IN THE MATTER OF THE PROVISION OF BASIC GENERATION SERVICE FOR THE PERIOD BEGINNING JUNE 1, 2023	**STATE OF NEW JERSEY BOARD OF PUBLIC UTILITIES BPU DOCKET NO. ER22030127**

ATLANTIC CITY ELECTRIC COMPANY

**BASIC GENERATION SERVICE
COMMENCING JUNE 1, 2023**

**COMPANY-SPECIFIC ADDENDUM
FILING**

Proposal Dated July 1, 2022

ATLANTIC CITY ELECTRIC COMPANY'S
COMPANY-SPECIFIC ADDENDUM

The following contains the company-specific material (referred to herein as the "Addendum") of Atlantic City Electric Company ("ACE" or the "Company") for the joint compliance filing made with the New Jersey Board of Public Utilities (the "Board" or "BPU") on this date by the Electric Distribution Companies (the "EDCs") in this docket. Capitalized terms used herein shall have the meanings defined in the joint filing.

As described in the generic section of this filing, two (2) different methods will be utilized for the pricing of Basic Generation Service ("BGS") to customers – residential and small commercial energy pricing and variable hourly energy pricing. The residential and small commercial energy pricing formerly referred to as "Basic Generation Service–Fixed Price" or "BGS-FP"[1] is now termed "Basic Generation Service–Residential Small Commercial Pricing" or "BGS-RSCP" and the hourly energy pricing service is termed "Basic Generation Service – Commercial and Industrial Energy Pricing" or "BGS- CIEP." BGS-RSCP is to be available to all residential and small commercial customers, specifically those customers taking service on Rate Schedules RS, MGS (Secondary, Secondary Electric Vehicle Charging, and Primary), AGS (Secondary and Primary), DDC, SPL, and CSL. These rate classes comprise the vast majority of ACE's customers and approximately 85% of the usage on the ACE electric system. As described in detail later in this filing, BGS-RSCP commercial or industrial customers can opt in to BGS-CIEP.

[1] In this document, "Basic Generation Service-Fixed Price" or "BGS-FP" has the same meaning as, and is entirely interchangeable with, "Basic Generation Service-Residential Small Commercial Pricing" or "BGS-RSCP."

BGS-CIEP will continue to be the only default supply option available to customers taking service under ACE's Rate Schedule TGS (Transmission General Service). Pursuant to the Board's Decision on June 18, 2012, in BPU Docket No. ER12020150, changing the BGS-CIEP required customer capacity peak load share ("PLS") to 500 kW or greater effective June 1, 2013, will be the only default supply option available to customers on Rate Schedules MGS Secondary, MGS Primary, AGS Secondary or AGS Primary with an annual PLS for generation capacity equal to or greater than 500 kW as of November 1 of the year prior to the BGS auction. There are an estimated 238 eligible CIEP customers representing approximately 15% of the usage on the ACE electric system, whose only default supply option is BGS-CIEP. As described in detail later in this filing, BGS-CIEP will also be available to any commercial or industrial customer on a voluntary basis, regardless of such customer's regular Rate Schedule.

A. CONTINGENCY PLANS

While not every contingency can be anticipated, ACE can differentiate four (4) areas of concern as follows:

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

b) a default by one of the winning bidders prior to June 2023;

c) a default during the June 1, 2023 - May 31, 2024 supply period, under the BGS-CIEP contracts entered into for 12 months; and/or

d) a default during the June 1, 2023 - May 31, 2026 supply period, under the BGS-RSCP contracts entered into for 36 months.

1. Insufficient Number of Bids in Auction

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

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

In the event that the Auction Volume is reduced to less than 100% of BGS-RSCP or BGS-CIEP Load, ACE, at its option, will implement a Contingency Plan for the remaining tranches. Under the Plan, ACE will purchase necessary services (including, but not limited to, network transmission, capacity, energy and ancillary services, and any required Renewable Portfolio Standards ("RPS") Renewable Energy Certificate) for the remaining tranches through PJM-administered markets until May 31, 2024. Any unsubscribed tranches for the period after May 31, 2024, may be included in a subsequent auction or treated pursuant to the provisions of part 4 of the Contingency Plan described below. This Contingency Plan will alert bidders that, in order to secure BGS-RSCP and BGS-CIEP prices from New Jersey BGS customers for their supply, it will be necessary to bid in to the auctions.

Since the Contingency Plan calls for the purchase of BGS supply in PJM-administered markets, it is considered a prominent feature of the auction proposal because it provides bidders a strong incentive to participate in the auction process. If bidders were to believe that a less than fully subscribed auction would lead to a negotiation or a secondary market in which ACE, on behalf of its customers, would seek to acquire BGS supplies, the incentive to participate in the auctions and the incentive to offer the best deal in the auctions would be subsequently diminished.

2. Defaults Prior to June 1, 2023

If a winning bidder defaults prior to the beginning of the BGS service, then, at ACE's option, the open tranches may first be offered to the other winning bidders or will be filled as provided in part 3, below. Additional costs incurred by ACE in implementing the Contingency Plan will be assessed against the defaulting suppliers' credit security.

3. Defaults During the June 1, 2023 - May 31, 2024 Supply Period

If a default occurs during the June 1, 2023 - May 31, 2024 period, for those contracts entered into for 12 months, at ACE's option, the tranches supplied by the defaulting supplier may be offered to the other winning bidders, may be bid out or may be procured from PJM-administered markets. Additional costs incurred by ACE in implementing this part of the Contingency Plan will be assessed against the defaulting suppliers' credit security.

If circumstances are such that it is not practical to find another such supplier, ACE proposes to utilize a process similar to the "flexible portfolio approach" for BGS wholesale supply, as previously described in ACE's filing in BPU Docket No. EM00080604, as noted in the Board's November 29, 2000 Order in that docket. This approach relies on a combination of competitive sources for BGS power, including Requests for Proposal(s), broker markets, capacity costs based on the PJM Reliability Pricing Model ("RPM"), and the PJM spot energy market.

4. Defaults During the June 1, 2023 - May 31, 2026 Supply Period

If a default occurs during the June 1, 2023 - May 31, 2026 period, for those contracts entered into for 36 months, at ACE's option, the tranches supplied by the defaulting supplier may be offered to the other winning bidders, may be bid out or may be procured from PJM-administered markets. Among the options for bidding out the tranches, ACE may include such tranches in the next BGS procurement. Additional costs incurred by ACE in implementing this part of the Contingency Plan will be assessed against the defaulting suppliers' credit security.

If circumstances are such that it is not practical to find another such supplier, ACE proposes to utilize a process similar to the "flexible portfolio approach" for BGS wholesale supply, as previously described in the Company's filing in BPU Docket No. EM00080604, as noted in the Board's November 29, 2000 Order in that docket. This approach relies on a combination of competitive sources for BGS power, including requests for proposal, broker markets, capacity costs based on the PJM RPM, and the PJM spot energy market.

B. <u>ACCOUNTING AND COST RECOVERY</u>

The accounting and cost recovery that ACE will use for its BGS service is summarized in this Section. These provisions are intended to be applicable to ACE only. Each EDC will provide these individual BGS cost recovery methodologies.

ACE’s BGS accounting will account for BGS-RSCP revenues and BGS-CIEP revenues individually as follows:

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

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

1. all payments made for the provision of BGS-RSCP and BGS CIEP service, including CIEP Standby Fee payments; and

2. any administrative costs associated with the provision of BGS-RSCP and BGS-CIEP service:

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

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

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

Directly-incurred costs for ACE include, but are not limited to, the following:

- labor costs and expenses associated with employees who are considered incremental to the BGS process;
- system and software costs related to tracking BGS costs and invoicing;
- power procurement residual costs; and
- other administrative fees incurred in connection with the BGS process, including, but not limited to, fees/licenses, costs associated with public hearings, postage, and information technology support and programming changes necessitated by BPU directives.

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

As noted, one element of commonly-incurred costs has 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. Due to restrictions and safeguards related to the COVID-19 pandemic, the February 2022 BGS Auction was conducted remotely, as was the 2021 BGS Auction (*i.e.*, the aforementioned office space was not utilized), without issue. Given the success of conducting the recent auction in this manner, ACE believes that it would be prudent (and will reduce costs for the benefit of BGS customers) to conduct future BGS Auctions in this same remote manner. As such, in the 2021 BGS Proposal filed on July 1, 2021, the EDCs proposed to begin the process of subletting or otherwise closing the physical BGS office located in Newark, New Jersey, in an effort to eliminate or otherwise the costs related to the same. On November 17, 2021 the Board approved the EDCs' request to close or sublet the physical BGS office and effective May 16, 2022, the BGS office was sublet to a new (sub)tenant; and

3. any cost for procurement of capacity, energy, ancillary service, transmission, RPS compliance, and other expenses related to the Contingency Plan, and any payments to the winners of a subsequent bid process to cover defaults made under the Contingency Plan, less any payments recovered from defaulting bidders. In the event that implementation of the Contingency Plan is required for BGS CIEP load, CIEP Standby Fee payments will be tracked separately.

BGS-RSCP and BGS-CIEP rates will be subject to deferred accounting since there will be differences between the BGS costs (as defined above) and BGS-related revenues. Adjustment type charges (also subject to deferred accounting) are necessary in order to balance out the difference between the amount paid to the BGS-RSCP and BGS-CIEP supplier(s) for BGS-RSCP and BGS-CIEP supply, and the revenue from customers for BGS-RSCP and BGS-CIEP services. These reconciliation charges ("RC"), including interest, will be calculated periodically for BGS-RSCP and BGS-CIEP on a cent per kWh basis, and the respective rates will be applied to all BGS-RSCP and BGS-CIEP kWh. These charges will be combined with the fixed, seasonally-differentiated BGS-RSCP and hourly BGS-CIEP charges for billing although they will be published in ACE's Rider BGS as separate BGS-RSCPRC and BGS-CIEPRC rates that will be revised periodically.

