STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

IN THE MATTER OF THE PROVISION OF BASIC GENERATION SERVICE FOR THE PERIOD BEGINNING JUNE 1, 2020	Docket No. ER19040428

ROCKLAND ELECTRIC COMPANY

PROPOSAL FOR BASIC GENERATION SERVICE REQUIREMENTS TO BE PROCURED EFFECTIVE JUNE 1, 2020

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 18, 2019 in Docket ER19040428 , 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 1, 2019 on the procurement of basic generation service ("BGS") for the period beginning June 1, 2020. 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, 2020, filed by New Jersey's four EDCs on July 1, 2019 ("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 56.2 MW of BGS-CIEP eligible load per tranche) in the BGS-CIEP Auction.

As to the BGS-RSCP Auction, RECO currently has two 36-month tranches that terminate on May 31, 2020, one 36-month tranche that terminates on May 31, 2021, and one 36-month tranche that terminates on May 31, 2022. 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, 2020, RECO will include two 36-month tranches (for the period June 1, 2020 through May 31, 2023).

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, 2020; 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

[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.

(footnote continued…)

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 2019 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.

[2] Excluding the two 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, transmission (including SECA, transmission enhancement and RMR), and any other expenses related to the implementation of RECO's contingency plan.

(b) Defaults prior to June 1, 2020

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 tranches, RECO only will seek replacement supply until May 31, 2021. 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, 2021.

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 to BGS-RSCP and BGS-CIEP suppliers;

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.

RECO has no directly-incurred 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 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 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 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 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. The Company is proposing to combine the BGS-RSCP rate structures of Service Classification ("SC") No. 1, Residential Service and SC No. 5, Residential Space Heating Service. This change is necessary due to the Company's proposal in its on-going base rate proceeding in BPU Docket No. ER19050552 to set equal the distribution rates of SC Nos. 1 and 5. Should the Board reject the Company's proposal in the base rate proceeding, the Company will separate the BGS-RSCP rate structures of SC Nos. 1 and 5 in the future updates to the Company's BGS Proposal.

For the BGS rates applicable to BGS-RSCP eligible SC No. 2 demand billed customers, the Company is maintaining the 33% demand differential for the first 5 kW and above 5 kW demand that was previously approved in its filing in Docket No. ER14040370.

Final tariff leaves including the actual BGS rates and tariff provisions to become effective on June 1, 2020 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. As explained below, RECO does not need to conduct an RFP for the 2020 BGS auction.

With regard to the purchase of energy, in the Board's November 21, 2017 Order in Docket No. ER17040335, 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, 2018. On January 30, 2018, Rockland conducted its RFP for the period June 1, 2018 through May 31, 2021. As a result of the RFP, RECO entered into a three year Fixed for Floating Energy Swap contract with Shell Trading Risk Management, LLC. The Board approved this RFP result in its February 8, 2018 Order in ER17040335. The RFP price will be rolled into Rockland's BGS auction price to develop a weighted average BGS-RSCP price for the period June 1, 2020 through May 31, 2021. Therefore, RECO does not need to conduct an RFP for the 2020 BGS auction.

With regard to the procurement of capacity, on August 16, 2013, the Federal Energy Regulatory Commission ("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 number ER13-1380. Lower Hudson Valley capacity is not actively traded, and the Company does not expect the above to change before the BGS Auction.[4] As a result of the capacity market changes at the NYISO noted above, Rockland 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 19, 2018 Order in Docket number ER18040356. The impact of these capacity purchases are expected to be minimal because the Company's Central and Western Divisions constitute only about ten percent of the Company's BGS load.

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

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

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 2018 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. 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 2020 with a migration adjustment for retail access. The values in Table #3 will be updated in January 2020 to better reflect the amount by Service Classification that could be in effect starting on June 1, 2020.

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 2020 to May 2021, 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 June 2016 to May 2019, which equals 0.4952%. Marginal losses are excluded from the loss factors based on historic de-rating factors for the period January 2016 to December 2018.

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 Service Classification 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. 3 peak and off-peak kWh consumption. To correct for this difference, the shortfall is divided by the total kWh for Service Classification No. 3 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 2019. The values in the top portion of Table #9 will be updated in January 2020 to better reflect the aggregate amount by rate schedule that could be in effect on June 1, 2020. 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. However, the Capacity Proxy Price of 152.06 is used for Delivery Year

2022/2023[5] in place of the 2022/2023 Base Residual Auction ("BRA") value in the development of the average price of generation capacity. The Capacity Proxy Price will be replaced with the results of the Third Incremental RPM Auction for the 2022/2023 Delivery Year when available. 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 2020 to 2023 for RECO using proxy price for 2023), and NYISO zones as calculated in Table #19. Also shown is the level of blocking in the BGS charges for SC Nos. 1/5, which will be utilized in the later calculations of the blocking of BGS charges for this combined 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 $16.72 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.

[5] The 2022/2023 Delivery Year is June 1, 2022 through May 31, 2023.

