IN THE MATTER OF THE PROVISION OF	:	
BASIC GENERATION SERVICE FOR BASIC	:	
GENERATION SERVICE REQUIREMENTS	:	
EFFECTIVE JUNE 1, 2014	:	Docket No. **ER13050378**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

PROPOSAL FOR

BASIC GENERATION SERVICE REQUIREMENTS

TO BE PROCURED EFFECTIVE JUNE 1, 2014

COMPANY SPECIFIC ADDENDUM

December 2, 2013

I. USE OF COMMITTED SUPPLY AND CONTINGENCY PLANS

Committed Supply

"Committed Supply," means power supplies to which PSE&G has an existing physical or financial entitlement. This will include non-utility generation contracts, including any restructured replacement power contracts and power supplied under the PEP tariff by Qualifying Facilities (QFs).

Except where retained to meet requirements of the Contingency Plan, PSE&G will continue to sell power obtained from the non-utility generation contracts into the PJM Spot Market and these sales will be considered prudent unless and until the Board determines that a different selling protocol is appropriate. All net revenues from these sales will be credited to the Non-Utility Generation Charge (NGC), formerly called the Non-Utility Generation Transition Charge. Just as they are currently, PSE&G's actual non-utility generation contract costs will continue to be charged to the NGC with full and timely cost recovery assured. In the event that PSE&G is required to invoke the Contingency Plan, Committed Supply may be used to offset requirements associated with the Contingency Plan.

To the extent permitted by applicable regulatory and contractual provisions, PSE&G will provide renewable attributes available to PSE&G from these non-utility generation contracts on a pro-rata basis to BGS-FP Suppliers. The renewable energy purchased by PSE&G, as part of its Committed Supply, will be reported to the Board of Public Utilities (Board or BPU) in its compliance reports and, subject to the foregoing limitations, will be applied towards the minimum renewable energy percentages required for BGS-FP Supply. PSE&G will use its best efforts to obtain and provide to the BPU the documentation necessary to verify the renewable attributes of Committed Supply, as required in N.J.A.C. 14:8-2.11(c). BGS-FP Suppliers will be responsible for obtaining and providing related verification information to PSE&G for the minimum Class I and Class II percentages required in the Renewable Portfolio Standards (RPS) associated with the tranches they serve, net of renewable attributes of the Committed Supply energy proportionately applied, subject to the foregoing limitations, to each BGS-FP Supplier's tranches using the BGS-FP Supplier Responsibility Share. Such verification will be provided to the PSE&G no later than two weeks prior to the due date for the annual RPS report of October 1st, or extended due date if applicable.

PSE&G will not credit the pro-rata share of the Reliability Pricing Model Auction Credit received from PJM ("RPM Credit") for any Regional Greenhouse Gas Initiative (RGGI) programs to any BGS-FP Supplier Master Agreements (SMAs). All PSE&G RPM credits are applied to the applicable component of the RGGI Recovery Charge.

Contingency Plans

While not every contingency can be anticipated, we can differentiate three time periods of concern:

(a) There are an insufficient number of bids to provide for a fully subscribed Auction Volume either for the BGS-FP auction or the BGS-CIEP auction;
(b) A default by one of the winning bidders prior to June 1, 2014;
(c) A default during the June 1, 2014 – May 31, 2017 supply period.

(a) Insufficient Number of Bids in Auction

In order 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 target volume of BGS-FP and BGS-CIEP Load purchased at each auction will be decided after the first round bids are received. Provided that there are sufficient bids at the starting prices, the auctions will be held for 100 percent of BGS-FP and BGS-CIEP Load.

It is possible that the amount of initial bids will not result in a competitive auction for 100 percent of the BGS-FP 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 percent of BGS-FP or BGS-CIEP Load, PSE&G will implement a contingency plan for the remaining tranches. Under that plan, PSE&G, at its option, will purchase necessary services for the remaining tranches through PJM-administered markets until May 31, 2015, and may retain Committed Supply to serve these tranches. After May 31, 2015 any unfilled tranches may be included in a subsequent auction or treated as in Contingency Plans Part (c) below. This Contingency Plan will alert bidders that in order to secure BGS-FP or BGS-CIEP prices from New Jersey BGS customers for their supply, it will be necessary to bid in the auctions. Failure to bid will mean that the BGS market faced by suppliers will be a spot market with volatility and related risks.

Since the contingency plan calls for the purchase of BGS supply in PJM-administered markets, it is considered a strong 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 PSE&G, on behalf of its customers, would seek to acquire fixed priced supplies, the incentive to participate in the auction and the incentive to offer the best prices in the auction would be diminished.

(b) Defaults prior to June 1st 2014.

If a winning bidder defaults prior to the beginning of the BGS service, then, at the option of the EDC, the open tranches may be offered to the other winning bidders or these tranches may be bid out or procured in PJM-administered markets, and Committed Supply may be retained to serve these tranches. Additional costs incurred by PSE&G in implementing this Contingency Plan will be assessed against the defaulting supplier's credit security.

(c) Defaults during the Supply Period

If a default occurs during the June 1, 2014 through May 31, 2017 period, at the option of PSE&G, the available tranches may be offered to other winning bidders, bid out, or procured in PJM administered markets and Committed Supply may be retained to serve these tranches. Additional costs incurred by PSE&G in implementing this Contingency Plan will be assessed against the defaulting supplier's credit security.

II. ACCOUNTING AND COST RECOVERY

The accounting and cost recovery that PSE&G proposes for its BGS service is summarized in this section. These provisions are intended to be applicable to PSE&G only. Each EDC will provide individual BGS cost recovery proposals.

BGS-FP and BGS-CIEP Reconciliation Charges

PSE&G's BGS accounting will account for BGS-FP revenues and BGS-CIEP revenues individually as follows:

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

PSE&G will account for BGS-FP and BGS-CIEP costs individually as the sum of the following:

1. Payments made to winning BGS bidders for the provision of BGS-FP or BGS-CIEP service;
2. Any administrative costs associated with the provision of BGS-FP and BGS-CIEP service;
3. The cost of any procurement of necessary services including capacity, energy, ancillary services, transmission and other expenses related to the Contingency Plan less any payments recovered from defaulting bidders.

Adjustment type charges are necessary in order to balance out the difference between (1) the monthly amount paid to the BGS-FP and BGS-CIEP supplier(s) for BGS-FP and BGS-CIEP supply and (2) the total revenue from customers for BGS-FP and BGS-CIEP services respectively.

These reconciliation charge rates are calculated separately each month for BGS-FP and BGS-CIEP on a monthly dollars per kWh basis and the respective rates applied to all BGS-FP and BGS-CIEP kWh billed. These charges are combined with BGS-FP and hourly BGS-CIEP charges for billing although they are published in separate BGS-FP reconciliation charge and BGS-CIEP reconciliation charge tariff sheets that are revised monthly to reflect adjustments made based on actual costs. These tariff sheets are filed with the Board approximately 1 day prior to the first day of the effective month.

The BGS-FP reconciliation charge and BGS-CIEP reconciliation charge are subject to deferred accounting with interest at the NGC rate previously set by the Board and are determined individually as set forth below:

The reconciliation charges are used in both BGS-FP and BGS-CIEP to true up the differences between BGS payments to suppliers and BGS revenues from customers. Differences in costs and cost recovery for a month “x” are computed in month x+1 and applied to BGS rates for month x+2. Two of these differences are shown below:

1. The difference between BGS Costs (as defined above) essentially amounts paid to suppliers for month “x” (this amount is known and paid to suppliers in month x+1) and the calendar month “x” BGS revenue, which is also determined in month x+1. This difference is calculated in month x+1 for recovery in month x+2.
2. The difference between the total adjustment charge revenue intended to be recovered in month “x” and the actual adjustment charge revenue recovered in month “x”. This difference is driven by differences between actual kWh in month “x” and the kWh used to calculate the charge. This amount is known in month x+1.

The reconciliation charges to be applied in month x+2 are calculated as the net of the two differences described above for month “x” (plus or minus any cumulative under or over recovery from prior months) divided by the forecast of BGS kWh in month “x+2”.

Accounting for the NGC

Except where retained to meet requirements of the Contingency Plan, PSE&G will continue to sell power obtained from the non-utility generation contracts into the PJM Spot Market and these sales will be considered prudent unless and until the Board determines that a different selling protocol is appropriate. All net revenues from these sales will be credited to the NGC. Just as they are currently, PSE&G’s actual non-utility generation contract costs will continue to be charged to the NGC with full and timely cost recovery assured.

III. DESCRIPTION OF BGS TARIFF SHEETS AND OTHER TARIFF ITEMS

General

As described in the generic section of this filing, two different methods will continue to be utilized for the pricing for BGS default supply service to customers: a fixed energy pricing and a variable hourly energy pricing. For Public Service, the fixed energy pricing is termed "Basic Generation Service – Fixed Pricing" or BGS-FP, and the hourly energy pricing service is termed "Basic Generation Service – Commercial and Industrial Energy Pricing" or BGS-CIEP.

The company is not proposing any modification of the criteria for BGS-CIEP eligibility from the current peak load share of 500kW. Thus BGS-CIEP is proposed to continue to be the default service for all customers served under delivery rate schedules HTS-High Voltage, HTS-Subtransmission, and LPL-Primary and for LPL-Secondary customers with a peak load share (PLS) of 500 kW or higher.