A BGS deferral/credit will be determined individually for the BGS-RSCP and BGS-CIEP rates as the difference between recorded BGS-RSCP or BGS-CIEP revenue and the total BGS-RSCP or BGS-CIEP cost. The individual BGS deferrals will be accounted for in the following manner:

1. If individual BGS costs, as defined above, are higher than individual BGS recorded revenue, the difference will be charged on a monthly basis to the cost deferral to be reconciled and recovered from customers, with interest, on a periodic, basis through the BGS-RSCPRC and/or the BGS-CIEPRC.
2. If individual BGS costs, as defined above, are lower than individual BGS recorded revenue, the difference will be credited monthly, to the cost deferral to be reconciled and returned to customers, with interest, on a periodic basis, through the BGS-RSCPRC and/or BGS-CIEPRC.

An additional deferred balance will be maintained individually for the BGS-RSCPRC and BGS-CIEPRC rates to ensure full recovery of all of the costs associated with the provision of BGS service.

In the event the Contingency Plan is required to be implemented to serve BGS-CIEP load, the difference between CIEP Standby Fee revenues and CIEP Standby Fee payments made to winning BGS-CIEP auction bidders will be maintained in a separate deferred balance account. Interest on this account will be accrued monthly, using the same methodology and interest rate as used for the BGS-RSCP and BGS-CIEP deferred balances. Any debit/credit balance in this account at the end of the BGS period of June 1, 2023 through May 31, 2024 will be applied as a $/kWh adjustment to the CIEP Standby Fee for the next BGS-CIEP annual period. In this manner, the mechanism to reconcile any CIEP Standby Fee deferred balance is applied, to the greatest extent practicable, to all BGS-CIEP eligible customers who paid the CIEP Standby Fee, and not only to those taking BGS-CIEP service.

With the exception of any adjustment to the CIEP Standby Fee which may be required, ACE will follow the following schedule for the periodic reconciliation of its BGS-RSCP and BGS-CIEP rates:

1. For BGS-RSCPRC and BGS-CIEPRC rates effective June 1, the actual data for the months of August through March will be used. Projected data for April and May will be used for the amount of BGS-RSCPRC and BGS-CIEPRC to be recovered/returned in those months.
2. For BGS-RSCPRC and BGS-CIEPRC rates effective October 1, the actual data for the months of April through July will be used. Projected data for August and September will be used for the amount of BGS-RSCPRC and BGS-CIEPRC to be

recovered/returned in those months.

ACE will file BGS-RSCPRC and BGS-CIEPRC rates with the Board at least 30 days in advance of the date upon which they are requested to be effective. The BGS Reconciliation Rate is capped at two cents per kWh. The filed rates will become effective 30 days after filing, absent a determination of manifest error by the Board.

C. DESCRIPTION OF BGS TARIFF SHEETS

This Section describes the proposed tariff sheets needed to implement ACE's BGS proposal. The proposed tariff sheets for Tariff Rider Basic Generation Service ("Rider BGS") are included as **Attachment 1**. Rider BGS provides the rates, terms, and conditions for customers being served under the BGS-RSCP or BGS-CIEP pricing mechanisms.

1. BGS-RSCP

BGS-RSCP is to be available to all customers served on Rate Schedules RS, DDC, SPL, and CSL. BGS-RSCP is also available to customers with a PLS of less than 500 kW who are served under Rate Schedules MGS Secondary, MGS Secondary Electric Vehicle Charging, MGS Primary, AGS Secondary, and AGS Primary. On any meter reading date, and with prior requisite notice, a customer taking supply service under BGS-RSCP may switch to third-party supply service, and a customer taking third-party supply service may switch to BGS-RSCP supply service.

As indicated on the proposed tariff sheets, BGS-RSCP is made up of two components: BGS Supply Charges and the BGS Reconciliation Charge. Additionally, each BGS customer is subject to transmission charges as discussed below.

a. <u>BGS Supply Charges</u>

The values of the BGS Supply charges applicable to Rate Schedules RS, MGS Secondary, MGS Secondary Electric Vehicle Charging, MGS Primary, AGS Secondary, AGS Primary, DDC, SPL, and CSL include the costs related to energy, generation capacity, RPS, ancillary services, and administration. This is a continuation of the current approved methodology for recovering all electric supply service costs in the kilowatt- hour charges for these Rate Schedules.

Typically, the generation capacity costs used in the development of the BGS-RSCP rates are the relevant current wholesale market prices for capacity based on the average, 2023/2024, 2024/2025, and 2025/2026 Base Residual Auctions ("BRA") results under the RPM applicable to load served in the ACE 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. However, PJM has issued a schedule of upcoming BRAs, and the recently conducted BRA produced a preliminary price paid for capacity of $49.59 per MW-day for the 2023/2024 Delivery Year for the ACE Zone. Due to the postponement of the BRAs, contracts from the 2021 and 2022 BGS auctions contained supplements with Capacity Proxy Prices. With the prior postponements of the BRAs for the 2023/2024 and 2024/2025 Delivery Years, a Capacity Proxy Price of $146.51 per MW-Day was used in place of the 2023/2024 BRA value in the 2021 contracts, while a Capacity Proxy Price of $118.12 was used in place of the 2023/2024 BRA and a Capacity Proxy Price of $87.98 per MW-Day was used in place of the 2024/2025 BRA in the 2022 contracts.

Given the continued delay in the schedule of BRAs for the 2024/2025 Delivery Year and 2025/2026 Delivery Year, a Capacity Proxy Price of $66.38 per MW-Day and a Capacity Proxy Price of $44.63 per MW-Day have been used in place of the prices paid for capacity for 2024/2025 and 2025/2026 Delivery Years, respectively.

For Energy Year ("EY") 2025, if Supplement A to the BGS-RSCP Supplier Master Agreement is approved by the BPU and if the BRA for the 2024/2025 Delivery has not occurred at least five (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 RPM or its successor or otherwise, and the Capacity Proxy Price for the 2024/2025 Delivery Year.

For EY 2026, if Supplement B to the BGS-RSCP Supplier Master Agreement is approved by the BPU and if the BRA for the 2025/2026 Delivery has not occurred at least five (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 RPM or its successor or otherwise, and the Capacity Proxy Price for the 2025/2026 Delivery Year.

ACE will file new tariff sheets for EY 2025 and EY 2026, reflecting the impact of this price adjustment in a manner similar to **Attachment 4**, page 1 – Development of Capacity Proxy Price True Up - $/MWh. The rate design spreadsheets include the formulas that will be used to reflect the impact of payments made pursuant to the Supplements. However, the spreadsheets do not provide a value for the EY 2025 and EY 2026 true-ups as the actual values are not known at this time. **Attachment 4**, pages 2 and 3 provide illustrative examples of how the Capacity Proxy Price True Up will be calculated for EY 2025 and EY 2026 respectively and prospectively.

The Supplements to the SMAs signed by BGS-RSCP Suppliers in February 2021 and February 2022 are still in effect for approximately two-thirds of the load for Energy Year 2024 (the year beginning June 1, 2023). Payments to BGS-RSCP suppliers that executed the Supplements to the SMAs approved by the BPU on November 18, 2020 and November 17, 2021 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 2023/2024 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, ACE 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 2021 and February 2022. The value of the recently conducted BRA in June of 2022 is used as an approximation for the price paid by BGS-RSCP Suppliers for Capacity in the Company's PJM Zone for the 2023/2024 Delivery Year ($49.59 per MW-Day).

The specific values that will be utilized for the BGS Supply Charges will be calculated as the tranche-weighted average of the winning BGS-RSCP bid prices for the ACE zone, adjusted for the seasonal payment factors for ACE's Atlantic Electric zone, adjusted by the appropriate factor (multiplier and constant, if applicable) as shown on Table No. 14 of the Development of Post Transition Period BGS Cost and Bid Factor Tables, included in **Attachment 2**.

It is the intent of ACE that the factors in the tables will be applied to the tranche-weighted average of the winning BGS-RSCP bid prices adjusted for the seasonal payment factors. For the period beginning June 1, 2023, the pricing will be based on the 36-month auction price, the 36-month price from the auction held in February 2022 and the 36-month price from the auction held in February 2021. The tables will be updated annually prior to future BGS auctions and will be utilized to develop customer charges for a related annual period in a similar manner as described above. The updates will reflect then current factors such as updated futures prices, factors based on 12-month data, and any changes in the customer groups and loads eligible for the BGS-RSCP class.

b. <u>BGS Reconciliation Charge</u>

This is the implementation of the BGS Reconciliation Charge for BGS-RSCP as explained in the Accounting and Cost Recovery section of this Addendum.

c. <u>Transmission Charges</u>

Transmission service will continue to be billed under the rates, terms, and conditions of the customer's applicable Rate Schedule as set forth in the ACE Tariff for Electric Service. The transmission charges applicable to ACE's BGS-RSCP customers are based on the annual transmission rate for network service for the ACE zone, as stated in PJM's Open Access Transmission Tariff ("OATT"). As part of a settlement approved by the Federal Energy Regulatory Commission ("FERC") on August 9, 2004, certain transmission owners in PJM, including ACE, agreed to re-examine their existing rates, and to propose a method (such as a formula rate) to harmonize new and existing transmission investments by January 31, 2005, with such new rate(s) (if any) to go into effect June 1, 2005. The objective of the formula rate filing is to establish a just and reasonable method for determining the transmission revenue requirements for the affected transmission pricing zones which would reflect both existing and new investment on a current basis. The formula rate tracks increases and decreases in costs such that no under- and no over-recovery of actual costs will occur. The formula rate protocols include provisions for an annual update to the rate based on current levels of costs and reconciliation of prior period costs and revenues. Pursuant to the protocols established in the settlement, the Company will file updates to the formula rate at FERC on or about May 15 of each year to be effective on June 1st of that same year. The Company will make corresponding filings with the Board each year seeking approval of the formula rates on a retail level.

