IN THE MATTER OF THE PROVISION OF BASIC GENERATION SERVICE FOR THE PERIOD BEGINNING JUNE 1, 2021	**STATE OF NEW JERSEY BOARD OF PUBLIC UTILITIES BPU DOCKET NO. ER20030190**

ATLANTIC CITY ELECTRIC COMPANY

BASIC GENERATION SERVICE
COMMENCING JUNE 1, 2021

COMPANY-SPECIFIC ADDENDUM
COMPLIANCE FILING
December 4 , 2020

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 shall have the meanings defined in the joint filing.

As described in the generic section of this filing, two (2) different methods will be utilized for the pricing of Basic Generation Service ("BGS") to customers – residential and small commercial energy pricing and variable hourly energy pricing. The residential and small commercial energy pricing formerly referred to as "Basic Generation Service–Fixed Price" or "BGS-FP"[1] now termed "Basic Generation Service–Residential Small Commercial Pricing" or "BGS-RSCP" and the hourly energy pricing service termed "Basic Generation Service – Commercial and Industrial Energy Pricing" or "BGS- CIEP." BGS-RSCP is to be available to all residential and small commercial customers, specifically those customers taking service on Rate Schedules RS, MGS (Secondary and Primary), AGS (Secondary and Primary), DDC, SPL, and CSL. These rate classes comprise the vast majority of ACE's customers and approximately 86% 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

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

Board's Decision on June 18, 2012, in BPU Docket No. ER12020150, changing the BGS-CIEP required customer capacity peak load share ("PLS") to 500 kW or greater effective June 1, 2013, will be the only default supply option available to customers on Rate Schedules MGS Secondary, MGS Primary, AGS Secondary or AGS Primary with an annual PLS for generation capacity equal to or greater than 500 kW as of November 1 of the year prior to the BGS auction. There are an estimated 232 eligible CIEP customers representing approximately 14% 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.

Pursuant to the Board's Order dated January 20, 2009, in BPU Docket No. ER08050310, ACE will not provide to the BGS Suppliers any Pennsylvania New Jersey Maryland ("PJM") credit issued as a result of Demand Response ("DR") programs implemented after June 1, 2009. For many years, ACE operated a DR program known as the Residential Controllable Smart Thermostat Program (the "RCSTP"), which was available to a limited number of residential customers. This program derived credits through the PJM Reliability Pricing Model Capacity Market and the PJM energy markets. PJM credits associated with this DR program were credited to the RGGI Recovery Charge delineated in Rider RGGI in the Company's Tariff for Electric Service. The RCSTP ended on May 31, 2020 and references to it will be deleted from future BGS company-specific addenda.

A. <u>COMMITTED SUPPLY</u>

"Committed Supply" means power supplies to which ACE has an existing physical or financial entitlement. For ACE, Committed Supply includes its Non-Utility Generation ("NUG") contracts, including any restructured replacement power contracts, which may extend into or through the BGS bid period. ACE retains the right to negotiate changes in, and operational control over, all of its NUG contracts.

As a result of the Board's December 18, 2002 Order in BPU Docket Nos. EX01110754 and EO02070384 (the "BGS Orders"), effective August 1, 2003, ACE's NUG-related Committed Supply (capacity, energy, and ancillaries, if any) is being sold in the wholesale markets. NUG-related capacity, energy, and ancillaries (if any) will continue to be sold in the wholesale markets. These sales shall be considered prudent unless and until the Board determines that a different protocol is appropriate. Just as they are currently, ACE's actual above-market NUG contract costs will continue to be charged to the Non-Utility Generation Charge ("NGC") clause, with full and timely cost recovery assured, and subject to deferral in accordance with ACE's restructuring order. In setting the NGC, the actual NUG contract costs will be offset with revenues received from the sale of NUG power in the wholesale markets.

If ACE is required to invoke the Contingency Plan (discussed at length below), Committed Supply may be used to offset requirements associated with the Contingency Plan. Any generation from ACE's Committed Supply that qualifies as a Class I or Class II renewable resource will be used to meet the Renewable Portfolio Standards ("RPS") requirements, and, since ACE has no BGS supply requirements, it will, to the extent permitted by applicable regulatory and contractual provisions, be credited on a pro-rata basis to winning BGS-RSCP and BGS-CIEP suppliers. This will assure that these environmental benefits are retained by BGS customers in ACE's service territory. Winning BGS-RSCP and BGS-CIEP suppliers will be responsible for obtaining and providing related verification information to ACE for the minimum Class I and Class II percentages required by the RPS associated with the tranches they serve, net of renewable attributes of the Committed Supply energy proportionately applied and subject to the foregoing limitations to each supplier's tranches.

The ACE NUG-related Committed Supply subject to the foregoing limitations eligible to supply the Class II renewable energy certificate to the BGS suppliers expired on September 5, 2016.

B. 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 2021;

c) a default during the June 1, 2021 - May 31, 2022 supply period, under the BGS-CIEP contracts entered into for 12 months; and/or

d) a default during the June 1, 2021 - May 31, 2024 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 RPS Renewable Energy Certificate) for the remaining tranches through PJM-administered markets until May 31, 2022 and may retain Committed Supply to serve these tranches. Any unsubscribed tranches for the period after May 31, 2022, may be included in a subsequent auction or treated pursuant to the provisions of part 4 of the Contingency Plan described below. This Contingency Plan will alert bidders that, in order to secure BGS-RSCP and BGS-CIEP prices from New Jersey BGS customers for their supply, it will be necessary to bid in to the auctions.

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

2. <u>Defaults Prior to June 1, 2021</u>

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

3. <u>Defaults During the June 1, 2021 - May 31, 2022 Supply Period</u>

If a default occurs during the June 1, 2021 - May 31, 2022 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, and Committed Supply may be retained to serve these tranches. 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, 2021 - May 31, 2024 Supply Period

If a default occurs during the June 1, 2021 - May 31, 2024 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, and Committed Supply may be retained to serve these tranches. 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 RFPs, broker markets, capacity costs based on the PJM RPM, and the PJM spot energy market.

C. 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.
- rent and maintenance of office space in New Jersey for the Auction Manager;
- outside counsel legal costs associated with the prosecution and/or defense of BGS patent claims; and
- facility costs associated with viewing the annual auction in real time, which include, but are not limited to, costs for physical space and equipment/media connections.

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

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

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

3. any cost for procurement of capacity, energy, ancillary service, transmission, RPS compliance, and other expenses related to the Contingency Plan, and any payments to the winners of a subsequent bid process to cover defaults made under the Contingency Plan, less any payments recovered from defaulting bidders. In the

event that implementation of the Contingency Plan is required for BGS CIEP load, CIEP Standby Fee payments will be tracked separately.