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 $16.72 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. However, the Capacity Proxy Price of

$152.06 is used for Delivery Year 2022/2023 in place of the 2022/2023 BRA value in the development of the average price of generation capacity. The Capacity Proxy Price will be replaced with the results of the Third Incremental RPM Auction for the 2022/2023 Delivery Year when available. The table also includes the impacts of RECO's RFP for the Central and Western Divisions.[6] However, upon the conclusion of the RECO RFP cost will be applied to the results of the prior two BGS auctions. From these values, the weighted average total price (shown on line #25) 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 seasonal factors for the 12-month BGS period beginning June 1, 2020 (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), excluding the weighted average transmission rate included therein, and the Bid Factors from Table B.

[6] The prices shown for the tranches to be secured in the 2020 auction and RFP are for illustrative purposes only, and will be replaced with actual data in determining RECO's final June 2020 BGS-RSCP rates.

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 energy 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, 2020/2021, 2021/2022, and 2022/2023 BRA for RPM results applicable to load served in the RECO zone. With the postponement of the BRA for the 2022/2023 Delivery Year, a Capacity Proxy Price of $152.06_per MW-Day has been used in place of the 2022/2023 BRA value.

For Energy Year ("EY") 2023, payments to BGS suppliers that execute the Supplement to the BGS-RSCP Supplier Master Agreement approved by the NJBPU on November 13, 2019 will be adjusted for the capacity price difference between the PJM Zonal Net Load Price (inclusive of the results of the Third Incremental RPM Auction for Delivery Year 2022/2023), and the Capacity Proxy Price for the 2022/2023 Delivery Year. RECO will file new tariff sheets for EY 2023, 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.

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. 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.

Attachment A

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, 5 and 6

Applicable to Service Classification Nos. 1, 2 (Non-Demand Billed), 3, 4, 5, and 6
Charges per kilowatthour:

Service Classification	Summer Months*	Other Months
1 – First 600 kWh	X.XXX¢	X.XXX¢
1 – Over 600 kWh	X.XXX¢	X.XXX¢
2 - (Non-Demand Billed) – All kWh	X.XXX¢	X.XXX¢
3 – Peak	XX.XXX ¢	X.XXX¢
3 – Off-Peak	X.XXX¢	X.XXX¢
4 – All kWh	X.XXX¢	X.XXX¢
5 – First 600 kWh	X.XXX¢	X.XXX¢
5 – Over 600 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.. $ X.XXX
Charge applicable in other months... $ X.XXX

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)

Attachment B

Development of BGS Cost and Bid Factors for Rates Effective June 1, 2020

Based on 2018 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*

	Profile Meter Data	*Profile Meter Data*	*Profile Meter Data*	*--- Other Analysis ---*		*Profile Meter Data*
	SC1/SC5	**SC3**	**SC2 ND**	**SC4**	**SC6**	**SC2 Dem**
January	51.45%	43.90%	45.36%	30.41%	30.41%	53.06%
February	48.85%	46.70%	49.23%	30.61%	30.61%	53.24%
March	47.20%	45.98%	48.16%	27.94%	27.94%	50.74%
April	51.26%	50.82%	54.69%	29.48%	29.48%	54.72%
May	53.78%	49.33%	59.55%	23.12%	23.12%	55.82%
June	50.30%	48.08%	52.78%	19.64%	19.64%	52.13%
July	55.92%	53.70%	52.11%	20.63%	20.63%	55.26%
August	56.85%	53.98%	51.95%	21.37%	21.37%	55.09%
September	51.13%	49.67%	50.55%	26.82%	26.82%	51.60%
October	53.26%	53.07%	58.49%	30.52%	30.52%	57.86%
November	47.36%	43.87%	45.76%	28.40%	28.40%	51.36%
December	48.45%	44.13%	43.66%	29.03%	29.03%	51.20%

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/SC5**	**SC3**	**SC2 ND**	**SC4**	**SC6**	**SC2 Dem**
January	----	34.1%	----	----	----	----
February	----	37.3%	----	----	----	----
March	----	34.5%	----	----	----	----
April	----	34.1%	----	----	----	----
May	----	35.3%	----	----	----	----
June	----	34.8%	----	----	----	----
July	----	37.7%	----	----	----	----
August	----	41.2%	----	----	----	----
September	----	39.1%	----	----	----	----
October	----	40.4%	----	----	----	----
November	----	37.5%	----	----	----	----
December	----	36.5%	----	----	----	----

Table #3 **Class Usage @ customer**
Calendar month billed sales forecasted for 2020

in MWh	SC1/SC5	SC3	SC2 ND	SC4	SC6	SC2 Dem	Total
January	56,888	35	2,257	474	496	28,484	88,633
February	49,261	42	2,610	434	410	29,343	82,098
March	45,593	23	2,260	408	406	27,368	76,057
April	40,187	22	1,745	355	424	26,400	69,132
May	42,283	16	1,579	330	399	25,690	70,296
June	56,587	20	1,462	302	372	26,671	85,413
July	79,519	25	1,947	319	351	32,579	114,739
August	81,339	22	1,863	338	345	31,384	115,290
September	67,719	19	1,731	389	407	30,909	101,173
October	47,192	17	1,419	432	481	26,598	76,139
November	43,912	21	1,635	470	524	27,122	73,684
December	51,342	27	2,056	508	540	27,835	82,307
Total	661,821	288	22,564	4,755	5,152	340,381	1,034,960