As in prior years, all other non-residential customers also have the option of electing BGS-CIEP as their default supply service. All non-residential customers with BGS-CIEP as their optional default service will be notified of their option to switch to BGS-CIEP through PSE&G's website and tariffs. Annually, customers eligible for this option must notify PSE&G no later than the second business day of January of any given year to have BGS-CIEP as their default supply service option for the annual period beginning June 1st of that year. The BGS-FP default service will be available to residential and small and medium sized non-residential customers, specifically those served on Rate Schedules RS, RHS, RLM, WH, WHS, HS, BPL, BPL-POF, PSAL, GLP and LPL-Secondary (PLS less than 500 kW).

The following sections describe the tariff sheets that would implement Public Service's BGS service effective June 1, 2014.

BGS-FP

Public Service is not proposing any change in the structure of the Basic Generation Service – Fixed Pricing (BGS-FP) default supply service. The form of the BGS-FP tariff sheets are included in Attachment 1 and are indicated as Sheet Nos. 75, 76, and 79. Once the results of the BGS-FP Bid are finalized, the values on these tariff sheets will be updated reflecting the results of the bid.

As indicated on these form of tariff sheets, the BGS-FP default service is made up of several components: BGS Energy Charges, BGS Capacity Charges, BGS Transmission Charges, and the BGS Reconciliation Charges. These charges will apply for usage in the calendar months of June through September, or October through May, as applicable.

BGS Energy Charges

The values of the BGS Energy charges applicable to Rate Schedules RS, RHS, RLM, WH, WHS, HS, BPL, BPL-POF and PSAL include the costs related to energy, ancillary services and generation capacity and transmission-related costs. This overall approach is a continuation of the current approved methodology of recovering all electric supply service costs in the kilowatt-hour charges for these rate schedules. The generation capacity and transmission related costs will continue to be recovered through separate charges for customers on Rates GLP and LPL-Secondary (less than 500 kW) based on the customer specific assigned generation capacity and transmission obligation values. The resulting BGS Energy Charges applicable to this latter set of customers thus do not include the costs related to generation capacity and transmission service.

In order to more accurately reflect the costs of providing energy and other electric services when relying on the day-ahead PJM verses the real-time markets, the Company will apply two ancillary services costs, one applied to BGS-FP service and the other applied to BGS-CIEP service. A continuation of the $3.00 per MWH ancillary services rate that was used in the calculation of the BGS-FP rates for the June 2013 to May 2014 is used since it is more reflective of costs borne in the day-ahead market. A BGS-CIEP ancillary services cost of $6.00 per MWh is applied since it is more reflective of costs borne in the real-time market.

The transmission related costs included in the BGS Energy Charges for Rate Schedules RS, RHS, RLM, WH, WHS, HS, BPL, BPL-POF, and PSAL are based on the then effective transmission rate for network service for the PSE&G zone, as stated in PJM's Open Access Transmission Tariff (OATT). These BGS Energy charges will change from time to time as FERC approves changes in the PJM OATT and related charges and the BPU approves the corresponding changes in the BGS tariff sheets.

The specific values that will be utilized for the BGS Energy Charges will be calculated from the winning BGS-FP bid prices for the Public Service zone. It is the intent of the EDCs that the factors in the tables will be applied to the tranche-weighted average winning bid prices adjusted for seasonal payment factors resulting from the auctions for BGS-FP with terms covering the period from June 1, 2014 to May 31, 2015. For example, for Public Service, for the period beginning June 1, 2014, the weighting will be based on the load (i.e. successfully bid tranches) at the 36-month prices from the 2012, 2013, and 2014 BGS-FP auctions, and the seasonal payment factors calculated in Attachment 2.

The tables will be updated annually prior to future BGS auctions and utilized to develop customer charges for a related annual period in a similar manner as discussed 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-FP class.

BGS Capacity Charges

These charges are the separate charges previously mentioned that are designed to recover the costs associated with generation capacity for customers served on Rate Schedules GLP and LPL-Secondary (less than 500 kW). These charges are expressed on a per kW of generation capacity obligation basis.

The generation capacity costs designed to be used in the development of the BGS-FP rates are the relevant current wholesale market prices for capacity based on the average, 2014/2015, 2015/2016, and 2016/2017 Base Residual Auction for RPM (Reliability Pricing Model) results applicable to load served in the PSEG zone.

BGS Transmission Charges

Similar to the BGS Capacity Charges, the BGS Transmission Charges recover the customer specific costs associated with network transmission service for customers on Rates GLP and LPL-Secondary (less than 500 kW). The charge is based on the annual transmission rate for network service for the PSE&G zone, as stated in PJM's Open Access Transmission Tariff (OATT), and as approved by the BPU for inclusion in the BGS Transmission Charge. Bids should be based on the BGS Transmission Charges in effect on January 1, 2014. The winning bid prices will be adjusted for any changes in the BPU-approved BGS Transmission Charges as they occur subsequent to January 1, 2014 and following the procedures in Section 15.9 of the BGS-FP Supplier Master Agreements.

Transmission Cost Adjustment

In compliance with the BGS-FP Supplier Master Agreement, PSE&G will file with the BPU to change the transmission cost components of the BGS charges to customers as FERC approves changes in the Network Integration Transmission Service rates for the PSE&G zone in the PJM OATT, or the FERC approves other network transmission-related charges in the PJM OATT. PSE&G will review and verify the basis for any BGS transmission charge adjustment and will file supporting documentation from the OATT, as well as any rate translation spreadsheets used.

For the BGS-FP energy only rates (Rate Schedules RS, RHS, RLM, WH, WHS, HS, BPL, BPL-POF and PSAL), upon BPU approval, changes in the OATT rate (per kW of transmission obligation) will be implemented by multiplying such change in the OATT rate by each rate class' ratio of the kW of transmission load of that class divided by the expected annual kWh of that class, and then adjusted for applicable losses. The results, in dollars per kWh, will then be added to all BGS-FP Energy charges for each class.

In the event that PJM institutes a charge for transmission network service on an energy basis (per kWh), this charge, corrected for applicable losses, will be added to the BGS-FP Energy charges for all kWhs for all rate schedules.

BGS Reconciliation Charge

The BGS Reconciliation Charge for the BGS-FP default service is explained in the prior Section II - Accounting and Cost Recovery and will be combined with the BGS-FP energy charge for billing on a monthly basis.

BGS-CIEP

The bid product in the 2014 BGS-CIEP auction will continue to be the Generation Capacity Cost, as it was in last year's BGS-CIEP auction. Public Service will continue the use of a value for the CIEP Standby Fee equal to 0.000150 dollars per kWh.

The form of tariff sheets for the Basic Generation Service – Commercial and Industrial Energy Pricing (BGS-CIEP) are included in Attachment 1 and are indicated as Sheet Nos. 73, 82 and 83.

Similar to the BGS-FP, the charges for BGS-CIEP are comprised of several components: BGS Energy Charges, BGS Capacity Charges, BGS Transmission Charges and the BGS Reconciliation Charges.

BGS Energy Charges

The primary component of this charge will be the actual PJM load weighted average real-time Locational Marginal Price (LMP) of energy for the Public Service Transmission Zone. To this will be added an ancillary service cost (including PJM Administrative Costs) for the Public Service zone of $6.00 dollars per MWh that was estimated as being reflective of ancillary service costs in the PSEG zone for energy purchased in the real time market. This sum will then be adjusted for losses. Because the LMPs are calculated to include a marginal loss component for the transmission system, a loss correction is performed. This is done by removing the mean hourly marginal transmission loss factor for the PSE&G transmission zone (equal to 0.87662%) from the BPU approved PSE&G delivery tariff loss factors. The result is reflective of losses from the customer meter to the transmission nodes (at which the LMPs are calculated).

BGS Capacity Charges

These charges will recover the costs associated with generation capacity. The BGS Capacity Charge component of the BGS-CIEP bid is set equal to the BGS-CIEP auction clearing price. These charges are expressed on a per kW of generation capacity obligation basis.

BGS Transmission Charges

BGS-CIEP Transmission Charges recover the customer specific costs associated with Transmission service for customers on BGS-CIEP. The charges are based on the annual transmission rate for network transmission service for the PSE&G zone, in PJM's Open Access Transmission Tariff (OATT), and as approved by the BPU for inclusion in the BGS-CIEP Transmission Charges. This charge is expressed as a monthly charge on a per kW of transmission obligation basis. In compliance with the BGS-CIEP Supplier Master Agreement, PSE&G will file with the BPU to change the transmission cost components of the BGS charges to customers as FERC approves changes in the Network Integration Transmission Service rates for the PSE&G zone in the PJM OATT, or the FERC approves other network transmission-related charges in the PJM OATT. PSE&G will review and verify the basis for any BGS transmission charge adjustment and will file supporting documentation from the OATT, as well as any rate translation spreadsheets used.

BGS Reconciliation Charge

The BGS Reconciliation Charge for the BGS-CIEP default service is explained in the prior Section II - Accounting and Cost Recovery and will be combined with the BGS-CIEP energy charge for billing on a monthly basis.