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

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

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

reconciled and returned to customers, with interest, on a periodic basis, through the BGS-RSCPRC and/or BGS-CIEPRC.

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

In the event that 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, 2021 through May 31, 2022 will be applied as a $/kWh adjustment to the CIEP Standby Fee for the next BGS-CIEP annual period. In this manner, the mechanism to reconcile any CIEP Standby Fee deferred balance is applied, to the greatest extent practicable, to all BGS-CIEP eligible customers who paid the CIEP Standby Fee, and not only to those taking BGS-CIEP service.

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

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

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

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

D. DESCRIPTION OF BGS TARIFF SHEETS

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

1. BGS-RSCP

BGS-RSCP is to be available to all customers served on Rate Schedules RS, DDC, SPL, and CSL. BGS-RSCP is also available to customers with a PLS of less than 500 kW who are served under Rate Schedules MGS Secondary, MGS 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, MGS Secondary, MGS Primary, AGS Secondary, AGS Primary, DDC, SPL, and CSL include the costs related to energy, generation capacity, RPS, ancillary services, and administration. This is a continuation of the current approved methodology for recovering all electric supply service costs in the kilowatt- hour charges for these Rate Schedules.

Typically, the generation capacity costs used in the development of the BGS-RSCP rates are the relevant current wholesale market prices for capacity based on the average, 2021/2022, 2022/2023, and 2023/2024 Base Residual Auctions ("BRA") results under the Reliability Pricing Model ("RPM") applicable to load served in the ACE zone. With the postponements of the BRAs for the 2022/2023 and 2023/2024 Delivery Years, a Capacity Proxy Price of $152.06 per MW-Day and $146.51 per MW-Day has been used in place of the 2022/2023 and 2023/2024 BRA values respectively.

For Energy Year ("EY") 2023, with Supplement A to the BGS-RSCP Supplier Master Agreement approved by the BPU on November 18, 2020, 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 2022/2023 Delivery Year.

For EY 2024, with Supplement B to the BGS-RSCP Supplier Master Agreement approved by the BPU on November 18, 2020, payments to BGS-RSCP suppliers will be adjusted for the capacity price difference between the Zonal Capacity Price which is the price paid by BGS-RSCP Suppliers for Capacity in the Company's PJM zone, as may be determined under the Reliability

Pricing Model or its successor or otherwise, and the Capacity Proxy Price for the 2023/2024 Delivery Year.

ACE will file new tariff sheets for EY 2023 and EY 2024, 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 this true up as the actual value is not known at this time. **Attachment 4**, pages 2 and 3 are illustrative examples of how the Capacity Proxy Price True Up will be calculated for EY 2023 and EY 2024, respectively and prospectively.

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 (the winning bids from the prior two auctions will have transmission charges removed by the methods shown in **Attachment 5** – Development of Assumed Transmission Price in Bids), 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, 2021, the pricing will be based on the 36-month auction price, the 36-month price from the auction held in February 2020 and the 36-month price from the auction held in February 2019. 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- 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 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.

For prior BGS Contracts EY 2019 and EY 2020, the BGS price will be adjusted to remove the BGS Transmission Charge as shown in **Attachment 5** - Development of Assumed Transmission Price in Bids. The Transmission Obligations and kWh used per tranche are the same as were used in the BGS Pricing Spreadsheet at the time of the BGS Auctions held in February of 2019 and February of 2020.

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

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

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

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

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

a. BGS Energy Charge

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

b. BGS Capacity Charges

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

c. BGS Reconciliation Charge

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

d. CIEP Standby Fee

For the period June 1, 2021 through May 31, 2022, the EDCs will pay each BGS-CIEP supplier a CIEP Standby Charge equal to $0.000150 per kWh times their pro-rata share of the total energy usage measured at the meters of all of ACE's BGS-CIEP eligible customers. The CIEP Standby Fee is a delivery charge that is applicable to all customers having BGS-CIEP as their default supply service. This includes all customers served on Rate Schedules TGS, all customers served on Rate Schedules MGS Secondary, MGS Primary, AGS Secondary, and AGS Primary with a peak load share of 500 kW or greater, and all customers on Rate Schedules MGS Secondary, MGS Primary, AGS Secondary, and AGS Primary with a peak load share of less than 500 kW that have elected the BGS-CIEP default supply option. Any under- or over-recovery of the CIEP Standby Fee will continue to be subject to deferred accounting.

E. 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 2021 through May 2022, with migration adjustments. The values in Table No. 3 will be updated in January 2021 to better reflect forecasts for the June 1st delivery year.

Table No. 4 (Forward Prices – Energy Only @ Bulk System) contains the forward prices for energy, by time period and month, for the BGS analysis period. These values are the energy on- peak forwards as of November 2, 2020, for the PJM West trading hub for the period of June 2021 to May 2022, 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 2020. Table No. 10 will be updated in January 2021, 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 2021/2022, the Capacity Proxy Price for Delivery Year 2022/2023, and the Capacity Proxy Price for Delivery Year 2023/2024. 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 2022/2023 and the 2023/2024 delivery years when available as may be determined through the Reliability Pricing Model 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 $15.39 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 2021 to May 2022 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 prior two BGS auctions, reduced by the assumed transmission price in those bids, arrived at by the methods shown in **Attachment 5 –** Development of Assumed Transmission Price in Bids, as well as the results of the current auction. The Capacity Proxy Price True Up cost in $ per MWh is not known at this time and no value is entered for that variable. However, upon determination of the Zonal Capacity Prices, which are the prices paid by BGS-RSCP Suppliers for Capacity for the 2022/2023 and 2023/2024 Delivery Years through the Reliability Pricing Model or its successor or otherwise, such prices will be applied. 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.

F. <u>CONCLUSION</u>

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

1. it is necessary and in the public interest for the electric public utilities to secure service for the BGS-RSCP and BGS-CIEP customers, as approved herein, for the period June 1, 2021 to May 31, 2024;
2. the Company's proposed accounting for BGS is approved for purposes of accounting and BGS cost recovery;

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

Attachment 1

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

RIDER (BGS)
Basic Generation Service (BGS)

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

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

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	$ 0.004626
MGS Secondary, AGS Secondary, SPL/CSL, DDC	$ 0.004626
MGS Primary, AGS Primary	$ 0.004505

BGS-CIEP

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

Generation Capacity Obligation Charge

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

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

Ancillary Service Charge

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

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

BGS Reconciliation Charge:

	Charge ($ per kWh)
Service taken at Secondary Voltage	$ 0.002486
Service taken at Primary Voltage	$ 0.002421
Service taken at Sub-Transmission Voltage	$ 0.002393
Service taken at Transmission Voltage	$ 0.002370

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.