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

	On-Peak	Off-Peak
January	47.99	38.51
February	45.46	36.43
March	33.41	26.24
April	28.84	22.47
May	28.30	22.01
June	28.32	18.05
July	33.45	21.32
August	31.03	19.80
September	30.20	19.23
October	28.56	22.17
November	29.33	23.06
December	33.95	26.97

Table #5

Losses	SC1/SC5	SC3	SC2 ND	SC4	SC6	SC2 Dem
Expansion Factor =	1.08524	1.08524	1.08524	1.08147	1.08147	1.08524
Expansion Factor (net Marginal Losses)	1.07496	1.07496	1.07496	1.07122	1.07122	1.07496

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/SC5	SC3	SC2 ND	SC4	SC6	SC2 Dem
Summer - all hrs		$ 28.01	$ 27.68	$ 27.70	$ 23.90	$ 23.84	$ 27.88
	PJM on pk	$ 33.69	$ 33.64	$ 33.57	$ 33.24	$ 33.19	$ 33.55
	PJM off pk	$ 21.37	$ 21.33	$ 21.40	$ 21.20	$ 21.16	$ 21.32
Winter - all hrs		$ 34.13	$ 35.45	$ 34.68	$ 32.14	$ 31.75	$ 34.02
	PJM on pk	$ 38.06	$ 39.60	$ 38.31	$ 38.03	$ 37.60	$ 37.61
	PJM off pk	$ 30.18	$ 31.82	$ 31.06	$ 29.74	$ 29.38	$ 29.90
Annual		$ 31.50	$ 33.13	$ 32.51	$ 29.80	$ 29.48	$ 31.83
System Total		$ 31.61					

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/SC5	SC3	SC2 ND	SC4	SC6	SC2 Dem
Summer - all hrs		$ 7,988	$ 2	$ 194	$ 32	$ 35	$ 3,388
	PJM on pk	$ 5,181	$ 1	$ 122	$ 10	$ 11	$ 2,186
	PJM off pk	$ 2,807	$ 1	$ 72	$ 22	$ 24	$ 1,202
Winter - all hrs		$ 12,857	$ 7	$ 540	$ 110	$ 117	$ 7,445
	PJM on pk	$ 7,193	$ 4	$ 298	$ 37	$ 40	$ 4,399
	PJM off pk	$ 5,664	$ 3	$ 242	$ 72	$ 77	$ 3,045
Annual		$ 20,844	$ 10	$ 734	$ 142	$ 152	$ 10,833
System Total		$ 32,714					

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/SC5	SC3	SC2 ND	SC4	SC6	SC2 Dem
Summer - all hrs		$ 28.01	$ 27.68	$ 27.70	$ 23.90	$ 23.84	$ 27.88
	RECO On pk		$ 35.28				
	RECO Off pk		$ 22.97				
Winter - all hrs		$ 34.13	$ 35.45	$ 34.68	$ 32.14	$ 31.75	$ 34.02
	RECO On pk		$ 40.43				
	RECO Off pk		$ 32.65				
Annual Average		$ 31.50	$ 33.13	$ 32.51	$ 29.80	$ 29.48	$ 31.83
System Average		$ 31.61					

Table #9 **Generation & Transmission Obligations and Costs and Other Adjustments**
Obligations - annual average forecasted for 2019; costs are market estimates

in MW	SC1/SC5	SC3	SC2 ND	SC4	SC6	SC2 Dem	Total FP	
Gen Obl - MW	301.781	0.086	4.236	0.0	0.0	83.030	389.133	FALSE
Trans Obl - MW	269.748	0.080	4.855	0.0	0.0	92.636	367.319	FALSE

\# 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*	$ 42,548	per MW-yr	116.57	

Generation Capacity cost	summer	$162.49 $/MW/day	Resulting avg gen cap cost =	summer >> $	59.31 per kW/yr
(see Table 19)	winter	$146.66 $/MW/day		winter >> $	53.53 per kW/yr

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

	---------- SC1/SC5 ----------	
	Charges	% usage
Block 1 (0-600 kWh/month)	6.474 ¢/kWh	42.10%
Block 2 (>600 kWh/m)	9.835 ¢/kWh	57.90%
Calculated inversion =	3.361 ¢/kWh	

Table #10 **Ancillary Services**
forecasted overall annual average $18.71 /MWh

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

	SC1/SC5	SC3	SC2 ND	SC4	SC6
Transmission Obl - all months	$ 17.34	$ 11.82	$ 9.15	$ -	$ -
Generation Obl -					
per annual MWh	$ 25.29	$ 16.56	$ 10.41	$ -	$ -
per summer MWh	$ 20.98	$ 19.82	$ 11.99	$ -	$ -
per winter MWh	$ 28.55	$ 15.17	$ 9.70	$ -	$ -

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/SC5	SC3	SC2 ND	SC4	SC6
Summer - all hrs		$ 85.04	$ 78.03	$ 67.56	$ 42.61	$ 42.55
	RECO On pk		$ 117.67			
	RECO Off pk		$ 53.50			
	Block 1	$ 65.58				
	Block 2	$ 99.19				
Winter - all hrs		$ 98.74	$ 81.15	$ 72.24	$ 50.85	$ 50.46
	RECO On pk		$ 113.01			
	RECO Off pk		$ 63.18			
Annual -all hrs		$ 92.84	$ 80.22	$ 70.79	$ 48.51	$ 48.19

