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July 1, 2025

**VIA ELECTRONIC MAIL**

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Sherri L. Lewis, RMC  
Secretary of the Board  
Board of Public Utilities  
44 South Clinton Avenue, 1<sup>st</sup> Floor  
P.O. Box 350  
Trenton, New Jersey 08625-0350

**RE:** In the Matter of the Provision of Basic Generation Service (“BGS”)  
for the Period Beginning June 1, 2026  
BPU Docket No. ER25040190

Dear Secretary Lewis:

In accordance with the Preliminary 2026 BGS Schedule set forth in the New Jersey Board of Public Utilities’ (the “Board” or “BPU”) April 23, 2025 Decision and Order in the above-referenced matter, enclosed please find Atlantic City Electric Company’s (“ACE”) Company-Specific Addendum proposal (the “Proposal”) for the Energy Year beginning June 1, 2026.

Pursuant to the terms of the Preliminary 2026 BGS Schedule, a generic Proposal for the Basic Generation Service to Be Procured Effective June 1, 2026 (the “BGS Proposal”) has been contemporaneously filed by Public Service Electric and Gas Company on behalf of all New Jersey electric distribution companies (“EDCs”), including ACE. The BGS Proposal describes the BGS auction process, including the pre-qualification of bidders, setting of starting prices, BGS pricing and rate design methodology, and the respective roles of the EDCs and the Board. The BGS Proposal also includes the proposed Supplier Master Agreements.

The BGS Proposal and ACE’s Company-Specific Addendum can also be accessed on the BGS Auction website at <http://bgs-auction.com/bgs.auction.regproc.asp>.

Sherri L. Lewis, RMC

July 1, 2025

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Pursuant to the Order issued by the Board in connection with *In the Matter of the New Jersey Board of Public Utilities' Response to the COVID-19 Pandemic for a Temporary Waiver of Requirements for Certain Non-Essential Obligations*, BPU Docket No. EO20030254, Order dated March 19, 2020, this document is being electronically filed with the Secretary of the Board, the Division of Law, the New Jersey Division of Rate Counsel, and the Service List. No paper copies will follow.

Thank you for your cooperation and courtesies. Feel free to contact the undersigned with any questions.

Respectfully submitted,

/s/Kenneth L. Wan

Kenneth L. Wan  
An Attorney at Law of the  
State of New Jersey

Enclosure

cc: Service List

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**IN THE MATTER OF THE  
PROVISION OF BASIC  
GENERATION SERVICE FOR  
THE PERIOD BEGINNING  
JUNE 1, 2026**

**STATE OF NEW JERSEY  
BOARD OF PUBLIC UTILITIES  
  
BPU DOCKET NO. ER25040190**

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**ATLANTIC CITY ELECTRIC COMPANY**

**BASIC GENERATION SERVICE  
COMMENCING JUNE 1, 2026**

**COMPANY-SPECIFIC ADDENDUM  
FILING**

**Proposal Dated July 1, 2025**

**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” 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 will be available to all residential and small commercial customers, specifically those customers taking service on Rate Schedules RS, EV-ERR, 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 94% 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.

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 Secondary Electric Vehicle Charging, 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 204 eligible CIEP customers representing approximately 6% 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 2026;
- c) a default during the June 1, 2026 - May 31, 2027 supply period, under the BGS-CIEP contracts entered into for 12 months; and/or
- d) a default during the June 1, 2026 - May 31, 2029 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, 2027. Any unsubscribed tranches for the period after May 31, 2027, 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 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, 2026**

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 supplier’s credit security.

**3. Defaults During the June 1, 2026 - May 31, 2027 Supply Period**

If a default occurs during the June 1, 2026 - May 31, 2027 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, 2026 - May 31, 2029 Supply Period**

If a default occurs during the June 1, 2026 - May 31, 2029 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. ACCOUNTING AND COST RECOVERY**

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;
- 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 ("EY") 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.

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. ACE currently calculates the reconciliation charges (“RC”), including interest, twice a year (For rates effective June 1 and October 1). To minimize rate volatility caused by uneven reconciliation periods (i.e., 4 months and 8 months), ACE proposes transitioning to a quarterly reconciliation process. This proposed change also brings ACE into alignment with the other NJ EDCs who reconcile quarterly. The RC including interest, will be calculated quarterly 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 quarterly.

The following table summarizes ACE’s proposed quarterly reconciliation schedule:

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

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 quarterly 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 quarterly basis through the BGS-RSCPRC and/or BGS-CIEPRC.

A separate deferred balance will be maintained individually for the BGS-RSCPRC and BGS-CIEPRC rates to ensure full recovery and reconciliation of all 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, 2026 through May 31, 2027 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 quarterly 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 January through March will be used.
2. For BGS-RSCPRC and BGS-CIEPRC rates effective September 1, the actual data for the months of April through June will be used.
3. For BGS-RSCPRC and BGS-CIEPRC rates effective December 1, the actual data for the months of July through September will be used.
4. For BGS-RSCPRC and BGS-CIEPRC rates effective March 1, the actual data for the months of October through December will be used.

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 will be 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, EV-ERR, 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. BGS Supply Charges**

The values of the BGS Supply charges applicable to Rate Schedules RS, EV-ERR, 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 currently 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 would have been based on the average of the relevant wholesale market prices for capacity which resulted from the Base Residual Auctions (“BRA”) under the RPM applicable to load served in the ACE zone for the following three years (i.e. average of 2026/2027, 2027/2028, and 2028/2029). Given recent delays in conducting the BRAs, expected capacity prices for future years may no longer be known, resulting in the need for Capacity Proxy prices (i.e. capacity price

estimates) within BGS auction contracts. The contract supplements with Capacity Proxy prices for the applicable delivery years with delayed BRAs are later adjusted to the actual BRA price once known. Due to the delays of the BRAs, contracts from the 2024 and 2025 BGS auctions contained supplements with Capacity Proxy Prices.

Previously, with the delays of the BRAs for the 2025-2026, 2026/2027, and 2027/2028 Delivery Years, a Capacity Proxy Price of \$47.46 per MW-Day was used in place of the 2025/2026 BRA value and \$49.05 per MW-Day was used in place of the 2026/2027 BRA value in the 2024 contracts/ A Capacity Proxy Price of \$270.35 per MW-Day was used in place for both the 2026/2027 BRA and 2027/2028 BRA in the 2025 contracts.

For 2026 contracts, the results of the BRAs for the 2026/2027, 2027/2028, and 2028/2029 Delivery Year are not yet available, with the BRAs scheduled to be held in July 2025, December 2025, and June 2026, respectively. Therefore, a Capacity Proxy price of \$270.43 per MW-Day has been used for the 2026/2027 Delivery Year and a Capacity Proxy Price of \$270.43 per MW-Day has been used in place of the prices paid for capacity for 2027/2028 and 2028/2029 Delivery Years, respectively.

For EY 2027, if Supplement A to the BGS-RSCP Supplier Master Agreement is approved by the BPU and the BRA for the 2026/2027 Delivery has not occurred at least 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 Reliability Pricing Model or its successor or otherwise, and the Capacity Proxy Price for the 2026/2027 Delivery Year.