Other Items

CIEP Standby Fee

PSE&G will continue to pay each BGS-CIEP supplier a CIEP Standby Fee which is set at 0.000150 dollars per kWh times their pro-rata share of the total energy usage measured at the meters of all of PSE&G's customers whose default service option is limited to BGS-CIEP and those customers who have elected BGS-CIEP as their default supply.

A tariff sheet, included in Attachment 1 and indicated as Sheet No. 73, shows the CIEP Standby Fee as a Delivery Charge that is applicable to all customers having BGS-CIEP as their sole default supply service option and those customers who have elected BGS-CIEP as their default supply. This includes all customers served on Rate Schedules LPL-Secondary (peak load share of 500 kW or greater), LPL-Primary, HTS-Subtransmission, HTS-High Voltage, and all customers on Rate Schedules HS, GLP, and LPL-Secondary (less than 500 kW) that have elected the BGS-CIEP default supply option.

Description of BGS Pricing Spreadsheets

As described in the generic write-up, the resulting charge for each BGS rate element (i.e. Rate RS summer charge, winter charge, etc.) for the non-hourly BGS supply service will generally be based on factors applied to the tranche weighted average winning bid prices adjusted for seasonal payments. These 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 all-in BGS cost. The tables included in Attachments 2 and 3 present all of the input data, intermediate calculations, and the final results in the calculation of these factors.

The following is a description of the calculations shown in the spreadsheet titled "Development of BGS-FP Cost and Bid Factors for the 2014/2015 BGS Filing", and included as Attachment 2.

Table #1 (% Usage during PJM On-Peak Period) contains the percentage of on-peak load, inputted by month, for each 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 AM to 11 PM, Monday through Friday. All remaining weekday hours and all hours on weekends and holidays recognized by the National Electric Reliability Council (NERC) are considered the off-peak period. This is consistent with the time periods used in the forwards market for trading of bulk power. The values in this table for each month are the average on-peak percentages from the years 20010 and 2011 and 2012, as calculated from the same load research data used for retail settlement for current customers that have chosen to be supplied by a Third Party Supplier (TPS). The average for a three-year period was used to reduce the variability of weather effects on the percentage from any single year.

Table #2 (% Usage During PSE&G 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 Public Service's delivery rate schedules. Since, excluding the hourly price BGS rates, only Rate Schedule RLM and LPL-Sec are billed on a time-of-day basis utilizing time periods, these are the only two columns in this table where data has been inputted. These are the percentage of actual on-peak kWh usage for the years 2010, 2011, and 2012. As was done with Table #1, the three-year average was used to reduce the effects of weather in a particular year.

<u>Table #3</u> (Class Usage @ customer) contains the calendar month sales forecasted for the calendar year 2013. For Rate LPL-Secondary, these values have been reduced for the percentage of customers having a Peak Load Share of 500 kW or greater, and thus having BGS-CIEP as their default service. These monthly percentages were based on the 2012 monthly percentages of total actual sales for customers meeting this Peak Load Share threshold.

<u>Table #4</u> (Forwards 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 most recent energy on-peak forwards values available for the PJM West trading hub for the period of June 2014 to May 2015 and the historical ratio of actual off-peak to on-peak PJM LMPs from August 2010 through July 2013.

An adjustment of the forwards prices contained in Table #4 is then made to correct for the effects of transmission congestion in the PJM system between the PJM West trading hub and the Public Service zone where the BGS supply will be utilized.

<u>Table #5</u> (Congestion Factors) contains an estimate of the average congestion 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 Public Service zone. These Hub to Zone differentials are based on the average percent differences, by season, from August 2010 through July 2013.

<u>Table #6</u> (Losses) The factors utilized for total average losses, including PJM losses, are inputted in the upper portion of Table #6 (Losses) by rate schedule. Delivery loss factors used are those in the Company's filed tariff. PJM losses are the average percentage PJM EHV losses plus inadvertent energy for the three-year period June 2001 through May 2004, a value equal to 0.550%.

The lower portion of this table shows the derivation of the effective losses from the customer meter to the transmission nodes at which the LMPs are calculated. The loss factors shown are the Delivery loss factors from the Company's filed tariff less the mean hourly marginal loss factors for the PSE&G transmission zone as calculated by PJM. The resulting loss factor is reflective of losses from the customer meter to the transmission nodes (at which the LMPs are calculated) and at which payments to the winning bidders are based. The marginal loss factors used above are actual marginal loss de-ration factors based May 2010 to April 2013 data adjusted for the portion of marginal losses attributed to PJM extra-high voltage.

Since the service for all of the rates indicated is at secondary voltages, the applicable loss factors are identical for all rates.

Table #7 (Summary of Average BGS Energy Only Unit Costs @ Customer – PJM Time Periods) is the calculation of the energy only costs by rate, time period and season. These values are the seasonal and time period average costs per MWh as measured at the customer billing meter (from Table #3), based on the forwards prices (from Table #4) corrected for congestion (from Table #5), losses (from Table #6), and monthly time period weights (from Table #1). These average costs do not include the costs associated with ancillary Services, Generation Obligation or Transmission costs, which will be considered in subsequent calculations.

Table #8 (Summary of Average BGS Energy Only Costs @ Customer – PJM Time Periods) indicates the total value, in thousands of dollars, of the average BGS energy only costs. These are the results of the multiplication of the unit costs from Table #7, the monthly time period weights from Table #1 and the total sales to customers from Table #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 #9 (Summary of Average BGS Energy Only Unit Costs @ Customer – PSE&G Time Periods) shows the result of the corrections for the two rates billed on a time of day basis, Rates RLM and LPL-Secondary (less than 500 kW). These values are calculated based on the assumption that the MWhs included in the PJM on-peak time period and not included in the PSE&G on-peak time periods are at the average of the on- and off-peak PJM prices.

Table #10 (Generation & Transmission Obligations and Costs and Other Adjustments) The next steps set up the values necessary for the inclusion of the costs of the Generation Capacity and Transmission obligations. The top portion of Table #10 shows the total obligations, by rate schedule, that are currently being utilized in the year 2013. The values in the top portion of Table #10 will be updated in January 2014 to reflect the aggregate amount by rate schedule that will be in effect on June 1, 2014. Similar to the methodology used in Table #3, the obligations for Rate LPL-Secondary have been reduced for the percentage of customers having a Peak Load Share of 500 kW or greater. The middle portion of this table shows the number of summer and winter days and months that are used in this analysis. The bottom portion of this table shows the annual cost for transmission service and the average price of generation capacity for the three relevant RPM auctions. The cost of transmission service is equal to the rate in the PJM OATT for network transmission service in the PSE&G zone. The generation capacity costs used are the relevant current wholesale market prices for capacity.

This table also shows the level of blocking in current BGS charges for Rates RS and RHS, which will be utilized in the later calculations of the blocking of the new BGS charges for these rates. The Company has previously objected to the blocking of these charges since there is no compelling cost basis for any such blocking. The Company proposes to keep blocking in this year's filing, but wishes to note that it does not believe that there is a cost basis for doing so.

Table #11 (Ancillary Services) An estimate of the effects of the costs of ancillary services is included in the development of the final BGS rates. The use of the $3.00 per MWh value utilized in last year's BGS spreadsheet is proposed to continue. Since the actual costs are a complex combination of many factors, this Board-approved estimate of the overall annual average value, expressed on a dollar per MWh basis, is used as a reasonable and practical alternative.

Table #12 (Summary of Obligation Costs Expressed as $/MWh @ Customer – For Non-Demand Rates Only) shows the result of the allocation of both the transmission and generation costs on a per kWh basis to those rates whose BGS service will only be recovered through energy charges, Rates RS through BPL. The obligation costs for the rates not indicated in this table, Rates GLP and LPL-Sec, will be recovered directly through a distinct obligation charge based on a separate charge times each customer's assigned transmission and generation capacity obligation. The annual values are calculated as the total obligations (upper part of Table #10) times their costs (lower part of Table #10) divided by the appropriate total rate schedule MWh (from Table #3).

Table #13 (Summary of BGS Unit Costs @ Customer) is the result of the inclusion of the transmission, generation capacity, and ancillary Services costs to the energy only costs shown in Table #9. The top portion of this table shows the total estimated all-in BGS costs for the non-demand rates (Rates RS, RHS, RLM, WH, WHS, HS, PSAL and BPL), whose BGS costs are proposed to be recovered on an energy only basis through kWh charges. The all-in costs for the residential non-time of day rates, Rates RS and RHS, are blocked in the summer based on the current level of BGS blocking inputted in Table #10 so as to maintain the same BGS rate differential that currently exists. The middle section shows the results for the demand rates (Rates GLP and LPL-Sec) whose BGS costs will be recovered through both energy charges on a per kWh basis and obligation charges on a per kW of obligation basis. The left hand columns indicate the unit energy costs, while the right hand columns indicate the obligation costs. The bottom portion of this table shows the total estimated costs for BGS, based on the assumptions utilized in the above tables, and the average per unit cost, as measured at the customer meters or the transmission nodes.

Table #14 (Ratio of BGS Unit Costs @ Customer to All-In Average Cost @ Transmission Nodes) indicates the ratio of the individual rate element costs from Table #13 to the overall all-in cost as measured at the transmission nodes, plus constants, where applicable. These bid factor ratios are a key element in the calculation of the actual BGS-FP charges, and will be used in later tables to convert the winning bids into actual BGS rates charged to customers.

