total Tranches * (3) / 100 * (6) * (8) * 1,000
12		Winter	5,723,039	24,652,152	14,739,958	45,115,149	= (1) / Total Tranches * (3) / 100* (7) * (9) * 1,000
13		Total	9,659,334	41,607,854	24,878,072	76,145,260	= (11) + (12)
	Average Cost (NJ Statewide Auction)						
14		Summer	7.383 ¢/kWh				= sum(line 11) / (8) / 1000 * 100 rounded to 3 decimal places
15		Winter	7.382 ¢/kWh				= sum(line 12) / (9) / 1000 * 100 rounded to 3 decimal places
16		Total	**7.382** ¢/kWh				= sum(line 13) / (10) / 1000 * 100 rounded to 3 decimal places

Line #	Average Cost (Including RECO RFP)	BGS Auction	RECO RFP	Total	Notes
17	Tranches	4	0.444	4.444	Includes RECO RFP equivalent tranches
18	Price ¢/kWh	7.382	9.492		BGS Auction from (16) Note 9.492¢ for RFP is illustrative
19	Weighted Avg BGS	6.644	0.948	7.593	= (17) / Total Tranches * (18)
20	**Weighted Avg Total Price**			$\boxed{\textbf{7.593}}$	= (19)

* Includes Impact of PJM Marginal Losses

** Auction results set to 1.0 to avoid using an atypical result from the current 12-month forward prices.

Table B **Ratio of BGS Unit Costs Less Transmission @ customer to All-In Average Cost @ transmission nodes**
(from Table 15 of Bid Factor Spreadsheet)

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

		SC1	SC3	SC2 ND	SC4	SC6	SC1 TOD
Summer - all hrs		**0.998**		**0.970**	**0.900**	**0.899**	
	RECO On pk		**1.280**				**1.409**
	RECO Off pk		**0.806**				**0.814**
	Constant Blk 1 $	**(35.23)**					
	Constant Blk 2 $	**26.54**					
Winter - all hrs		**1.137**		**1.060**	**1.006**	**0.997**	
	RECO On pk		**1.368**				**1.657**
	RECO Off pk		**0.973**				**0.969**
Annual - all hrs		1.076	1.071	1.035	0.977	0.969	1.076

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

	SC2 Dem Multiplier	SC2 Dem Constant
Summer - all hrs	**1.029**	**(9.235)**
Winter - all hrs	**1.112**	**(8.446)**
Annual - including T&G Obl $	**1.082**	

PLUS:

Gen Cost (per kW of Billed Demand/Month)

	0	< 5 kW	> 5 kW
summer	$ -	$ 1.584	$ 1.584
winter	$ -	$ 1.487	$ 1.487

Table C **Determination of Preliminary Retail Rates to be Charged to BGS Customers**

All-In Average costs @ Trans node =	$ 75.93	/MWh*	* Price from Table A (which does not include
Less Transmission	$ -	/MWh**	transmission for the Central/Western Division).
BGS Cost	$ 75.93	/MWh	

Retail BGS Rates (excl SUT) (¢/kWh)

	SC1	SC3	SC2 ND	SC4	SC6	SC2 Dem	SC1 TOD
Summer							
All kWh (¢/kWh)	7.578		7.365	6.834	6.826	6.890	
Peak kWh (¢/kWh)		9.719					10.699
Off-Peak kWh (¢/kWh)		6.120					6.181
Block1	4.055						
Block2	10.232						
Demand Charge ($/kW) 1st 5kW						1.584	
Demand Charge ($/kW)> 5 kW						1.584	
Winter							
All kWh (¢/kWh)	8.633		8.049	7.639	7.570	7.599	
Peak kWh (¢/kWh)		10.387					12.582
Off-Peak kWh (¢/kWh)		7.388					7.358
Demand Charge ($/kW) 1st 5kW						1.487	
Demand Charge ($/kW) > 5 kW						1.487	