In addition to the formula rate protocols described above, the transmission charge may change from time to time as FERC approves other changes in the PJM OATT and related charges. The transmission cost component of the BGS-RSCP charges to customers will change from time to time as FERC approves changes in the Network Integration Transmission Service rates for the ACE zone in the PJM OATT or FERC approves other network transmission-related charges in the PJM OATT.

ACE will provide the basis for any transmission cost adjustment, and will file supporting documentation from the OATT, as well as any rate translation spreadsheets used.

2. <u>BGS-CIEP</u>

BGS-CIEP will be the only default supply option available to customers served on Rate Schedule TGS (Transmission General Service), and to customers served on Rate Schedules MGS Secondary, MGS Secondary Electric Vehicle Charging, MGS Primary, AGS Secondary, and AGS Primary with a PLS of 500 kW and higher as of November 1 of the year prior to the BGS auctions. Additionally, BGS-CIEP is available on a voluntary basis to any commercial or industrial customer taking service under the MGS or AGS Rate Schedules. To be eligible for BGS-CIEP, the customer will need to notify ACE of its choice no later than the second working day of a given year and must commit to having BGS-CIEP as its default supply service option for a 12-month period commencing June 1st of that year. All commercial and industrial customers taking service under the MGS or AGS Rate Schedules will be notified of their option to switch to BGS-CIEP through the Company's website and tariffs. Customers who elected BGS-CIEP in a prior procurement period and who are eligible to receive BGS-RSCP service may return to BGS-RSCP if they notify ACE of their intent to return to BGS-RSCP default service no later than the second working day of January. Such election will be effective on June 1st of that year.

The charges for BGS-CIEP are comprised of three segments: BGS Energy Charges, BGS Capacity Charges, and the BGS Reconciliation Charges. Transmission service will continue to be billed under the rates, terms, and conditions of the customer's applicable Rate Schedule as set forth in the ACE Tariff for Electric Service. The transmission charges applicable to ACE's BGS-CIEP customers are based on the annual transmission rate for network service for the ACE zone, as stated in PJM's OATT. As part of a settlement approved by FERC on August 9, 2004, certain transmission owners in PJM, including ACE, agreed to re-examine their existing rates and to propose a method (such as a formula rate) to harmonize new and existing transmission investments by January 31, 2005, with such new rate (if any) to go into effect June 1, 2005. The objective of the formula rate filing is to establish a just and reasonable method for determining the transmission revenue requirements for the affected transmission pricing zones which would reflect both existing and new investment on a current basis. The formula rate tracks increases and decreases in costs such that no under- and no over-recovery of actual costs will occur. The formula rate protocols include provisions for an annual update to the rate based on current levels of costs, and reconciliation of prior period costs and revenues. Pursuant to the protocols established in the settlement, the Company will file updates to the formula rate at FERC on or about May 15 of each year, to be effective on June 1 of that year. The Company will make corresponding filings with the Board each year seeking approval of the formula rates on a retail level.

In addition to the formula rate protocols described above, the transmission charge may change from time to time as FERC approves other changes in the PJM OATT and related charges. The transmission cost component of the BGS-CIEP charges to customers will change from time to time as FERC approves changes in the Network Integration Transmission Service rates for the ACE zone in the PJM OATT or FERC approves other network transmission-related charges in the PJM OATT.

ACE will provide the basis for any transmission cost adjustment, and will file supporting documentation from the OATT, as well as any rate translation spreadsheets used.

a. BGS Energy Charge

One of the primary components of this charge will be the actual real time PJM load-weighted average Residual Metered Load Aggregate Locational Marginal Price ("LMP"), of energy for ACE's Atlantic Electric Transmission Zone. An estimate of the Ancillary Service cost for the ACE zone expressed on a dollar per MWh basis and administrative costs will be added to this charge. This sum will then be adjusted for losses for service according to the Rate Schedule for which this service is applicable.

b. BGS Capacity Charges

These charges will recover the costs associated with generation capacity. Effective with the supply period beginning June 1, 2009, the BGS Capacity Charge is based on the results of the BGS-CIEP auction process. This charge, Sales and Use Tax ("SUT"), and the Board Revenue Assessment will be applied to the customer's share of the PJM zonal capacity obligation.

c. BGS Reconciliation Charge

This is the BGS Reconciliation Charge for the BGS-CIEP service as explained in the Accounting and Cost Recovery section of this Addendum.

d. CIEP Standby Fee

For the period June 1, 2023 through May 31, 2024, the EDCs will pay each BGS-CIEP supplier a CIEP Standby Charge equal to $0.000150 per kWh times their pro-rata share of the total energy usage measured at the meters of all of ACE's BGS-CIEP eligible customers. The CIEP

Standby Fee is a delivery charge that is applicable to all customers having BGS-CIEP as their default supply service. This includes all customers served on Rate Schedules TGS, all customers served on Rate Schedules MGS Secondary, MGS Secondary Electric Vehicle Charging, MGS Primary, AGS Secondary, and AGS Primary with a peak load share of 500 kW or greater, and all customers on Rate Schedules MGS Secondary, MGS Secondary Electric Vehicle Charging, MGS Primary, AGS Secondary, and AGS Primary with a peak load share of less than 500 kW that have elected the BGS-CIEP default supply option. Any under- or over-recovery of the CIEP Standby Fee will continue to be subject to deferred accounting.

D. BGS RATE DESIGN METHODOLOGY

1. ACE BGS-RSCP Pricing Spreadsheet

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

Table No. 1 (% Usage During PJM On-Peak Period) contains the percentage of on-peak load, by month, for each applicable Rate Schedule. The on-peak period as used in this table (referred to as PJM periods) is defined as the 16-hour period from 7 A.M. to 11 P.M., Monday through Friday. All remaining weekday hours and all hours on weekends and holidays recognized by the National Electric Reliability Council (also known as 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 based on the most recent available settlement data for current ACE customers.

Table No. 2 (% Usage During ACE On-Peak Billing Period) contains the percentage of on- peak load, by month, for each applicable Rate Schedule based on the definitions of time periods as contained in ACE's delivery Rate Schedules. These percentages are based on usage history for the RS TOU BGS customers for the most recent period.

Table No. 3 (Class Usage @ Customer) contains the billing month sales forecasted for the period of June 2023 through May 2024, with migration adjustments. The values in Table No. 3 will be updated in January 2023 to better reflect forecasts for the June 1st delivery year.

Table No. 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 the energy on- peak forwards as of June 1, 2022, for the PJM West trading hub for the period of June 2023 to May 2024, as utilized in BGS market-to-market calculations, and the historical ratio of actual off-peak to on-peak PJM LMPs for the prior summer and winter periods. An adjustment of the forward prices contained in Table No. 4 must be made to correct for the pricing differential between the PJM West trading hub and the ACE zone where the BGS supply will be utilized.

Table No. 5 (Zone-Hub Basis Differential) contains an estimate of the average zone-hub basis differential factors, by month and time period, which, when multiplied by the prices at the PJM West trading hub, will result in costs for power delivered into the ACE zone.

Table No. 6 (Losses) contains the factors utilized for average system losses by Rate Schedule and voltage level. Loss factors are developed by including losses at the 500kV transmission level as well as losses at lower transmission and distribution voltage levels currently approved for use by the Board.

Table No. 7 (Summary of Average BGS Energy Unit Costs @ Customer – PJM Time Periods) is the calculation of the energy costs by rate, time period and season. These values are the seasonal and time period average costs per Megawatt hour ("MWh") as measured at the customer billing meter (from Table No. 3), based on the forwards prices (from Table No. 4), corrected for zone-hub basis differential (from Table No. 5), losses (from Table No. 6), and monthly time period weights (from Table No. 1). These average costs do not include the costs associated with Ancillary Services, RPS compliance or Generation Obligation costs, which will be considered in subsequent calculations.

Table No. 8 (Summary of Average BGS Energy Costs @ Customer – PJM Time Periods) indicates the total value, in thousands of dollars, of the average BGS energy costs. These are the results of the multiplication of the unit costs from Table No. 7, the monthly time period weights from Table No. 1, and the total sales to customers from Table No. 3. Since the end result of these calculations are to be utilized in the development of retail BGS rates, the rates utilizing time of day pricing must be developed based upon the time periods as defined for billing.

Table No. 9 (Summary of Average BGS Energy Unit Costs @ Customer – ACE Time Periods) shows the result of the corrections for the RS TOU BGS rate. These values are calculated based on the assumption that the MWhs included in the PJM on-peak time period and not included in the ACE on-peak time periods are at the average of the on- and off-peak PJM prices.

Table No. 10 (Generation Obligations and Costs and Other Adjustments) includes the values necessary for the inclusion of the costs of the Generation Capacity obligations. The top portion of Table No. 10 shows the total generation obligations with a migration adjustment, by applicable Rate Schedule, that are currently being utilized in the year 2022. Table No. 10 will be updated in January 2023, similar to Table No. 3. 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 seasonally differentiated average market price of generation capacity, using the relevant RPM auction result for Delivery Year 2023/2024, the Capacity Proxy Price for Delivery Year 2024/2025, and the Capacity Proxy Price for Delivery Year 2025/2026. The Capacity Proxy Price will be replaced with the Zonal Capacity Prices, which are the prices paid by BGS-RSCP Suppliers for Capacity for the 2024/2025 and the 2025/2026 Delivery Years when available as may be determined through the RPM or its successor or otherwise.