The top portion of this table indicates these ratios for the non-demand rates while the ratios for the demand rates are shown on the bottom portion of the table. Since the unit rates charged for generation and transmission obligation (as shown in the right hand columns) for Rates GLP and LPL-Sec are not unitized but kept at the estimated market value, it is necessary to modify the energy ratios for these two rate classes to assure that the resulting overall revenue from charges to the customers equals the payment to suppliers. The first of the values indicated, the "multiplier" is utilized as a ratio, with the "constant" term an additive adjustment to the resulting value. For example, if the tranche weighted average winning bid prices adjusted for seasonal payment factors is $83.41 per MWh and the GLP multiplier for summer is 1.078 and the constant is $(28.454), the summer BGS rate charged customers would equal ($83.41 * 1.078) - $28.454, or $61.46 per MWh.

Assumptions This unnumbered table summarizes some of the most important assumptions utilized in the above calculations.

Table #15 (Summary of Total BGS Costs by Season) shows the calculation of the total BGS Costs, utilizing the total customer usage from Table #3 and the all-in unit costs from Table #13. The lower left portion of this table indicates the relative percentage of total costs by season for all rate schedules, while the center shows the calculation of the overall average all-in 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 this table, are the seasonal payment ratios upon which payments to the winning bidders are based.

Table #16 (Spreadsheet Error Checking) shows the reconciliation between the customer revenue calculation to the BGS supplier payments, utilizing an assumed winning bid price (as indicated) and the calculated summer-winter payment ratios, the customer usage from Table #3 and the all-in unit costs from Table #13.

Table #17 (Total Supplier Energy @ transmission nodes) shows the calculation of the total supplier energy by season, utilizing the total customer usage from Table #3 and the meter to transmission node loss factors from the lower portion of Table #6.

The second spreadsheet used in the calculation of the final BGS-FP rates is included as Attachment #3, and is titled “Calculation of June 2014 to May 2015 BGS-FP Rates”. The tables in this spreadsheet calculate the weighted average winning bid price and convert it into the final BGS-FP rates that are charged to customers. An explanation of each of the six tables, labeled as Table A through F, is as follows.

Table A (Auction Results) contains the results of the prior two BGS auctions as well as the results (shown with illustrative values) of the current auction. 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 of “Notes:”.

Table B (Ratio of BGS Unit Costs @ Customer to All-In Average Cost @ transmission nodes) is a repeat of the values shown in Table #14 from Attachment 2, the bid factors calculated based on current market conditions.

Table C (Preliminary Resulting BGS Rates) contains the preliminary customer BGS-FP 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-FP 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 done 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-FP energy related charges.

Table E (Final Resulting BGS Rates) contains the final adjusted BGS-FP rates, which are equal to the preliminary BGS–FP 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-FP rates developed in Table E and the anticipated total season payments to BGS suppliers, based on the data in Table A.

IV. CONCLUSION

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

1. It is necessary and in the public interest for the electric public utilities to secure service for the BGS-FP and BGS-CIEP customers, as approved herein, for the period June 1, 2014 to May 31, 2017.
2. The Company's proposed treatment of its Committed Supply is approved.
3. The Company's proposed accounting for BGS is approved for purposes of accounting and BGS cost recovery.
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 Rate Design Methodology and Tariff Sheets are approved.

V. Attachment 1 - Tariff Sheets

"Form Of" BGS-FP,BGS-CIEP and CIEP Standby Fee tariff sheets

COMMERCIAL AND INDUSTRIAL ENERGY PRICING (CIEP) STANDBY FEE

APPLICABLE TO:

Default electric supply service for Rate Schedules LPL-Secondary (500 kilowatts or greater), LPL-Primary, HTS-Subtransmission, HTS-High Voltage and to customers served under Rate Schedules HS, GLP and LPL-Secondary (less than 500 kilowatts) who have elected BGS-CIEP as their default supply service.

	Charge (per kilowatthour)
Commercial and Industrial Energy Pricing (CIEP) Standby Fee	$ 0.000150
Charge including New Jersey Sales and Use Tax (SUT)	$ 0.000161

The above charges shall recover costs associated with the administration, maintenance and availability of the Basic Generation Service default electric supply service for applicable rate schedules. These charges shall be combined with the Distribution Kilowatthour Charges for billing.

Kilowatt threshold noted above is based upon the customer's Peak Load Share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM). See Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions of this Tariff.

Date of Issue: May 10, 2013 Effective: June 1, 2013
Issued by ROSE M. CHERNICK, Vice President Finance – PSE&G
80 Park Plaza, Newark, New Jersey 07102
Filed pursuant to Order of Board of Public Utilities dated February 7, 2013
in Docket No. ER12060485

BASIC GENERATION SERVICE – FIXED PRICING (BGS-FP)
ELECTRIC SUPPLY CHARGES

APPLICABLE TO:

Default electric supply service for Rate Schedules RS, RHS, RLM, WH, WHS, HS, BPL, BPL-POF, PSAL, GLP and LPL-Secondary (less than 500 kilowatts).

BGS ENERGY CHARGES:

Applicable to Rate Schedules RS, RHS, RLM, WH, WHS, HS, BPL, BPL-POF and PSAL

Charges per kilowatthour:

Rate Schedule	For usage in each of the months of October through May: Charges	Charges Including SUT	For usage in each of the months of June through September: Charges	Charges Including SUT
RS – first 600 kWh	$x.xxxxxx	$x.xxxxxx	$x.xxxxxx	$x.xxxxxx
RS – in excess of 600 kWh	x.xxxxxx	x.xxxxxx	x.xxxxxx	x.xxxxxx
RHS – first 600 kWh	x.xxxxxx	x.xxxxxx	x.xxxxxx	x.xxxxxx
RHS – in excess of 600 kWh	x.xxxxxx	x.xxxxxx	x.xxxxxx	x.xxxxxx
RLM On-Peak	x.xxxxxx	x.xxxxxx	x.xxxxxx	x.xxxxxx
RLM Off-Peak	x.xxxxxx	x.xxxxxx	x.xxxxxx	x.xxxxxx
WH	x.xxxxxx	x.xxxxxx	x.xxxxxx	x.xxxxxx
WHS	x.xxxxxx	x.xxxxxx	x.xxxxxx	x.xxxxxx
HS	x.xxxxxx	x.xxxxxx	x.xxxxxx	x.xxxxxx
BPL	x.xxxxxx	x.xxxxxx	x.xxxxxx	x.xxxxxx
BPL-POF	x.xxxxxx	x.xxxxxx	x.xxxxxx	x.xxxxxx
PSAL	x.xxxxxx	x.xxxxxx	x.xxxxxx	x.xxxxxx

The above Basic Generation Service Energy Charges reflect costs for Energy, Generation Capacity, Transmission, and Ancillary Services (including PJM Interconnection, L.L.C. (PJM) Administrative Charges). The portion of these charges related to Network Integration Transmission Service, including the PJM Seams Elimination Cost Assignment Charges, the PJM Reliability Must Run Charge and PJM Transmission Enhancement Charges may be changed from time to time on the effective date of such change to the PJM rate for these charges as approved by the Federal Energy Regulatory Commission (FERC).

Kilowatt threshold noted above is based upon the customer's Peak Load Share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM). See Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions of this Tariff.

BASIC GENERATION SERVICE – FIXED PRICING (BGS-FP)
ELECTRIC SUPPLY CHARGES
(Continued)

BGS ENERGY CHARGES:

Applicable to Rate Schedules GLP and LPL-Sec.

Charges per kilowatthour:

	For usage in each of the months of October through May		For usage in each of the months of June through September	
Rate Schedule	Charges	Charges Including SUT	Charges	Charges Including SUT
GLP	$ x.xxxxxx	$ x.xxxxxx	$ x.xxxxxx	$ x.xxxxxx
GLP Night Use	x.xxxxxx	x.xxxxxx	x.xxxxxx	x.xxxxxx
LPL-Sec. under 500 kW				
On-Peak	x.xxxxxx	x.xxxxxx	x.xxxxxx	x.xxxxxx
Off-Peak	x.xxxxxx	x.xxxxxx	x.xxxxxx	x.xxxxxx

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

Kilowatt thresholds noted above are based upon the customer's Peak Load Share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM). See Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions of this Tariff.

BASIC GENERATION SERVICE – FIXED PRICING (BGS-FP)
ELECTRIC SUPPLY CHARGES
(Continued)

BGS CAPACITY CHARGES:

Applicable to Rate Schedules GLP and LPL-Sec.

Charges per kilowatt of Generation Obligation:

Charge applicable in the months of June through September...$x.xxxx
Charge including New Jersey Sales and Use Tax (SUT) ....$x.xxxx

Charge applicable in the months of October through May...$x.xxxx
Charge including New Jersey Sales and Use Tax (SUT) ....$x.xxxx

The above charges shall recover each customer's share of the overall summer peak load assigned to the Public Service Transmission Zone by the PJM Interconnection, L.L.C. (PJM) as adjusted by PJM assigned capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions.

BGS TRANSMISSION CHARGES

Applicable to Rate Schedules GLP and LPL-Sec.