Table D Calculation of Rate Adjustment Factors

	SC1	SC3	SC2 ND	SC4	SC6	SC2 Dem	SC1 TOD
Total BGS Revenue (Excl SUT) - in $1000							
Summer	$ 23,076	$ 10	$ 318	$ 120	$ 97	$ 9,507	$ 23,066
Winter	$ 34,034	$ 17	$ 909	$ 349	$ 269	$ 18,314	$ 34,016
Total	$ 57,110	$ 27	$ 1,227	$ 469	$ 366	$ 27,821	$ 57,082

Total	
Summer	$ 33,128
Winter	$ 53,892
Total	$ 87,020

Total Supplier Payments - in $1000

Eastern Division	Total	Transmission	Net BGS
Summer	$ 31,030		$ 31,030
Winter	$ 45,115		$ 45,115
Total	$ 76,145	$ -	$ 76,145

Central/Western Division	Total	Transmission	Net BGS
Summer	$ 4,470	$ -	$ 4,470
Winter	$ 6,439	$ -	$ 6,439
Total	$ 10,909	$ -	$ 10,909

Total RECO FP	Total	Transmission	Net BGS
Summer	$ 35,500	$ -	$ 35,500
Winter	$ 51,554	$ -	$ 51,554
Total	$ 87,054	$ -	$ 87,054

Differences	BGS Revenue	BGS Costs	Difference	Rate Adjustment Factors
Summer	$ 33,128	$ 35,500	$ 2,372	**1.0716**
Winter	$ 53,892	$ 51,554	$ (2,338)	**0.95662**
Total	$ 87,020	$ 87,054	$ 34	

Table E **Final Retail BGS Rates (¢/kWh)**

Rates Excluding SUT:

	SC1	SC3	SC2 ND	SC4	SC6	SC2 Dem	SC1 TOD
Summer							
All kWh (¢/kWh)	8.121		7.892	7.323	7.315	7.383	
Peak kWh (¢/kWh)		10.415					11.465
Off-Peak kWh (¢/kWh)		6.558					6.624
Block1	4.345						
Block2	10.965						
Demand Charge ($/kW) 1st 5kW						1.697	
Demand Charge ($/kW) > 5 kW						1.697	
Winter							
All kWh (¢/kWh)	8.259		7.700	7.308	7.242	7.269	
Peak kWh (¢/kWh)		9.936					12.036
Off-Peak kWh (¢/kWh)		7.068					7.039
Demand Charge ($/kW) 1st 5kW						1.422	
Demand Charge ($/kW) > 5 kW						1.422	

Rates Including SUT: SUT @ 6.625%

	SC1	SC3	SC2 ND	SC4	SC6	SC2 Dem	SC1 TOD
Summer							
All kWh (¢/kWh)			8.415	7.808	7.800	7.872	
Peak kWh (¢/kWh)		11.105					12.225
Off-Peak kWh (¢/kWh)		6.992					7.063
Block1	4.633						
Block2	11.691						
Demand Charge ($/kW) 1st 5kW						1.81	
Demand Charge ($/kW)> 5 kW						1.81	
Winter							
All kWh (¢/kWh)	8.806		8.210	7.792	7.722	7.751	
Peak kWh (¢/kWh)		10.594					12.833
Off-Peak kWh (¢/kWh)		7.536					7.505
Demand Charge ($/kW) 1st 5kW						1.52	
Demand Charge ($/kW) > 5 kW						1.52	

Table F **Spreadsheet Error Checking**

Total BGS Revenue (Excl SUT) - in $1000

	SC1	SC3	SC2 ND	SC4	SC6	SC2 Dem
Summer	$ 24,730	$ 11	$ 341	$ 129	$ 104	$ 10,187
Winter	$ 32,560	$ 17	$ 869	$ 334	$ 258	$ 17,519
Total	$ 57,290	$ 28	$ 1,210	$ 463	$ 362	$ 27,706