For EY 2028, if Supplement B to the BGS-RSCP Supplier Master Agreement is approved by the BPU and if the BRA for the 2027/2028 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 2027/2028 Delivery Year.

For EY 2029, if Supplement C to the BGS-RSCP Supplier Master Agreement is approved by the BPU and if the BRA for the 2028/2029 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 2028/2029 Delivery Year.

ACE will file new tariff sheets for EY 2027, EY 2028, and 2029, 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 2027, EY 2028, and 2029 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 2027, EY 2028, and EY 2029 respectively and prospectively.

The Supplements to the SMAs signed by BGS-RSCP Suppliers in February 2024 and February 2025 are still in effect for approximately two-thirds of the load for EY 2027 (the year beginning June 1, 2026). Payments to BGS-RSCP suppliers that executed the Supplements to the

SMAAs approved by the BPU on November 17, 2023 and November 21, 2024 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 2026/2027 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 2024 and February 2025. The value of \$280.00 per MW day is used as an approximation for the price paid by BGS-RSCP Suppliers for Capacity in the Company's PJM Zone for the 2026/2027 Delivery Year.

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, 2026, the pricing will be based on the 36-month auction price, the 36-month price from the auction held in February 2025, and the 36-month price from the auction held in February 2024. 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. BGS Reconciliation Charge**

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. Transmission 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-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-recovery nor 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 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.

With the objective of incentivizing the installation and operation of electric vehicle (“EV”) chargers within the State of New Jersey, and in support of furthering New Jersey clean energy and climate goals, the Company proposed a two-year pilot program (that commenced in June 2024) to offer transmission and supply charge for Monthly General Service Secondary Electric Vehicle Charging (MGS-SEVC) customers billed on a kWh basis. The Company is proposing to end the two-year pilot after the second year is completed (after May 2026 bills) as addressed in the Direct Current Fast Charging (“DCFC”) Two Year Pilot Program section of this Addendum. The proposed change will revert the customer charge used for the billing of transmission and the capacity cost demand charge (applicable to customers over 500 MW) back to a kW based charge.

## **2. BGS-CIEP**

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 1 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 1 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.

With the objective of incentivizing the installation and operation of EV chargers within the State of New Jersey, and in support of furthering New Jersey clean energy and climate goals, the Company proposed a two-year pilot program, to offer transmission and supply charge for Monthly General Service Secondary Electric Vehicle Charging (MGS-SEVC) customers billed on a kWh basis. The Company is proposing to end the two-year pilot after the second year is completed (after May 2026 bills) as addressed in the DCFC Two Year Pilot Program section of this Addendum. The proposed change will revert the charges used for the billing of transmission and capacity costs (applicable to customers over 500 MW) back to a kW based charge.

**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.

Unlike prior years, there is no capacity price available for June 1, 2026 at this time, but is scheduled to occur in July 2026. Therefore, as discussed above a Capacity Proxy Price of \$270.43 per MW-Day has been used for the 2026/2027 Delivery Year. For EY 2027, if Supplement A to the BGS-RSCP Supplier Master Agreement is approved by the BPU and the BRA for the 2026/2027 Delivery has not occurred at least 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 Reliability Pricing Model or its successor or otherwise, and the Capacity Proxy Price for the 2026/2027 Delivery Year. ACE will file new tariff sheets for EY 2027 reflecting the impact of this price adjustment, in a manner similar to Attachment 5 – Development of Capacity Proxy Price True Up - \$/MW-day.

**Direct Current Fast Charging (“DCFC”) Two Year Pilot Program**

In the BPU’s 2023 BGS Order dated November 9, 2022, released in connection with BPU Docket No. ER22030127, the Board directed Staff to work with interested parties to come to a consensus in an effort to find a BGS rate design solution for EV chargers before the filing of the proposal for the 2024 BGS Auction (*i.e.*, the proposal due July 1, 2023). The Board also ordered

the EDCs, in their next BGS filing(s), to make a proposal regarding rate design for DCFC stations. As specified in the November 9, 2022 Order, EV charging companies (specifically, Electrify America) proposed a rate design to recover generation and transmission capacity charges with the following characteristics: 1) a revenue-neutral volumetric rate; and 2) availability, on an opt-in basis, for DCFC loads with a requirement for a multiyear commitment and portfolio enrollment. This request for a full volumetric generation and transmission capacity charge would replace existing rates that are currently billed based on demand or capacity. It was communicated that eliminating these primarily fixed demand and capacity charges would allow station operators to better predict operating costs. Costs would be entirely paid to the EDC based on the amount of kWh used by the charging company customers and correspondingly recovered from that customer on the same kWh basis through the charging fee. This position was re-affirmed based on additional discussions held after the November Order. On November 17, 2023, the BPU approved this program, effective for the billing periods beginning in June 2024 for a period of two years. In its July 1, 2024 filed Company Specific Addendum in the 2025 BGS Auction proceeding (Docket No. ER24030191), the Company included a description of the second year of its DCFC pilot program - with rates to be effective for the billing periods beginning June of 2025 and ending in May of 2026. In the subsequent November 21, 2024 BGS Board Order, the Board directed the EDCs to include an update on the status of the pilot programs and proposals to either implement permanent DCFC programs or provide justification for ending the programs in their 2026 BGS Auction proceeding filings.

#### **Program experience**

After soliciting DCFC customers eligible for the program in late 2023 and early 2024, the program saw low participation. For year 2, the low participation continued. Program

implementation costs, to date, is approximately \$23,000 for the required system changes and customer outreach. For the capacity demand charge change (applicable to customers over 500 MW) conversion to a per kWh rate, ACE had no customer participate in that pilot.

#### **Program status**

As noted above, interest in the program was marginal for both years. The intent of the pilot program was to lessen the risk of capacity and transmission obligation costs when charged similar to other commercial and industrial customers (on a \$/MW-day basis) due to low load factor DCFC installations – and instead incorporate these costs into a \$/kWh rate for the customers’ capacity and transmission obligation charges. However, there has not been interest from the larger DCFC population of installations to participate in the program (including the DCFC entities that originally advocated for its creation), likely due to other options available to them (such as soliciting for supply service and a desirable rate design from a Third Party Supplier) or concerns over the economic benefits (or costs) of the program - due to the need for participants to share in the program implementation costs and any under or over-recovery balances in the DCFC reconciliation charges, or changes associated with the economic risks due to increased utilization of charging stations. As such, ACE is proposing to end the DCFC program after the second year is completed (after May 2026 bills) and not implement a permanent DCFC program thereafter. ACE believes that the current demand transmission rate design that was applicable before the pilot is appropriate for the rate class of those customers. At program end, if there remains a balance of DCFC Reconciliation Charges or the Implementation Cost Deferred Balance, ACE proposes that such balances be transferred to the BGS reconciliation charge(s) for recovery.