Table No. 11 (Ancillary Services and RPS) contains an estimate of the effects of the costs of ancillary services and RPS. The values of $2.00 per MWh and $17.21 per MWh are used, respectively. Since the actual costs are a complex combination of many factors, an estimate of the overall annual average value, expressed on a dollar per MWh basis, is used as a reasonable and practical alternative.

Table No. 12 (Summary of Obligation Costs Expressed as $/MWh @ Customer) shows the result of the allocation of the generation costs, on a per MWh basis, to all Rate Schedules. For RS TOU BGS, the per MWh Generation Capacity Obligation Costs are based on the on-peak usage only.

Table No. 13 (Summary of BGS Unit Costs @ Customer) is the result of the inclusion of the generation capacity, Ancillary Services, and RPS costs to the energy only costs shown in Table No. 9. This table shows the total estimated costs for BGS, based on the assumptions utilized in the above tables, and the average per unit cost, as measured at the customer meters or the bulk system meters.

Table No. 14 (Ratio of BGS Unit Costs @ Customer to Average Cost @ transmission nodes) indicates the ratio of the individual rate element costs from Table No. 13 to the overall cost as measured at the transmission nodes, plus constants, where applicable.

Table No. 15 (Summary of Total BGS Costs by Season) shows the calculation of the total BGS Costs, utilizing the total customer usage from Table No. 3 and the BGS unit costs from Table No. 13. The lower left portion of the table indicates the relative percentage of total costs by season for all Rate Schedules, while the center shows the calculation of the overall average seasonal unit costs on a dollar per MWh basis. The ratio of these overall average seasonal costs to the overall total cost, shown in the lower right-hand portion of Table No. 15, are the seasonal payment ratios upon which payments to the winning bidders are based. The final section summarizes some of the most important assumptions utilized in the above calculations.

Table No. 16 (Retail Rates Charged to BGS-RSCP Customers), shows the calculation of retail rates to be charged to the BGS-RSCP customers for their BGS services. This table utilizes the information computed in Table No. 14 (Ratio of BGS Unit Costs) and applies the applicable ratios for each rate class to the BGS average price which, in turn, is based on the weighted average winning bids . The upper left portion of this table provides the BGS average price.

Table No. 17 (Retail Rates Charged to BGS-RSCP Customers Including Revenue Assessment and SUT), shows the BGS-RSCP customer rates inclusive of the BPU and Division of Rate Counsel revenue assessments, as well as SUT. This table utilizes the information provided in Table No. 16 and applies the applicable revenue assessment factor and SUT rate to derive the tax effected BGS-RSCP customer's rates.

The second spreadsheet used in the calculation of the final BGS-RSCP rates is included as **Attachment 3** and is titled "Calculation of June 2023 to May 2024 BGS-RSCP Rates." The tables in this spreadsheet calculate the weighted average winning bid price and convert it into the final BGS-RSCP rates that are charged to customers. An explanation of each of the six tables, labeled as Tables A through F, is as follows:

Table A (Auction Results) contains the results of the 2021/2022 BGS auction, the results of the 2022/2023 BGS auction, and the results of the current auction. The Capacity Proxy Price True Up cost in $ per MWh will be used to reflect the impact of payments made pursuant to the Supplements executed by BGS Suppliers in February 2021 and February 2022. Upon conclusion of the Third Incremental RPM Auction through the RPM 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 2023/2024 Delivery Year. The value of the recently concluded BRA in June of 2022 is used as an approximation of the price paid by BGS-RSCP Suppliers for Capacity in the Company's PJM Zone for 2023/2024. From these values, the weighted average annual bid price (shown on line 13) is calculated. All of the formulas used in this table are shown in the right-hand column of this table, under the heading "Notes."

Table B (Ratio of BGS Unit Costs @ Customer to Average Cost @ transmission nodes) is a repeat of the values shown in Table No. 14 from **Attachment 2**, the bid factors calculated based on current market conditions.

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

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

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

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

E. <u>CONCLUSION</u>

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

1. it is necessary and in the public interest for the electric public utilities to secure service for the BGS-RSCP and BGS-CIEP customers, as approved herein, for the period June 1, 2023 to May 31, 2026;
2. the Company's proposed accounting for BGS is approved for purposes of accounting and BGS cost recovery;

3. the proposed BGS Contingency Plan is approved, and there will exist a presumption of prudence with respect to the BGS Auction Plan method and the costs incurred for BGS service under the Auction Plan and the related Contingency Plan; and
4. the Company’s Rate Design Methodology and Tariff Sheets are approved.

Attachment 1

ATLANTIC CITY ELECTRIC COMPANY
BPU NJ No. 11 Electric Service - Section IV Revised Sheet Replaces Revised Sheet No. 60

RIDER (BGS)
Basic Generation Service (BGS)

Basic Generation Service (BGS) will be arranged for any customer taking service under Electric Rate Schedules RS, MGS Secondary, MGS-SEVC, MGS Primary, AGS Secondary, AGS Primary, TGS, DDC, SPL, and CSL who has not notified the Company of an Alternative Electric Supplier choice. BGS is also available to customers whose arrangements with Alternative Electric Suppliers have terminated for any reason, including nonpayment.

BGS is offered under two different terms of service; Basic Generation Service-Residential Small Commercial Pricing (BGS-RSCP) and Basic Generation Service -Commercial and Industrial Energy Pricing (BGS-CIEP). BGS-RSCP is offered to customers on Rate Schedules RS, DDC, SPL and CSL. BGS-RSCP is also offered to customers on Rate Schedules MGS Secondary, MGS-SEVC, MGS Primary, AGS Secondary, AGS Primary with an annual peak load share (“PLS”) for generation capacity of less than 500 kW as of November 1 or each year. Additionally, BGS customers on Rate Schedule RS have the option of taking BGS-RSCP on a time of use basis.

BGS customers on Rate Schedule TGS and BGS customers on Rate Schedules MGS Secondary, MGS-SEVC, MGS Primary, AGS Secondary or AGS Primary with a PLS for generation capacity equal to or greater than 500 kW as of November 1 of each year are required to take service under BGS-CIEP.

Customers on Rate Schedules MGS Secondary, MGS-SEVC, MGS Primary, AGS Secondary or AGS Primary with a PLS of less than 500 kW, have the option of taking either BGS-RSCP or BGS-CIEP service. Customers who elect BGS-CIEP must notify the Company of their selection no later than the second working day of January of the year they wish to begin BGS-CIEP service. Such election will be effective on June 1 of that year and remain as the customer’s default supply for the following twelve months. Customers electing BGS-CIEP as their default supply in a prior procurement period and who are otherwise eligible to return to BGS-RSCP may return to BGS RSCP by notifying the Company no later than the second working day of January of the year that they wish to return to BGS-RSCP service. Such election shall be effective on June 1 of that year.

BGS-RSCP Supply Charges ($/kWh):	SUMMER	WINTER
Rate Schedule	June Through September	October Through May
RS		$ x.xxxxxx
<=750 kwhs summer	$ x.xxxxxx	
> 750 kwh summer	$ x.xxxxxx	
RS TOU BGS Option		
On Peak (See Note 1)	$ x.xxxxxx	$ x.xxxxxx
Off Peak (See Note 1)	$ x.xxxxxx	$ x.xxxxxx
MGS-Secondary and MGS-SEVC	$ x.xxxxxx	$ x.xxxxxx
MGS-Primary	$ x.xxxxxx	$ x.xxxxxx
AGS-Secondary	$ x.xxxxxx	$ x.xxxxxx
AGS-Primary	$ x.xxxxxx	$ x.xxxxxx
DDC	$ x.xxxxxx	$ x.xxxxxx
SPL/CSL	$ x.xxxxxx	$ x.xxxxxx

Note 1: On Peak hours are considered to be 8:00 AM to 8:00 PM, Monday through Friday.

The above Basic Generation Service Energy Charges reflect costs for Energy, Generation Capacity, Ancillary Services and Administrative Charges pursuant to N.J.S.A. 48:2-60 plus New Jersey Sales and Use Tax as set forth in Rider SUT.

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ATLANTIC CITY ELECTRIC COMPANY
BPU NJ No. 11 Electric Service - Section IV Revised Sheet Replaces Revised Sheet No. 60a

RIDER (BGS) continued
Basic Generation Service (BGS)

BGS Reconciliation Charge ($/kWh):

The above charge shall recover the difference between the monthly amount paid to Basic Generation Service (BGS) suppliers and the total revenue from customers for BGS for the preceding months for the applicable BGS supply. These charges include New Jersey Sales and Use Tax as set forth in Rider SUT and are changed on June 1 and October 1 of each year.

Rate Schedule	Charge ($ per kWh)
RS	$ 0.001710
MGS Secondary, MGS-SEVC, AGS Secondary, SPL/CSL, DDC	$ 0.001710
MGS Primary, AGS Primary	$ 0.001665

BGS-CIEP

Energy Charges

BGS Energy Charges for Rate Schedule TGS, AGS and MGS customers with a Peak Load Share (PLS) of 500 kW or more, and AGS and MGS customers with a PLS of less than 500 kW who have elected BGS-CIEP are hourly and are provided at the real time PJM Load Weighted Average Residual Metered Load Aggregate Locational Marginal Prices for the Atlantic Electric Transmission Zone, adjusted for losses, plus administrative charges pursuant to N.J.S.A. 48:2-60 and New Jersey Sales and Use Tax as set forth in Rider SUT.