Charges per kilowatt of Transmission Obligation:

Currently effective Annual Transmission Rate for
Network Integration Transmission Service for the
Public Service Transmission Zone as derived from the
FERC Electric Tariff of the PJM Interconnection, LLC .... $ xx,xxx.xx per MW per year
PJM Seams Elimination Cost Assignment Charges ....$ x.xx per MW per month
PJM Reliability Must Run Charge..$ x.xx per MW per month
PJM Transmission Enhancements
Trans-Allegheny Interstate Line Company .... $ xxx.xx per MW per month
Virginia Electric and Power Company ....$ xx.xx per MW per month
Potomac-Appalachian Transmission Highline L.L.C. ....$ xx.xx per MW per month
PPL Electric Utilities Corporation ....$ x.xx per MW per month
American Electric Power Service Corporation ....$ x.xx per MW per month
Atlantic City Electric Company. ....$ x.xx per MW per month
Delmarva Power and Light Company..$ x.xx per MW per month
Potomac Electric Power Company. ....$ xx.xx per MW per month

Above rates converted to a charge per kW of Transmission
Obligation, applicable in all months... $ x.xxxx
Charge including New Jersey Sales and Use Tax (SUT) .... $ x.xxxx

The above charges shall recover each customer's share of the overall summer peak transmission load assigned to the Public Service Transmission Zone by the PJM Interconnection, L.L.C. (PJM) as adjusted by PJM assigned transmission capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions. These charges will be changed from time to time on the effective date of such change to the PJM rate for charges for Network Integration Transmission Service, including the PJM Seams Elimination Cost Assignment Charges, the PJM Reliability Must Run Charge and PJM Transmission Enhancement Charges as approved by Federal Energy Regulatory Commission (FERC).

BASIC GENERATION SERVICE – COMMERCIAL AND INDUSTRIAL ENERGY PRICING (CIEP)
ELECTRIC SUPPLY CHARGES

APPLICABLE TO:

Default electric supply service for Rate Schedules LPL-Secondary (500 kilowatts or greater), LPL-Primary, HTS-Subtransmission, HTS-High Voltage and to customers served under Rate Schedules HS, GLP and LPL-Secondary (less than 500 kilowatts) who have elected BGS-CIEP as their default supply service.

BGS ENERGY CHARGES:

Charges per kilowatthour:

BGS Energy Charges are hourly and include PJM Locational Marginal Prices, and PJM Ancillary Services. The total BGS Energy Charges are based on the sum of the following:

- The real time PJM Load Weighted Average Locational Marginal Prices for the Public Service Transmission Zone, adjusted for losses (tariff losses, as defined in Standard Terms and Conditions Section 4.3, adjusted to remove the mean hourly PJM marginal losses of ~~0.92408~~0.87662%), and adjusted for SUT, plus
- Ancillary Services (including PJM Administrative Charges) at the rate of $0.006000 per kilowatthour, adjusted for losses (tariff losses, as defined in Standard Terms and Conditions Section 4.3, adjusted to remove the mean hourly PJM marginal losses of ~~0.92408~~0.87662%), and adjusted for SUT, plus

BGS CAPACITY CHARGES:

Charges per kilowatt of Generation Obligation:

Charge applicable in the months of June through September ....$ x.xxxx
Charge including New Jersey Sales and Use Tax (SUT) ....$ x.xxxx

Charges applicable in the months of October through May..$ x.xxxx
Charges including New Jersey Sales and Use Tax (SUT) ....$ x.xxxx

The above charges shall recover each customer's share of the overall summer peak load assigned to the Public Service Transmission Zone by the PJM Interconnection, L.L.C. (PJM) as adjusted by PJM assigned capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions.

BASIC GENERATION SERVICE – COMMERCIAL AND INDUSTRIAL ENERGY PRICING (CIEP)
ELECTRIC SUPPLY CHARGES
(Continued)

BGS TRANSMISSION CHARGES

Charges per kilowatt of Transmission Obligation:

Currently effective Annual Transmission Rate for Network Integration Transmission Service for the Public Service Transmission Zone as derived from the FERC Electric Tariff of the PJM Interconnection, LLC	$ xx,xxx.xx per MW per year
PJM Seams Elimination Cost Assignment Charges	$ x.xx per MW per month
PJM Reliability Must Run Charge	$ x.xx per MW per month
PJM Transmission Enhancements	
Trans-Allegheny Interstate Line Company	$ xxx.xx per MW per month
Virginia Electric and Power Company	$ xx.xx per MW per month
Potomac-Appalachian Transmission Highline L.L.C.	$ xx.xx per MW per month
PPL Electric Utilities Corporation	$ x.xx per MW per month
American Electric Power Service Corporation	$ x.xx per MW per month
Atlantic City Electric Company.	$ x.xx per MW per month
Delmarva Power and Light Company	$ x.xx per MW per month
Potomac Electric Power Company.	$ xx.xx per MW per month

Above rates converted to a charge per kW of Transmission Obligation, applicable in all months	$ x.xxxx
Charge including New Jersey Sales and Use Tax (SUT)	$ x.xxxx

The above charges shall recover each customer’s share of the overall summer peak transmission load assigned to the Public Service Transmission Zone by the PJM Interconnection, L.L.C. (PJM) as adjusted by PJM assigned transmission capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions. These charges will be changed from time to time on the effective date of such charge to the PJM rate for charges for Network Integration Transmission Service, including the PJM Seams Elimination Cost Assignment Charges, the PJM Reliability Must Run Charge and PJM Transmission Enhancement Charges as approved by Federal Energy Regulatory Commission (FERC).

Kilowatt threshold noted above is based upon the customer’s Peak Load Share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM). See Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions of this Tariff.

VI. ATTACHMENT 2 – SPREADSHEETS FOR THE DEVELOPMENT OF BGS COST AND BID FACTORS

(Pages 1 through 7)

Development of BGS-FP Cost and Bid Factors for 2014/15 BGS Filing

Adjusted to Billing Time Periods

Based on average of year 2010, 2011 & 2012 Load Profile Information

Table #1 **% Usage During PJM On-Peak Period** *On-Peak periods defined as the 16 hr PJM Trading period, adj for NERC holidays*

(data rounded to nearest .01%)	*Profile Meter Data* **RS**	*Profile Meter Data* **RHS**	*Profile Meter Data* **RLM**	*Profile Meter Data* **WH**	*Profile Meter Data* **WHS**	*Profile Meter Data* **HS**	*--- Other Analysis ---* **PSAL**	**BPL**	*Profile Meter Data* **GLP**	*Profile Meter Data* **LPL-S**
January	46.43%	45.47%	47.33%	39.53%	39.53%	45.37%	30.57%	30.57%	54.77%	53.83%
February	46.43%	45.47%	47.33%	39.53%	39.53%	45.37%	30.57%	30.57%	54.77%	53.83%
March	51.27%	51.23%	52.07%	43.67%	43.67%	51.87%	24.93%	24.93%	60.37%	59.67%
April	50.57%	50.83%	51.33%	41.47%	41.47%	53.57%	25.57%	25.57%	59.57%	59.10%
May	47.77%	49.80%	48.77%	40.77%	40.77%	59.23%	23.40%	23.40%	57.57%	57.57%
June	53.03%	53.97%	54.23%	44.30%	44.30%	64.93%	22.07%	22.07%	61.37%	60.00%
July	49.10%	50.00%	50.40%	41.17%	41.17%	60.40%	18.07%	18.07%	57.27%	55.00%
August	53.90%	55.00%	55.73%	45.47%	45.47%	65.00%	22.00%	22.00%	62.07%	59.83%
September	48.93%	50.67%	50.20%	40.47%	40.47%	60.40%	21.30%	21.30%	58.20%	57.40%
October	49.83%	50.33%	50.87%	42.80%	42.80%	53.53%	26.30%	26.30%	58.57%	58.17%
November	49.77%	48.17%	50.27%	41.97%	41.97%	47.67%	30.93%	30.93%	57.97%	57.00%
December	49.77%	48.17%	50.27%	41.97%	41.97%	47.67%	30.93%	30.93%	57.97%	57.00%

Based on average of year 2010, 2011 & 2012 Load Profile Information

Table #2 **% Usage During PSE&G On-Peak Billing Period** *On-Peak periods as defined in specified rate schedule (average of %s for 2011, 2012 & 2013)*

(data rounded to nearest .01%)	*N/A* **RS**	*N/A* **RHS**	*Profile Meter Data* **RLM**	*N/A* **WH**	*N/A* **WHS**	*N/A* **HS**	*N/A* **PSAL**	*N/A* **BPL**	*N/A* **GLP**	*Profile Meter Data* **LPL-S**
January	----	----	42.95%	----	----	----	----	----	----	48.81%
February	----	----	42.44%	----	----	----	----	----	----	48.67%
March	----	----	42.35%	----	----	----	----	----	----	49.29%
April	----	----	43.14%	----	----	----	----	----	----	50.47%
May	----	----	44.12%	----	----	----	----	----	----	51.25%
June	----	----	46.63%	----	----	----	----	----	----	51.67%
July	----	----	47.51%	----	----	----	----	----	----	51.33%
August	----	----	48.22%	----	----	----	----	----	----	50.51%
September	----	----	47.84%	----	----	----	----	----	----	51.48%
October	----	----	46.24%	----	----	----	----	----	----	51.62%
November	----	----	44.01%	----	----	----	----	----	----	50.08%
December	----	----	42.79%	----	----	----	----	----	----	49.72%