## **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 2026 through May 2027, with migration adjustments. The values in Table No. 3 will be updated in January 2026 to better reflect forecasts for the June 1 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 2, 2025, for the PJM West trading hub for the period of June 2026 to May 2027, 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 2025. Table No. 10 will be updated in January 2026, 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 2026/2027, the Capacity Proxy Price for Delivery Year 2027/2028, and the Capacity Proxy Price for Delivery Year 2028/2029. 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 2027/2028 and the 2028/2029 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 \$18.23 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 2026 to May 2027 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 2024/2025 BGS auction, the results of the 2025/2026 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 2024 and February 2025. 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 2026/2027 Delivery Year. The value of \$280.00 per MW-Day is used as an approximation of the price paid by BGS-RSCP Suppliers for Capacity in the Company's PJM Zone for 2026/2027. 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. CONCLUSION**

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, 2026 to May 31, 2029;
2. the Company's proposed accounting for BGS is approved for purposes of accounting and BGS cost recovery;
3. the Company's proposed reconciliation charge schedule is approved;
4. 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;
5. the Company's termination of the DCFC Two-Year Pilot Program is approved; and
6. the Company's Rate Design Methodology and Tariff Sheets are approved.

# Attachment 1

Tariff – Clean

**ATLANTIC CITY ELECTRIC COMPANY****BPU NJ No. 11 Electric Service - Section IV 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, EV-ERR, 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 and EV-ERR		\$ 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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**Date of Issue:**
**Effective Date:**
**Issued by:**



**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 and EV-ERR	\$ 0.004652
MGS Secondary, MGS-SEVC, AGS Secondary, SPL/CSL, DDC	\$ 0.004652
MGS Primary, AGS Primary	\$ 0.004558

**BGS-CIEP**

**Energy Charges**

BGS Energy Charges for Rate Schedule TGS, AGS, MGS and MGS-SEVC 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.

**Date of Issue:**

**Effective Date:**

**Issued by:**

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**RIDER (BGS) continued**  
**Basic Generation Service (BGS)**

**BGS Reconciliation Charge:**

	Charge (\$ per kWh)
Service taken at Secondary Voltage	\$ 0.000279
Service taken at Primary Voltage	\$ 0.000273
Service taken at Sub-Transmission Voltage	\$ 0.000270
Service taken at Transmission Voltage	\$ 0.000266

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.

**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.

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**Date of Issue:**

**Effective Date:**

**Issued by:**

**ATLANTIC CITY ELECTRIC COMPANY****BPU NJ No. 11 Electric Service - Section IV Revised Sheet Replaces Sheet No. 60c****RIDER (BGS) continued  
Basic Generation Service (BGS)****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**

	<b><u>RS</u></b>	<b><u>MGS Secondary And MGS- SEVC</u></b>	<b><u>MGS Primary</u></b>	<b><u>AGS Secondary</u></b>	<b><u>AGS Primary</u></b>	<b><u>TGS</u></b>	<b><u>SPL/ CSL</u></b>	<b><u>DDC</u></b>
VEPCo	0.000421	0.000302	0.000166	0.000226	0.000189	0.000162	-	0.000132
TrAILCo	0.000341	0.000244	0.000134	0.000182	0.000152	0.000131	-	0.000108
PSE&G	0.001382	0.000989	0.000547	0.000742	0.000622	0.000532	-	0.000437
PPL	0.000106	0.000076	0.000042	0.000057	0.000047	0.000041	-	0.000033
PECO	0.000205	0.000146	0.000081	0.000110	0.000092	0.000079	-	0.000064
Pepco	0.000020	0.000014	0.000007	0.000011	0.000009	0.000007	-	0.000006
MAIT	0.000042	0.000030	0.000016	0.000022	0.000018	0.000016	-	0.000013
JCP&L	0.000003	0.000002	0.000001	0.000002	0.000001	0.000001	-	0.000001
EL05-121	0.000019	0.000014	0.000007	0.000010	0.000009	0.000007	-	0.000006
Delmarva	0.000010	0.000007	0.000004	0.000005	0.000004	0.000004	-	0.000003
BG&E	0.000043	0.000031	0.000017	0.000022	0.000019	0.000016	-	0.000014
AEP-East	0.000062	0.000044	0.000025	0.000033	0.000028	0.000023	-	0.000019
Silver Run	0.000290	0.000208	0.000114	0.000156	0.000130	0.000112	-	0.000092
NIPSCO	0.000003	0.000002	0.000001	0.000001	0.000001	0.000001	-	0.000001
CW Edison	-	-	-	-	-	-	-	-
ER18-680 & Form 715	-	-	-	-	-	-	-	-
SFC	0.000004	0.000003	0.000002	0.000002	0.000002	0.000002	-	0.000001
Duquesne	0.000002	0.000001	0.000001	0.000001	0.000001	0.000001	-	-
Transource	0.000044	0.000031	0.000017	0.000023	0.000019	0.000017	-	0.000014
Total	0.002997	0.002144	0.001182	0.001605	0.001343	0.001152	-	0.000944

**Date of Issue:****Effective Date:****Issued by:**

# Attachment 1

Tariff - Redlined

**ATLANTIC CITY ELECTRIC COMPANY****BPU NJ No. 11 Electric Service - Section IV ~~Thirtieth Revised~~ Sheet Replaces ~~Twenty-Ninth 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, EV-ERR, 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 and EV-ERR		\$ <a href="#">0.139134x.xxxxxx</a>
<=750 kwhs summer	\$ <a href="#">0.130407x.xxxxxx</a>	
> 750 kwh summer	\$ <a href="#">0.140360x.xxxxxx</a>	
RS TOU BGS Option		
On Peak (See Note 1)	\$ <a href="#">0.186568x.xxxxxx</a>	\$ <a href="#">0.213762x.xxxxxx</a>
Off Peak (See Note 1)	\$ <a href="#">0.080642x.xxxxxx</a>	\$ <a href="#">0.078513x.xxxxxx</a>
MGS-Secondary and MGS-SEVC	\$ <a href="#">0.121496x.xxxxxx</a>	\$ <a href="#">0.114061x.xxxxxx</a>
MGS-Primary	\$ <a href="#">0.131077x.xxxxxx</a>	\$ <a href="#">0.133131x.xxxxxx</a>
AGS-Secondary	\$ <a href="#">0.124290x.xxxxxx</a>	\$ <a href="#">0.115945x.xxxxxx</a>
AGS-Primary	\$ <a href="#">0.210787x.xxxxxx</a>	\$ <a href="#">0.191397x.xxxxxx</a>
DDC	\$ <a href="#">0.103797x.xxxxxx</a>	\$ <a href="#">0.095110x.xxxxxx</a>
SPL/CSL	\$ <a href="#">0.082239x.xxxxxx</a>	\$ <a href="#">0.078984x.xxxxxx</a>

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.

**Date of Issue:** [March 18, 2025](#)**Effective Date:** [June 1, 2025](#)

**Issued by:** [J. Tyler Anthony, President and Chief Executive Officer – Atlantic City Electric Company](#)  
**Filed pursuant to Board of Public Utilities of the State of New Jersey directives associated with the**  
**BPU Docket No. ER24030191**

**Issued by:**

**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 and EV-ERR	\$ 0.004652
MGS Secondary, MGS-SEVC, AGS Secondary, SPL/CSL, DDC	\$ 0.004652
MGS Primary, AGS Primary	\$ 0.004558

**BGS-CIEP**

**Energy Charges**

BGS Energy Charges for Rate Schedule TGS, AGS, MGS and MGS-SEVC 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)	<del>\$0.647094x.xxxxxx</del>	<del>\$0.647094x.xxxxxx</del>

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.