Generation Capacity Obligation Charge

	Summer	Winter
Charge per kilowatt of Generation Obligation ($ per kW per day)	$x.xxxxxx	$x.xxxxxx

This charge is equal to the winning bid price from the BGS-CIEP default service auction plus administrative charges pursuant to N.J.S.A. 48:2-60 and New Jersey Sales and Use Tax as set forth in Rider SUT. The above charge shall be applied to each customer's annual peak load share ("PLS") for generation capacity, adjusted for the applicable PJM-determined Zonal Scaling Factor and the applicable PJM-determined capacity reserve margin factor, on a daily basis for each day in each customer's respective billing cycle.

Ancillary Service Charge

	Charge ($ per kWh)
Service taken at Secondary Voltage	$ x.xxxxxx
Service taken at Primary Voltage	$ x.xxxxxx
Service taken at Sub-Transmission Voltage	$ x.xxxxxx
Service taken at Transmission Voltage	$ x.xxxxxx

This charge represents the average annual cost of Ancillary Services in the Atlantic Electric Transmission zone adjusted for losses, plus administrative charges pursuant to N.J.S.A. 48:2-60 and New Jersey Sales and Use Tax as set forth in Rider SUT.

BGS Reconciliation Charge:

	Charge ($ per kWh)
Service taken at Secondary Voltage	$ 0.013106
Service taken at Primary Voltage	$ 0.012763
Service taken at Sub-Transmission Voltage	$ 0.012618
Service taken at Transmission Voltage	$ 0.012495

The above charge shall recover the difference between the monthly amount paid to Basic Generation Service (BGS) suppliers and the total revenue from customers for BGS for the preceding months for the applicable BGS supply. These charges include administrative charges pursuant to N.J.S.A. 48:2-60 and New Jersey Sales and Use Tax as set forth in Rider SUT and are changed on June 1 and October 1 of each year.

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BPU NJ No. 11 Electric Service - Section IV Revised Sheet Replaces Revised Sheet No. 60b

RIDER (BGS) continued
Basic Generation Service (BGS)

CIEP Standby Fee $x.xxxxxx per kWh

This charge recovers the costs associated with the winning BGS-CIEP bidders maintaining the availability of the hourly priced default electric supply service plus administrative charges pursuant to N.J.S.A. 48:2-60 and New Jersey Sales and Use Tax as set forth in Rider SUT. This charge is assessed on all kWhs delivered to all CIEP- eligible customers on Rate Schedules MGS Secondary, MGS-SEVC, MGS Primary, AGS Secondary, AGS Primary or TGS.

Transmission Enhancement Charge

This charge reflects Transmission Enhancement Charges ("TECs"), implemented to compensate transmission owners for the annual transmission revenue requirements for "Required Transmission Enhancements" (as defined in Schedule 12 of the PJM OATT) that are requested by PJM for reliability or economic purposes and approved by the Federal Energy Regulatory Commission (FERC). The TEC charge (in $ per kWh by Rate Schedule), including administrative charges pursuant to N.J.S.A. 48:2-60 and New Jersey Sales and Use Tax as set forth in Rider SUT, is delineated in the following table.

Rate Class

	RS	MGS Secondary And MGS-SEVC	MGS Primary	AGS Secondary	AGS Primary	TGS	SPL/ CSL	DDC
VEPCo	0.000367	0.000278	0.000256	0.000179	0.000156	0.000133	-	0.000114
TrAILCo	0.000300	0.000250	0.000170	0.000173	0.000138	0.000101	-	0.000104
PSE&G	0.003256	0.002478	0.002276	0.001591	0.001385	0.001184	-	0.001018
PATH	0.000010	0.000007	0.000006	0.000004	0.000004	0.000003	-	0.000003
PPL	0.000090	0.000068	0.000063	0.000044	0.000038	0.000033	-	0.000028
PECO	0.000211	0.000175	0.000119	0.000123	0.000097	0.000071	-	0.000074
Pepco	0.000021	0.000018	0.000013	0.000013	0.000010	0.000007	-	0.000007
MAIT	0.000042	0.000032	0.000029	0.000020	0.000018	0.000015	-	0.000013
JCP&L	0.000003	0.000002	0.000002	0.000001	0.000001	0.000001	-	0.000001
EL05-121	0.000019	0.000015	0.000013	0.000010	0.000009	0.000006	-	0.000006
Delmarva	0.000009	0.000007	0.000005	0.000005	0.000004	0.000003	-	0.000003
BG&E	0.000049	0.000041	0.000028	0.000029	0.000022	0.000017	-	0.000017
AEP-East	0.000081	0.000062	0.000057	0.000039	0.000034	0.000030	-	0.000026
Silver Run	0.000325	0.000247	0.000227	0.000159	0.000139	0.000118	-	0.000101
NIPSCO	0.000003	0.000002	0.000002	0.000002	0.000001	0.000001	-	0.000001
CW Edison	-	-	-	-	-	-	-	-
ER18-680 & Form 715	-	-	-	-	-	-	-	-
SFC	0.000004	0.000003	0.000003	0.000002	0.000002	0.000002	-	0.000001
PSEG ROE-TEC	(0.000112)	(0.000094)	(0.000064)	(0.000065)	(0.000052)	(0.000038)	-	(0.000039)
Total	0.004678	0.003591	0.003205	0.002329	0.002006	0.001687	-	0.001478

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Attachment 2

Table #1 **% usage during PJM On-Peak period**
(data rounded to nearest %)

On-Peak periods defined as the 16 hr PJM Trading period, adj for NERC holidays

	RS	RS TOU - BGS	MGS - SEC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC
January	51.64%	51.71%	52.70%	51.94%	52.47%	51.34%	40.37%	51.60%
February	51.87%	51.99%	53.12%	51.00%	51.96%	50.37%	37.23%	50.79%
March	52.03%	52.12%	57.55%	51.73%	54.24%	51.96%	35.77%	52.56%
April	51.53%	51.70%	52.64%	49.23%	52.82%	49.61%	30.29%	49.56%
May	52.00%	52.59%	53.03%	50.87%	52.26%	49.98%	27.24%	49.82%
June	58.04%	58.01%	59.05%	56.01%	56.96%	54.36%	27.10%	53.58%
July	59.79%	59.99%	58.50%	55.52%	57.13%	54.14%	26.84%	53.15%
August	60.56%	60.82%	63.24%	57.36%	59.54%	56.25%	31.08%	55.15%
September	52.39%	52.64%	57.90%	51.65%	56.06%	52.24%	34.15%	52.27%
October	55.11%	55.33%	57.55%	54.00%	57.62%	54.96%	38.77%	53.66%
November	45.69%	45.45%	50.47%	46.61%	51.14%	48.32%	36.66%	47.50%
December	49.30%	49.30%	53.51%	49.63%	51.78%	49.69%	38.51%	48.51%

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

	RS TOU - BGS
January	36.02%
February	36.22%
March	33.73%
April	34.03%
May	36.44%
June	41.14%
July	44.43%
August	44.21%
September	36.43%
October	37.58%
November	30.36%
December	33.64%

Table #3 **Class Usage @ customer**
calendar month sales forecasted for period
in MWh

	RS	RS TOU - BGS	MGS - SEC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC	Total
Jan-24	356,017	201	70,298	2,182	64,084	4,973	4,821	837	503,413
Feb-24	311,491	176	69,511	2,011	66,513	6,479	4,402	831	461,414
Mar-24	294,525	166	69,429	1,778	64,393	5,311	4,377	823	440,802
Apr-24	220,582	124	62,857	1,671	57,713	4,543	3,869	743	352,103
May-24	207,181	117	65,725	2,338	61,140	5,036	3,686	766	345,988
Jun-23	284,433	160	80,994	2,345	70,765	5,662	3,759	918	449,036
Jul-23	439,531	248	89,323	2,554	81,014	4,835	4,006	1,014	622,525
Aug-23	509,610	287	91,891	2,000	80,005	4,845	4,298	1,048	693,985
Sep-23	423,352	239	84,455	2,180	76,381	4,581	4,396	981	596,565
Oct-23	309,250	174	77,008	2,104	69,442	4,649	4,523	908	468,058
Nov-23	251,309	142	73,207	2,103	64,647	4,719	4,824	872	401,822
Dec-23	295,228	166	73,994	1,993	68,006	3,888	4,863	875	449,013
Total	3,902,508	2,199	908,692	25,259	824,103	59,522	51,824	10,618	5,784,724

Table #4 **Forwards Prices - Energy Only @ bulk system**
($/MWH)

	On-Peak	Off/On Pk LMP ratio	Off-Peak
Jan-24	112.50	0.785	88.26
Feb-24	105.90	0.785	83.08
Mar-24	65.00	0.785	51.00
Apr-24	48.15	0.785	37.78
May-24	48.25	0.785	37.85
Jun-23	64.60	0.668	43.17
Jul-23	81.60	0.668	54.52
Aug-23	76.50	0.668	51.12
Sep-23	64.90	0.668	43.37
Oct-23	56.45	0.785	44.29
Nov-23	57.25	0.785	44.91
Dec-23	70.00	0.785	54.92

Table #5 **Zone-Hub Basis Differential** **'Based on 3 Year Average**

	On-Peak	Off-Peak
Jan-24	83%	88%
Feb-24	83%	88%
Mar-24	83%	88%
Apr-24	83%	88%
May-24	83%	88%
Jun-23	86%	90%
Jul-23	86%	90%
Aug-23	86%	90%
Sep-23	86%	90%
Oct-23	83%	88%
Nov-23	83%	88%
Dec-23	83%	88%