Table #3 **Class Usage @ customer**

calendar month sales forecasted for 2013, less % for LPL-Sec > 500 kW Peak Load Share

in MWh	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL	GLP	< 500 kW LPL-S
January	1,156,341	27,412	22,534	193	4	4,097	17,410	35,249	687,042	644,834
February	963,343	23,085	18,337	176	3	3,440	14,479	30,938	641,830	642,822
March	967,317	20,159	19,804	199	4	2,838	14,255	28,008	665,290	593,105
April	800,830	11,764	14,783	196	4	1,455	11,840	26,019	589,889	582,855
May	893,311	9,343	17,447	164	3	957	11,622	22,578	643,709	643,950
June	1,245,236	9,246	23,784	148	3	1,139	9,822	17,554	702,867	651,142
July	1,594,536	10,348	31,464	131	3	1,284	10,775	19,146	803,387	714,982
August	1,484,780	10,065	29,630	116	2	1,082	11,469	16,365	793,764	755,553
September	1,068,837	8,932	21,884	131	3	896	12,723	16,579	646,237	644,260
October	858,813	11,625	18,215	157	3	1,396	15,574	26,628	638,461	667,790
November	919,000	14,204	16,257	168	3	1,637	16,398	11,817	586,063	577,740
December	1,070,090	21,953	20,392	171	4	2,760	17,072	14,686	615,919	579,187
Total	13,022,434	178,136	254,531	1,950	39	22,981	163,439	265,567	8,014,458	7,698,219

Table #4 **Forwards Prices - Energy Only @ bulk system**

in $/MWh, not including PJM losses	On-Peak	Off/On Pk LMP ratio	Resulting Off-Peak
January	43.45	0.7792	33.856
February	43.45	0.7792	33.856
March	39.83	0.7792	31.036
April	39.83	0.7792	31.036
May	40.08	0.7792	31.230
June	43.56	0.6058	26.389
July	57.44	0.6058	34.797
August	50.38	0.6058	30.520
September	40.28	0.6058	24.402
October	37.40	0.7792	29.142
November	38.98	0.7792	30.373
December	40.45	0.7792	31.519

Table #5 **Zone to Western Hub Basis Differential**

	On-Peak	Off-Peak
January	110%	108%
February	110%	108%
March	110%	108%
April	110%	108%
May	110%	108%
June	109%	108%
July	109%	108%
August	109%	108%
September	109%	108%
October	110%	108%
November	110%	108%
December	110%	108%

NYMEX Forwards (November 2013) from I

08/2010 through 7/2013 average for Zone/Hub differentials

Table #6 **Losses**

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL	GLP	LPL-S
from meter to bulk system (includes Delivery & PJM EHV losses)										
Loss Factors =	8.0462%	8.0462%	8.0462%	8.0462%	8.0462%	8.0462%	8.0462%	8.0462%	8.0462%	8.0462%
Expansion Factor =	1.087503	1.087503	1.087503	1.087503	1.087503	1.087503	1.087503	1.087503	1.087503	1.087503
1 / Expansion Factor =	0.919538	0.919538	0.919538	0.919538	0.919538	0.919538	0.919538	0.919538	0.919538	0.919538
from meter to transmission node (includes Delivery less mean hourly PJM marginal losses)										
Loss Factors =	6.7200%	6.7200%	6.7200%	6.7200%	6.7200%	6.7200%	6.7200%	6.7200%	6.7200%	6.7200%
Expansion Factor =	1.072041	1.072041	1.072041	1.072041	1.072041	1.072041	1.072041	1.072041	1.072041	1.072041
1 / Expansion Factor =	0.932800	0.932800	0.932800	0.932800	0.932800	0.932800	0.932800	0.932800	0.932800	0.932800

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

		RS	RHS	RLM	WH	WHS	HS	PSAL	BPL	GLP	LPL-S
Summer - all hrs		$ 46.66	$ 46.35	$ 46.97	$ 43.62	$ 43.56	$ 49.02	$ 38.63	$ 39.00	$ 48.18	$ 47.57
	PJM on pk	$ 57.89	$ 57.19	$ 57.89	$ 56.55	$ 56.53	$ 57.56	$ 56.12	$ 56.63	$ 57.37	$ 57.04
	PJM off pk	$ 34.82	$ 34.41	$ 34.80	$ 33.94	$ 33.93	$ 34.67	$ 34.02	$ 34.37	$ 34.55	$ 34.45
Winter - all hrs		$ 42.70	$ 43.02	$ 42.77	$ 41.78	$ 41.78	$ 43.29	$ 40.27	$ 40.48	$ 43.60	$ 43.49
	PJM on pk	$ 48.47	$ 48.91	$ 48.45	$ 48.39	$ 48.39	$ 49.08	$ 48.54	$ 48.91	$ 48.36	$ 48.32
	PJM off pk	$ 37.18	$ 37.56	$ 37.16	$ 37.10	$ 37.10	$ 37.76	$ 37.01	$ 37.24	$ 37.11	$ 37.09
Annual		$ 44.34	$ 43.74	$ 44.53	$ 42.28	$ 42.28	$ 44.39	$ 39.82	$ 40.09	$ 45.28	$ 44.95
System Total		$ 44.69									

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

		RS	RHS	RLM	WH	WHS	HS	PSAL	BPL	GLP	LPL-S
Summer - all hrs		$ 251,647	$ 1,789	$ 5,014	$ 23	$ 0	$ 216	$ 1,730	$ 2,716	$ 141,961	$ 131,568
	PJM on pk	$ 160,169	$ 1,157	$ 3,256	$ 13	$ 0	$ 159	$ 525	$ 819	$ 100,981	$ 91,601
	PJM off pk	$ 91,478	$ 632	$ 1,758	$ 10	$ 0	$ 57	$ 1,206	$ 1,897	$ 40,979	$ 39,967
Winter - all hrs		$ 325,777	$ 6,004	$ 6,320	$ 59	$ 1	$ 804	$ 4,778	$ 7,931	$ 220,974	$ 214,501
	PJM on pk	$ 180,786	$ 3,286	$ 3,558	$ 29	$ 1	$ 446	$ 1,626	$ 2,658	$ 141,327	$ 135,787
	PJM off pk	$ 144,991	$ 2,718	$ 2,762	$ 31	$ 1	$ 359	$ 3,152	$ 5,272	$ 79,646	$ 78,714
Annual		$ 577,424	$ 7,792	$ 11,334	$ 82	$ 2	$ 1,020	$ 6,508	$ 10,646	$ 362,934	$ 346,070
System Total		$ 1,323,813									

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

		RS	RHS	RLM	WH	WHS	HS	PSAL	BPL	GLP	LPL-S
Summer - all hrs		$ 46.66	$ 46.35	$ 46.97	$ 43.62	$ 43.56	$ 49.02	$ 38.63	$ 39.00	$ 48.18	$ 47.57
	PSE&G On pk			$ 59.13							$ 58.55
	PSE&G Off pk			$ 35.93							$ 36.03
Winter - all hrs		$ 42.70	$ 43.02	$ 42.77	$ 41.78	$ 41.78	$ 43.29	$ 40.27	$ 40.48	$ 43.60	$ 43.49
	PSE&G On pk			$ 49.26							$ 49.10
	PSE&G Off pk			$ 37.79							$ 37.87
Annual Average		$ 44.34	$ 43.74	$ 44.53	$ 42.28	$ 42.28	$ 44.39	$ 39.82	$ 40.09	$ 45.28	$ 44.95
System Average		$ 44.69									

Table #10 **Generation & Transmission Obligations and Costs and Other Adjustments**

obligations - Peak Load shares eff 6/1/13, scaling factors eff 6/1/13, Transmission Loads eff 1/1/13; costs are market estimates

in MW	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL	GLP	Adj for PLS > 500 kW LPL-S
Gen Obl - MW	4,786.4	33.7	91.1	0.0	0.0	5.0	0.0	0.0	2,488.8	1,910.7
Trans Obl - MW	4,284.7	31.6	85.0	0.0	0.0	4.6	0.0	0.0	2,292.3	1,709.9

# of Months and Days used in this analysis

# of summer days =	122		# of summer months =	4
# of winter days =	243		# of winter months =	8
			total # months =	12

Transmission Cost	year round =	$41,866.57	per MW-yr
Generation Capacity cost	summer =	$ 171.21	$/MW/day
	winter =	$ 171.21	$/MW/day

	RS	RHS	
<u>% usage in Summer Blocks</u>			
Block 1 (0-600 kWh/m)	64.7%	63.3%	*(based on W/N actuals used in settlement and final rate design of 2009 Rate Case, rounded to .1%)*
Block 2 (>600 kWh/m)	35.3%	36.7%	
Required summer inversion =	0.8652	1.1569 ¢/kWh	*(same as 2003/2004 BGS blocking inversion)*

Table #11 **Ancillary Services**

forecasted overall annual average $ 3.00 per MWh @ bulk system

Table #12 **Summary of Obligation Costs Expressed as $/MWh @ customer (for non-demand rates only)**