~~CIEP-DCFC-EV Charges (MGS-SEVC class) Generation Capacity Charge~~  
~~Generation Capacity Charge per kilowatt hour (\$/kWh) \$0.035735~~

~~This charge is only available to the MGS-SEVC Rate Schedule on an opt-in basis. Customer's opting into this rate must have a Peak Load Share (PLS) of 500 kW or more, consistent with BGS-CIEP. The above charge shall be applied to MGS-SEVC customers who have opted into the volumetric option to pay for generation capacity costs plus Administrative Charges pursuant to N.J.S.A. 48:2-60 plus New Jersey Sales and Use Tax as set forth in Rider SUT. Customers who have elected for this rate must remain for a period of at least two years and also must enroll all of their charging company site locations. Customers on a rate schedule other than MGS-SEVC are not eligible for this option. MGS-SEVC customers on Rider BGS-RSCP are not eligible for this option. NEM customers are not eligible for this option.~~

**Ancillary Service Charge**

	Charge (\$ per kWh)
Service taken at Secondary Voltage	\$ <del>0.002256x.xxxxxx</del>
Service taken at Primary Voltage	\$ <del>0.002210x.xxxxxx</del>
Service taken at Sub-Transmission Voltage	\$ <del>0.002179x.xxxxxx</del>
Service taken at Transmission Voltage	\$ <del>0.002154x.xxxxxx</del>

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.

**Date of Issue:** April 30, 2025

**Effective Date:** June 1, 2025

Issued by: J. Tyler Anthony, President and Chief Executive Officer – Atlantic City Electric Company  
Filed pursuant to Board of Public Utilities of the State of New Jersey directives associated with the  
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Issued by:

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RIDER (BGS) continued  
Basic Generation Service (BGS)

**BGS Reconciliation Charge:**

	Charge (\$ per kWh)
Service taken at Secondary Voltage	\$ 0.000279
Service taken at Primary Voltage	\$ 0.000273
Service taken at Sub-Transmission Voltage	\$ 0.000270
Service taken at Transmission Voltage	\$ 0.000266

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.

**CIEP Standby Fee** ~~\$0.000160~~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.

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Date of Issue: ~~April 30, 2025~~

Effective Date: ~~June 1, 2025~~

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~~BPU Docket No. ER23030124 and ER24030194~~

Issued by:

**ATLANTIC CITY ELECTRIC COMPANY****BPU NJ No. 11 Electric Service - Section IV** ~~Second- Revised Sheet Replaces First Sheet No. 60c~~**RIDER (BGS) continued**  
**Basic Generation Service (BGS)****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**

	<b><u>RS</u></b>	<b><u>MGS Secondary And MGS- SEVC</u></b>	<b><u>MGS Primary</u></b>	<b><u>AGS Secondary</u></b>	<b><u>AGS Primary</u></b>	<b><u>TGS</u></b>	<b><u>SPL/ CSL</u></b>	<b><u>DDC</u></b>
VEPCo	0.000421	0.000302	0.000166	0.000226	0.000189	0.000162	-	0.000132
TrAILCo	0.000341	0.000244	0.000134	0.000182	0.000152	0.000131	-	0.000108
PSE&G	0.001382	0.000989	0.000547	0.000742	0.000622	0.000532	-	0.000437
PPL	0.000106	0.000076	0.000042	0.000057	0.000047	0.000041	-	0.000033
PECO	0.000205	0.000146	0.000081	0.000110	0.000092	0.000079	-	0.000064
Pepco	0.000020	0.000014	0.000007	0.000011	0.000009	0.000007	-	0.000006
MAIT	0.000042	0.000030	0.000016	0.000022	0.000018	0.000016	-	0.000013
JCP&L	0.000003	0.000002	0.000001	0.000002	0.000001	0.000001	-	0.000001
EL05-121	0.000019	0.000014	0.000007	0.000010	0.000009	0.000007	-	0.000006
Delmarva	0.000010	0.000007	0.000004	0.000005	0.000004	0.000004	-	0.000003
BG&E	0.000043	0.000031	0.000017	0.000022	0.000019	0.000016	-	0.000014
AEP-East	0.000062	0.000044	0.000025	0.000033	0.000028	0.000023	-	0.000019
Silver Run	0.000290	0.000208	0.000114	0.000156	0.000130	0.000112	-	0.000092
NIPSCO	0.000003	0.000002	0.000001	0.000001	0.000001	0.000001	-	0.000001
CW Edison	-	-	-	-	-	-	-	-
ER18-680 & Form 715	-	-	-	-	-	-	-	-
SFC	0.000004	0.000003	0.000002	0.000002	0.000002	0.000002	-	0.000001
Duquesne	0.000002	0.000001	0.000001	0.000001	0.000001	0.000001	-	-
Transource	0.000044	0.000031	0.000017	0.000023	0.000019	0.000017	-	0.000014
Total	0.002997	0.002144	0.001182	0.001605	0.001343	0.001152	-	0.000944

**Date of Issue: April 30, 2025****Effective Date: May 1, 2025**

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**Issued by:**



# 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 / EV-ERR	RS TOU - BGS	MGS - SEC / SEVC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC
January	54.37%	54.48%	57.03%	58.61%	57.42%	55.55%	41.24%	53.52%
February	51.16%	51.59%	54.30%	55.91%	54.91%	53.46%	37.78%	51.58%
March	51.85%	55.19%	54.10%	54.78%	55.19%	53.53%	31.65%	51.07%
April	56.11%	59.62%	59.48%	60.17%	59.88%	58.85%	32.88%	55.28%
May	55.11%	57.85%	57.74%	57.28%	58.03%	56.50%	28.01%	53.11%
June	48.62%	46.86%	50.20%	49.11%	51.42%	49.82%	23.28%	46.89%
July	57.73%	60.97%	58.86%	57.33%	57.29%	55.91%	26.76%	53.03%
August	57.21%	62.24%	59.12%	57.40%	56.15%	55.52%	29.81%	53.25%
September	50.87%	52.49%	54.78%	54.32%	54.90%	53.77%	32.16%	50.19%
October	51.29%	52.46%	56.48%	56.84%	57.44%	55.82%	36.91%	52.95%
November	49.86%	49.42%	55.55%	56.48%	55.32%	53.96%	37.78%	49.99%
December	50.51%	49.71%	54.58%	55.54%	54.94%	53.75%	39.80%	50.93%

Table #2

% Usage During ACECO On-Peak Billing Period

	RS TOU - BGS
January	38.00%
February	35.37%
March	40.17%
April	41.96%
May	42.45%
June	34.52%
July	44.87%
August	46.38%
September	38.39%
October	36.25%
November	34.54%
December	46.36%