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

	SC2 Dem
Summer - all hrs	$ 46.59
Winter - all hrs	$ 52.73
Annual - all hrs per MWh only	$ 50.54

PLUS:

Gen Cost (per kW of Billed Demand/Month)

	≤ 5 kW	> 5 kW
summer	$ 1.311	$ 4.541
winter	$ 1.291	$ 4.561

Trans cost
all months $ 3.55 per kW of T obl /month

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

Including T&G Obligation $		
Summer - all hrs	$	73.84
Winter - all hrs	$	80.95
Annual - including T&G Obl $	$	75.64

Gen Cost (per kW of Billed Demand/Month)		≤ 5 kW		> 5 kW
summer	$	1.311	$	4.541
winter	$	1.291	$	4.561

ALL RATES

Grand Total Cost in $1000 =	$	89,289	
All-In Average cost @ customer =	$	86.27	per MWh at customer (per customer metered MWh)
All-In Average costs @ transmission nodes =	$	80.26	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/SC5	SC3	SC2 ND	SC4	SC6
Summer - all hrs		**1.060**		**0.842**	**0.531**	**0.530**
RECO On pk			**1.466**			
RECO Off pk			**0.667**			
Constant Blk 1	**$**	**(19.46)**				
Constant Blk 2	**$**	**14.15**				
Winter - all hrs		**1.230**		**0.900**	**0.634**	**0.629**
RECO On pk			**1.408**			
RECO Off pk			**0.787**			
Annual - all hrs		1.157	1.000	0.882	0.604	0.600

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	**0.920**	**$**	**(27.249)**
Winter - all hrs	**1.009**	**$**	**(28.221)**
Annual - including T&G Obl $	0.943		

PLUS:

Gen Cost (per kW of Billed Demand/Month)

		≤ 5 kW		> 5 kW
summer	$	1.31	$	4.54
winter	$	1.29	$	4.56

Trans cost
all months $ 3.546 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/SC5	SC3	SC2 ND	SC4	SC6
Summer - all hrs		$ 67.70	$ 66.21	$ 58.41	$ 42.61	$ 42.55
	RECO On pk		$ 105.85			
	RECO Off pk		$ 41.68			
	Block 1	$ 48.24				
	Block 2	$ 81.85				
Winter - all hrs		$ 81.40	$ 69.34	$ 63.09	$ 50.85	$ 50.46
	RECO On pk		$ 101.19			
	RECO Off pk		$ 51.36			
Annual -all hrs		$ 75.50	$ 68.40	$ 61.64	$ 48.51	$ 48.19

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	$	46.59
Winter - all hrs	$	52.73
Annual - all hrs per MWh only	$	50.54
Including Generation Obligation $		
Summer - all hrs	$	63.03
Winter - all hrs	$	68.94
Annual - including T&G Obl $	$	66.83

PLUS:

Gen Cost (per kW of Billed Demand/Month)

		< 5 kW		> 5 kW
summer	$	1.311	$	4.541
winter	$	1.291	$	4.561

ALL RATES

Grand Total Cost in $1000 = $ 74,602
All-In Average cost @ customer = $ 72.08 per MWh at customer (per customer metered MWh)
All-In Average costs @ tansmission nodes = $ 67.06 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/SC5	SC3	SC2 ND	SC4	SC6
Summer - all hrs		**1.010**		**0.871**	**0.635**	**0.634**
	RECO On pk		**1.578**			
	RECO Off pk		**0.622**			
	Constant Blk 1 $	**(19.46)**				
	Constant Blk 2 $	**14.15**				
Winter - all hrs		**1.214**		**0.941**	**0.758**	**0.752**
	RECO On pk		**1.509**			
	RECO Off pk		**0.766**			
Annual - all hrs		1.126	1.020	0.919	0.723	0.719

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	**0.940**	**(16.440)**
Winter - all hrs	**1.028**	**(16.214)**
Annual - including T&G Obl $	**0.997**	

PLUS:

Gen Cost (per kW of Billed Demand/Month)

	< 5 kW	> 5 kW
summer	$ 1.311	$ 4.541
winter	$ 1.291	$ 4.561

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

	SC1/SC5	SC3	SC2 ND	SC4	SC6	SC2 Dem
Total Costs by Rate - in $1000						
Summer	$ 24,251	$ 7	$ 473	$ 57	$ 63	$ 8,622
Winter	$ 37,191	$ 16	$ 1,124	$ 173	$ 186	$ 17,126
Total	$ 61,442	$ 23	$ 1,597	$ 231	$ 248	$ 25,748
% of Annual Total $ by Rate						
Summer	39%	29%	30%	25%	25%	33%
Winter	61%	71%	70%	75%	75%	67%