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

RIDER (BGS) continued
Basic Generation Service (BGS)

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

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

	Rate Class							
	RS	MGS Secondary	MGS Primary	AGS Secondary	AGS Primary	TGS	SPL/ CSL	DDC
VEPCo	0.000202	0.000160	0.000122	0.000116	0.000096	0.000090	-	0.000073
TrAILCo	0.000339	0.000246	0.000270	0.000173	0.000133	0.000123	-	0.000107
PSE&G	0.000460	0.000365	0.000277	0.000265	0.000219	0.000203	-	0.000165
PATH	(0.000003)	(0.000002)	(0.000002)	(0.000002)	(0.000001)	(0.000001)	-	(0.000001)
PPL	0.000118	0.000085	0.000094	0.000060	0.000047	0.000043	-	0.000037
PECO	0.000130	0.000095	0.000103	0.000066	0.000051	0.000047	-	0.000042
Pepco	0.000025	0.000018	0.000019	0.000013	0.000010	0.000009	-	0.000007
MAIT	0.000021	0.000017	0.000013	0.000012	0.000010	0.000010	-	0.000007
JCP&L	0.000003	0.000002	0.000002	0.000002	0.000001	0.000001	-	0.000001
EL05-121	0.000016	0.000013	0.000010	0.000010	0.000007	0.000007	-	0.000006
Delmarva	0.000007	0.000005	0.000005	0.000003	0.000003	0.000002	-	0.000002
BG&E	0.000029	0.000021	0.000023	0.000015	0.000012	0.000011	-	0.000010
AEP-East	0.000042	0.000033	0.000026	0.000025	0.000020	0.000018	-	0.000015
Silver Run	0.000154	0.000122	0.000093	0.000088	0.000074	0.000068	-	0.000055
NIPSCO	0.000001	0.000001	0.000001	0.000001	0.000001	0.000001	-	0.000001
CW Edison	0.000001	0.000001	0.000001	-	-	-	-	-
Total	0.001545	0.001182	0.001057	0.000847	0.000683	0.000632	-	0.000527

Date of Issue: **Effective Date:**
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	RS TOU - BGS	MGS - SEC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC
January	52.69%	52.69%	54.94%	50.61%	55.90%	52.43%	36.95%	49.60%
February	50.55%	50.97%	55.66%	50.18%	55.41%	52.50%	34.00%	50.31%
March	47.96%	48.57%	53.76%	48.67%	53.71%	49.96%	29.28%	47.46%
April	53.67%	53.91%	57.67%	51.47%	57.33%	53.75%	26.20%	50.77%
May	54.06%	54.18%	52.20%	50.02%	55.86%	53.30%	21.40%	49.72%
June	52.03%	52.14%	55.16%	49.52%	53.58%	50.64%	18.26%	46.49%
July	52.94%	53.12%	57.57%	54.10%	56.82%	53.24%	19.32%	49.95%
August	54.74%	55.01%	59.38%	55.61%	56.51%	53.77%	23.06%	50.18%
September	47.63%	47.66%	55.25%	52.48%	55.74%	51.56%	27.15%	47.62%
October	53.44%	53.25%	61.31%	55.32%	61.17%	57.34%	35.38%	53.17%
November	47.60%	47.74%	50.73%	51.27%	53.27%	50.00%	33.80%	46.33%
December	49.74%	49.89%	52.63%	52.83%	54.49%	50.85%	36.07%	48.04%

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

	RS TOU - BGS
January	38.41%
February	39.57%
March	37.39%
April	34.81%
May	37.99%
June	39.70%
July	39.67%
August	41.23%
September	42.59%
October	35.50%
November	38.35%
December	35.24%

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

	RS	RS TOU - BGS	MGS - SEC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC	Total
Jan-22	331,800	341	70,408	1,047	73,952	9,202	4,436	804	491,990
Feb-22	312,629	330	64,910	1,313	66,172	7,273	3,991	742	457,360
Mar-22	284,918	302	71,224	690	72,726	4,826	3,989	818	439,493
Apr-22	221,555	235	61,331	1,063	58,251	5,792	3,416	706	352,350
May-22	195,495	196	65,783	1,147	66,423	6,224	3,438	750	339,458
Jun-21	256,756	245	71,047	1,191	72,643	7,500	3,528	810	413,720
Jul-21	427,553	393	86,339	1,287	88,967	7,094	3,699	986	616,318
Aug-21	471,662	440	91,120	1,202	96,204	8,776	3,852	1,043	674,301
Sep-21	452,640	415	92,784	1,039	91,361	7,206	3,981	1,065	650,491
Oct-21	214,669	211	64,574	945	62,676	2,360	3,995	737	350,166
Nov-21	183,528	188	65,834	736	66,528	9,200	4,307	752	331,073
Dec-21	265,709	275	64,328	938	69,248	6,630	4,319	732	412,179
Total	3,618,914	3,572	869,682	12,599	885,151	82,083	46,953	9,945	5,528,898

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

	On-Peak	Off/On Pk LMP ratio	Off-Peak
Jan-22	46.80	0.790	36.95
Feb-22	43.65	0.790	34.47
Mar-22	35.35	0.790	27.91
Apr-22	30.15	0.790	23.81
May-22	30.10	0.790	23.77
Jun-21	31.00	0.670	20.76
Jul-21	36.85	0.670	24.68
Aug-21	33.45	0.670	22.40
Sep-21	32.25	0.670	21.60
Oct-21	31.40	0.790	24.79
Nov-21	31.80	0.790	25.11
Dec-21	34.50	0.790	27.24

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

	On-Peak	Off-Peak
Jan-22	92%	97%
Feb-22	92%	97%
Mar-22	92%	97%
Apr-22	92%	97%
May-22	92%	97%
Jun-21	89%	89%
Jul-21	89%	89%
Aug-21	89%	89%
Sep-21	89%	89%
Oct-21	92%	97%
Nov-21	92%	97%
Dec-21	92%	97%

Table #6

Losses	**RS**	**RS TOU - BGS**	**MGS - SEC**	**MGS - PRI**	**AGS - SEC**	**AGS - PRI**	**SPL/CSL**	**DDC**
Delivery Loss Factor	6.6720%	6.6720%	6.6720%	4.1641%	6.6720%	4.1641%	6.6720%	6.6720%
Loss Factors + EHV Losses =	7.0688%	7.0688%	7.0688%	4.5715%	7.0688%	4.5715%	7.0688%	7.0688%
Expansion Factor =	1.07606	1.07606	1.07606	1.04790	1.07606	1.04790	1.07606	1.07606
Marginal Loss Factor (w/ EHV Losses) =	1.8039%	1.8039%	1.8039%	1.8039%	1.8039%	1.8039%	1.8039%	1.8039%
Loss Factor w/o Marginal Loss =	5.3616%	5.3616%	5.3616%	2.8184%	5.3616%	2.8184%	5.3616%	5.3616%
Expansion Factor w/o Marginal Loss =	1.05665	1.05665	1.05665	1.02900	1.05665	1.02900	1.05665	1.05665