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Transmission Obl - all months	$ 13.78	$ 7.43	$ 30.94	$ -	$ -	$ 8.38	$ -	$ -
Generation Obl -								
per annual MWh	$ 22.97	$ 11.82	$ 49.49	$ -	$ -	$ 13.60	$ -	$ -
recovery per summer MWh	$ 18.54	$ 18.24	$ 37.46	$ -	$ -	$ 23.73	$ -	$ -
recovery per winter MWh	$ 26.10	$ 10.05	$ 59.01	$ -	$ -	$ 11.20	$ -	$ -
			For RLM, per on-peak kWh only					

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

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

		RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Summer - all hrs		$ 86.66	$ 68.86		$ 46.89	$ 46.83	$ 74.26	$ 41.89	$ 42.26
	PSE&G On pk			$ 142.82					
	PSE&G Off pk			$ 39.19					
	Block 1 (0-600 kWh/m)	$ 83.61	$ 64.61						
	Block 2 (>600 kWh/m)	$ 92.26	$ 76.18						
Winter - all hrs		$ 82.71	$ 65.53		$ 45.04	$ 45.04	$ 68.53	$ 43.53	$ 43.74
	PSE&G On pk			$ 132.95					
	PSE&G Off pk			$ 41.05					
Annual -all hrs		$ 84.35	$ 66.26	$ 84.14	$ 45.54	$ 45.55	$ 69.63	$ 43.08	$ 43.35

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

		GLP	LPL-S
Summer - all hrs		$ 51.45	$ 50.83
	PSE&G On pk		$ 61.81
	PSE&G Off pk		$ 39.30
Winter - all hrs		$ 46.86	$ 46.75
	PSE&G On pk		$ 52.37
	PSE&G Off pk		$ 41.14
Annual - all hrs per MWh only		$ 48.55	$ 48.22
Including T&G Obligation $			
Summer - all hrs		$ 79.90	$ 73.85
	PSE&G On pk		$ 106.75
	PSE&G Off pk		$ 39.30
Winter - all hrs		$ 79.94	$ 72.57
	PSE&G On pk		$ 104.00
	PSE&G Off pk		$ 41.14
Annual - including T&G Obl $		$ 79.93	$ 73.03

Note: Obligation $ included in On pk costs

PLUS:	GLP	LPL-S	
Gen Cost			
summer	$ 5.2218	$ 5.2218	per kW of G obl /month
winter	$ 5.2004	$ 5.2004	per kW of G obl /month
annual	$ 5.2076	$ 5.2076	per kW of G obl /month
Trans cost			
all months	$ 3.4889	$ 3.4889	per kW of T obl /month

ALL RATES

Grand Total Cost in $1000 = $ 2,354,619
All-In Average cost @ customer = $ 79.49 per MWh at customer (per customer metered MWh)
All-In Average costs @ transmission nodes = $ 74.15 per MWh at transmission nodes (per metered MWh at transmission node)

Table #14 **Ratio of BGS Unit Costs @ customer to All-In Average Cost @ transmission nodes -** *rounded to 3 decimal places, unit obligation $ rounded to 4 decimal places*

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

		RS	RHS	RLM	WH	WHS	HS	PSAL	BPL	
Summer - all hrs					**0.632**	**0.632**	**1.001**	0.565	0.570	
	PSE&G On pk			**1.926**				Use weighted average		
	PSE&G Off pk			**0.529**				for all streetlighting =		**0.568**
	All usage Multiplier	**1.169**	**0.929**							
	Constant (in $/MWh)	**$ (3.054)**	**$ (4.246)**	for Block 1 (0-600 kWh/m) usage						
	Constant (in $/MWh)	**$ 5.598**	**$ 7.323**	for Block 2 (>600 kWh/m) usage						
Winter - all hrs		**1.115**	**0.884**		**0.607**	**0.607**	**0.924**	0.587	0.590	
	PSE&G On pk			**1.793**				Use weighted average		
	PSE&G Off pk			**0.554**				for all streetlighting =		**0.589**
Annual - all hrs		1.138	0.894	1.135	0.614	0.614	0.939	0.581	0.585	

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

		GLP Multiplier	GLP Constant (in $/MWh)	LPL-S Multiplier	LPL-S Constant (in $/MWh)
Summer - all hrs		**1.078**	**(28.454)**		
	PSE&G On pk			**1.440**	**(44.936)**
	PSE&G Off pk			**0.530**	**-**
Winter - all hrs		**1.078**	**(33.082)**		
	PSE&G On pk			**1.403**	**(51.629)**
	PSE&G Off pk			**0.555**	**-**
Annual - including T&G Obl $		1.078		0.985	

PLUS:

<u>Gen Cost</u>			
summer	$ 5.2218	$ 5.2218	per kW of G obl /month
winter	$ 5.2004	$ 5.2004	per kW of G obl /month
annual	$ 5.2076	$ 5.2076	per kW of G obl /month
<u>Trans cost</u>			
all months	$ 3.4889	$ 3.4889	per kW of T obl /month

Assumptions:

Gen Cost =	$ 171.21 /MW day	summer
	$ 171.21 /MW day	winter
Trans cost =	$ 41,866.57 per MW-yr	
Analysis time period =	4 summer months	
	8 winter months	
Ancillary Services =	$ 3.00 per MWh	
Energy Costs =	based on Forwards @ PJM West - corrected for congestion	
Usage patterns =	forecasted 2014 energy use by class, PJM and PSE&G on/off % from 2010, 2011 & 2012 class load profiles	
Obligations =	class totals in effect as of filing date	
Losses =	Delivery losses from tariff, PJM losses based on 3 year average %	
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	
PSE&G Billing time periods =	as per specific rate schedule	

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

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL	GLP	LPL-S
Total Costs by Rate - in $1000										
Summer	$ 467,416	$ 2,657	$ 9,448	$ 25	$ 1	$ 327	$ 1,876	$ 2,943	$ 235,548	$ 204,364
Winter	$ 630,986	$ 9,145	$ 11,968	$ 64	$ 1	$ 1,273	$ 5,165	$ 8,570	$ 405,032	$ 357,810
Total	$ 1,098,402	$ 11,802	$ 21,416	$ 89	$ 2	$ 1,600	$ 7,041	$ 11,513	$ 640,580	$ 562,174
% of Annual Total $ by Rate										
Summer	43%	23%	44%	28%	29%	20%	27%	26%	37%	36%
Winter	57%	77%	56%	72%	71%	80%	73%	74%	63%	64%

Total Costs - in $1000	
Summer	$ 924,605
Winter	$ 1,430,014
Total	$ 2,354,619

rounded to 4 decimal places

% of Annual Total $		If total $ were split on a per MWh basis (on transmission node MWhs):			
Summer	39%	$ 75.85 per MWh @ trans nodes	Ratio to All-In Cost >>>	Summer	**1.0230**
Winter	61%	$ 73.09 per MWh @ trans nodes		Winter	**0.9857**

Table #16 **Spreadsheet Error Checking -** *Reconciliation of Customer Revenue and Supplier Payments, based on above data only*

Assumed Winning Bid Price = $ 74.15 *(bid includes payments for all losses)*
Payment Ratio - Summer = 1.0230
Payment Ratio - Winter = 0.9857

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL	GLP	LPL-S
Total Rate Revenue - in $1000										
Summer	$ 467,493	$ 2,658	$ 9,449	$ 25	$ 1	$ 327	$ 1,886	$ 2,933	$ 235,640	$ 204,400
Winter	$ 630,730	$ 9,147	$ 11,970	$ 64	$ 1	$ 1,273	$ 5,182	$ 8,557	$ 404,965	$ 357,930
Total	$ 1,098,224	$ 11,805	$ 21,420	$ 89	$ 2	$ 1,600	$ 7,068	$ 11,490	$ 640,605	$ 562,330

Total Summer	$ 924,812
Total Winter	$ 1,429,819
Grand Total	$ 2,354,631

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL	GLP	LPL-S
Total Supplier Payment - in $1000										
Summer	$ 438,578	$ 3,138	$ 8,682	$ 43	$ 1	$ 358	$ 3,642	$ 5,663	$ 239,583	$ 224,920
Winter	$ 597,757	$ 10,934	$ 11,578	$ 112	$ 2	$ 1,456	$ 9,297	$ 15,351	$ 397,108	$ 386,458
Total	$ 1,036,336	$ 14,072	$ 20,260	$ 154	$ 3	$ 1,814	$ 12,939	$ 21,014	$ 636,691	$ 611,378

Total Summer	$ 924,608
Total Winter	$ 1,430,053
Grand Total	$ 2,354,661

Difference (in $1000) = $ (29)

Note: Minor differences in totals are due to rounding of Bid Factors and Payment Factors

Table #17 **Total Supplier Energy** *@ transmission nodes*

in MWh

Summer	12,189,432
Winter	19,566,303
Total	31,755,735

VII. Attachment 3 – Spreadsheets for the Calculation of BGS Rates

(Pages 1 through 6)