Table #6

Losses	**RS**	**RS TOU - BGS**	**MGS - SEC**	**MGS - PRI**	**AGS - SEC**	**AGS - PRI**	**SPL/CSL**	**DDC**
Delivery Loss Factor	6.6720%	6.6720%	6.6720%	4.1641%	6.6720%	4.1641%	6.6720%	6.6720%
Loss Factors + EHV Losses =	7.0688%	7.0688%	7.0688%	4.5715%	7.0688%	4.5715%	7.0688%	7.0688%
Expansion Factor =	1.07606	1.07606	1.07606	1.04790	1.07606	1.04790	1.07606	1.07606
Marginal Loss Factor (w/ EHV Losses) =	1.7299%	1.7299%	1.7299%	1.7299%	1.7299%	1.7299%	1.7299%	1.7299%
Loss Factor w/o Marginal Loss =	5.4329%	5.4329%	5.4329%	2.8916%	5.4329%	2.8916%	5.4329%	5.4329%
Expansion Factor w/o Marginal Loss =	1.05745	1.05745	1.05745	1.02978	1.05745	1.02978	1.05745	1.05745

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

	RS	**RS TOU - BGS**	**MGS - SEC**	**MGS - PRI**	**AGS - SEC**	**AGS - PRI**	**SPL/CSL**	**DDC**
Summer - all hrs	$ 58.77	$ 58.81	$ 58.59	$ 56.07	$ 58.16	$ 55.61	$ 52.46	$ 57.34
On Peak	$ 67.42	$ 67.42	$ 66.62	$ 64.80	$ 66.64	$ 64.42	$ 66.00	$ 66.56
Off Peak	$ 46.90	$ 46.89	$ 46.68	$ 45.35	$ 46.71	$ 45.15	$ 46.67	$ 46.70
Winter - all hrs	$ 60.25	$ 60.26	$ 58.05	$ 56.40	$ 58.14	$ 57.46	$ 57.05	$ 57.83
On Peak	$ 65.42	$ 65.40	$ 62.58	$ 61.43	$ 62.70	$ 62.42	$ 64.94	$ 62.97
Off Peak	$ 54.81	$ 54.83	$ 52.77	$ 51.23	$ 52.98	$ 52.35	$ 52.62	$ 52.59
Annual	$ 59.62	$ 59.64	$ 58.26	$ 56.28	$ 58.15	$ 56.84	$ 55.59	$ 57.65

System Average Cost @ customer - (limited to classes shown above) = $ 59.11

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

		RS	**RS TOU - BGS**	**MGS - SEC**	**MGS - PRI**	**AGS - SEC**	**AGS - PRI**	**SPL/CSL**	**DDC**
Summer - all hrs		$ 97,373	$ 55	$ 20,312	$ 509	$ 17,923	$ 1,108	$ 863	$ 227
	PJM on pk	$ 64,608	$ 37	$ 13,797	$ 324	$ 11,799	$ 697	$ 325	$ 141
	PJM off pk	$ 32,765	$ 18	$ 6,515	$ 185	$ 6,124	$ 411	$ 538	$ 86
Winter - all hrs		$ 135,294	$ 76	$ 32,628	$ 913	$ 29,996	$ 2,275	$ 2,018	$ 385
	PJM on pk	$ 75,291	$ 43	$ 18,945	$ 504	$ 17,169	$ 1,256	$ 826	$ 212
	PJM off pk	$ 60,003	$ 34	$ 13,684	$ 409	$ 12,827	$ 1,020	$ 1,192	$ 173
Annual		$ 232,667	$ 131	$ 52,941	$ 1,422	$ 47,919	$ 3,383	$ 2,881	$ 612

System Total $ 341,956

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

		RS	RS TOU - BGS	MGS - SEC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC
Summer - all hrs		$ 58.77	$ 58.81	$ 58.59	$ 56.07	$ 58.16	$ 55.61	$ 52.46	$ 57.34
	ACECO On pk		$ 71.43						
	ACECO Off pk		$ 49.76						
Winter - all hrs		$ 60.25	$ 60.26	$ 58.05	$ 56.40	$ 58.14	$ 57.46	$ 57.05	$ 57.83
	ACECO On pk		$ 67.91						
	ACECO Off pk		$ 56.17						
Annual Average		$ 59.62	$ 59.64	$ 58.26	$ 56.28	$ 58.15	$ 56.84	$ 55.59	$ 57.65
System Average		$ 59.11							

Table #10 **Generation Obligations and Costs and Other Adjustments**
obligations - values effective June 2022; costs are market estimates

in MW	RS	RS TOU - BGS	MGS - SEC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC	Total
Gen Load - MW	1,266.5	0.5	270.7	5.3	179.5	10.2	0.0	1.4	1,734.0
Gen Obl - MW	1,494.9	0.6	319.6	6.2	211.8	12.0	0.0	1.7	2,046.7

# of Months and Days used in this analysis

# of summer days =	122	# of summer months =	4
# of winter days =	244	# of winter months =	8
		total # months =	12

Generation Capacity Cost

	Base Capacity			
Summer	$53.53 $/MW/day		Summer Total	$ 13,366,439
Winter	$53.53 $/MW/day		Winter Total	$ 26,732,877
			Annual Total	$ 40,099,316

Residential Inversion Determination

---------- **Rate RS** ----------

	Charges	% usage		
Block 1 (0-750 kWh/m)	5.480200	62.96%	SUM 'First 750 KWh	1,168,949,487
Block 2 (>750 kWh/m)	6.345400	37.04%	SUM '> 750 KWh	687,639,380
Calculated inversion =	0.865200		WIN	2,243,087,584
				4,099,676,451

Table #11 **Ancillary Services & Renewable Power Cost (forecasted overall annual average)**

Ancillary Services	$ 2.00
Renewable Power Cost	$ 17.21
Total Ancillary Services & Renewable Power Costs	$ 19.21

Table #12 **Summary of Obligation Costs expressed as $/MWh @ customer**

	RS	RS TOU - BGS	MGS - SEC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC
Generation Obl -								
per annual MWh	$ 7.50	$ 13.06	$ 6.89	$ 4.82	$ 5.04	$ 3.97	$ -	$ 3.07
recovery per summer MWh	$ 5.89	$ 9.28	$ 6.02	$ 4.47	$ 4.49	$ 3.95	$ -	$ 2.74
recovery per winter MWh	$ 8.69	$ 16.40	$ 7.43	$ 5.02	$ 5.36	$ 3.97	$ -	$ 3.27

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

Includes energy, Generation capacity obligations, Ancillary Services, and Renewable Power Costs - unadjusted for billing vs. PJM time period differences.
in $/MWh

	RS	RS TOU - BGS	MGS - SEC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC
Summer - all hrs	$ 85.33	$ 88.75	$ 85.28	$ 80.68	$ 83.32	$ 79.69	$ 73.13	$ 80.75
On-Peak		$ 101.37						
Off-Peak		$ 70.43						
Block 1 (0-750 kWh/m)	$ 82.13							
Block 2 (>750 kWh/m)	$ 90.78							
Winter - all hrs	$ 89.61	$ 97.33	$ 86.15	$ 81.55	$ 84.17	$ 81.57	$ 77.72	$ 81.77
On-Peak		$ 104.98						
Off-Peak		$ 76.84						
Annual	$ 87.80	$ 85.25	$ 85.82	$ 81.23	$ 83.85	$ 80.94	$ 76.26	$ 81.39

Grand Total Cost in $1000 = $ 501,587

Average cost for rates shown (@ customer) = $ 86.71
Average costs for rates shown (@ transmission nodes) = $ 82.03

Table #14 **Ratio of BGS Unit Costs @ customer to Average Cost @ transmission nodes (rounded to 3 decimal places)**

Includes energy, Generation capacity obligations, Ancillary Services, and Renewable Power Costs - unadjusted for billing vs. PJM time period differences.

	RS	RS TOU - BGS	MGS - SEC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC
Summer - all hrs		**1.082**	**1.040**	**0.983**	**1.016**	**0.971**	**0.892**	**0.984**
On-Peak		**1.236**						
Off-Peak		**0.859**						
All usage Multiplier	**1.040**							
Constant	**$ (3.20)**		for Block 1 (0-750 kWh/m) usage					
Constant	**$ 5.45**		for Block 2 (>750 kWh/m) usage					
Winter - all hrs	**1.092**	**1.187**	**1.050**	**0.994**	**1.026**	**0.994**	**0.947**	**0.997**
On-Peak		**1.280**						
Off-Peak		**0.937**						
Annual	**1.070**	**1.039**	**1.046**	**0.990**	**1.022**	**0.987**	**0.930**	**0.992**

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

	RS	RS TOU - BGS	MGS - SEC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC
Total Costs by Rate - in $1000								
Summer	$ 141,386	$ 83	$ 29,565	$ 732	$ 25,676	$ 1,588	$ 1,204	$ 320
Winter	$ 201,238	$ 123	$ 48,420	$ 1,319	$ 43,428	$ 3,230	$ 2,749	$ 544
Total	$ 342,624	$ 206	$ 77,985	$ 2,052	$ 69,104	$ 4,818	$ 3,952	$ 864
% of Annual Total $ by Rate								
Summer	41%	40%	38%	36%	37%	33%	30%	37%
Winter	59%	60%	62%	64%	63%	67%	70%	63%

Total Costs - in $1000

Summer	$ 200,554
Winter	$ 301,051
Total	$ 501,605

% of Annual Total $ — If total $ were split on a per MWh basis (on bulk system MWhs):