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

	RS	**RS TOU - BGS**	**MGS - SEC**	**MGS - PRI**	**AGS - SEC**	**AGS - PRI**	**SPL/CSL**	**DDC**
Summer - all hrs	$ 27.09	$ 27.09	$ 27.50	$ 26.40	$ 27.40	$ 26.22	$ 23.75	$ 26.63
On Peak	$ 32.25	$ 32.23	$ 32.09	$ 31.30	$ 32.11	$ 31.14	$ 31.91	$ 32.11
Off Peak	$ 21.54	$ 21.53	$ 21.44	$ 20.88	$ 21.45	$ 20.81	$ 21.43	$ 21.44
Winter - all hrs	$ 33.26	$ 33.31	$ 32.58	$ 31.76	$ 32.75	$ 32.30	$ 31.41	$ 32.26
On Peak	$ 36.21	$ 36.26	$ 35.25	$ 34.52	$ 35.33	$ 35.12	$ 35.91	$ 35.25
Off Peak	$ 30.16	$ 30.19	$ 29.35	$ 28.86	$ 29.49	$ 29.23	$ 29.28	$ 29.35
Annual	$ 30.51	$ 30.71	$ 30.59	$ 29.75	$ 30.64	$ 30.03	$ 28.95	$ 30.05

System Average Cost @ customer - (limited to classes shown above) = $ 30.52

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

		RS	**RS TOU - BGS**	**MGS - SEC**	**MGS - PRI**	**AGS - SEC**	**AGS - PRI**	**SPL/CSL**	**DDC**
Summer - all hrs		$ 43,571	$ 40	$ 9,386	$ 125	$ 9,566	$ 802	$ 358	$ 104
	PJM on pk	$ 26,883	$ 25	$ 6,234	$ 78	$ 6,254	$ 499	$ 106	$ 61
	PJM off pk	$ 16,688	$ 15	$ 3,152	$ 46	$ 3,312	$ 303	$ 251	$ 43
Winter - all hrs		$ 66,859	$ 69	$ 17,218	$ 250	$ 17,551	$ 1,663	$ 1,002	$ 195
	PJM on pk	$ 37,240	$ 39	$ 10,210	$ 140	$ 10,565	$ 941	$ 367	$ 105
	PJM off pk	$ 29,618	$ 31	$ 7,007	$ 111	$ 6,986	$ 722	$ 635	$ 90
Annual		$ 110,430	$ 110	$ 26,604	$ 375	$ 27,118	$ 2,465	$ 1,359	$ 299

System Total $ 168,759

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

		RS	RS TOU - BGS	MGS - SEC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC
Summer - all hrs		$ 27.09	$ 27.09	$ 27.50	$ 26.40	$ 27.40	$ 26.22	$ 23.75	$ 26.63
	ACECO On pk		$ 33.68						
	ACECO Off pk		$ 22.53						
Winter - all hrs		$ 33.26	$ 33.31	$ 32.58	$ 31.76	$ 32.75	$ 32.30	$ 31.41	$ 32.26
	ACECO On pk		$ 37.40						
	ACECO Off pk		$ 30.87						
Annual Average		$ 30.51	$ 30.71	$ 30.59	$ 29.75	$ 30.64	$ 30.03	$ 28.95	$ 30.05
System Average		$ 30.52							

Table #10 **Generation Obligations and Costs and Other Adjustments**
obligations - values effective June 2020; costs are market estimates

in MW	RS	RS TOU - BGS	MGS - SEC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC	Total
Gen Load - MW	1,247.2	0.6	248.4	2.9	184.9	11.5	0.0	1.3	1,696.8
Gen Obl - MW	1,520.6	0.7	302.9	3.6	225.5	14.0	0.0	1.6	2,068.8

# 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

	Base Capacity			
Summer	$154.49	$/MW/day	Summer Total	$ 38,992,293
Winter	$154.49	$/MW/day	Winter Total	$ 77,664,976
			Annual Total	$ 116,657,269

Residential Inversion Determination

---------- Rate RS ----------

	Charges	% usage		
Block 1 (0-750 kWh/m)	5.480200	62.58%	SUM 'First 750 KWh	1,125,085,024
Block 2 (>750 kWh/m)	6.345400	37.42%	SUM '> 750 KWh	672,734,800
Calculated inversion =	0.865200		WIN	2,177,938,585
				3,975,758,409

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

Ancillary Services	$ 2.00
Renewable Power Cost	$ 15.39
Total Ancillary Services & Renewable Power Costs	$ 17.39

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

Generation Obl -	RS	RS TOU - BGS	MGS - SEC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC
per annual MWh	$ 23.69	$ 28.50	$ 19.64	$ 16.04	$ 14.36	$ 9.62	$ 0.00	$ 8.82
recovery per summer MWh	$ 17.82	$ 21.61	$ 16.73	$ 14.31	$ 12.17	$ 8.63	$ 0.00	$ 7.51
recovery per winter MWh	$ 28.40	$ 33.93	$ 21.52	$ 17.07	$ 15.79	$ 10.20	$ 0.00	$ 9.67

Table #13 **Summary of BGS Unit Costs @ customer**
Includes energy, Generation capacity obligations, Ancillary Services, and Renewable Power Costs - unadjusted for billing vs. PJM time period differences.
in $/MWh

		RS	RS TOU - BGS	MGS - SEC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC
Summer - all hrs		$ 63.62	$ 67.42	$ 62.94	$ 58.93	$ 58.28	$ 53.07	$ 42.46	$ 52.85
	On-Peak		$ 74.00						
	Off-Peak		$ 41.24						
	Block 1 (0-750 kWh/m)	$ 60.38							
	Block 2 (>750 kWh/m)	$ 69.03							
Winter - all hrs		$ 80.37	$ 85.95	$ 72.82	$ 67.06	$ 67.25	$ 60.72	$ 50.12	$ 60.65
	On-Peak		$ 90.05						
	Off-Peak		$ 49.59						
Annual		$ 72.92	$ 60.49	$ 68.94	$ 64.01	$ 63.71	$ 57.87	$ 47.67	$ 57.59
	Grand Total Cost in $1000 =	$ 388,831							
Average cost for rates shown (@ customer) =						$ 70.33			
Average costs for rates shown (@ transmission nodes) =						$ 66.59			

Table #14 **Ratio of BGS Unit Costs @ customer to Average Cost @ transmission nodes (rounded to 3 decimal places)**
Includes energy, Generation capacity obligations, Ancillary Services, and Renewable Power Costs - unadjusted for billing vs. PJM time period differences.