Total	
Summer	$ 35,502
Winter	$ 51,557
Total	$ 87,059

Supplier Payments - in $1000

Eastern Division

	Total	Transmission	Net BGS
Summer	$ 31,030	$ -	$ 31,030
Winter	$ 45,115	$ -	$ 45,115
Total	$ 76,145	$ -	$ 76,145

Central/Western Division

	Total	Transmission	Net BGS
Summer	$ 4,470	$ -	$ 4,470
Winter	$ 6,439	$ -	$ 6,439
Total	$ 10,909	$ -	$ 10,909

Total RECO FP

	Total	Transmission	Net BGS
Summer	$ 35,500	$ -	$ 35,500
Winter	$ 51,554	$ -	$ 51,554
Total	$ 87,054	$ -	$ 87,054

Differences

	BGS Revenue	BGS Costs	Difference
Summer	$ 35,502	$ 35,500	$ (2)
Winter	$ 51,557	$ 51,554	$ (3)
Total	$ 87,059	$ 87,054	$ (5)

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

Using 2024/2025 Illustrative Data for RECO

	Using 2024/2025 Illustrative Data for RECO	Capacity Proxy Price True-Up Development for Winning Suppliers from 2022 BGS-RSCP Auction	Capacity Proxy Price True-Up Development for Winning Suppliers from 2023 BGS-RSCP Auction	
		2024/25 Delivery Year	2024/25 Delivery Year	*Notes:*
1	**Zonal Capacity Price ($/MW-day)**	$54.50	$54.50	as may be determined by the RPM or its successor or otherw
2	**Capacity Proxy Price ($/MW-day)**	$87.98	66.38	per Board Orders dated 11/17/2021 and 11/09/2022
3	**Capacity Proxy Price True-Up - $/MW-day**	-$33.48	-$11.88	= line 1 - line 2
4	**BGS-RSCP Gen Obl - MW**	389.3	389.3	
5	**Days in Year**	365	365	
6	**Capacity Proxy Price True-Up Annual Cost**	-$4,756,957	-$1,687,953	= line 3 * line 4 * line 5
7	**Eligible Tranches**	1	2	from Table A
8	**Total Tranches**	4	4	from Table A
9	**% of tranches eligible for payment**	25.00%	50.00%	= line 7 / line 8
10	**Capacity Proxy Price True-Up Cost**	-$1,189,239	-$843,976	= line 6 * line 9
11	**Total Applicable Customer Usage @ transmission nodes -** *in MWh*	1,065,842	1,065,842	
12	**Eligible Customer Usage @ transmission nodes -** *in MWh*	266,461	532,921	= line 9 * line 11
13	**Capacity Proxy Price True-Up - $/MWh**	**-$4.46**	**-$1.58**	**= line 10/ line 12 - rounded to 2 decimal places**

Development of Capacity Proxy Price True-Up - $/MWh
Using 2025/2026 Illustrative Data for RECO

Using 2025/2026 Illustrative Data for RECO

		Capacity Proxy Price True-Up Development for Winning Suppliers from 2023 BGS-RSCP Auction	Capacity Proxy Price True-Up Development for Winning Suppliers from 2024 BGS-RSCP Auction	
		2025/26 Delivery Year	2025/26 Delivery Year	*Notes:*
1	**Zonal Capacity Price ($/MW-day)**	$50.00	$50.00	as may be determined by the RPM or its successor or otherwi
2	**Capacity Proxy Price ($/MW-day)**	$44.63	$47.46	per Board Order dated 11/09/2022
3	**Capacity Proxy Price True-Up - $/MW-day**	$5.37	$2.54	= line 1 - line 2
4	**BGS-RSCP Gen Obl - MW**	389.3	389.3	
5	**Days in Year**	365	365	
6	**Capacity Proxy Price True-Up Annual Cost**	$762,989	$360,892	= line 3 * line 4 * line 5
7	**Eligible Tranches**	2	1	from Table A
8	**Total Tranches**	4	4	from Table A
9	**% of tranches eligible for payment**	50.00%	25.00%	= line 7 / line 8
10	**Capacity Proxy Price True-Up Cost**	$381,494	$90,223	= line 6 * line 9
11	**Total Applicable Customer Usage @ transmission nodes -** *in MWh*	1,065,842	1,065,842	
12	**Eligible Customer Usage @ transmission nodes -** *in MWh*	532,921	266,461	= line 9 * line 11
13	**Capacity Proxy Price True-Up - $/MWh**	**$0.72**	**$0.34**	**= line 10/ line 12 - rounded to 2 decimal places**