Table #3

Class Usage @ customer  
calendar month sales forecasted for period  
in MWh

	RS / EV-ERR	RS TOU - BGS	MGS - SEC / SEVC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC	Total
Jan-27	359,051	153	81,705	4,705	83,092	27,629	5,891	901	563,126
Feb-27	322,014	138	78,199	4,611	79,657	26,247	4,999	847	516,712
Mar-27	278,864	119	75,288	4,621	75,804	24,066	4,800	815	464,377
Apr-27	239,893	102	74,221	4,301	75,001	24,227	4,348	796	422,890
May-27	199,318	85	72,499	4,330	73,689	22,782	3,777	767	377,247
Jun-26	288,222	123	85,664	4,843	88,348	27,249	3,774	889	499,113
Jul-26	440,369	188	97,532	5,695	100,575	31,364	3,917	1,002	680,643
Aug-26	495,605	212	102,275	5,937	105,020	32,372	4,206	1,055	746,681
Sep-26	437,980	187	102,670	5,758	105,159	32,261	4,712	1,069	689,795
Oct-26	247,097	106	81,134	4,412	83,738	25,841	4,645	867	447,839
Nov-26	228,875	98	78,023	4,520	80,468	25,159	5,113	848	423,103
Dec-26	277,806	119	75,097	3,968	76,853	23,463	5,320	824	463,450
Total	3,815,094	1,629	1,004,307	57,701	1,027,405	322,660	55,500	10,680	6,294,976

Table #4	Forwards Prices - Energy Only @ bulk system (\$/MWH)			Zone-Hub Basis Differential			'Based on 3 Year Average		
		On-Peak	Off/On Pk LMP ratio		Off-Peak		On-Peak	Off-Peak	
	Jan-27	90.00	0.804		72.37		80%	87%	
	Feb-27	77.25	0.804		62.12		80%	87%	
	Mar-27	51.35	0.804		41.29		80%	87%	
	Apr-27	49.85	0.804		40.08		80%	87%	
	May-27	50.55	0.804		40.65		80%	87%	
	Jun-26	56.70	0.593		33.65		80%	86%	
	Jul-26	86.80	0.593		51.51		80%	86%	
	Aug-26	75.35	0.593		44.72		80%	86%	
	Sep-26	58.50	0.593		34.72		80%	86%	
	Oct-26	56.25	0.804		45.23		80%	87%	
	Nov-26	55.40	0.804		44.55		80%	87%	
	Dec-26	64.70	0.804		52.03		80%	87%	

  

Table #6	Losses	RS / EV-ERR	RS TOU - BGS	MGS - SEC / SEVC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC
	Delivery Loss Factor	6.7721%	6.7721%	6.7721%	4.8389%	6.7721%	4.8389%	6.7721%	6.7721%
	Loss Factors + EHV Losses =	7.1684%	7.1684%	7.1684%	5.2435%	7.1684%	5.2435%	7.1684%	7.1684%
	Expansion Factor =	1.07722	1.07722	1.07722	1.05534	1.07722	1.05534	1.07722	1.07722
	Marginal Loss Factor (w/ EHV Losses) =	1.6465%	1.6465%	1.6465%	1.6465%	1.6465%	1.6465%	1.6465%	1.6465%
	Loss Factor w/o Marginal Loss =	5.6143%	5.6143%	5.6143%	3.6572%	5.6143%	3.6572%	5.6143%	5.6143%
	Expansion Factor w/o Marginal Loss =	1.05948	1.05948	1.05948	1.03796	1.05948	1.03796	1.05948	1.05948

  

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 / EV-ERR	RS TOU - BGS	MGS - SEC / SEVC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC	
	Summer - all hrs	\$ 51.00	\$ 51.60	\$ 50.60	\$ 49.46	\$ 50.37	\$ 49.15	\$ 44.16	\$ 49.46	
	On Peak	\$ 61.51	\$ 61.78	\$ 60.48	\$ 59.37	\$ 60.27	\$ 59.12	\$ 59.33	\$ 60.30	
	Off Peak	\$ 38.57	\$ 38.29	\$ 38.05	\$ 37.45	\$ 38.25	\$ 37.50	\$ 38.18	\$ 38.18	
	Winter - all hrs	\$ 51.88	\$ 51.95	\$ 50.62	\$ 49.58	\$ 50.65	\$ 49.75	\$ 50.05	\$ 50.46	
	On Peak	\$ 55.28	\$ 55.06	\$ 53.58	\$ 52.52	\$ 53.58	\$ 52.70	\$ 55.52	\$ 53.77	
	Off Peak	\$ 48.13	\$ 48.35	\$ 46.82	\$ 45.69	\$ 46.83	\$ 46.11	\$ 46.94	\$ 46.82	
	Annual	\$ 51.50	\$ 51.80	\$ 50.61	\$ 49.53	\$ 50.54	\$ 49.52	\$ 48.29	\$ 50.08	
	System Average Cost @ customer - (limited to classes shown above) =				\$ 51.05					

  

Table #8	Summary of Average BGS Energy Costs @ customer - PJM Time Periods based on Forwards prices corrected for congestion & losses in \$1000									
		RS / EV-ERR	RS TOU - BGS	MGS - SEC / SEVC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC	
	Summer - all hrs	\$ 84,774	\$ 37	\$ 19,639	\$ 1,100	\$ 20,104	\$ 6,058	\$ 733	\$ 199	
	PJM on pk	\$ 55,401	\$ 25	\$ 13,132	\$ 723	\$ 13,244	\$ 3,928	\$ 279	\$ 123	
	PJM off pk	\$ 29,372	\$ 12	\$ 6,507	\$ 377	\$ 6,860	\$ 2,130	\$ 455	\$ 75	
	Winter - all hrs	\$ 111,701	\$ 48	\$ 31,188	\$ 1,758	\$ 31,825	\$ 9,920	\$ 1,947	\$ 336	
	PJM on pk	\$ 62,479	\$ 27	\$ 18,536	\$ 1,061	\$ 19,064	\$ 5,797	\$ 782	\$ 187	
	PJM off pk	\$ 49,222	\$ 21	\$ 12,652	\$ 698	\$ 12,761	\$ 4,123	\$ 1,164	\$ 149	
	Annual	\$ 196,475	\$ 84	\$ 50,827	\$ 2,858	\$ 51,929	\$ 15,978	\$ 2,680	\$ 535	
	System Total	\$ 321,366								

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 / EV-ERR	RS TOU - BGS	MGS - SEC / SEVC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC
Summer - all hrs		\$ 51.00	\$ 51.60	\$ 50.60	\$ 49.46	\$ 50.37	\$ 49.15	\$ 44.16	\$ 49.46
	ACECO On pk		\$ 65.95						
	ACECO Off pk		\$ 41.29						
Winter - all hrs		\$ 51.88	\$ 51.95	\$ 50.62	\$ 49.58	\$ 50.65	\$ 49.75	\$ 50.05	\$ 50.46
	ACECO On pk		\$ 56.29						
	ACECO Off pk		\$ 49.15						
Annual Average		\$ 51.50	\$ 51.80	\$ 50.61	\$ 49.53	\$ 50.54	\$ 49.52	\$ 48.29	\$ 50.08
System Average		\$ 51.05							

Table #10      **Generation Obligations and Costs and Other Adjustments**  
*obligations - values effective June 2025; costs are market estimates in MW*