		RS	RS TOU - BGS	MGS - SEC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC
Summer - all hrs			**1.013**	**0.945**	**0.885**	**0.875**	**0.797**	**0.638**	**0.794**
	On-Peak		**1.111**						
	Off-Peak		**0.619**						
	All usage Multiplier	**0.955**							
	Constant **$**	**(3.24)**		for Block 1 (0-750 kWh/m) usage					
	Constant **$**	**5.41**		for Block 2 (>750 kWh/m) usage					
Winter - all hrs		**1.207**	**1.291**	**1.094**	**1.007**	**1.010**	**0.912**	**0.753**	**0.911**
	On-Peak		**1.352**						
	Off-Peak		**0.745**						
Annual		**1.095**	**0.908**	**1.035**	**0.961**	**0.957**	**0.869**	**0.716**	**0.865**

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

		RS	RS TOU - BGS	MGS - SEC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC
Total Costs by Rate - in $1000									
	Summer	$ 102,333	$ 101	$ 21,482	$ 278	$ 20,350	$ 1,623	$ 640	$ 206
	Winter	$ 161,561	$ 179	$ 38,477	$ 528	$ 36,045	$ 3,128	$ 1,599	$ 366
	Total	$ 263,894	$ 279	$ 59,959	$ 807	$ 56,394	$ 4,750	$ 2,238	$ 573
% of Annual Total $ by Rate									
	Summer	39%	36%	36%	34%	36%	34%	29%	36%
	Winter	61%	64%	64%	66%	64%	66%	71%	64%
Total Costs - in $1000									
	Summer	$ 147,012							
	Winter	$ 241,883							
	Total	$ 388,894							

% of Annual Total $			If total $ were split on a per MWh basis (on bulk system MWhs):					
	Summer	38%	$ 59.11	per MWh @ trans nodes	Ratio to BGS Cost	>>>	Summer	**1.0000**
	Winter	62%	$ 72.16	per MWh @ trans nodes	(rounded to 4 decimal places)		Winter	**1.0000**

Assumptions:

Gen Cost =	$154.49	per MW-day	summer
=	$154.49	per MW-day	winter
Ancillary Services =	$ 2.00	per MWH	
Renewable Power Cost =	$ 15.39	per MWH	

Energy Prices = Quotes for the period June 1, 2021 to May 31, 2022 - 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 2020
Losses = existing approved loss factors
PJM Time Periods = PJM trading time periods - 7 AM to 11 PM weekdays, local time, x NERC holidays
- New Year's, Memorial, 4th of July, Labor Day, Thanksgiving & Christmas

Table #16 **Retail Rates Charged to BGS RSCP (Previously "FP") Customers**

Includes energy, Generation Obligations, Ancillary Services, and Renewable Power Costs
in $/MWh

BGS Avg. Price >>>>>>>>>>> $ 66.617

		RS	RS TOU - BGS	MGS - SEC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC
Summer - all hrs			$ 76.058	$ 70.953	$ 66.448	$ 65.697	$ 59.840	$ 47.902	$ 59.615
	On-Peak		$ 83.416						
	Off-Peak		$ 46.476						
	Block 1 (0-750 kWh/m)	$ 68.054							
	Block 2 (>750 kWh/m)	$ 77.806							
Winter - all hrs		$ 74.204	$ 79.368	$ 67.257	$ 61.909	$ 62.093	$ 56.068	$ 46.293	$ 56.007
	On-Peak		$ 83.118						
	Off-Peak		$ 45.801						
Annual		$ 72.946	$ 60.488	$ 68.949	$ 64.019	$ 63.752	$ 57.890	$ 47.698	$ 57.624

Table #17 **Retail Rates Charged to BGS RSCP Customers including Revenue Assessment and SUT**

Includes energy, Generation Obligations, Ancillary Services, and Renewable Power Costs
in $/kWh

Revenue Assessment Factor 1.002575524
(BPU, RC Assessments)

		RS	RS TOU - BGS	MGS - SEC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC
Summer - all hrs				$ 0.075848	$ 0.071032	$ 0.070230	$ 0.063969	$ 0.051207	$ 0.063728
	On-Peak		$ 0.089172						
	Off-Peak		$ 0.049682						
	Block 1 (0-750 kWh/m)	$ 0.072750							
	Block 2 (>750 kWh/m)	$ 0.083174							
Winter - all hrs		$ 0.079324		$ 0.071898	$ 0.066180	$ 0.066377	$ 0.059937	$ 0.049487	$ 0.059871
	On-Peak		$ 0.088853						
	Off-Peak		$ 0.048961						
Annual		$ 0.077979	$ 0.064662	$ 0.073706	$ 0.068436	$ 0.068151	$ 0.061884	$ 0.050989	$ 0.061600

Attachment 3

Atlantic City Electric Company
Calculation of June 2021 to May 2022 BGS-RSCP Rates
based on results of February 2021 BGS RSCP Auction

Table A **Auction Results**

line #	**Payment Identifier >>**	*remaining portion of 36 month bid - 2019/20 filing*	*remaining portion of 36 month bid - 2020/21 filing*	*36 month bid - 2021/22 filing*	*Notes:*
1	Winning Bid - in $/MWh	$ 87.40	$ 82.69	$ 64.24	winning Bids
1A	Capacity Proxy Price True-Up - in $/MWh		$ -	$ -	entered after 2022 & 2023 BGS Auctions
1B	Transmission Price	$ 15.69	$ 18.45		asssumed transmission price in bids
1C	Total - in $/Mwh	$ 71.71	$ 64.24	$ 64.24	= line 1 + line 1A - line 1B
2	# of Tranches for Bid	7	8	7	from then current Bid
3	Total # of Tranches	22	22	22	from then current Bid
	Payment Factors				
4	Summer	1.0000	1.0000	1.0000	from then current Bid Factor Spreadsheet
5	Winter	1.0000	1.0000	1.0000	from then current Bid Factor Spreadsheet
	Applicable Customer Usage @ bulk system - in MWh				
6	Summer MWh	2,487,262			from current Bid Factor Spreadsheet
7	Winter MWh	3,352,248			
	Total Payment to Suppliers - in $1000				
8	Summer	$ 56,751	$ 58,102	$ 50,840	= ((1 - 1B) * (2)/(3) * (4) * (6)) + ((1A) * (2)/(3) * (6))
9	Winter	$ 76,488	$ 78,309	$ 68,520	= ((1 - 1B) * (2)/(3) * (5) * (7)) + ((1A) * (2)/(3) * (7))
10	Total	$ 133,239	$ 136,411	$ 119,360	
	Average Payment to Suppliers - in $/MWh				
11	Summer	$ 66.62			= sum(line 8) / (6) - rounded to 2 decimal places
12	Winter	$ 66.62			= sum(line 9) / (7) - rounded to 2 decimal places
13	Total weighted average	**$ 66.62**	<<< used in calculation of Customer Rates		= sum(line 10) / [(6) + (7)] rounded to 2 decimal places
	Reconciliation of amounts - in $1000				
14	Weighted avg * Total MWh =	$ 389,011			= (13) * [(6)+(7)] / 1000
15	Total Payment to Suppliers =	$ 389,010			= sum (line 10)
16	Difference =	$ 1			= line (14) - line (15)