Development of Capacity Proxy Price True-Up - $/MWh
Using 2026/2027 Illustrative Data for RECO

Using 2026/2027 Illustrative Data for RECO

		Capacity Proxy Price True-Up Development for Winning Suppliers from 2024 BGS-RSCP Auction 2026/27 Delivery Year	*Notes:*
1	**Zonal Capacity Price ($/MW-day)**	$50.00	as may be determined by the RPM or its successor or otherw
2	**Capacity Proxy Price ($/MW-day)**	$49.05	per Board Order dated xx/xx/2023
3	**Capacity Proxy Price True-Up - $/MW-day**	$0.95	= line 1 - line 2
4	**BGS-RSCP Gen Obl - MW**	389.3	
5	**Days in Year**	365	
6	**Capacity Proxy Price True-Up Annual Cost**	$134,979	= line 3 * line 4 * line 5
7	**Eligible Tranches**	1	from Table A
8	**Total Tranches**	4	from Table A
9	**% of tranches eligible for payment**	25.00%	= line 7 / line 8
10	**Capacity Proxy Price True-Up Cost**	$33,745	= line 6 * line 9
11	**Total Applicable Customer Usage @ transmission nodes -** *in MWh*	1,065,842	
12	**Eligible Customer Usage @ transmission nodes -** *in MWh*	266,461	= line 9 * line 11
13	**Capacity Proxy Price True-Up - $/MWh**	**$0.13**	**= line 10/ line 12 - rounded to 2 decimal places**

ROCKLAND ELECTRIC COMPANY
2025 BGS Auction

Table A Weighted Average Price Calculation

Line #	Specific BGS-FP Auction >>	2023 Auction 36 Month	2024 Auction 36 Month	2025 Auction 36 Month	Total	Notes:
1	Tranches	2	1	1	4	From then-current auction
2(a)	Winning Bid Price (¢/kWh)*	9.648	9.648	9.648		
2(b)	Capacity Proxy Price True-up - in (¢/kWh)*	0.720	0.340			Entered After 2025 BGS Auction
3	BGS (¢/kWh)	10.368	9.988	9.648		= 2(a) + 2(b)
4	Weighted Avg BGS	5.184	2.497	2.412	10.093	= (1) / Total Tranches * (3)
5	Weighted Avg Total Price (¢/kWh)				**10.093**	
	Seasonal Payment Factors					
6	Summer	1.0000	1.0000	1.0000 **		From then-current Bid Factor Spreadsheet
7	Winter	1.0000	1.0000	1.0000 **		From then-current Bid Factor Spreadsheet
	Applicable Customer Usage @ transmission nodes			(Eastern Division)		
8	Summer MWh	432,694				From then-current Bid Factor Spreadsheet
9	Winter MWh	633,148				From then-current Bid Factor Spreadsheet
10		1,065,842				
	Total Cost					
11	Summer	22,430,880	10,804,380	10,436,590	43,671,850	= (1) / Total Tranches * (3) / 100 * (6) * (8) * 1,000
12	Winter	32,822,375	15,809,697	15,271,522	63,903,594	= (1) / Total Tranches * (3) / 100* (7) * (9) * 1,000
13	Total	55,253,255	26,614,077	25,708,112	107,575,444	= (11) + (12)
	Average Cost (NJ Statewide Auction)					
14	Summer	10.093 ¢/kWh				= sum(line 11) / (8) / 1000 * 100 rounded to 3 decimal places
15	Winter	10.093 ¢/kWh				= sum(line 12) / (9) / 1000 * 100 rounded to 3 decimal places
16	Total	**10.093** ¢/kWh				= sum(line 13) / (10) / 1000 * 100 rounded to 3 decimal places