Total Costs - in $1000	
Summer	$ 33,473
Winter	$ 55,817
Total	$ 89,289

% of Annual Total $		If total $ were split on a per MWh basis (on transmission node MWhs):	Ratio to All-In Cost	
Summer	37%	$ 74.74 per MWh @ transmission nodes	Summer	**0.9313**
Winter	63%	$ 83.98 per MWh @ transmission nodes	Winter	**1.0463**

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

	SC1/SC5	SC3	SC2 ND	SC4	SC6	SC2 Dem
Total Costs by Rate - in $1000						
Summer	$ 19,306	$ 6	$ 409	$ 57	$ 63	$ 7,308
Winter	$ 30,659	$ 14	$ 982	$ 173	$ 186	$ 14,499
Total	$ 49,964	$ 20	$ 1,391	$ 231	$ 248	$ 21,807
% of Annual Total $ by Rate						
Summer	39%	29%	29%	25%	25%	34%
Winter	61%	71%	71%	75%	75%	66%

Total Costs - in $1000	
Summer	$ 27,148
Winter	$ 46,512
Total	$ 73,661

% of Annual Total $		If total $ were split on a per MWh basis (on transmission node MWhs):	Ratio to All-In Cost	
Summer	37%	$ 60.62 per MWh @ transmission nodes	Summer	**0.9040**
Winter	63%	$ 69.98 per MWh @ transmission nodes	Winter	**1.0436**

Table #18 **Forward Energy Prices**

PJM Forward Prices - Energy Only @ bulk system *in $/MWh*				**Zone to Western Hub Basis Differential** *in $/MWh*		**PJM Forward Prices (incl basis differential)** *in $/MWh*	
	On-Peak	**Off/On Peak LMP ratio**	**Off-Peak**	**On-Peak**	**Off-Peak**	**On-Peak**	**Off-Peak**
January	47.30	0.7876	37.25	97%	97%	45.88	36.13
February	44.65	0.7876	35.17	97%	97%	43.31	34.11
March	33.70	0.7876	26.54	97%	97%	32.69	25.74
April	29.50	0.7876	23.23	97%	97%	28.62	22.53
May	29.25	0.7876	23.04	97%	97%	28.37	22.35
June	29.30	0.6684	19.58	96%	91%	28.13	17.82
July	34.45	0.6684	23.03	96%	91%	33.07	20.96
August	31.95	0.6684	21.36	96%	91%	30.67	19.44
September	31.45	0.6684	21.02	96%	91%	30.19	19.13
October	29.35	0.7876	23.12	97%	97%	28.47	22.43
November	29.80	0.7876	23.47	97%	97%	28.91	22.77
December	33.40	0.7876	26.31	97%	97%	32.40	25.52

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

	On-Peak	**Off-Peak**
January	63.75	56.25
February	61.50	53.75
March	38.75	30.00
April	30.50	22.00
May	27.75	19.50
June	29.75	19.75
July	36.25	24.00
August	33.75	22.50
September	30.25	20.00
October	29.25	20.25
November	32.50	25.25
December	45.50	37.75

Weighted Average Forward Prices - Energy Only @ bulk system (88.2% PJM - 11.8% NYISO)
in $/MWh

	On-Peak	**Off-Peak**	
January	47.99	38.51	88.2%
February	45.46	36.43	11.8%
March	33.41	26.24	
April	28.84	22.47	
May	28.30	22.01	
June	28.32	18.05	
July	33.45	21.32	
August	31.03	19.80	
September	30.20	19.23	
October	28.56	22.17	
November	29.33	23.06	
December	33.95	26.97	

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

	PJM Base Capacity	PJM 88.2%	NYISO 11.8%	Weighted Average
Summer	$163.32	$163.32	$156.25	$162.49
Winter	$163.32	$163.32	22.34	$146.66

Table #20 **Ancillary Services**

PJM Ancillary Services	NYISO Ancillary Services	Renewable Power Cost	PJM 88.2%	NYISO 11.8%	Weighted Average
$2.00	$1.90	$16.72	$18.72	$18.62	$18.71

Assumptions:

Gen Cost =		$162.49	per MW-day in summer
		$146.66	per MW-day in winter
Trans cost =	$	42,548	per MW-yr
Analysis time period =		4	summer months
		8	winter months
Ancillary Services =	$	18.71	/MWh

Energy Costs = Based on Jun 2020 to May 2021 Forwards @ PJM West as of November 11, 2019
Based on May 2020 to Apr 2021 Forwards @ NYISO Zone G and Lower Hudson Valley (LHV) as of June 01, 2019
Usage patterns = Forecasted 2019 energy use by class, PJM on/off % from 2018 class load profiles,
RECO billing on/off % from 6/18 to 5/19 actual data
Obligations = Class totals for 2019
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