Atlantic City Electric Company
Calculation of June 2021 to May 2022 BGS-RSCP Rates
based on results of February 2021 BGS RSCP Auction

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

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

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

		RS	RS TOU - BGS	MGS - SEC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC
Summer - all hrs			**1.013**	**0.945**	**0.885**	**0.875**	**0.797**	**0.638**	**0.794**
	On-Peak		**1.111**						
	Off-Peak		**0.619**						
	All usage Multiplier	**0.955**							
	Constant	**(3.238)**		for Block 1 (0-750 kWh/m) usage					
	Constant	**5.414**		for Block 2 (>750 kWh/m) usage					
Winter - all hrs		**1.207**	**1.291**	**1.094**	**1.007**	**1.010**	**0.912**	**0.753**	**0.911**
	On-Peak		**1.352**						
	Off-Peak		**0.745**						
Annual - all hrs		**1.095**	**0.908**	**1.035**	**0.961**	**0.957**	**0.869**	**0.716**	**0.865**

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

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

		RS	RS TOU - BGS	MGS - SEC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC
Summer - all hrs			***6.7483***	***6.2953***	***5.8956***	***5.8290***	***5.3094***	***4.2502***	***5.2894***
	On-Peak		***7.4011***						
	Off-Peak		***4.1236***						
for Block 1 (0-750 kWh/m) usage		***6.0382***							
for Block 2 (>750 kWh/m) usage		***6.9034***							
Winter - all hrs		***8.0407***	***8.6003***	***7.2879***	***6.7083***	***6.7283***	***6.0755***	***5.0163***	***6.0688***
	On-Peak		***9.0066***						
	Off-Peak		***4.9630***						

Atlantic City Electric Company
Calculation of June 2021 to May 2022 BGS-RSCP Rates
based on results of February 2021 BGS RSCP Auction

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

	RS	RS TOU - BGS	MGS - SEC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC
Total Rate Revenue - in $1000								
Summer	$ 102,339	$ 87	$ 21,485	$ 278	$ 20,353	$ 1,623	$ 640	$ 207
Winter	$ 161,642	$ 146	$ 38,509	$ 529	$ 36,062	$ 3,129	$ 1,600	$ 367
Total	$ 263,982	$ 233	$ 59,994	$ 807	$ 56,415	$ 4,753	$ 2,240	$ 573
Total Summer	$ 147,013							
Total Winter	$ 241,984							
Grand Total	$ 388,997							
Total Supplier Payment - in $1000								
Summer	$ 165,693							
Winter	$ 223,316							
Total	$ 389,010							
Differences - in $1000								
Summer	$ 18,680							
Winter	$ (18,668)							
Total	$ 13							

kWh Rate Adjustment Factors	*rounded to 5 decimal places*
1.12707	
0.92286	

% difference
11.2741%
-8.3593%
0.0033%

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 2021 to May 2022 BGS-RSCP Rates
based on results of February 2021 BGS RSCP Auction

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

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

		RS	RS TOU - BGS	MGS - SEC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC
Summer - all hrs			***7.6058***	***7.0952***	***6.6448***	***6.5697***	***5.9841***	***4.7903***	***5.9615***
	On-Peak		***8.3416***						
	Off-Peak		***4.6476***						
for Block 1 (0-750 kWh/m) usage		***6.8055***							
for Block 2 (>750 kWh/m) usage		***7.7806***							
Winter - all hrs		***7.4204***	***7.9369***	***6.7257***	***6.1908***	***6.2093***	***5.6068***	***4.6293***	***5.6007***
	On-Peak		***8.3118***						
	Off-Peak		***4.5802***						

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

	RS	RS TOU - BGS	MGS - SEC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC
Total Rate Revenue - in $1000								
Summer	$ 115,344	$ 98	$ 24,215	$ 314	$ 22,940	$ 1,830	$ 721	$ 233
Winter	$ 149,173	$ 135	$ 35,538	$ 488	$ 33,280	$ 2,888	$ 1,476	$ 338
Total	$ 264,516	$ 233	$ 59,753	$ 801	$ 56,220	$ 4,718	$ 2,198	$ 571
Total Summer	$ 165,694							
Total Winter	$ 223,316							
Grand Total	$ 389,010							
Total Supplier Payment - in $1000								
Summer	$ 165,693							
Winter	$ 223,316							
Total	$ 389,010							
Differences - in $1000								
Summer	$ 1							
Winter	$ 0							
Total	$ 1							

Attachment 4

Development of Capacity Proxy Price True-Up - $/MWh
2021/2022 Delivery Year

		2021/22 Delivery Year	*Notes:*
1	**Zonal Capacity Price ($/MW-day)**	$154.49	as may be determined by the RPM, or its successor, or otherwise
2	**Capacity Proxy Price ($/MW-day)**	N/A	
3	**Capacity Proxy Price True-Up - $/MW-day**	N/A	= line 1 - line 2
4	**BGS-RSCP Gen Obl - MW**	1,696.8	
5	**Days in Year**	365	
6	**Capacity Proxy Price True-Up Annual Cost**	N/A	= line 3 * line 4 * line 5
7	**Eligible Tranches**	7	from Table A
8	**Total Tranches**	22	from Table A
9	**% of tranches eligible for payment**	31.82%	= line 7 / line 8
10	**Capacity Proxy Price True-Up Cost**	$0	= line 6 * line 9
11	**Total Applicable Customer Usage @ bulk system - in MWh**	5,839,510	
12	**Eligible Customer Usage @ bulk system - *in MWh***	1,858,026	= line 9 * line 11
13	**Capacity Proxy Price True-Up - $/MWh**	**$0.00**	**= line 10/ line 12 - rounded to 2 decimal places**