	RS / EV-ERR	RS TOU - BGS	MGS - SEC / SEVC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC	Total
Gen Load - MW	1,405.2	0.4	225.5	17.1	185.0	53.6	0.0	1.3	1,888.1
Gen Obl - MW	1,333.8	0.4	214.1	16.3	175.6	50.9	0.0	1.2	1,792.2
# 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			
Generation Capacity Cost									
	Summer	Base Capacity	\$270.43	\$/MW/day			Summer Total	\$ 59,129,200	
	Winter		\$270.43	\$/MW/day			Winter Total	\$ 117,773,734	
							Annual Total	\$ 176,902,934	
Residential Inversion Determination									
		Charges	----- Rate RS / EV-ERR -----	% usage	SUM 'First 750 KWh			1,142,265,335	
	Block 1 (0-750 kWh/m)	5.480200		64.11%	SUM '> 750 KWh			639,437,269	
	Block 2 (>750 kWh/m)	6.345400		35.89%					
	Calculated inversion =	0.865200			WIN			2,134,208,533	
								3,915,911,137	

Table #11      **Ancillary Services & Renewable Power Cost (forecasted overall annual average)**  
**Ancillary Services**      \$ 2.00  
**Renewable Power Cost**      \$ 18.23  
*Total Ancillary Services & Renewable Power Costs*      \$ 20.23

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

	RS / EV-ERR	RS TOU - BGS	MGS - SEC / SEVC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC
Generation Obl -								
per annual MWh	\$ 34.51	\$ 55.93	\$ 21.04	\$ 27.80	\$ 16.87	\$ 15.56	\$ 0.00	\$ 11.10
recovery per summer MWh	\$ 26.47	\$ 41.42	\$ 18.19	\$ 24.12	\$ 14.52	\$ 13.62	\$ 0.00	\$ 9.87
recovery per winter MWh	\$ 40.71	\$ 67.86	\$ 22.83	\$ 30.11	\$ 18.37	\$ 16.76	\$ 0.00	\$ 11.84

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 / EV-ERR	RS TOU - BGS	MGS - SEC / SEVC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC
Summer - all hrs		\$ 99.27	\$ 114.81	\$ 90.58	\$ 94.92	\$ 86.69	\$ 84.12	\$ 65.96	\$ 81.12
	On-Peak		\$ 129.16						
	Off-Peak		\$ 63.08						
	Block 1 (0-750 kWh/m)	\$ 96.16							
	Block 2 (>750 kWh/m)	\$ 104.82							
Winter - all hrs		\$ 114.39	\$ 141.60	\$ 95.24	\$ 101.04	\$ 90.81	\$ 87.86	\$ 71.84	\$ 84.09
	On-Peak		\$ 145.94						
	Off-Peak		\$ 70.94						
Annual		\$ 107.80	\$ 96.17	\$ 93.44	\$ 98.68	\$ 89.21	\$ 86.43	\$ 70.08	\$ 82.97
Grand Total Cost in \$1000 =		\$ 635,281							
Average cost for rates shown (@ customer) =						\$ 100.92			
Average costs for rates shown (@ transmission nodes) =						\$ 95.37			

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 / EV-ERR	RS TOU - BGS	MGS - SEC / SEVC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC
Summer - all hrs			1.204	0.950	0.995	0.909	0.882	0.692	0.851
	On-Peak		1.354						
	Off-Peak		0.661						
	All usage Multiplier	1.041							
	Constant	\$ (3.11)		for Block 1 (0-750 kWh/m) usage					
	Constant	\$ 5.55		for Block 2 (>750 kWh/m) usage					
Winter - all hrs		1.199	1.485	0.999	1.059	0.952	0.921	0.753	0.882
	On-Peak		1.530						
	Off-Peak		0.744						
Annual		1.130	1.008	0.980	1.035	0.935	0.906	0.735	0.870

Table #15

Summary of Total BGS Costs by Season

		RS / EV-ERR	RS TOU - BGS	MGS - SEC / SEVC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC
Total Costs by Rate - in \$1000									
	Summer	\$ 165,002	\$ 82	\$ 35,160	\$ 2,110	\$ 34,596	\$ 10,368	\$ 1,095	\$ 326
	Winter	\$ 246,268	\$ 130	\$ 58,682	\$ 3,584	\$ 57,059	\$ 17,520	\$ 2,794	\$ 560
	Total	\$ 411,270	\$ 212	\$ 93,841	\$ 5,694	\$ 91,655	\$ 27,888	\$ 3,890	\$ 886
% of Annual Total \$ by Rate									
	Summer	40%	38%	37%	37%	38%	37%	28%	37%
	Winter	60%	62%	63%	63%	62%	63%	72%	63%
Total Costs - in \$1000									
	Summer	\$ 248,738							
	Winter	\$ 386,598							
	Total	\$ 635,336							
% of Annual Total \$			If total \$ were split on a per MWh basis (on bulk system MWhs):						
	Summer	39%	\$ 89.84	per MWh @ trans nodes		Ratio to BGS Cost	>>>	Summer	1.0000
	Winter	61%	\$ 99.32	per MWh @ trans nodes		(rounded to 4 decimal places)		Winter	1.0000

Assumptions:

Gen Cost = \$270.43 per MW-day summer  
= \$270.43 per MW-day winter  
Ancillary Services = \$ 2.00 per MWh  
Renewable Power Cost = \$ 18.23 per MWh  
Energy Prices = [Quotes for the period June 1, 2026 to May 31, 2027 - 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 2025](#)  
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

BGS Avg. Price >>>>>>>>	\$	109.453
-------------------------	----	---------

<b>Table #17</b>	<b>Retail Rates Charged to BGS RSCP Customers including Revenue Assessment and SUT</b>
	<i>Includes energy, Generation Obligations, Ancillary Services, and Renewable Power Costs in \$/kWh</i>
Revenue Assessment Factor	1.002751434
(BPU, RC Assessments)	

			RS / EV-ERR	RS TOU - BGS	MGS - SEC / SEVC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC						
Summer - all hrs					\$	0.118011	\$	0.123601	\$	0.112918	\$	0.109564	\$	0.085962	\$	0.105713
		On-Peak		\$	0.168197											
		Off-Peak		\$	0.082111											
		Block 1 (0-750 kWh/m)	\$	0.125791												
		Block 2 (>750 kWh/m)	\$	0.135611												
Winter - all hrs			\$	0.134774	\$	0.112293	\$	0.119037	\$	0.107010	\$	0.103525	\$	0.084641	\$	0.099141
		On-Peak		\$	0.171980											
		Off-Peak		\$	0.083629											
Annual			\$	0.132239	\$	0.117962	\$	0.114685	\$	0.121121	\$	0.109419	\$	0.106025	\$	0.086014

# Attachment 3

Atlantic City Electric Company  
Calculation of June 2026 to May 2027 BGS-RSCP Rates  
based on results of February 2026 BGS RSCP Auction

Table A      Auction Results

line #	Payment Identifier >>	remaining portion of 36 month bid - 2024/25 filing	remaining portion of 36 month bid - 2025/26 filing	36 month bid - 2026/27 filing
1	Winning Bid - in \$/MWh	\$ 81.42	\$ 110.50	\$ 111.45
1A	Capacity Proxy Price True-Up - in \$/MWh	\$ 22.68	\$ 0.95	\$ 0.94
1B				
1C	Total - in \$/Mwh	\$ 104.10	\$ 111.45	\$ 112.39
2	# of Tranches for Bid	7	7	8
3	Total # of Tranches	22	22	22
	Payment Factors			
4	Summer	1.0000	1.0000	1.0000
5	Winter	1.0000	1.0000	1.0000
	Applicable Customer Usage @ bulk system - in MWh			
6	Summer MWh	2,768,722		
7	Winter MWh	3,892,510		
	Total Payment to Suppliers - in \$1000			
8	Summer	\$ 91,708	\$ 98,183	\$ 113,155
9	Winter	\$ 128,931	\$ 138,034	\$ 159,083
10	Total	\$ 220,638	\$ 236,216	\$ 272,238
	Average Payment to Suppliers - in \$/MWh			
11	Summer	\$ 109.45		
12	Winter	\$ 109.45		
13	Total weighted average	\$ 109.45	<<< used in calculation of Customer Rates	
	Reconciliation of amounts - in \$1000			
14	Weighted avg * Total MWh =	\$ 729,092		
15	Total Payment to Suppliers =	\$ 729,093		
16	Difference =	\$ (1)		