Attachment C

Table A Weighted Average Price Calculation

Line #	Specific BGS-FP Auction >>		2018 Auction 36 Month	2019 Auction 36 Month	2020 Auction 36 Month		Total	Notes:
1	Tranches		1	1	2		4	From then-current auction
2(a)	Winning Bid Price (¢/kWh)*		8.594	8.803	8.803			(Note: 2020 Auction Price Shown for Illustrative Purposes Only)
2(b)	Capacity Proxy Price True-up - in (¢/kWh)*				0.000			Entered After 2022 BGS Auction
2(C)	Winning Bid Price (¢/kWh)*		8.594	8.803	8.803			= 2(a) + 2(b)
3	Transmission (¢/kWh)		1.320	1.320	1.320			Average transmission cost included in bid
4	BGS (¢/kWh)		7.274	7.483	7.483			=(2) - (3)
5	Weighted Avg BGS		1.818	1.871	3.741		7.431	= (1) / Total Tranches * (4)
6	Weighted Avg Trans		0.330	0.330	0.660		1.320	= (1) / Total Tranches * (3)
7	Weighted Avg Total Price (¢/kWh)						**8.751**	
	Seasonal Payment Factors							
8		Summer	1.0000	1.0000	1.0000 **			From then-current Bid Factor Spreadsheet
9		Winter	1.0000	1.0000	1.0000 **			From then-current Bid Factor Spreadsheet
	Applicable Customer Usage @ transmission nodes				(Eastern Division)			
10		Summer MWh	394,915					From then-current Bid Factor Spreadsheet
11		Winter MWh	586,129					From then-current Bid Factor Spreadsheet
12			981,044					
	Total Cost							
13		Summer	8,484,754	8,691,097	17,382,194		34,558,045	= (1) / Total Tranches * (2c) / 100 * (8) * (10) * 1,000
14		Winter	12,592,985	12,899,238	25,798,476		51,290,699	= (1) / Total Tranches * (2c) / 100* (9) * (11) * 1,000
15		Total	21,077,739	21,590,335	43,180,670		85,848,744	= (13) + (14)
	Average Cost (NJ Statewide Auction)							
16		Summer	8.751 ¢/kWh					= sum(line 13) / (10) / 1000 * 100 rounded to 3 decimal places
17		Winter	8.751 ¢/kWh					= sum(line 14) / (11) / 1000 * 100 rounded to 3 decimal places
18		Total	**8.751** ¢/kWh					= sum(line 15) / (12) / 1000 * 100 rounded to 3 decimal places
	Average Cost (Including RECO RFP)							
			BGS Auction	RECO RFP			Total	
19	Tranches		4	0.536			4.536	Includes RECO RFP equivalent tranches
20	Price ¢/kWh		8.751	5.514				BGS Auction from (18) Note 5.514¢ for RFP is illustrative (excludes transmission).
21	Transmission		1.320	0.000				
22	BGS		7.431	5.514				= (20) - (21)
23	Weighted Avg BGS		6.553	0.652			7.204	= (19) / Total Tranches * (22)
24	Weighted Avg Trans		1.164	0.000			1.164	= (19) / Total Tranches * (21)
25	**Weighted Avg Total Price**						$\boxed{\textbf{8.368}}$	= (23) + (24)

* 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/SC5	SC3	SC2 ND	SC4	SC6
Summer - all hrs		**1.010**		**0.871**	**0.635**	**0.634**
	RECO On pk		**1.578**			
	RECO Off pk		**0.622**			
	Constant Blk 1 $	**(19.46)**				
	Constant Blk 2 $	**14.15**				
Winter - all hrs		**1.214**		**0.941**	**0.758**	**0.752**
	RECO On pk		**1.509**			
	RECO Off pk		**0.766**			
Annual - all hrs		1.126	1.020	0.919	0.723	0.719

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	**0.940**	**(16.440)**
Winter - all hrs	**1.028**	**(16.214)**
Annual - including T&G Obl $	**0.997**	

PLUS:

Gen Cost (per kW of Billed Demand/Month)

	0	< 5 kW	> 5 kW
summer	$ -	$ 1.311	$ 4.541
winter	$ -	$ 1.291	$ 4.561

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

All-In Average costs @ Trans node =	$	83.68	/MWh*
Less Transmission	$	(11.64)	/MWh**
BGS Cost	$	72.04	/MWh

* Price from Table A (which does not include transmission for the Central/Western Division).
** RECO average transmission rate of 13.20 minus Central/West transmission contribution to weighted average rate 0.536/4.536 *$13.20 per MWh). $1.56

Retail BGS Rates (excl SUT) (¢/kWh)

	SC1/SC5	SC3	SC2 ND	SC4	SC6	SC2 Dem
Summer						
All kWh (¢/kWh)	7.276		6.274	4.574	4.567	5.128
Peak kWh (¢/kWh)		11.368				
Off-Peak kWh (¢/kWh)		4.481				
Block1	5.330					
Block2	8.691					
Demand Charge ($/kW) 1st 5kW						1.311
Demand Charge ($/kW)> 5 kW						4.541
Winter						
All kWh (¢/kWh)	8.745		6.779	5.460	5.417	5.784
Peak kWh (¢/kWh)		10.870				
Off-Peak kWh (¢/kWh)		5.518				
Demand Charge ($/kW) 1st 5kW						1.291
Demand Charge ($/kW) > 5 kW						4.561

Table D **Calculation of Rate Adjustment Factors**

	SC1/SC5	SC3	SC2 ND	SC4	SC6	SC2 Dem
Total BGS Revenue (Excl SUT) - in $1000						
Summer	$ 20,749	$ 6	$ 439	$ 62	$ 67	$ 8,231
Winter	$ 32,939	$ 15	$ 1,055	$ 186	$ 199	$ 16,206
Total	$ 53,688	$ 21	$ 1,494	$ 248	$ 266	$ 24,437