Average Cost (Including RECO RFP)

Line #		BGS Auction	RECO RFP	Total	Notes
17	Tranches	4	0.444	4.444	Includes RECO RFP equivalent tranches
18	Price ¢/kWh	10.093	9.492		BGS Auction from (16) Note 9.492¢ for RFP is illustrative
19	Weighted Avg BGS	9.085	0.948	10.033	= (17) / Total Tranches * (18)
20	**Weighted Avg Total Price**			$\boxed{\mathbf{10.033}}$	= (19)

* Includes Impact of PJM Marginal Losses

** Auction results set to 1.0 to avoid using an atypical result from the current 12-month forward prices.

ROCKLAND ELECTRIC COMPANY
2026 BGS Auction

Attachment C

Table A Weighted Average Price Calculation

Line #	Specific BGS-FP Auction >>	2024 Auction 36 Month	2025 Auction 36 Month	2026 Auction 36 Month	Total	Notes:
1	Tranches	1	1	2	4	From then-current auction
2(a)	Winning Bid Price (¢/kWh)*	9.648	9.648	9.648		
2(b)	Capacity Proxy Price True-up - in (¢/kWh)*	0.130				Entered After 2026 BGS Auction
3	BGS (¢/kWh)	9.778	9.648	9.648		= 2(a) + 2(b)
4	Weighted Avg BGS	2.445	2.412	4.824	9.681	= (1) / Total Tranches * (3)
5	Weighted Avg Total Price (¢/kWh)				**9.681**	
	Seasonal Payment Factors					
6	Summer	1.0000	1.0000	1.0000 **		From then-current Bid Factor Spreadsheet
7	Winter	1.0000	1.0000	1.0000 **		From then-current Bid Factor Spreadsheet
	Applicable Customer Usage @ transmission nodes			(Eastern Division)		
8	Summer MWh	432,694				From then-current Bid Factor Spreadsheet
9	Winter MWh	633,148				From then-current Bid Factor Spreadsheet
10		1,065,842				
	Total Cost					
11	Summer	10,577,216	10,436,590	20,873,180	41,886,986	= (1) / Total Tranches * (3) / 100 * (6) * (8) * 1,000
12	Winter	15,477,295	15,271,522	30,543,043	61,291,860	= (1) / Total Tranches * (3) / 100* (7) * (9) * 1,000
13	Total	26,054,511	25,708,112	51,416,223	103,178,846	= (11) + (12)
	Average Cost (NJ Statewide Auction)					
14	Summer	9.681 ¢/kWh				= sum(line 11) / (8) / 1000 * 100 rounded to 3 decimal places
15	Winter	9.681 ¢/kWh				= sum(line 12) / (9) / 1000 * 100 rounded to 3 decimal places
16	Total	**9.681** ¢/kWh				= sum(line 13) / (10) / 1000 * 100 rounded to 3 decimal places

Line #	Average Cost (Including RECO RFP)	BGS Auction	RECO RFP	Total	Notes
17	Tranches	4	0.444	4.444	Includes RECO RFP equivalent tranches
18	Price ¢/kWh	9.681	9.492		BGS Auction from (16) Note 9.492¢ for RFP is illustrative
19	Weighted Avg BGS	8.714	0.948	9.662	= (17) / Total Tranches * (18)
20	**Weighted Avg Total Price**			$\boxed{\mathbf{9.662}}$	= (19)

* Includes Impact of PJM Marginal Losses

** Auction results set to 1.0 to avoid using an atypical result from the current 12-month forward prices.