Summer	40%	$ 80.32 per MWh @ trans nodes	Ratio to BGS Cost	>>>	Summer	**1.0000**
Winter	60%	$ 83.22 per MWh @ trans nodes	(rounded to 4 decimal places)		Winter	**1.0000**

Assumptions:

Gen Cost = $53.53 per MW-day summer
= $53.53 per MW-day winter
Ancillary Services = $ 2.00 per MWH
Renewable Power Cost = $ 17.21 per MWH
Energy Prices = Quotes for the period June 1, 2023 to May 31, 2024 - corrected for hub-zone basis differential.
Usage patterns = forecasted energy use by class, on/off % from class load profiles
Obligations = class totals as of June 2022
Losses = existing approved loss factors
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

Table #16 **Retail Rates Charged to BGS RSCP (Previously "FP") Customers**
Includes energy, Generation Obligations, Ancillary Services, and Renewable Power Costs
in $/MWh

BGS Avg. Price >>>>>>>>>>> $ 65.503

		RS	RS TOU - BGS	MGS - SEC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC
Summer - all hrs			$ 72.391	$ 69.581	$ 65.767	$ 67.975	$ 64.965	$ 59.679	$ 65.834
	On-Peak		$ 82.694						
	Off-Peak		$ 57.471						
	Block 1 (0-750 kWh/m)	$ 66.308							
	Block 2 (>750 kWh/m)	$ 75.145							
Winter - all hrs		$ 70.536	$ 76.672	$ 67.823	$ 64.206	$ 66.273	$ 64.206	$ 61.170	$ 64.399
	On-Peak		$ 82.679						
	Off-Peak		$ 60.524						
Annual		$ 70.088	$ 68.058	$ 68.516	$ 64.848	$ 66.944	$ 64.651	$ 60.918	$ 64.979

Table #17 **Retail Rates Charged to BGS RSCP Customers including Revenue Assessment and SUT**
Includes energy, Generation Obligations, Ancillary Services, and Renewable Power Costs
in $/kWh

Revenue Assessment Factor 1.003023015
(BPU, RC Assessments)

		RS	RS TOU - BGS	MGS - SEC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC
Summer - all hrs				$ 0.074415	$ 0.070336	$ 0.072698	$ 0.069478	$ 0.063825	$ 0.070408
	On-Peak		$ 0.088439						
	Off-Peak		$ 0.061464						
	Block 1 (0-750 kWh/m)	$ 0.070914							
	Block 2 (>750 kWh/m)	$ 0.080366							
Winter - all hrs		$ 0.075436		$ 0.072535	$ 0.068666	$ 0.070877	$ 0.068666	$ 0.065419	$ 0.068873
	On-Peak		$ 0.088423						
	Off-Peak		$ 0.064729						
Annual		$ 0.074957	$ 0.072786	$ 0.073276	$ 0.069353	$ 0.071595	$ 0.069143	$ 0.065150	$ 0.069493

Attachment 3

Atlantic City Electric Company
Calculation of June 2023 to May 2024 BGS-RSCP Rates
based on results of February 2023 BGS RSCP Auction

Table A **Auction Results**

line #	**Payment Identifier >>**	*remaining portion of 36 month bid - 2021/22 filing*	*remaining portion of 36 month bid - 2022/23 filing*	*36 month bid - 2023/24 filing*	*Notes:*
1	Winning Bid - in $/MWh	$ 64.20	$ 75.57	$ 75.57	winning Bids
1A	Capacity Proxy Price True-Up - in $/MWh	$ (11.87)	$ (8.40)		entered after 2023 BGS Auction
1B	Total - in $/Mwh	$ 52.33	$ 67.17	$ 75.57	= line 1 + line 1A
2	# of Tranches for Bid	7	7	8	from then current Bid
3	Total # of Tranches	22	22	22	from then current Bid
	Payment Factors				
4	Summer	1.0000	1.0000	1.0000	from then current Bid Factor Spreadsheet
5	Winter	1.0000	1.0000	1.0000	from then current Bid Factor Spreadsheet
	Applicable Customer Usage @ bulk system - in MWh				
6	Summer MWh	2,497,012			from current Bid Factor Spreadsheet
7	Winter MWh	3,617,699			
	Total Payment to Suppliers - in $1000				
8	Summer	$ 41,576	$ 53,367	$ 68,618	= (1 + 1A) * (2)/(3) * (4) * (6) / 1000
9	Winter	$ 60,236	$ 77,318	$ 99,414	= (1 + 1A) * (2)/(3) * (5) * (7) / 1000
10	Total	$ 101,813	$ 130,685	$ 168,032	
	Average Payment to Suppliers - in $/MWh				
11	Summer	$ 65.50			= sum(line 8) / (6) - rounded to 2 decimal places
12	Winter	$ 65.50			= sum(line 9) / (7) - rounded to 2 decimal places
13	Total weighted average	**$ 65.50**	<<< used in calculation of Customer Rates		= sum(line 10) / [(6) + (7)] rounded to 2 decimal places
	Reconciliation of amounts - in $1000				
14	Weighted avg * Total MWh =	$ 400,532			= (13) * [(6)+(7)] / 1000
15	Total Payment to Suppliers =	$ 400,530			= sum (line 10)
16	Difference =	$ 2			= line (14) - line (15)

Atlantic City Electric Company
Calculation of June 2023 to May 2024 BGS-RSCP Rates
based on results of February 2023 BGS RSCP Auction

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

from Table #14 of the bid factor spreadsheet --- round to 3 decimal places

includes energy, G obligations, Ancillary Services, and Renewable Power Cost - adjusted to billing time periods

		RS	RS TOU - BGS	MGS - SEC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC
Summer - all hrs			**1.082**	**1.040**	**0.983**	**1.016**	**0.971**	**0.892**	**0.984**
	On-Peak		**1.236**						
	Off-Peak		**0.859**						
	All usage Multiplier	**1.040**							
	Constant	**(3.205)**		for Block 1 (0-750 kWh/m) usage					
	Constant	**5.447**		for Block 2 (>750 kWh/m) usage					
Winter - all hrs		**1.092**	**1.187**	**1.050**	**0.994**	**1.026**	**0.994**	**0.947**	**0.997**
	On-Peak		**1.280**						
	Off-Peak		**0.937**						
Annual - all hrs		**1.070**	**1.039**	**1.046**	**0.990**	**1.022**	**0.987**	**0.930**	**0.992**

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

includes energy, G obligations, Ancillary Services, and Renewable Power Cost - adjusted to billing time periods

		RS	RS TOU - BGS	MGS - SEC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC
Summer - all hrs			***7.0874***	***6.8123***	***6.4389***	***6.6551***	***6.3603***	***5.8429***	***6.4455***
	On-Peak		***8.0962***						
	Off-Peak		***5.6267***						
for Block 1 (0-750 kWh/m) usage		***6.4919***							
for Block 2 (>750 kWh/m) usage		***7.3571***							
Winter - all hrs		***7.1529***	***7.7752***	***6.8778***	***6.5110***	***6.7206***	***6.5110***	***6.2031***	***6.5306***
	On-Peak		***8.3844***						
	Off-Peak		***6.1376***						

Atlantic City Electric Company
Calculation of June 2023 to May 2024 BGS-RSCP Rates
based on results of February 2023 BGS RSCP Auction

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

	RS	RS TOU - BGS	MGS - SEC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC
Total Rate Revenue - in $1000								
Summer	$ 112,876	$ 66	$ 23,616	$ 585	$ 20,509	$ 1,267	$ 962	$ 255
Winter	$ 160,624	$ 92	$ 38,655	$ 1,053	$ 34,674	$ 2,578	$ 2,194	$ 435
Total	$ 273,500	$ 158	$ 62,271	$ 1,638	$ 55,183	$ 3,845	$ 3,155	$ 690

Total Summer	$ 160,135
Total Winter	$ 240,306
Grand Total	$ 400,441

Total Supplier Payment - in $1000	
Summer	$ 163,561
Winter	$ 236,969
Total	$ 400,530
Differences - in $1000	
Summer	$ 3,426
Winter	$ (3,337)
Total	$ 90

kWh Rate Adjustment Factors	*rounded to 5 decimal places*
1.02140	
0.98611	

% difference
2.0948%
-1.4081%
0.0223%

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

Atlantic City Electric Company
Calculation of June 2023 to May 2024 BGS-RSCP Rates
based on results of February 2023 BGS RSCP Auction

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

includes energy, G obligations, Ancillary Services, and Renewable Power Cost - adjusted to billing time periods

		RS	RS TOU - BGS	MGS - SEC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC
Summer - all hrs			***7.2391***	***6.9581***	***6.5767***	***6.7975***	***6.4964***	***5.9679***	***6.5834***
	On-Peak		***8.2695***						
	Off-Peak		***5.7471***						
for Block 1 (0-750 kWh/m) usage		***6.6308***							
for Block 2 (>750 kWh/m) usage		***7.5145***							
Winter - all hrs		***7.0535***	***7.6672***	***6.7823***	***6.4206***	***6.6273***	***6.4206***	***6.1169***	***6.4399***
	On-Peak		***8.2679***						
	Off-Peak		***6.0523***						

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

	RS	RS TOU - BGS	MGS - SEC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC
Total Rate Revenue - in $1000								
Summer	$ 115,291	$ 67	$ 24,121	$ 597	$ 20,948	$ 1,294	$ 982	$ 261
Winter	$ 158,392	$ 91	$ 38,118	$ 1,039	$ 34,193	$ 2,542	$ 2,163	$ 429
Total	$ 273,683	$ 158	$ 62,240	$ 1,636	$ 55,140	$ 3,837	$ 3,145	$ 689
Total Summer	$ 163,561							
Total Winter	$ 236,968							
Grand Total	$ 400,529							
Total Supplier Payment - in $1000								
Summer	$ 163,561							
Winter	$ 236,969							
Total	$ 400,530							
Differences - in $1000								
Summer	$ 0							
Winter	$ (2)							
Total	$ (2)							