Calculation of June 2014 to May 2015 BGS-FP Rates

Illustrative purposes only

Table A **Auction Results**

line #	Specific BGS-FP Auction >>	*remaining portion of 36 month bid - 2012 auction*	*remaining portion of 36 month bid - 2013 auction*	*36 month bid - 2014 auction*	*Notes:*
1	**Winning Bid - in $/MWh**	$ 83.88	$ 92.18	$ 74.15	Illustrative Bid
	(includes all payments, including impact of PJM marginal losses)				
2	**# of Tranches for Bid**	29	28	28	from then current Bid
3	**Total # of Tranches**	85	85	85	from then current Bid
	Payment Factors				
4	Summer	1.0025	1.0163	1.0230	
5	Winter	0.9984	0.9900	0.9857	
	Applicable Customer Usage @ transmission nodes - *in MWh*				
6	Summer MWh	12,189,432			from Table #17 of the current Bid Factor Spreadsheet
7	Winter MWh	19,566,303			
	Total Payment to Suppliers - *in $1000*				
8	Summer	$ 349,708	$ 376,167	$ 304,586	= (1) * (2)/(3) * (4) * (6)
9	Winter	$ 559,050	$ 588,193	$ 471,090	= (1) * (2)/(3) * (5) * (7)
10	Total	$ 908,758	$ 964,360	$ 775,675	Note: $ reflect total payment
	Average Payment to Suppliers - *in $/MWh*				
11	Summer	$ 84.537			= sum(line 8) / (6) - rounded to 3 decimal places
12	Winter	$ 82.710			= sum(line 9) / (7) - rounded to 3 decimal places
13	Total weighted average	**$ 83.412**	<<< used in calculation of Customer Rates		= sum(line 10) / [(6) + (7)] rounded to 3 decimal places
	Reconciliation of amounts - *in $1000*				
14	Weighted Average * Total MWh =	$ 2,648,809			= (13) * [(6)+(7)] / 1000
15	Total Payment to Suppliers =	$ 2,648,794			= sum (line 10)
16	Difference =	$ 15			= line (14) - line (15)

Calculation of June 2014 to May 2015 BGS-FP Rates

Illustrative purposes only

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

from Table #14 of the bid factor spreadsheet ---
rounded to 3 decimal places, unit obligation $ rounded to 4 decimal places

NON-DEMAND RATES

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

		RS		RHS	RLM	WH	WHS	HS	PSAL	BPL	
Summer - all hrs						**0.632**	**0.632**	**1.001**	0.565	0.570	
	PSE&G On pk				**1.926**				Use weighted average		
	PSE&G Off pk				**0.529**				for all streetlighting =		**0.568**
	All usage Multiplier	**1.169**		**0.929**							
	Constant (in $/MWh)	**$ (3.054)**	**$**	**(4.246)**	for Block 1 (0-600 kWh/m) usage						
	Constant (in $/MWh)	**$ 5.598**	**$**	**7.323**	for Block 2 (>600 kWh/m) usage						
Winter - all hrs		**1.115**		**0.884**		**0.607**	**0.607**	**0.924**	0.587	0.590	
	PSE&G On pk				**1.793**				Use weighted average		
	PSE&G Off pk				**0.554**				for all streetlighting =		**0.589**
Annual - all hrs		1.138		0.894	1.135	0.614	0.614	0.939	0.581	0.585	

DEMAND RATES

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

		GLP Multiplier	GLP Constant (in $/MWh)	LPL-S Multiplier	LPL-S Constant (in $/MWh)
Summer - all hrs		**1.078**	**(28.454)**		
	PSE&G On pk			**1.440**	**(44.936)**
	PSE&G Off pk			**0.530**	**-**
Winter - all hrs		**1.078**	**(33.082)**		
	PSE&G On pk			**1.403**	**(51.629)**
	PSE&G Off pk			**0.555**	**-**
Annual - including T&G Obl $		1.078		0.985	

PLUS:	**GLP**	**LPL-S**	
Gen Cost			
summer	$ 5.2076	$ 5.2076	per kW of G obl /month
winter	$ 5.2076	$ 5.2076	per kW of G obl /month
Trans cost			
all months	$ 3.4889	$ 3.4889	per kW of T obl /month

Calculation of June 2014 to May 2015 BGS-FP Rates
Illustrative purposes only

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

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

		RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Summer - all hrs					***5.2716***	***5.2716***	***8.3495***	***4.7378***	***4.7378***
	PSE&G On pk			***16.0652***					
	PSE&G Off pk			***4.4125***					
for Block 1 (0-600 kWh/m) usage		***9.4455***	***7.3244***						
for Block 2 (>600 kWh/m) usage		***10.3107***	***8.4813***						
Winter - all hrs		***9.3004***	***7.3736***		***5.0631***	***5.0631***	***7.7073***	***4.9130***	***4.9130***
	PSE&G On pk			***14.9558***					
	PSE&G Off pk			***4.6210***					

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

		GLP	LPL-S
Summer - all hrs		***6.1464***	
	PSE&G On pk		***7.5177***
	PSE&G Off pk		***4.4208***
Winter - all hrs		***5.6836***	
	PSE&G On pk		***6.5398***
	PSE&G Off pk		***4.6294***

PLUS:	GLP	LPL-S	
Gen Cost			
summer	**$ 5.2076**	**$ 5.2076**	per kW of G obl /month
winter	**$ 5.2076**	**$ 5.2076**	per kW of G obl /month
Trans cost			
all months	**$ 3.4889**	**$ 3.4889**	per kW of T obl /month

Calculation of June 2014 to May 2015 BGS-FP Rates

Illustrative purposes only

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

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Total Preliminary Rate Revenue - in $1000								
Summer	$ 525,905	$ 2,990	$ 10,630	$ 28	$ 1	$ 367	$ 2,122	$ 3,300
Winter	$ 709,532	$ 10,289	$ 13,466	$ 72	$ 1	$ 1,432	$ 5,829	$ 9,626
Total	$ 1,235,437	$ 13,280	$ 24,096	$ 100	$ 2	$ 1,799	$ 7,951	$ 12,925

	GLP Energy $	GLP Obligation $	LPL-S Energy $	LPL-S Obligation $
Summer	$ 181,089	$ 83,833	$ 166,152	$ 63,663
Winter	$ 288,056	$ 167,666	$ 275,449	$ 127,327
Total	$ 469,145	$ 251,499	$ 441,600	$ 190,990

	Energy $	Obligation $	Total $
Total Summer	$ 892,583	$ 147,496	$ 1,040,079
Total Winter	$ 1,313,753	$ 294,993	$ 1,608,745
Grand Total	$ 2,206,335	$ 442,489	$ 2,648,825

Total Supplier Payment - in $1000	
Summer	$ 1,030,461
Winter	$ 1,618,333
Total	$ 2,648,794
Differences - in $1000	
Summer	$ (9,618)
Winter	$ 9,588
Total	$ (31)

kWh Rate Adjustment Factors	*rounded to 5 decimal places*
0.98922	
1.00730	

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)

Calculation of June 2014 to May 2015 BGS-FP Rates

Illustrative purposes only

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

NON-DEMAND RATES --

includes energy, G&T obligations, and Ancillary Services - adjusted to billing time periods & adjustment to energy price

		RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Summer - all hrs					***5.2148***	***5.2148***	***8.2595***	***4.6867***	***4.6867***
	PSE&G On pk			***15.8920***					
	PSE&G Off pk			***4.3649***					
for Block 1 (0-600 kWh/m) usage		***9.3437***	***7.2454***						
for Block 2 (>600 kWh/m) usage		***10.1996***	***8.3899***						
Winter - all hrs		***9.3683***	***7.4274***		***5.1001***	***5.1001***	***7.7636***	***4.9489***	***4.9489***
	PSE&G On pk			***15.0650***					
	PSE&G Off pk			***4.6547***					

DEMAND RATES --

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

		GLP	LPL-S
Summer - all hrs		***6.0801***	
	PSE&G On pk		***7.4367***
	PSE&G Off pk		***4.3731***
Winter - all hrs		***5.7251***	
	PSE&G On pk		***6.5875***
	PSE&G Off pk		***4.6632***

PLUS:	GLP	LPL-S
Gen Cost		
summer	**$5.2076**	**$5.2076**
winter	**$5.2076**	**$5.2076**
Trans cost		
all months	**$3.4889**	**$3.4889**

Calculation of June 2014 to May 2015 BGS-FP Rates

Illustrative purposes only

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

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL	GLP	LPL-S
Total Rate Revenue - in $1000										
Summer	$ 520,237	$ 2,958	$ 10,515	$ 27	$ 1	$ 364	$ 2,099	$ 3,264	$ 262,968	$ 228,024
Winter	$ 714,712	$ 10,365	$ 13,564	$ 73	$ 1	$ 1,442	$ 5,872	$ 9,696	$ 457,826	$ 404,785
Total	$ 1,234,949	$ 13,323	$ 24,080	$ 100	$ 2	$ 1,806	$ 7,971	$ 12,960	$ 720,794	$ 632,809

Total Summer	$ 1,030,458
Total Winter	$ 1,618,336
Grand Total	$ 2,648,794

Total Supplier Payment - in $1000	
Summer	$ 1,030,461
Winter	$ 1,618,333
Total	$ 2,648,794

Differences - in $1000		% difference
Summer	$ (3)	-0.0003%
Winter	$ 3	0.0002%
Total	$ (0)	0.0000%