Notes:

winning Bids  
entered after 2026 BGS Auction

= line 1 + line 1A - line 1B

from then current Bid  
from then current Bid

from then current Bid Factor Spreadsheet  
from then current Bid Factor Spreadsheet

from current Bid Factor Spreadsheet

= (1 + 1A) \* (2)/(3) \* (4) \* (6) / 1000  
= (1 + 1A) \* (2)/(3) \* (5) \* (7) / 1000

= sum(line 8) / (6) - rounded to 2 decimal places  
= sum(line 9) / (7) - rounded to 2 decimal places

= sum(line 10) / [ (6) + (7)]  
rounded to 2 decimal places

= (13) \* [(6)+(7)] / 1000  
= sum (line 10)  
= line (14) - line (15)



Atlantic City Electric Company  
Calculation of June 2026 to May 2027 BGS-RSCP Rates  
based on results of February 2026 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 / EV-ERR	RS TOU - BGS	MGS - SEC / SEVC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC
Summer - all hrs			1.204	0.950	0.995	0.909	0.882	0.692	0.851
	On-Peak		1.354						
	Off-Peak		0.661						
	All usage Multiplier	1.041							
	Constant	(3.105)		for Block 1 (0-750 kWh/m) usage					
	Constant	5.547		for Block 2 (>750 kWh/m) usage					
Winter - all hrs		1.199	1.485	0.999	1.059	0.952	0.921	0.753	0.882
	On-Peak		1.530						
	Off-Peak		0.744						
Annual - all hrs		1.130	1.008	0.980	1.035	0.935	0.906	0.735	0.870

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 / EV-ERR	RS TOU - BGS	MGS - SEC / SEVC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC
Summer - all hrs			13.1781	10.3980	10.8906	9.9493	9.6538	7.5741	9.3145
	On-Peak		14.8199						
	Off-Peak		7.2348						
for Block 1 (0-750 kWh/m) usage		11.0835							
for Block 2 (>750 kWh/m) usage		11.9487							
Winter - all hrs		13.1234	16.2538	10.9344	11.5911	10.4199	10.0806	8.2418	9.6538
	On-Peak		16.7463						
	Off-Peak		8.1433						

Atlantic City Electric Company  
Calculation of June 2026 to May 2027 BGS-RSCP Rates  
based on results of February 2026 BGS RSCP Auction

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

	RS / EV-ERR	RS TOU - BGS	MGS - SEC / SEVC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC
Total Rate Revenue - in \$1000								
Summer	\$ 189,389	\$ 82	\$ 40,359	\$ 2,421	\$ 39,708	\$ 11,898	\$ 1,258	\$ 374
Winter	\$ 282,536	\$ 117	\$ 67,374	\$ 4,111	\$ 65,468	\$ 20,102	\$ 3,205	\$ 643
Total	\$ 471,925	\$ 199	\$ 107,733	\$ 6,532	\$ 105,176	\$ 32,000	\$ 4,463	\$ 1,017
Total Summer	\$ 285,488							
Total Winter	\$ 443,558							
Grand Total	\$ 729,046							
Total Supplier Payment - in \$1000								
Summer	\$ 303,045							
Winter	\$ 426,048							
Total	\$ 729,093							
Differences - in \$1000								
Summer	\$ 17,557							
Winter	\$ (17,510)							
Total	\$ 47							

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 2026 to May 2027 BGS-RSCP Rates  
based on results of February 2026 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 / EV-ERR	RS TOU - BGS	MGS - SEC / SEVC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC
Summer - all hrs			13.9886	11.0375	11.5604	10.5612	10.2475	8.0399	9.8873
	On-Peak		15.7313						
	Off-Peak		7.6797						
for Block 1 (0-750 kWh/m) usage		11.7651							
	for Block 2 (>750 kWh/m) usage	12.6835							
Winter - all hrs		12.6053	15.6121	10.5027	11.1335	10.0085	9.6826	7.9164	9.2727
	On-Peak		16.0852						
	Off-Peak		7.8218						

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

		RS / EV-ERR	RS TOU - BGS	MGS - SEC / SEVC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC
Total Rate Revenue - in \$1000									
	Summer	\$	201,035	\$	87	\$	42,841	\$	2,570
	Winter	\$	271,382	\$	113	\$	64,714	\$	3,949
	Total	\$	472,417	\$	200	\$	107,555	\$	6,519
		\$	42,150	\$	12,630	\$	1,335	\$	397
	Total Summer	\$	303,045						
	Total Winter	\$	426,046						
	Grand Total	\$	729,092						
Total Supplier Payment - in \$1000									
	Summer	\$	303,045						
	Winter	\$	426,048						
	Total	\$	729,093						
Differences - in \$1000									
	Summer	\$	0						
	Winter	\$	(1)						
	Total	\$	(1)						

# Attachment 4

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

2026/2027 Delivery Year - Illustrative Data

	Capacity Proxy Price True-Up Development for Winning Suppliers from 2024 BGS-RSCP Auction	Capacity Proxy Price True-Up Development for Winning Suppliers from 2025 BGS-RSCP Auction	Capacity Proxy Price True-Up Development for Winning Suppliers from 2026 BGS-RSCP Auction (if needed)	
	2026/27 Delivery Year	2026/27 Delivery Year	2026/27 Delivery Year	Notes:
1 Zonal Capacity Price (\$/MW-day)	\$280.00	\$280.00	\$280.00	as may be determined by the RPM, or its successor, or otherwise
2 Capacity Proxy Price (\$/MW-day)	\$49.05	\$270.35	\$270.43	per Board Orders dated 11/17/2023 and 11/21/2024 and XX/XX/2025
3 Capacity Proxy Price True-Up - \$/MW-day	\$230.95	\$9.65	\$9.57	= line 1 - line 2
4 BGS-RSCP Gen Obl - MW	1,792.2	1,792.2	1,792.2	
5 Days in Year	365	365	365	
6 Capacity Proxy Price True-Up Annual Cost	\$151,076,924	\$6,312,589	\$6,260,256	= line 3 * line 4 * line 5
7 Eligible Tranches	7	7	8	from Table A
8 Total Tranches	22	22	22	from Table A
9 % of tranches eligible for payment	31.82%	31.82%	36.36%	= line 7 / line 8
10 Capacity Proxy Price True-Up Cost	\$48,069,930	\$2,008,551	\$2,276,457	= line 6 * line 9
11 Total Applicable Customer Usage @ bulk system - in MWh	6,661,232	6,661,232	6,661,232	
12 Eligible Customer Usage @ bulk system - in MWh	2,119,483	2,119,483	2,422,266	= line 9 * line 11
13 Capacity Proxy Price True-Up - \$/MWh	\$22.68	\$0.95	\$0.94	= line 10/ line 12 - rounded to 2 decimal places