Attachment 4

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

2023/2024 Illustrative Data for ACE

		Capacity Proxy Price True-Up Development for Winning Suppliers from 2021 BGS-RSCP Auction 2023/24 Delivery Year	Capacity Proxy Price True-Up Development for Winning Suppliers from 2022 BGS-RSCP Auction 2023/24 Delivery Year	*Notes:*
1	**Zonal Capacity Price ($/MW-day)**	$49.59	$49.59	as may be determined by the RPM, or its successor, or otherwise
2	**Capacity Proxy Price ($/MW-day)**	$146.51	$118.12	per Board Orders dated 11/18/2020 and 11/17/2021
3	**Capacity Proxy Price True-Up - $/MW-day**	-$96.92	-$68.53	= line 1 - line 2
4	**BGS-RSCP Gen Obl - MW**	2,046.7	2,046.7	
5	**Days in Year**	366	366	
6	**Capacity Proxy Price True-Up Annual Cost**	-$72,602,759	-$51,335,813	= line 3 * line 4 * line 5
7	**Eligible Tranches**	7	7	from Table A
8	**Total Tranches**	22	22	from Table A
9	**% of tranches eligible for payment**	31.82%	31.82%	= line 7 / line 8
10	**Capacity Proxy Price True-Up Cost**	-$23,100,878	-$16,334,122	= line 6 * line 9
11	**Total Applicable Customer Usage @ bulk system - in MWh**	6,114,711	6,114,711	
12	**Eligible Customer Usage @ bulk system - *in MWh***	1,945,590	1,945,590	= line 9 * line 11
13	**Capacity Proxy Price True-Up - $/MWh**	**-$11.87**	**-$8.40**	**= line 10/ line 12 - rounded to 2 decimal places**

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

2024/2025 Illustrative Data for ACE

		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 (if needed) *	
		2024/25 Delivery Year	2024/25 Delivery Year	*Notes:*
1	**Zonal Capacity Price ($/MW-day)**	$50.00	$50.00	as may be determined by the RPM, or its successor, or otherwise
2	**Capacity Proxy Price ($/MW-day)**	$87.98	$66.38	per Board Order dated 11/17/2021 and XX/XX/2022
3	**Capacity Proxy Price True-Up - $/MW-day**	-$37.98	-$16.38	= line 1 - line 2
4	**BGS-RSCP Gen Obl - MW**	2,046.7	2,046.7	
5	**Days in Year**	365	365	
6	**Capacity Proxy Price True-Up Annual Cost**	-$28,373,078	-$12,236,730	= line 3 * line 4 * line 5
7	**Eligible Tranches**	7	8	from Table A
8	**Total Tranches**	22	22	from Table A
9	**% of tranches eligible for payment**	31.82%	36.36%	= line 7 / line 8
10	**Capacity Proxy Price True-Up Cost**	-$9,027,798	-$4,449,720	= line 6 * line 9
11	**Total Applicable Customer Usage @ bulk system - in MWh**	6,114,711	6,114,711	
12	**Eligible Customer Usage @ bulk system - *in MWh***	1,945,590	2,223,531	= line 9 * line 11
13	**Capacity Proxy Price True-Up - $/MWh**	**-$4.64**	**-$2.00**	**= line 10/ line 12 - rounded to 2 decimal places**

* **Winners in the 2023 BGS Auction will only receive a true-up if results of 2024/2025 BRA are not known at least 5 days prior to the 2023 BGS-RSCP Auction.**

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

2025/2026 Illustrative Data for ACE

		Capacity Proxy Price True-Up Development for Winning Suppliers from 2023 BGS-RSCP Auction 2025/26 Delivery Year	*Notes:*
1	**Zonal Capacity Price ($/MW-day)**	$50.00	as may be determined by the RPM, or its successor, or otherwise
2	**Capacity Proxy Price ($/MW-day)**	$44.63	per Board Order dated XX/XX/2022
3	**Capacity Proxy Price True-Up - $/MW-day**	$5.37	= line 1 - line 2
4	**BGS-RSCP Gen Obl - MW**	2,046.7	
5	**Days in Year**	365	
6	**Capacity Proxy Price True-Up Annual Cost**	$4,011,675	= line 3 * line 4 * line 5
7	**Eligible Tranches**	8	from Table A
8	**Total Tranches**	22	from Table A
9	**% of tranches eligible for payment**	36.36%	= line 7 / line 8
10	**Capacity Proxy Price True-Up Cost**	$1,458,791	= line 6 * line 9
11	**Total Applicable Customer Usage @ bulk system - in MWh**	6,114,711	
12	**Eligible Customer Usage @ bulk system - *in MWh***	2,223,531	= line 9 * line 11
13	**Capacity Proxy Price True-Up - $/MWh**	**$0.66**	**= line 10/ line 12 - rounded to 2 decimal places**

Table A With Additional Line Item

Calculation of June 2024 to May 2025 BGS-RSCP Rates

Illustrative Purposes Only for ACE

Table A **Auction Results**

line #	**Specific BGS-RSCP Auction >>**	*remaining portion of 36 month bid - 2022 auction*	*remaining portion of 36 month bid - 2023 auction* *	*36 month bid - 2024 auction*	*Notes:*
1	**Winning Bid - in $/MWh**	$ 75.57	$ 75.57	$ 75.57	winning Bids
1A	**24/25 Capacity Proxy Price True-up - in $/MWh**	$ (4.64)	$ (2.00)		entered after 2024 BGS Auction
1B	**Total - in $/MWh**	$ 70.93	$ 73.57	$ 75.57	= line 1 + line 1A
2	**# of Tranches for Bid**	7	8	7	from then current Bid
3	**Total # of Tranches**	22	22	22	from then current Bid
	Payment Factors				
4	Summer	1.0000	1.0000	1.0000	from then current Bid Factor Spreadsheet
5	Winter	1.0000	1.0000	1.0000	from then current Bid Factor Spreadsheet
	Applicable Customer Usage @ bulk system - in MWh				
6	Summer MWh	2,497,012			from current Bid Factor Spreadsheet
7	Winter MWh	3,617,699			
	Total Payment to Suppliers - *in $1000*				
8	Summer	$ 56,354	$ 66,802	$ 60,041	= (1 + 1A) * (2)/(3) * (4) * (6) / 1000
9	Winter	$ 81,647	$ 96,783	$ 86,988	= (1 + 1A) * (2)/(3) * (5) * (7) / 1000
10	Total	$ 138,001	$ 163,585	$ 147,028	
	Average Payment to Suppliers - *in $/MWh*				
11	Summer	$ 73.37			= sum(line 8) / (6) - rounded to 2 decimal places
12	Winter	$ 73.37			= sum(line 9) / (7) - rounded to 2 decimal places
13	Total weighted average	**$ 73.37**	<<< used in calculation of Customer Rates		= sum(line 10) / [(6) + (7)] rounded to 2 decimal places

* **Winners in the 2023 BGS Auction will only receive a true-up if results of 2024/2025 BRA are not known at least 5 days prior to the 2023 BGS-RSCP Auction.**

Atlantic City Electric Company
Development of BGS Rates
June 2023 - May 2024

Table A With Additional Line Item

Calculation of June 2025 to May 2026 BGS-RSCP Rates

Illustrative Purposes Only for ACE

Table A **Auction Results**

line #	**Specific BGS-RSCP Auction >>**	*remaining portion of 36 month bid - 2023 auction*	*remaining portion of 36 month bid - 2024 auction*	*36 month bid - 2025 auction*	*Notes:*
1	**Winning Bid - in $/MWh**	$ 75.57	$ 75.57	$ 75.57	winning Bids
1A	**25/25 Capacity Proxy Price True-up - in $/MWh**	$ 0.66			entered after 2025 BGS Auction
1B	**Total - in $/MWh**	$ 76.23	$ 75.57	$ 75.57	= line 1 + line 1A
2	**# of Tranches for Bid**	8	7	7	from then current Bid
3	**Total # of Tranches**	22	22	22	from then current Bid
	Payment Factors				
4	Summer	1.0000	1.0000	1.0000	from then current Bid Factor Spreadsheet
5	Winter	1.0000	1.0000	1.0000	from then current Bid Factor Spreadsheet
	Applicable Customer Usage @ bulk system - in MWh				
6	Summer MWh	2,497,012			from current Bid Factor Spreadsheet
7	Winter MWh	3,617,699			
	Total Payment to Suppliers - *in $1000*				
8	Summer	$ 69,217	$ 60,041	$ 60,041	= (1 + 1A) * (2)/(3) * (4) * (6) / 1000
9	Winter	$ 100,283	$ 86,988	$ 86,988	= (1 + 1A) * (2)/(3) * (5) * (7) / 1000
10	Total	$ 169,500	$ 147,028	$ 147,028	
	Average Payment to Suppliers - *in $/MWh*				
11	Summer	$ 75.81			= sum(line 8) / (6) - rounded to 2 decimal places
12	Winter	$ 75.81			= sum(line 9) / (7) - rounded to 2 decimal places
13	Total weighted average	**$ 75.81**	<<< used in calculation of Customer Rates		= sum(line 10) / [(6) + (7)] rounded to 2 decimal places

In the Matter of the Provision of Basic Generation Service for the Period Beginning June 1, 2023
BPU Docket No. ER22030127
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