Total	
Summer	$ 29,554
Winter	$ 50,600
Total	$ 80,154

Total Supplier Payments - in $1000

Eastern Division	Total	Transmission	Net BGS
Summer	$ 34,558	$ 4,594	$ 29,964
Winter	$ 51,291	$ 9,188	$ 42,103
Total	$ 85,849	$ 13,782	$ 72,067

Central/Western Division	Total	Transmission	Net BGS
Summer	$ 2,946	$ -	$ 2,946
Winter	$ 4,331	$ -	$ 4,331
Total	$ 7,277	$ -	$ 7,277

Total RECO FP	Total	Transmission	Net BGS
Summer	$ 37,504	$ 4,594	$ 32,910
Winter	$ 55,622	$ 9,188	$ 46,434
Total	$ 93,126	$ 13,782	$ 79,344

Differences	BGS Revenue	BGS Costs	Difference	Rate Adjustment Factors
Summer	$ 29,554	$ 32,910	$ 3,356	**1.11356**
Winter	$ 50,600	$ 46,434	$ (4,166)	**0.91766**
Total	$ 80,154	$ 79,344	$ (810)	

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

Rates Excluding SUT:

	SC1/SC5	SC3	SC2 ND	SC4	SC6	SC2 Dem
Summer						
All kWh (¢/kWh)	8.102		6.986	5.093	5.086	5.710
Peak kWh (¢/kWh)		12.659				
Off-Peak kWh (¢/kWh)		4.990				
Block1	5.935					
Block2	9.678					
Demand Charge ($/kW) 1st 5kW						1.460
Demand Charge ($/kW) > 5 kW						5.057
Winter						
All kWh (¢/kWh)	8.025		6.221	5.010	4.971	5.308
Peak kWh (¢/kWh)		9.975				
Off-Peak kWh (¢/kWh)		5.064				
Demand Charge ($/kW) 1st 5kW						1.185
Demand Charge ($/kW) > 5 kW						4.185

Rates Including SUT: SUT @ 6.625%

	SC1	SC3	SC2 ND	SC4	SC6	SC2 Dem
Summer						
All kWh (¢/kWh)			7.449	5.430	5.423	6.088
Peak kWh (¢/kWh)		13.498				
Off-Peak kWh (¢/kWh)		5.321				
Block1	6.328					
Block2	10.319					
Demand Charge ($/kW) 1st 5kW						1.5600
Demand Charge ($/kW)> 5 kW						5.3900
Winter						
All kWh (¢/kWh)	8.557		6.633	5.342	5.300	5.660
Peak kWh (¢/kWh)		10.636				
Off-Peak kWh (¢/kWh)		5.399				
Demand Charge ($/kW) 1st 5kW						1.2600
Demand Charge ($/kW) > 5 kW						4.4600

Table F Spreadsheet Error Checking

Total BGS Revenue (Excl SUT) - in $1000

	SC1/SC5	SC3	SC2 ND	SC4	SC6	SC2 Dem
Summer	$ 23,104	$ 7	$ 489	$ 69	$ 75	$ 9,165
Winter	$ 30,227	$ 14	$ 968	$ 171	$ 183	$ 14,872
Total	$ 53,331	$ 21	$ 1,457	$ 240	$ 258	$ 24,037

Total	
Summer	$ 32,909
Winter	$ 46,435
Total	$ 79,344

Supplier Payments - in $1000

Eastern Division

	Total	Transmission	Net BGS
Summer	$ 34,558	$ 4,594	$ 29,964
Winter	$ 51,291	$ 9,188	$ 42,103
Total	$ 85,849	$ 13,782	$ 72,067

Central/Western Division

	Total	Transmission	Net BGS
Summer	$ 2,946	$ -	$ 2,946
Winter	$ 4,331	$ -	$ 4,331
Total	$ 7,277	$ -	$ 7,277

Total RECO FP

	Total	Transmission	Net BGS
Summer	$ 37,504	$ 4,594	$ 32,910
Winter	$ 55,622	$ 9,188	$ 46,434
Total	$ 93,126	$ 13,782	$ 79,344

Differences

	BGS Revenue	BGS Costs	Difference
Summer	$ 32,909	$ 32,910	$ 1
Winter	$ 46,435	$ 46,434	$ (1)
Total	$ 79,344	$ 79,344	$ (0)

Attachment D

Development of Capacity Proxy Price True-Up - $/MWh
2020/2021 Delivery Year

		2020/21 Delivery Year	*Notes:*
1	**PJM Final Zonal Net Load Price ($/MW-day) - Zone**	$163.32	PJM RPM Final Zonal Net Load Price - Zone
2	**Capacity Proxy Price ($/MW-day)**	N/A	
3	**Capacity Proxy Price True-Up - $/MW-day**	N/A	= line 1 - line 2
4	**BGS-RSCP Gen Obl - MW**	389.1	
5	**Days in Year**	365	
6	**Capacity Proxy Price True-Up Annual Cost**	N/A	= line 3 * line 4 * line 5
7	**Eligible Tranches**	2	from Table A
8	**Total Tranches**	4	from Table A
9	**% of tranches eligible for payment**	50.00%	= line 7 / line 8
10	**Capacity Proxy Price True-Up Cost**	$0	= line 6 * line 9
11	**Total Applicable Customer Usage @ transmission nodes -** *in MWh*	981,044	
12	**Eligible Customer Usage @ transmission nodes -** *in MWh*	490,522	= line 9 * line 11
13	**Capacity Proxy Price True-Up - $/MWh**	**$0.00**	**= line 10/ line 12 - rounded to 2 decimal places**