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

2027/2028 Delivery Year - Illustrative Data

	Capacity Proxy Price True-Up Development for Winning Suppliers from 2025 BGS-RSCP Auction	Capacity Proxy Price True-Up Development for Winning Suppliers from 2026 BGS-RSCP Auction (if needed)	
	2027/28 Delivery Year	2027/28 Delivery Year	Notes:
1 Zonal Capacity Price (\$/MW-day)	\$280.00	\$280.00	as may be determined by the RPM, or its successor, or otherwise per Board Orders dated 11/21/2024 and XX/XX/2025
2 Capacity Proxy Price (\$/MW-day)	\$270.35	\$270.43	
3 Capacity Proxy Price True-Up - \$/MW-day	\$9.65	\$9.57	= line 1 - line 2
4 BGS-RSCP Gen Obl - MW	1,792.2	1,792.2	
5 Days in Year	366	366	
6 Capacity Proxy Price True-Up Annual Cost	\$6,329,883	\$6,277,408	= 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	\$2,014,054	\$2,282,694	= line 6 * line 9
11 Total Applicable Customer Usage @ bulk system - in MWh	6,661,232	6,661,232	
12 Eligible Customer Usage @ bulk system - in MWh	2,119,483	2,422,266	= line 9 * line 11
13 Capacity Proxy Price True-Up - \$/MWh	\$0.95	\$0.94	= line 10/ line 12 - rounded to 2 decimal places

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

2028/2029 Delivery Year - Illustrative Data

1 Zonal Capacity Price (\$/MW-day)	2028/29	
2 Capacity Proxy Price (\$/MW-day)	Delivery Year	Notes:
	\$280.00	as may be determined by the RPM, or its successor, or otherwise
	\$270.43	per Board Order dated XX/XX/2025
3 Capacity Proxy Price True-Up - \$/MW-day	\$9.57	= line 1 - line 2
4 BGS-RSCP Gen Obl - MW	1,792.2	
5 Days in Year	365	
6 Capacity Proxy Price True-Up Annual Cost	\$6,260,256	= 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	\$2,276,457	= line 6 * line 9
11 Total Applicable Customer Usage @ bulk system - in MWh	6,661,232	
12 Eligible Customer Usage @ bulk system - in MWh	2,422,266	= line 9 * line 11
13 Capacity Proxy Price True-Up - \$/MWh	\$0.94	= line 10/ line 12 - rounded to 2 decimal places

Capacity Proxy Price True-Up Development for Winning Suppliers from 2026 BGS-RSCP Auction (if needed)

Table A With Additional Line Item  
Calculation of June 2027 to May 2028 BGS-RSCP Rates  
*Illustrative Purposes Only for ACE*

Table A    Auction Results					Notes:
line #	Specific BGS-RSCP Auction >>	remaining portion of 36 month bid - 2025 auction	remaining portion of 36 month bid - 2026 auction	36 month bid - 2027 auction	
1	Winning Bid - in \$/MWh	\$ 110.50	\$ 111.45	\$ 112.39	winning Bids entered after 2027 BGS Auction = line 1 + line 1A
1A	27/28 Capacity Proxy Price True-up - in \$/MWh	\$ 0.95	\$ 0.94		
1B	Total - in \$/MWh	\$ 111.45	\$ 112.39	\$ 112.39	
2	# of Tranches for Bid	7	8	7	from then current Bid
3	Total # of Tranches	22	22	22	
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	2,768,722			from current Bid Factor Spreadsheet
7	Winter MWh	3,892,510			
Total Payment to Suppliers - in \$1000					
8	Summer	\$ 98,183	\$ 113,155	\$ 99,011	= (1 + 1A) * (2)/(3) * (4) * (6) / 1000 = (1 + 1A) * (2)/(3) * (5) * (7) / 1000
9	Winter	\$ 138,034	\$ 159,083	\$ 139,198	
10	Total	\$ 236,216	\$ 272,238	\$ 238,209	
Average Payment to Suppliers - in \$/MWh					
11	Summer	\$ 112.09			= sum(line 8) / (6) - rounded to 2 decimal places
12	Winter	\$ 112.09			= sum(line 9) / (7) - rounded to 2 decimal places
13	Total weighted average	\$ 112.09	<<< used in calculation of Customer Rates		= sum(line 10) / [(6) + (7)] rounded to 2 decimal places



Table A With Additional Line Item  
Calculation of June 2028 to May 2029 BGS-RSCP Rates  
*Illustrative Purposes Only for ACE*

Table A		Auction Results			
line #	Specific BGS-RSCP Auction >>	remaining portion of 36 month bid - 2026 auction	remaining portion of 36 month bid - 2027 auction	36 month bid - 2028 auction	Notes:
1	Winning Bid - in \$/MWh	\$ 111.45	\$ 112.39	\$ 112.39	winning Bids entered after 2028 BGS Auction = line 1 + line 1A
1A	28/29 Capacity Proxy Price True-up - in \$/MWh	\$ 0.94			
1B	Total - in \$/MWh	\$ 112.39	\$ 112.39	\$ 112.39	
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	2,768,722			from current Bid Factor Spreadsheet
7	Winter MWh	3,892,510			
Total Payment to Suppliers - in \$1000					
8	Summer	\$ 113,155	\$ 99,011	\$ 99,011	= (1 + 1A) * (2)/(3) * (4) * (6) / 1000 = (1 + 1A) * (2)/(3) * (5) * (7) / 1000
9	Winter	\$ 159,083	\$ 139,198	\$ 139,198	
10	Total	\$ 272,238	\$ 238,209	\$ 238,209	
Average Payment to Suppliers - in \$/MWh					
11	Summer	\$ 112.39			= sum(line 8) / (6) - rounded to 2 decimal places
12	Winter	\$ 112.39			= sum(line 9) / (7) - rounded to 2 decimal places
13	Total weighted average	\$ 112.39	<<< used in calculation of Customer Rates		= sum(line 10) / [(6) + (7)] rounded to 2 decimal places

# Attachment 5

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

	Capacity Proxy Price True-Up Development for Winning Suppliers from 2026 BGS-CIEP Auction (if needed) 2026/27 Delivery Year		
1 Zonal Capacity Price (\$/MW-day)		\$280.00	
2 Capacity Proxy Price (\$/MW-day)		<u>\$270.43</u>	Notes: as may be determined by the RPM or its successor or otherwise per Board Order dated XX/XX/2025
3 Capacity Proxy Price True-Up - \$/MW-day		<u>\$9.57</u>	= line 1 - line 2
4 Winning Bid - in \$/MW-day		\$605.22	illustrative winning bid in 2026 BGS-CIEP Auction
5 Payment to Suppliers - in \$/MW-day		<u>\$614.79</u>	<<< used in calculation of Customer Rates = line 3 + line 4

In the Matter of the Provision of Basic Generation Service (“BGS”) for the Period Beginning June 1, 2026  
BPU Docket No. ER25040190

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