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

		2022/23 Delivery Year	*Notes:*
1	**Zonal Capacity Price ($/MW-day)**	$155.00	as may be determined by the RPM, or its successor, or otherwise
2	**Capacity Proxy Price ($/MW-day)**	$152.06	per Board Order dated 11/18/2020
3	**Capacity Proxy Price True-Up - $/MW-day**	$2.94	= line 1 - line 2
4	**BGS-RSCP Gen Obl - MW**	1,696.8	
5	**Days in Year**	365	
6	**Capacity Proxy Price True-Up Annual Cost**	$1,820,831	= line 3 * line 4 * line 5
7	**Eligible Tranches**	15	from Table A
8	**Total Tranches**	22	from Table A
9	**% of tranches eligible for payment**	68.18%	= line 7 / line 8
10	**Capacity Proxy Price True-Up Cost**	$1,241,476	= line 6 * line 9
11	**Total Applicable Customer Usage @ bulk system - in MWh**	5,839,510	
12	**Eligible Customer Usage @ bulk system - *in MWh***	3,981,484	= line 9 * line 11
13	**Capacity Proxy Price True-Up - $/MWh**	**$0.31**	**= line 10/ line 12 - rounded to 2 decimal places**

Development of Capacity Proxy Price True-Up - $/MWh
Using 2023/2024 Illustrative Data for ACE

		2023/24 Delivery Year	*Notes:*
1	**Zonal Capacity Price ($/MW-day)**	$155.00	as may be determined by the RPM, or its successor, or otherwise
2	**Capacity Proxy Price ($/MW-day)**	$146.51	per Board Order dated 11/18/2020
3	**Capacity Proxy Price True-Up - $/MW-day**	$8.49	= line 1 - line 2
4	**BGS-RSCP Gen Obl - MW**	1,696.8	
5	**Days in Year**	365	
6	**Capacity Proxy Price True-Up Annual Cost**	$5,258,114	= line 3 * line 4 * line 5
7	**Eligible Tranches**	7	from Table A
8	**Total Tranches**	22	from Table A
9	**% of tranches eligible for payment**	31.82%	= line 7 / line 8
10	**Capacity Proxy Price True-Up Cost**	$1,673,036	= line 6 * line 9
11	**Total Applicable Customer Usage @ bulk system - in MWh**	5,839,510	
12	**Eligible Customer Usage @ bulk system - *in MWh***	1,858,026	= line 9 * line 11
13	**Capacity Proxy Price True-Up - $/MWh**	**$0.90**	**= line 10/ line 12 - rounded to 2 decimal places**

Table A With Additional Line Item

Calculation of June 2022 to May 2023 BGS-RSCP Rates

Illustrative Purposes Only for ACE

Table A **Auction Results**

line #	**Specific BGS-RSCP Auction >>**	*remaining portion of 36 month bid - 2020 auction*	*remaining portion of 36 month bid - 2021 auction*	*36 month bid - 2022 auction*	*Notes:*
1	**Winning Bid - in $/MWh**	$ 82.69	$ 64.24	$ 64.24	winning Bids
1A	**22/23 Capacity Proxy Price True-up - in $/MWh**	$ 0.31	$ 0.31		entered after 2022 BGS Auction
1B	**Transmission Price**	$ 18.45			asssumed transmission price in bids
1C	**Total - in $/MWh**	$ 64.55	$ 64.55	$ 64.24	= line 1 + line 1A - line 1B
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	2,487,262			from current Bid Factor Spreadsheet
7	Winter MWh	3,352,248			
	Total Payment to Suppliers *- in $1000*				
8	Summer	$ 58,383	$ 51,085	$ 50,840	= ((1 - 1B) * (2)/(3) * (4) * (6)) + ((1A) * (2)/(3) * (6))
9	Winter	$ 78,686	$ 68,851	$ 68,520	= ((1 - 1B) * (2)/(3) * (5) * (7)) + ((1A) * (2)/(3) * (7))
10	Total	$ 137,069	$ 119,936	$ 119,360	
	Average Payment to Suppliers *- in $/MWh*				
11	Summer	$ 64.45			= sum(line 8) / (6) - rounded to 2 decimal places
12	Winter	$ 64.45			= sum(line 9) / (7) - rounded to 2 decimal places
13	Total weighted average	**$ 64.45**	<<< used in calculation of Customer Rates		= sum(line 10) / [(6) + (7)] rounded to 2 decimal places

Atlantic City Electric Company
Development of BGS Rates
June 2021 - May 2022

Table A With Additional Line Item

Calculation of June 2023 to May 2024 BGS-RSCP Rates

Illustrative Purposes Only for ACE

Table A **Auction Results**

line #	**Specific BGS-RSCP Auction >>**	*remaining portion of 36 month bid - 2021 auction*	*remaining portion of 36 month bid - 2022 auction*	*36 month bid - 2023 auction*	*Notes:*
1	**Winning Bid - in $/MWh**	$ 64.24	$ 64.24	$ 64.24	winning Bids
1A	**23/24 Capacity Proxy Price True-up - in $/MWh**	$ 0.90			entered after 2023 BGS Auction
1B	**Total - in $/MWh**	$ 65.14	$ 64.24	$ 64.24	= line 1 + line 1A
2	**# of Tranches for Bid**	7	7	8	from then current Bid
3	**Total # of Tranches**	22	22	22	from then current Bid
	Payment Factors				
4	Summer	1.0000	1.0000	1.0000	from then current Bid Factor Spreadsheet
5	Winter	1.0000	1.0000	1.0000	from then current Bid Factor Spreadsheet
	Applicable Customer Usage @ bulk system - in MWh				
6	Summer MWh	2,487,262			from current Bid Factor Spreadsheet
7	Winter MWh	3,352,248			
	Total Payment to Suppliers *- in $1000*				
8	Summer	$ 51,552	$ 50,840	$ 58,102	= ((1) * (2)/(3) * (4) * (6)) + ((1A) * (2)/(3) * (6))
9	Winter	$ 69,480	$ 68,520	$ 78,309	= ((1) * (2)/(3) * (5) * (7)) + ((1A) * (2)/(3) * (7))
10	Total	$ 121,032	$ 119,360	$ 136,411	
	Average Payment to Suppliers *- in $/MWh*				
11	Summer	$ 64.53			= sum(line 8) / (6) - rounded to 2 decimal places
12	Winter	$ 64.53			= sum(line 9) / (7) - rounded to 2 decimal places
13	Total weighted average	**$ 64.53**	<<< used in calculation of Customer Rates		= sum(line 10) / [(6) + (7)] rounded to 2 decimal places