Development of Capacity Proxy Price True-Up - $/MWh
Using 2022/2023 Illustrative Data for RECO

		2022/23 Delivery Year	*Notes:*
1	**PJM Final Zonal Net Load Price ($/MW-day) - Zone**	$155.00	PJM RPM Final Zonal Net Load Price - Zone
2	**Capacity Proxy Price ($/MW-day)**	$152.06	
3	**Capacity Proxy Price True-Up - $/MW-day**	$2.94	= line 1 - line 2
4	**BGS-RSCP Gen Obl - MW**	389.1	
5	**Days in Year**	365	
6	**Capacity Proxy Price True-Up Annual Cost**	$417,578.62	= line 3 * line 4 * line 5
7	**Eligible Tranches**	2	from Table A
8	**Total Tranches**	4	from Table A
9	**% of tranches eligible for payment**	50.00%	= line 7 / line 8
10	**Capacity Proxy Price True-Up Cost**	$208,789	= line 6 * line 9
11	**Total Applicable Customer Usage @ transmission nodes -** *in MWh*	981,044	
12	**Eligible Customer Usage @ transmission nodes -** *in MWh*	490,522	= line 9 * line 11
13	**Capacity Proxy Price True-Up - $/MWh**	**$0.43**	**= line 10/ line 12 - rounded to 2 decimal places**

ROCKLAND ELECTRIC COMPANY **Attachment D**

2022 BGS Auction

Table A Weighted Average Price Calculation

Line #	Specific BGS-FP Auction >>		2020 Auction 36 Month	2021 Auction 36 Month	2022 Auction 36 Month	Total	Notes:
1	Tranches		2	1	1	4	From then-current auction
2(a)	Winning Bid Price (¢/kWh)*		8.803	8.803	8.803		(Note: 2022 Auction Price Shown for Illustrative Purposes Only)
2(b)	Capacity Proxy Price True-up - in (¢/kWh)*		0.043		0.000		Entered After 2022 BGS Auction
2(C)	Winning Bid Price (¢/kWh)*		8.846	8.803	8.803		= 2(a) + 2(b)
3	Transmission (¢/kWh)		1.320	1.320	1.320		Average transmission cost included in bid
4	BGS (¢/kWh)		7.526	7.483	7.483		=(2) - (3)
5	Weighted Avg BGS		3.763	1.871	1.871	7.504	= (1) / Total Tranches * (4)
6	Weighted Avg Trans		0.660	0.330	0.330	1.320	= (1) / Total Tranches * (3)
7	Weighted Avg Total Price (¢/kWh)					**8.825**	
	Seasonal Payment Factors						
8		Summer	1.0000	1.0000	1.0000 **		From then-current Bid Factor Spreadsheet
9		Winter	1.0000	1.0000	1.0000 **		From then-current Bid Factor Spreadsheet
	Applicable Customer Usage @ transmission nodes				(Eastern Division)		
10		Summer MWh	394,915				From then-current Bid Factor Spreadsheet
11		Winter MWh	586,129				From then-current Bid Factor Spreadsheet
12			981,044				
	Total Cost						
13		Summer	17,382,194	8,691,097	8,691,097	34,764,388	= (1) / Total Tranches * (2c) / 100 * (8) * (10) * 1,000
14		Winter	25,798,476	12,899,238	12,899,238	51,596,952	= (1) / Total Tranches * (2c) / 100* (9) * (11) * 1,000
15		Total	43,180,670	21,590,335	21,590,335	86,361,340	= (13) + (14)
	Average Cost (NJ Statewide Auction)						
16		Summer	8.803 ¢/kWh				= sum(line 13) / (10) / 1000 * 100 rounded to 3 decimal places
17		Winter	8.803 ¢/kWh				= sum(line 14) / (11) / 1000 * 100 rounded to 3 decimal places
18		Total	**8.803** ¢/kWh				= sum(line 15) / (12) / 1000 * 100 rounded to 3 decimal places

	Average Cost (Including RECO RFP)	BGS Auction	RECO RFP	Total	
19	Tranches	4	0.536	4.536	Includes RECO RFP equivalent tranches
20	Price ¢/kWh	8.803	5.514		BGS Auction from (18) Note 5.514¢ for RFP is illustrative (excludes transmission).
21	Transmission	1.320	0.000		
22	BGS	7.483	5.514		= (20) - (21)
23	Weighted Avg BGS	6.599	0.652	7.250	= (19) / Total Tranches * (22)
24	Weighted Avg Trans	1.164	0.000	1.164	= (19) / Total Tranches * (21)
25	**Weighted Avg Total Price**			**8.414**	= (23) + (24)

* 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.