Attachment 5

Development of Assumed Transmission Price in Bids
Calculation for 2019/2020 and 2020/2021

line #		*remaining portion of 36 month bid - 2019/20 filing*	*remaining portion of 36 month bid - 2020/21 filing*	*Notes:*
1	**Eligible Tranches**	7	8	
2	**Total Tranches**	22	22	
3	**Tranche %**	31.82%	36.36%	= line 1 / line 2
4	**Transmission Obligations (MW)**	1821.8	1996.4	Obligations from filng years
5	**Adjustment Transmission Obligation (MW)**	579.6	726.0	= line 3 * line 4
6	**NITS Rate ($/MW-yr)**	$ 51,759.65	$ 54,394.71	NITS Rates from from 2019 and 2020
7	**Payment ($/yr)**	$ 30,002,382	$ 39,488,979	= line 5 * line 6
8	**Pre Loss Usage (MWh)**	6,010,045	5,886,173	Applicable usage from filing years
9	**Allocated Usage (MWh)**	1,912,287	2,140,426	= line 3 * line 8
10	**Transmission Price ($/MWh)**	**$ 15.69**	**$ 18.45**	= line 7 / line 9 (To Attachment 3, Table A, Line 1B)

In the Matter of the Provision of Basic Generation Service for the Period Beginning June 1, 2021
BPU Docket No. ER20030190
Service List

Applebaum, David A. - david.applebaum@nexteraenergy.com
Artale, Carol - carol.artale@bpu.nj.gov
Atzl, Jr., William A. - atzlw@coned.com
Beck, Michael - michael.beck@law.njoag.gov
Bevan, Murray E. - mbevan@bmgzlaw.com
Bhatia, Dinkar - DBhatia@hartreepartners.com
Brabston, Robert - robert.brabston@bpu.nj.gov
Brand, Stefanie - sbrand@rpa.nj.gov
Burcat, Bruce H. - bburcat@marec.us
Camacho-Welch, Aida - aida.camacho@bpu.nj.gov
Carley, John L. - carleyj@coned.com
Catanach, James - jcatanach@firstenergycorp.com
Chang, Max - mchang@synapse-energy.com
Codd, Chris - chris_codd@transalta.com
Comes, Margaret - comesm@coned.com
Davies, Matthew - matthew_davies@transcanada.com
Depillo, Raymond - raymond.depillo@pseg.com
DeVito, Susan - susan.devito@pepcoholdings.com
Dworetzky, Jeanne J. - jeanne.dworetzky@exeloncorp.com
Eckert, Joshua - jeckert@firstenergycorp.com
Filewicz, Myron - myron.filewicz@pseg.com
Flanagan, Paul - Paul.Flanagan@bpu.nj.gov
Forshay, Paul F. - paul.forshay@eversheds-sutherland.com
Gabel, Steven - steven@gabelassociates.com
Gallagher, Sean - sgallagher@seia.org
Gerard, Morgan - morgan.gerard@troutmansanders.com
Gibbs, Robert - robert.gibbs@directenergy.com
Goldenberg, Steven - sgoldenberg@ghclaw.com
Gupta, Divesh - divesh.gupta@constellation.com
Hahn, Thomas M. - thomas.hahn@pepcoholdings.com
Hanks, Marc A. - marc.hanks@directenergy.com
Hoatson, Thom - thoatson@lspower.com
holly@gabelassociates.com
Holub, John - john@njrma.org
Hubschman, Don - dmhubschman@aepes.com
Jacob, Shajan - jacobs@coned.com
Kaufman, Adam - akaufman@kzgrp.com
Klots, Cynthia - cynthia.klots@dteenergy.com
LaCasse, Chantale - chantale.lacasse@nera.com
Laskey, James - jlaskey@nmmlaw.com
Layugan, Debora - dlayugan@rpa.nj.gov
Leyden, Shawn P. - shawn.leyden@pseg.com
Lipman, Brian O. - blipman@rpa.nj.gov
Maher, Kathleen K. - kathleen.maher@constellation.com
Marks, Deborah S. - deborah.marks@pseg.com
McGarvey, Christine - clmcgarvey@aepes.com
Megdal, Ira G. - imegdal@cozen.com
Minogue, Holly - holly.minogue@gabelassociates.com
Moran, Ryan - ryan.moran@bpu.nj.gov
Moran, Terrence J. - terrence.moran@pseg.com
Morgan, Karen - karen.morgan@bateswhite.com
Mossburg, Frank - frank.mossburg@bateswhite.com
Moury, Karen - kmoury@eckertseamans.com
Myers, James C. - jmeyer@riker.com
Northcutt, Rachel - rachel.northcutt@nera.com
Novak, Diana N. - dnnovak@pepco.com
Orlandi, Kathleen - kathleen.orlandi@nera.com
Passanante, Philip J. - philip.passanante@pepcoholdings.com
Peng, Yongmei - ypeng@firstenergycorp.com
Rantala, Stacey - srantala@energymarketers.com
Rattansi, Aliraza - arattansi@firstenergycorp.com
Rawlings, Lyle - lyle@advancedsolarproducts.com
rcantor@njbia.org
rfv@vitol.com
Richter, David K. - david.richter@pseg.com
Riepl, Glenn - gfriepl@aep.com
Roach, Craig - craig.roach@bateswhite.com
Rodriguez, Jesse A. - jesse.rodriguez@exeloncorp.com
Romero, Marjorie - marjorie.romero@bateswhite.com
Ruggiero, Cheryl M. - ruggieroc@coned.com
Secretary of the Board - board.secretary@bpu.nj.gov
Shea, Joseph A. - joseph.sheajr@pseg.com
Silverman, Abe - abe.silverman@bpu.nj.gov
Spielvogel, Larry - spielvogel@comcast.net
Spricigo, Jennifer - jspricigo@firstenergycorp.com
sss@vitol.com
Thomas, Glen - gthomas@gtpowergroup.com
Thompson, Howard O. - hthompson@russotumulty.com
Torkelson, Christopher - ctorkelson@eckertseamans.com
Tudor, Daniel A. - datudor@pepco.com
Urbish, Madaline - maddy@rivercrossingsg.com
Wadsworth, Joe - jxw@vitol.com
Wand, T. David - dwand@rpa.nj.gov
Weber, Sharon - sjweber@pplweb.com
Weisband, Heather - heather.weisband@bpu.nj.gov
Weissman, Matthew - matthew.weissman@pseg.com
Williams, Aundrea - aundrea.williams@nexteraenergyservices.com
zkf@vitol.com